National Energy Board

Office national de l'énergie

Canadian Energy Overview 2008

AN ENERGY MARKET ASSESSMENT MAY 2009

Canada

National Energy Board

Office national de l'énergie

Canadian Energy Overview 2008

AN ENERGY MARKET ASSESSMENT MAY 2009

Canada

Permission to Reproduce

Materials may be reproduced for personal, educational and/or non-profit activities, in part or in whole and by any means, without charge or further permission from the National Energy Board, provided that due diligence is exercised in ensuring the accuracy of the information reproduced; that the National Energy Board is identified as the source institution; and that the reproduction is not represented as an official version of the information reproduced, nor as having been made in affiliation with, or with the endorsement of the National Energy Board.

For permission to reproduce the information in this publication for commercial redistribution, please e-mail: info@neb-one.gc.ca

Autorisation de reproduction

Le contenu de cette publication peut être reproduit à des fins personnelles, éducatives et(ou) sans but lucratif, en tout ou en partie et par quelque moyen que ce soit, sans frais et sans autre permission de l'Office national de l'énergie, pourvu qu'une diligence raisonnable soit exercée afin d'assurer l'exactitude de l'information reproduite, que l'Office national de l'énergie soit mentionné comme organisme source et que la reproduction ne soit présentée ni comme une version officielle ni comme une copie ayant été faite en collaboration avec l'Office national de l'énergie ou avec son consentement.

Pour obtenir l'autorisation de reproduire l'information contenue dans cette publication à des fins commerciales, faire parvenir un courriel à : info@neb-one.gc.ca

Cat. No. NE2-4/2008E
ISBN 978-1-100-12621-0

This report is published separately in both official languages. This publication is available upon request in multiple formats.

Copies are available on request from:
The Publications Office
National Energy Board
444 Seventh Avenue S.W.
Calgary, Alberta, T2P 0X8
E-mail: publications@neb-one.gc.ca
Fax: 403-292-5576
Phone: 403-299-3562
1-800-899-1265
Internet: www.neb-one.gc.ca

For pick up at the NEB office:
Library
Ground Floor

Printed in Canada

Nº de cat. NE2-4/2008F
ISBN 978-1-100-91554-8

Ce rapport est publié séparément dans les deux langues officielles. On peut obtenir cette publication sur supports multiples, sur demande.

Demandes d'exemplaires :
Bureau des publications
Office national de l'énergie
444, Septième Avenue S.-O.
Calgary (Alberta) T2P 0X8
Courriel : publications@neb-one.gc.ca
Télécopieur : 403-292-5576
Téléphone : 403-299-3562
1-800-899-1265
Internet : www.neb-one.gc.ca

Des exemplaires sont également disponibles à la bibliothèque de l'Office :
Rez-de-chaussée

Imprimé au Canada

FIGURES

TABLES

BPS	Bulk Power System
CanWEA	Canadian Wind Energy Association
CBM	coalbed methane
CCS	carbon capture and storage
CH_4	methane
CMHC	Canada Mortgage and Housing Corporation
CO_2	carbon dioxide
ECAM	Energy Cost Adjustment Mechanism
EIA	Energy Information Administration
EMA	Energy Market Assessment
ERCB	Alberta Energy Resource Conservation Board
GDP	gross domestic product
GHG	greenhouse gas
H_2O	water vapor
HDD	heating degree days
HFC	hydrofluorocarbons
IEA	International Energy Agency
IPL	international power line
LMCI	Land Matters Consultation Initiative
LNG	liquefied natural gas
N_2O	nitrous oxide
NAFTA	North American Free Trade Agreement
NEB or Board	National Energy Board
NERC	North American Reliability Corporation
NGLs	natural gas liquids
NRCan	Natural Resources Canada
NRF	New Royalty Framework
NSB	North Sea Brent
O_3	ozone
OECD	Organization for Economic Co-operation and Development
OPEC	Organization for Petroleum Exporting Countries
PADD	Petroleum Administration for Defense District
PFC	perfluorocarbons
RPP	Regulated Price Plan
RRO	Regulated Rate Option
SAGD	Steam Assisted Gravity Drainage
SF_6	sulphur hexafluoride
THAI™	toe-to-heel air injection
U.S.	United States
WCI	Western Climate Initiative
WCSB	Western Canada Sedimentary Basin
WTI	West Texas Intermediate

L I S T O F U N I T S

$10^6m^3/d$	million cubic metres per day
b/d	Barrels per day
bbl	barrel
Bcf/d	Billion cubic feet per day
BTU	British thermal unit
BTU/ft^2	British thermal unit per square feet
Cdn$ or $	Canadian dollars
GJ	gigajoule
GW.h	Gigawatt hour
ha	hectare
kW.h	Kilowatt hours
m^3	cubic metres
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
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 promote safety and security, environmental protection and efficient energy infrastructure and markets in the Canadian public interest within the mandate set by Parliament in the regulation of pipelines, energy development and trade. The Board's main responsibilities include regulating the construction and operation of interprovincial and international oil and gas pipelines as well as international and designated interprovincial power lines. The Board regulates pipeline tolls and tariffs for pipelines under its jurisdiction. The Board regulates the exports and imports of natural gas as well as exports of oil, natural gas liquids (NGLs) and electricity. The Board also regulates oil and gas exploration, development and production in frontier lands and offshore areas not covered by provincial or federal management agreements. The Board's advisory function requires it to keep under review matters over which Parliament has jurisdiction relating to all aspects of energy supply, transmission and 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 (EMA), entitled *Canadian Energy Overview*. This year's report, *Canadian Energy Overview 2008* is a summary of major developments related to energy in Canada in 2008.

EXECUTIVE SUMMARY

The year 2008 was exceptional in global energy markets. Rising energy prices, growing concerns and increasing political momentum about climate change, and heightened public interest in energy and environmental issues characterized the first half of the year. Decreased demand and significantly reduced prices, the financial and credit crisis, and a realization that the industrialized economies were plunging into a recession shifted public focus to economic concerns in the second half. Canada and the world saw highly volatile crude oil and natural gas prices, which created uncertainty and made it difficult for industry, consumers and government to prioritize investments. Superimposed over the price volatility was a weakened global banking sector that resulted in a credit environment in which access to necessary capital for spending was extremely difficult.

Canada has a responsibility to promote and encourage sustainable energy development and practices that benefit all Canadians. Energy, the environment, and the economy are becoming increasingly interconnected. Numerous federal and provincial policies aimed at sustainable development and reducing the consumption of energy were advanced in early 2008. The federal government released more details on its *Regulatory Framework for Greenhouse Gas Emissions* and provincial governments introduced legislation setting firm targets for the reduction of greenhouse gases (GHGs). The focus both federally and provincially reflects a North American push to reduce fuel consumption.

Energy remained a vital component of our national economy accounting for seven per cent of gross domestic product (GDP) in 2008. With record-high energy prices, our net export revenues represented a record 28 per cent of our merchandise trade and, although the outlook for prices appears to be lower in the near term, the energy industry will continue to be a significant driver for the Canadian economy now and into the future.

With rising prices in the first half of 2008, many energy projects became economical, despite the high production and operating costs. New projects, particularly large oil sands projects, can take years to develop and offset the natural decline of existing conventional fields. Canadian overall production of crude oil in 2008 was down slightly from 2007. Increases in oil sands production were offset because of planned and unplanned maintenance. Although exports of crude oil remained at levels seen in 2007, export revenues were much higher because of higher prices. The latter half of 2008 saw a pull back in capital spending with many projects aimed at increasing production and refining capacity either postponed or cancelled. Many agencies have reduced their supply forecasts for Canadian crude oil over the next few years given the state of the global economy.

Similar to oil, natural gas production was down. Exports declined while net export revenues were up substantially because of higher prices. The emergence of shale gas plays in the U.S. caused a supply glut which, when added to an economic slowdown and reduced demand, contributed to lower prices in the latter half of 2008. Drilling in Canada has dropped and unconventional resource plays have not yet reached their potential. The general outlook for prices remains uncertain given the shale gas supply as well as increased potential supply of liquefied natural gas (LNG) for the North American market.

Electricity industry activity during 2008 included new infrastructure additions and efforts to maintain adequate supply and reliable operation. This includes development of renewables, other supply initiatives, and emphasis on conservation and efficiency improvements. Installed capacity increased, although Canadian electricity generation decreased slightly from 2007. Over the past few years, electricity demand growth in Canada had shown some signs of moderating. Preliminary results for 2008 show annual demand declined by 1.3 per cent. This decline is slight and might be explained by slowing economic activity, energy conservation and improved efficiency. However, electricity prices increased in some Canadian jurisdictions because of the cumulative effects of higher fuel costs in recent years and higher costs for new generation and transmission. Net exports increased by four per cent, nearly double the previous five-year average. Although exports may moderate in the future in reaction to the economic slowdown, electricity exports are expected to continue to be a significant source of revenue, and imports will provide reliability for those provinces interconnected with adjacent U.S. regions.

2008 was a year of extremes. As we enter 2009, there is a sense of uncertainty with respect to the global economic picture. What remains certain, however, is that Canada has numerous opportunities with respect to technology, sustainability and environmental protection.

Energy and the Canadian Economy

2008 was a year of global economic volatility, and the Canadian economy was no exception. Canadians witnessed a unique year, one in which economic growth characterized the first half of the year and a building financial crisis dominated the latter half. Energy prices quickly rose in early 2008, reaching a peak in the summer, only to plummet later in the year. The economic slowdown which was first seen in the U.S. was soon felt in our own economy, and Canadians ended 2008 wondering how long and how deep a recession could last.

In 2008, oil hit a record high of US$147 per barrel in July, only to hit a low of US$30 in December before ending the year at US$45. Early-2008 energy prices increased energy export revenue to a record $133 billion, the highest amount ever recorded, accounting for 28 per cent of the value of all exports. Just a year earlier, energy export revenues amounted to only $93 billion (21 per cent of all exports).

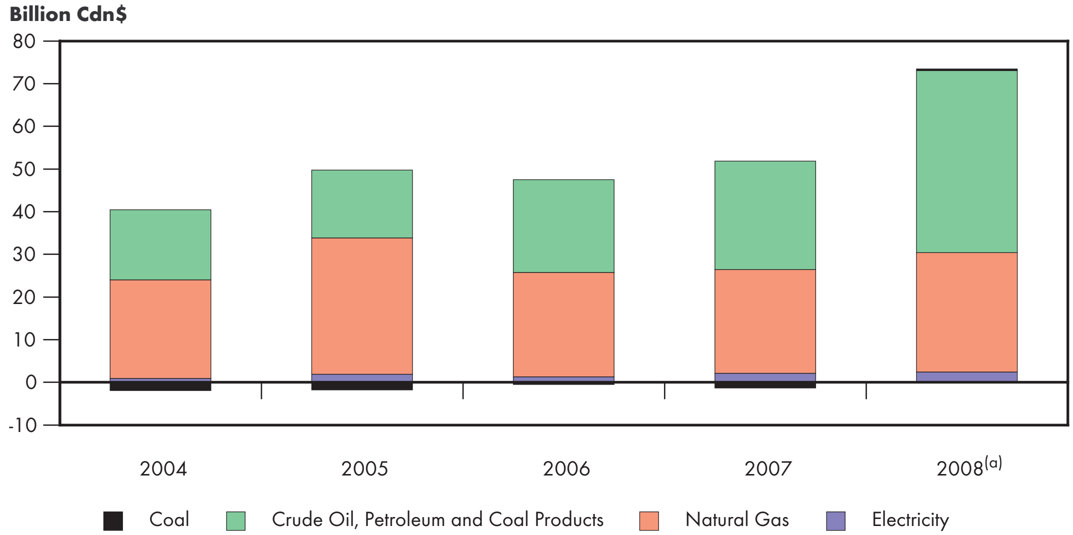
The energy industry continued to contribute significantly to the Canadian economy in 2008, despite the economic challenges presented late in the year. The Canadian energy industry accounted for seven per cent of Canada's GDP in 2008, and directly employed 363,000 people (two per cent of the Canadian labour force). The increase in oil price in early 2008 also influenced net energy export revenue (the value of energy exports minus the value of energy imports). 2008 net export revenues reached $73 billion, an increase of almost 45 per cent over 2007 levels. Historically, net natural gas export revenue has been larger than crude oil and products net export revenues; however, in 2007 net crude oil and products exports exceeded net natural gas export revenue by more than $1 billion. This trend continued into 2008, as the value of crude oil net exports surpassed the value of natural gas by almost $15 billion.

Along with oil and natural gas, net electricity export revenue also exceeded 2007 levels as a result of favourable water conditions in the main hydro-generating provinces and export growth in Ontario. Lastly, 2008 saw Canada become a net exporter of coal for the first time, creating a revenue of $360 million.

A decline in both natural gas and petroleum production contributed to a 2.1 per cent drop in total Canadian energy production. As conventional fields in western Canada were depleted, new wells coming on-stream could not keep pace. Conversely, hydroelectricity production increased 10 per cent over the past five years and other energy sources (mainly wood) actually declined slightly. Notably, the investment in wind projects has increased the energy produced from wind by almost 265 per cent from 2004 to 2008. Wind energy represents about 0.1 per cent of the energy produced in Canada. Finally, the uncertainty about energy prices has caused some pull back in investments by oil and gas producers. Detailed Canadian production trends are provided in Table 2.1.

FIGURE 2.1

Net Energy Export Revenues, 2004 – 2008



(a) Estimate

Source: Statistics Canada, NEB

TABLE 2.1

Domestic Energy Production by Energy Source (petajoules)

	2004	2005	2006	2007	2008[a]
Petroleum[b]	6 680	6 612	6 908	7 126	6 996
Natural gas[c]	6 555	6 559	6 589	6 481	6 240
Hydroelectricity	1 212	1 290	1 258	1 317	1 330
Nuclear	1 084	1 104	1 184	1 084	1 089
Coal	1 416	1 401	1 419	1 482	1 461
Wind	3	6	9	11	13
Other[d]	681	612	527	636	628
Total	**17 631**	**17 584**	**17 895**	**18 137**	**17 757**
Annual % Change	**3.9%**	**-0.3%**	**1.8%**	**1.4%**	**-2.1%**

(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

Source: Statistics Canada, NEB

According to the International Energy Agency (IEA)[1], the United States and Canada are the largest consumers of energy on a per person basis in the world, consuming almost 200 GJ[2] per capita – the equivalent of each Canadian and U.S. resident using more then 5 000 litres (or 32 barrels) of crude oil per year. This is approximately twice the per capita energy consumption seen in other Organization

1 International Energy Agency, *Worldwide Trends in Energy Use and Efficiency*, 2008.

2 The per capita energy consumption differs among sources and heavily depends on the assumptions that go into calculating this number.

for Economic Co-operation and Development (OECD) countries. In non-OECD countries, energy consumption per capita, on average, is only 23 per cent of that in OECD countries.

How are Energy and the Environment Connected?

Energy and environment are important issues for Canadians. A number of terms are commonly used to explain the interrelationship:

Energy Intensity: Energy Intensity is a measure of energy efficiency. It is defined as the amount of energy used to produce one unit of output or some other goal. It can be measured per unit of GDP, per person, per physical units of output, or other measures. Whichever way you measure it, lower energy intensity means less energy required to achieve the same goal, thus implying the use of more efficient technologies, devices and practices. For example:

- a more efficient space heater will use less natural gas to heat the same size house (Joules per square metre [BTU/ft^2]);
- a more efficient vehicle will use less gasoline to drive the same distance (litres/100 kilometres); and
- a more efficient paper mill will use less energy to produce the same amount of paper.

GHG Emission Intensity of Demand: GHG emission intensity measures the amount of greenhouse gases emitted into the atmosphere per unit of energy consumed (PJ). This is also known as an emission coefficient. As GHG emission intensity of demand declines, fewer GHGs are emitted for the same amount of energy used, implying the use of cleaner technologies, devices and fuels. For example: using a less emission-intensive fuel (like natural gas instead of coal) for an industrial process will result in fewer GHGs for the same amount of energy used.

GHG Emission Intensity of Output: When we measure the GHG emission intensity in terms of output, we look at emissions per 1 unit of output or some other goal. Thus, as GHG emission intensity of output declines, it means that the same goal or output can be achieved with less GHG emissions, implying reduced energy intensity and/or the use of less emission-intensive fuels. For example:

- a hybrid vehicle will create less GHG emissions while driving the same distance compared to a regular gasoline vehicle; and
- electricity generated from wind emits less GHGs into the air than electricity from fossil fuels, such as natural gas or coal, for the same amount electricity produced.

Canadian energy demand trends are driven by changes in population, economic conditions, energy prices, weather, conservation, technology and consumer preferences. Over the past five years, total Canadian energy consumption has remained relatively stable, with transportation seeing the largest gains resulting in a 5.7 per cent increase in the amount of energy used between 2004 and 2008. Since the population has grown over this time there has been a modest 1.4 per cent decline in the per capita use of energy. Initial estimates suggest no overall growth of energy demand from 2007 to 2008. Demand in the residential, commercial and transportation sectors increased slightly, but was offset by the decline in the industrial sector.

Secondary energy demand, (also known as end use demand), is the energy used by the final consumer in Canada and is considered in terms of residential, commercial, industrial and transportation use. Initial 2008 estimates suggest no overall secondary energy demand growth. The industrial sector saw a decline of 1.5 per cent. Overall, 2008 total secondary energy demand is estimated to be 10 679 PJ, which is 0.2 per cent below 2007 levels (Table 2.2).

Transportation energy costs increased in 2008. For example, regular gasoline pump prices and diesel prices increased on average almost 12 per cent and 26 per cent, respectively. Canadians saw the highest gasoline and diesel prices in July. By October, total motor gasoline sales were down slightly by 0.4 per cent year over year, while diesel sales were still up by 1.2 per cent.

TABLE 2.2

Domestic Secondary Energy Consumption (petajoules)

	2004	2005	2006	2007	2008[a]
Residential[b]	1 421	1 403	1 347	1 448	1 466
Commercial	1 468	1 493	1 425	1 471	1 499
Industrial[b][c]	5 015	4 857	4 967	5 166	5 090
Transportation	2 483	2 519	2 514	2 616	2 624
Total	**10 387**	**10 272**	**10 253**	**10 701**	**10 679**
Annual % Change	**1.3%**	**-1.1%**	**-0.2%**	**4.4%**	**-0.2%**

(a) Estimates

(b) Includes biomass (wood and pulping liquor)

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

Source: Statistics Canada, NEB

Advancing Clean Energy

Policies addressing climate change and air pollution continue to advance in Canada. The share of "clean" energy within the total energy mix has grown faster than the fossil fuel energy share. This trend is expected to continue. Clean or green energy is loosely defined as energy sources having minimal environmental impact, or technology that reduces the majority of harmful side effects associated with energy use. Since all energy development and use has some environmental impact, the list of what is truly clean energy is open to debate. Green energy is most often associated with renewable energy, specifically wind, solar, bio energy (i.e. ethanol, biomass) and hydro power. In addition, as nuclear power does not directly emit greenhouse gases, it is often grouped in the list of clean energy sources. Having access to all these resources places Canada in a unique position in terms of energy opportunity.

New developments in distributed generation, transmission, monitoring and controls, energy storage, and even changes to legislation for allowing electricity grid access are all components of an evolving clean and green energy future. Clean technology goes beyond power generation technology. Priorities in Canada for advancing clean energy include research and development funding for carbon capture and storage (CCS) technology. These improvements have the potential for large benefits to consumers and the environment.

Even with high fuel prices and economic challenges, transportation energy consumption increased in 2008, although by less than one per cent. When compared with previous consumption, where just a year ago Canadians increased their transportation energy consumption by four per cent (2006 to 2007), a slowing in energy consumption growth is evident. The slight increase between 2007 and 2008 is attributable to population and commercial sector growth, which helped push passenger and freight transportation demand up slightly this year.

The volatile economy that characterized 2008 is reflected in Canada's GDP, a lead indicator of our economic health. Not surprisingly, Canadian GDP was stronger in the first half of 2008. Until July, GDP was on average 1.3 per cent higher than in the corresponding months of the previous year. Combined with population growth, which Statistics Canada reports to have increased by 1.2 per cent, Canada saw a 2.5 per cent GDP increase in the service industry. In the goods-producing industry, economic growth declined, with GDP decreasing by 2.7 per cent. This decline was brought about by higher energy and material prices in the first half of the year, followed by the economic slowdown seen later in 2008. By November, GDP was one per cent lower than a year earlier, signaling the arrival of a recession[3].

3 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.

On average, 2008 GDP was about 0.6 per cent higher than in 2007. To put this in perspective, the last time Canada experienced negative year-to-year growth was back in 1991 and since then (1992–2007) GDP grew by an average of three per cent per year.

Extreme volatility in energy prices as experienced in 2008 creates market distortions and results in undesirable effects on both consumers and producers. On one hand, lower prices remove the incentives for consumers to shift toward conservation. They also reverse the momentum for higher investment in energy supply and create business uncertainty. On the other hand, sharply rising prices create economic costs to consumers and the economy.

Environmental Initiatives

The year began with the advancement of several provincial and federal policies that would impact energy demand. These included expansion of clean energy and renewable energy strategies; application of new codes and standards as they relate to buildings, equipment, and appliances; and new transportation initiatives (particularly biofuel production targets and public transportation initiatives). Early 2008 also saw momentum on climate change initiatives. In March, the federal government released further details on targets and compliance mechanisms for the *Regulatory Framework for Greenhouse Gas Emissions* as it relates to large final emitters, that is, the industrial and power generation sectors. The extent and schedule of climate change measures varies greatly by province. One of the main characteristics seen in 2008 was a continuing trend in convergence of energy efficiency and conservation along with renewable energy policies.

On 23 September 2008, partners of the Western Climate Initiative (WCI) released a proposed design for a comprehensive regional cap-and-trade program to reduce the GHGs that contribute to global warming. The proposed design contains a number of recommendations, including which GHG sources should be included in a regional cap-and-trade system, implementation time frames, emission reporting requirements, carbon offsets, compliance and enforcement and other program features. The WCI cap-and-trade program covers the largest sources of emissions from each participating U.S. state and Canadian province, including power generation, industry, transportation, and residential and commercial fuel use. Along with a number of western states, British Columbia, Manitoba, Ontario and Quebec are partners in the initiative. The WCI is now the largest climate collaborative in North America, representing approximately 20 per cent of the U.S. economy, 73 per cent of Canada's economy, and 50 per cent of all GHG emissions in Canada.

In 2008, provincial legislation on climate change was introduced so that all provinces now have, at least at some level, climate change initiatives in place. Notably, both British Columbia and Manitoba legislation now include across-the-board climate change targets, aiming for GHG reductions in British Columbia of 33 per cent by 2020 (from 2007 levels), and a six per cent reduction as soon as 2012 (from 1990 levels) in Manitoba. As part of its *Energy Plan*, British Columbia also implemented a carbon-based price premium on gasoline, diesel and home heating fuels. Quebec's 2007 *Climate Change Action Plan*, had also levied a tax on fossil fuels.

The *Alberta Climate Change and Emissions Management Amendment Act* for industrial and power generation sectors, which sets a 12 per cent annual intensity reduction target, was introduced in 2008. There were further expansions of demand-side management programs in Quebec, Ontario, Saskatchewan and the Atlantic provinces.

In July, the Alberta government also announced its commitment to provide $2 billion in funding for the development of CCS technology. CCS provides an opportunity for Alberta to reduce GHG emissions while ensuring continued Albertan and Canadian economic success and growth. CCS is

Greenhouse Gas Reduction Targets

Climate change and GHGs emissions have been increasingly important issues in Canada. The Canadian and provincial governments have implemented several initiatives to address these issues. Programs under the climate change agenda include increasing energy efficiency and conservation, and promoting the use of renewable fuels. Currently, there are GHG reduction targets set in every province as well as at the federal level. There are no targets in the Territories.

Federal and Provincial Greenhouse Gas Reduction Targets

Jurisdiction	Initiative Title	Target
Federal	Turning the Corner	Reduce GHGs by 20% from 2006 levels by 2020
Alberta	Climate Change Strategy 2008	Reduce GHGs by 14% from 2005 levels by 2050
British Columbia	*Greenhouse Gas Reduction Targets Act*	Reduce GHGs by 33% from 2007 levels by 2020
Manitoba	*The Climate Change and Emissions Reduction Act*	Reduce GHGs by 6% from 1990 levels by 2012
New Brunswick	Climate Change Action Plan, 2007 – 2012	Reduce GHGs by 10% from 1990 levels by 2020
Newfoundland	New England Governors/ Eastern Canadian Premiers Climate Change Action Plan 2001	Reduce GHGs by 10% from 1990 levels by 2020
Nova Scotia	*Environmental Goals and Sustainable Prosperity Act*	Reduce GHGs by 10% from 1990 levels by 2020
Ontario	Go Green: Ontario's Action Plan on Climate Change	Reduce GHGs by 15% from 1990 levels by 2020
Prince Edward Island	New England Governors/ Eastern Canadian Premiers Climate Change Action Plan 2001	Reduce GHGs to 1990 levels by 2010, and 10% below 1990 levels by 2020
Quebec	Quebec and Climate Change: A Challenge for the Future	Reduce GHGs by 6% from 1990 levels by 2012
Saskatchewan	Saskatchewan Energy and Climate Change Plan 2007	Stabilize GHG emissions by 2010, reduce GHGs by 32% from current levels by 2020 and 80% from current levels by 2050

a scientifically-proven technology that will reduce carbon dioxide (CO_2) emissions from large scale operations including oil sands facilities, and coal-fired electricity generation. The initial goal is to store five Mt of CO_2 in the ground annually by 2015[4].

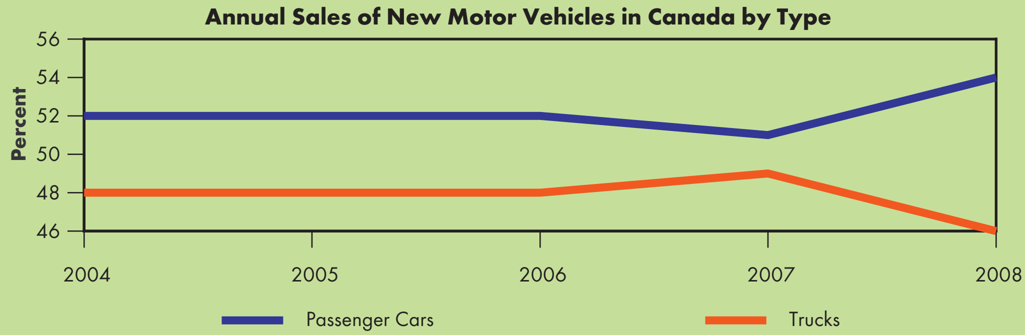
4 Earth's most abundant GHGs are:

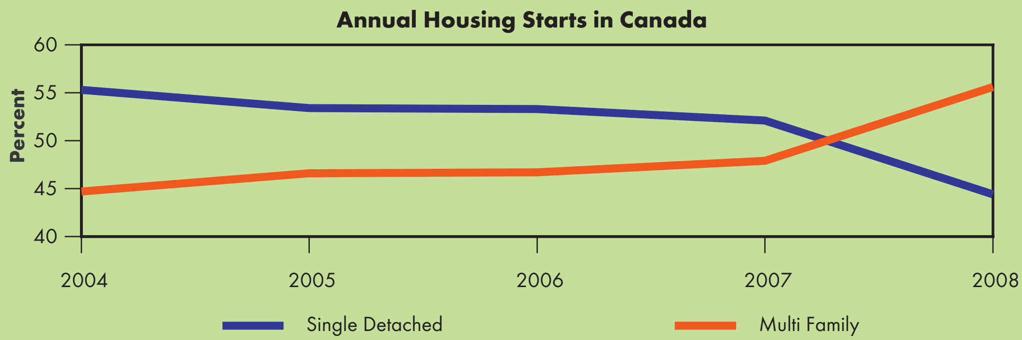
- water vapor (H_2O), which contributes 36-72 per cent of the Earth's greenhouse effect;
- CO_2, which contributes 9-26 per cent of the Earth's greenhouse effect;
- methane (CH_4), which contributes 4-9 per cent of the Earth's greenhouse effect; and
- ozone (O_3), which contributes 3-7 per cent of the Earth's greenhouse effect.

Other GHGs present at low concentrations include nitrous oxide (N_2O), sulphur hexafluoride (SF_6), perfluorocarbons (PFCs), and hydrofluorocarbons (HFCs). All of these gases, with the general exception of the last three, can be of natural or industrial origin.

Consumer Behavioural Trends

There are several trends affecting consumer behaviour, including energy prices, disposable income and the health of the economy. Consumers are also becoming more aware of how their choices are affecting the environment. The changing trends in consumer behaviour impact energy consumption.





2.1 Looking Ahead

In Canada, energy consumption growth is expected to continue to slow in response to sluggish economic conditions. Global economic conditions, energy price concerns, potential supply constraints and heightened environmental awareness could influence consumer spending habits and therefore energy demand trends. New government programs and policies are also expected to impact energy demand trends over the next few years. While governments continue to make strides with legislation and consumer awareness initiatives, reductions in Canadian energy consumption rely on behavioural shifts at the individual level. Transformational changes in lifestyles will slowly bring about change and result in stabilized, if not reduced, energy consumption.

Already there are signs that changes in consumer preferences are starting to occur. Canadians increasingly take into consideration environmental costs associated with their purchasing decisions. For example, recent years have seen a significant shift in new vehicle purchasing trends with Canadians' more likely to opt for smaller economy vehicles over larger trucks and sport utility vehicles (in 2008, 54 per cent of all new vehicle sales were passenger cars and 46 per cent were trucks and sport utility vehicles, a change from 51 per cent and 49 per cent respectively in 2007). If this is a stable shift in consumer preferences, then we would expect to see the emergence of a more fuel efficient vehicle fleet, which would have implications for future energy consumption. Canadians housing choices are also affecting demand. According to the Canadian Mortgage and Housing Corporation (CMHC), in 2008 the share of multi-family dwelling construction exceeded single-family housing starts at 56 per cent of all housing starts that year (up from 48 per cent in 2007). CMHC expects this trend to continue into 2009 and such trends should decrease the energy intensity of the residential sector. Over time, these changes will directly impact energy demand in the residential and passenger transportation sectors and as a result GHG emissions will also be impacted.

Upstream Oil and Gas Activity

Measures of upstream oil and gas activity include dollars spent to acquire land rights, the number of active seismic crews, the number of active drilling rigs, number of wells drilled and the capital expenditures involved.

Cost pressures associated with strong economic growth continued from 2007. In mature basins like the Western Canada Sedimentary Basin (WCSB), the cost to produce natural gas was further increased in 2008 as new wells, on average, produced at lower rates and recovered less energy. These cost pressures, however, were offset by surging commodity prices for both oil and gas through the first seven months of the year, with oil reaching a record US$147/bbl and natural gas peaking at over US$13/MMbtu in July before prices reversed course and dropped dramatically by year-end. By the close of 2008, oil slid to US$40/bbl and gas prices landed at US$6/MMbtu.

Petroleum Rights in Canada

Rights to oil and gas resources are owned or shared by provincial, territorial, federal, or First Nation governments. Crown rights are administered and dispensed by regulatory bodies, usually at auctions, to ensure competition for extraction of oil and gas and that Canadian citizens receive fair value. In the western provinces and for Crown lands in Ontario, Crown rights are leased to operators who pay the highest bonus and the revenues generated by the auction go directly into provincial coffers. In the territories of northern Canada and in Maritime provinces, including offshore areas, regulatory bodies use auctions to solicit commitments for industry spending and do not directly generate significant revenue for respective governments. In Quebec, land is licensed by application, except for offshore areas, where there is a call for bids.

Finally, any oil or gas produced under a Crown lease usually generates royalty payments for governments, although royalty rates vary from jurisdiction to jurisdiction.

Acquisition of petroleum rights in western Canada was the main upstream oil and gas story as high oil and gas prices pushed industry to spend a total of $5 billion, nearly double the amount of land bonuses received in 2007. British Columbia led all provinces in land bonuses received with a provincial record of $2.7 billion for 757 000 hectares ($3 518/ha) compared to $1.1 billion for 596 000 hectares ($1 758/ha) in the prior year. Most activity in British Columbia was focused on the Peace River region, where $1.3 billion ($11 000/ha) was spent obtaining drilling rights to Montney Formation tight gas, and areas north of Fort Nelson, where $1.1 billion ($4 000/ha) was spent obtaining rights to Horn River Basin gas shales.

Saskatchewan also set a new record, acquiring $1.1 billion in land bonuses for 766 000 hectares ($1 461/ha), more than quadrupling the previous year's record of $250 million. The majority of activity was in southeast Saskatchewan, mostly for the Bakken oil play, where $917 million was spent for 496 000 hectares ($1 848/ha).

Alberta took in $1.2 billion in land bonuses, continuing the steady decline from $3.4 billion in 2006. Land bonuses for leases in the oil sands declined by over 50 per cent for the second straight year, to $288 million for 1.7 million hectares, averaging just $174/ha. This is down significantly from $650 million for 1.3 million hectares ($573/ha) in 2007 and $1.9 billion for 1.5 million hectares ($1 216/ha) in 2006. The decline is attributed to the most prospective areas of the oil sands already being under lease, negative industry response to the new royalty framework[5], and Alberta not having the hot non-bitumen resource plays like Saskatchewan and British Columbia.

The Northwest Territories received over $1.2 billion in exploration commitments, mainly from a single land sale in which BP Canada committed to $1.2 billion in exploratory spending for a parcel in the Beaufort Sea. However, Yukon had two land sales in 2008 and received zero bids. Offshore Nova Scotia received commitments for $353 million in exploration expenditures while the Canada-Newfoundland and Labrador Offshore Petroleum Board received commitments for almost $319 million in expenditures.

> ***Land Matters Consultation Initiative: Listening to the Public Interest***
>
> In 2008, the National Energy Board met with more than 400 Canadians, including landowners, industry representatives and government departments, as part of our Land Matters Consultation Initiative (LMCI).
>
> The LMCI provides a Canadian forum for discussing land matters to help improve understanding of the various issues and also generate new ideas to improve the way in which these issues are incorporated into the Board's public interest considerations. The initiative also provides an opportunity for companies and landowners to foster and strengthen effective working relationships.
>
> The LMCI is divided into four streams:
>
> 1. company interactions with landowners;
> 2. improving the accessibility of NEB processes;
> 3. pipeline abandonment – financial issues; and
> 4. pipeline abandonment – physical issues.
>
> Further information on the LMCI can be found on our web site at www.neb-one.gc.ca.

The average number of seismic survey crews active in Canada grew slightly from 2007, from eight to nine. Continued low seismic crew activity since 2007 indicates that 2009 will not see a resurgence in exploration activity. The oil and gas industry completed 20,721 wells across Canada in 2008, eight per cent higher than the number of wells completed in 2007[6].

The rise in commodity prices caused oil- and gas-related activity in western Canada to remain fairly strong in 2008 with drilling activity, often measured in terms of drilling days or the number of active rigs per week or month, increasing. While the capacity of the drilling rig fleet in western Canada shrank in 2008, averaging 878 rigs after peaking at 901 in 2007[7], monthly active rig utilization increased to an average 364 versus 339, as did total operating time, to almost 133,000 from 120,000 days. However, this was still significantly less than the 504 rig average and 158,000 operating days in 2006. Figure 3.1 provides the weekly active rigs in western Canada. Note that there was a rapid drop in drilling activity in December 2008 as a result of the economic downturn.

Approximately 16,300 oil and gas wells were drilled in western Canada in 2008, a ten per cent decline from 2007 (Figure 3.2) and something that appears to be at odds with the increase in rig activity and operating days described above. This discrepancy is explained by the increased use of

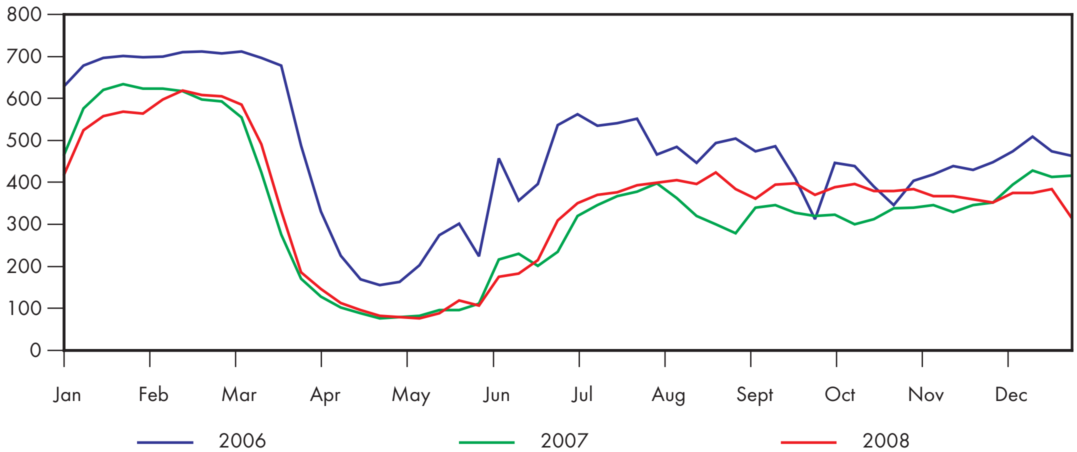
5 The New Royalty Framework (NRF), announced in October of 2007 and applicable to all conventional oil and gas wells drilled on or after 1 January 2009, increased the amount of royalty to be paid per well depending on the price of oil and gas and well production. In November 2008, in response to the global economic downturn and to encourage drilling in the province, the Alberta Government announced a five-year transitional option for oil and gas wells drilled on or after 19 November 2008, which allows a company to keep the previous royalty framework on a well-by-well basis. On 1 January 2014, all wells will automatically switch to the NRF.

6 *Nickle's Daily Oil Bulletin*, December drilling lower, completions higher, 12 January 2009.

7 Canadian Association of Oilwell Drilling Contractors, Average Monthly Drilling Rig Count – Western Canada.

FIGURE 3.1

Weekly Active Rigs in WCSB



Source: Nickle's Daily Oil Bulletin

deep horizontal wells with long lateral reaches to exploit Bakken oil in Saskatchewan and shale gas in British Columbia, which take significantly more time to drill when compared to vertical wells. Supporting this conclusion is significant growth to the average length of wells drilled in 2008 over wells drilled in 2007, increasing to 1 290 metres from 1 194 metres. This shift toward Saskatchewan Bakken oil and British Columbia shale gas was further demonstrated by a redistribution of exploration by geographic region. The number of wells drilled in Saskatchewan increased by 22 per cent, rising to 3,898 from 3,202, while the number of wells drilled in British Columbia remained relatively unchanged, rising slightly to 847 from 843, despite the significant decrease in total wells drilled across western Canada. The number of wells drilled in Alberta took the brunt of this drop, falling 17 per cent to 11,569, down from 14,001.

The number of oil wells drilled in the year increased by five per cent, with natural gas drilling down by 17 per cent. As a result of the ongoing decline in gas economics relative to oil, the percentage of wells directed to natural gas slid to 64 per cent from 69 per cent.

Total oil and gas capital expenditures in Canada rose by two per cent to an estimated $43.9 billion. Capital spending associated with oil sands projects rose to an estimated $17.3 billion, eight per cent more than 2007 levels. This increase was driven in part by cost overruns rather than new projects. Conventional oil and gas expenditures fell to an estimated $26.6 billion, two per cent less than 2007 and the third straight year of decline.

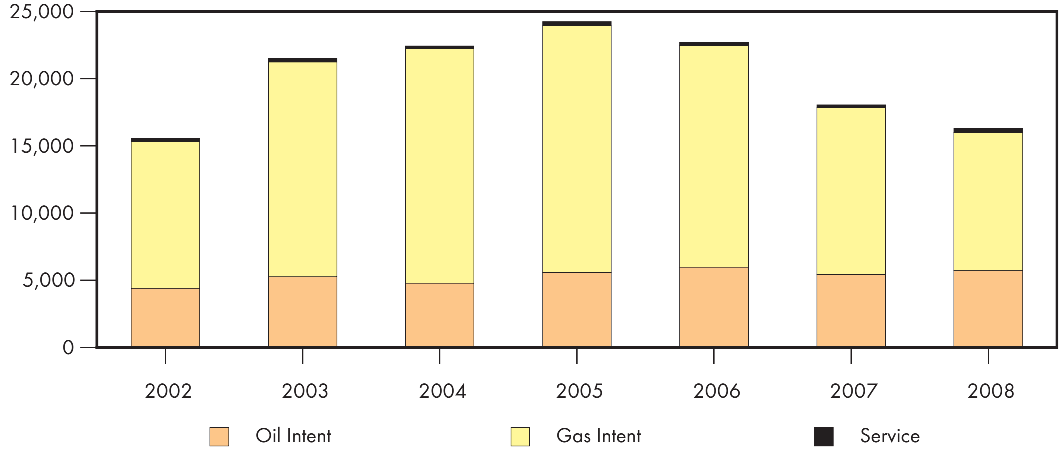
Technological Achievements in Drilling and Production

The application of hydraulic fracturing, a technique where induced high pressures are used to crack the reservoir and create a network of fractures through which oil or gas can flow more readily, has been in practice for decades. Horizontal drilling, another technique to improve recovery, has been in common usage since the mid 1990s. However, using them both together had been problematic until the last few years. Previously, the fracturing could not be easily controlled and long segments of the horizontal well would remain untouched. Now, operators can isolate segments of the horizontal well and fracture each segment sequentially in a technique called-multi stage fracturing, turning long stretches of what was tight oil bearing or gas bearing rock into a prolific reservoir.

These combined techniques are being successfully used to produce natural gas from gas shales as well as from tight sandstones of Alberta and northeast British Columbia. These techniques have also led to the successful recovery of oil from the Bakken oil play in southeastern Saskatchewan.

FIGURE 3.2

Number of Wells Drilled – Western Canada, 2002 – 2008



Source: NEB

3.1 Looking Ahead

Low commodity prices, cost overruns and a lack of skilled labour have already resulted in numerous oil sands projects being cancelled or deferred as producers adjusted their operating budgets for 2009. Statistics Canada expects that 2009 oil and gas capital expenditures will fall 21 per cent from 2008 levels[8], the largest drop being in the oil sands sector, which they project will decrease 31 per cent.

It is expected that the average number of active rigs in western Canada will drop substantially in 2009 from 2008 levels. The first twelve weeks of 2009 have already seen the average number of active rigs in western Canada down 33 per cent from the first twelve weeks of 2008[9]. This represents a 33 per cent reduction from 2007 levels and a 45 per cent reduction from 2006. The Petroleum Services Association of Canada has projected that 2009 will see a 21 per cent overall drop from 2008 levels in the number of wells drilled and is warning about substantial layoffs in the oil and gas services sector.

Furthermore, it is unlikely there will be high levels of land activity in 2009 with most of the petroleum rights for core areas of the gas shales of British Columbia, the oil sands of Alberta, and the Bakken oil play in southeast Saskatchewan already leased from past sales. Low commodity prices, forecasted to persist through the year, will also impact industry spending on future lease acquisitions.

With significantly reduced natural gas drilling in 2009, Canadian natural gas production is expected to be lower than in 2008, even with increased drilling in such high-productivity natural gas plays like the Horn River Basin and Montney gas shales. While oil sands production is forecasted to increase, conventional light and heavy crude oil production will continue their natural annual decline of roughly three per cent, leading to a small overall increase in Canadian oil production.

8 Statistics Canada, *Private and public investment 2009 intentions*, 2009.

9 *Nickle's Daily Oil Bulletin*.

Crude Oil

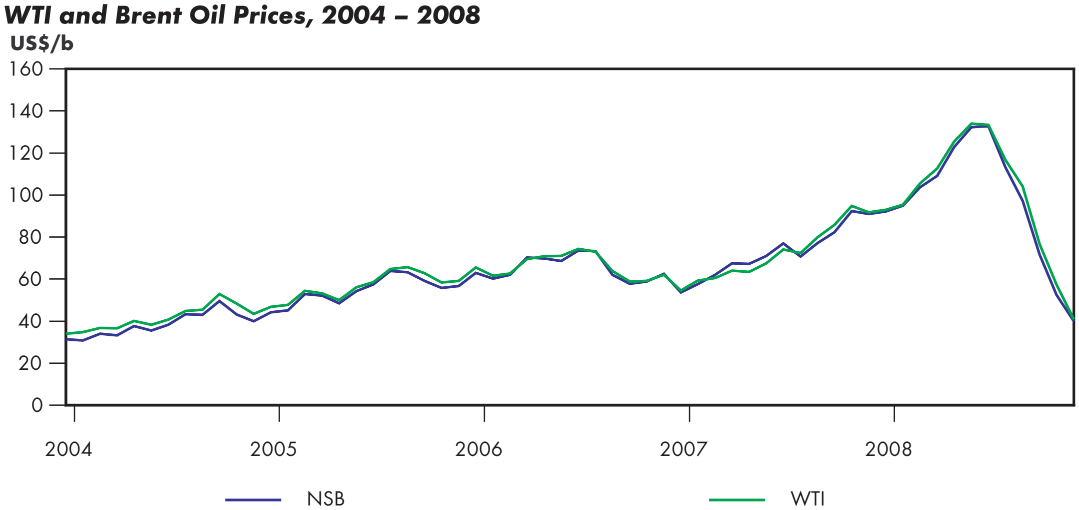
4.1 International Markets

2008 was an extraordinary year in crude oil markets. On the first trading day of the year, the near-month West Texas Intermediate (WTI) contract broke US$100/bbl (intra-day) for the first time. In July, the WTI reached an all-time high of US$147/bbl (intra-day) before a slowing global economy caused prices to tumble, ending the year at US$45/bbl. WTI averaged US$100/bbl over the year, compared to about US$73/bbl in 2007. Figure 4.1 shows historical prices for WTI at Cushing, Oklahoma, and North Sea Brent (NSB), a common benchmark for European crude oil pricing.

The first half of 2008 was characterized by continued growth in global demand for crude oil and petroleum products. While rising prices were contributing to decreased demand in OECD countries, demand continued to grow in emerging economies including China and India partly due to government fuel subsidies. In the context of rising demand, global supplies remained tight and OECD inventories remained below the five-year average, providing fundamental support for prices. With low Organization of Petroleum Exporting Countries (OPEC) spare capacity, the market paid special attention to ongoing geopolitical threats to supply, particularly in Iraq, Iran and Nigeria, at times producing significant price swings. Superimposed on the tight supply and demand situation, investment money flowed into commodities and the oil market specifically, driven by attractive returns. This increased investment also contributed to greater volatility in oil prices. The U.S. dollar decline over the first half of the year also contributed to higher oil prices.

F I G U R E 4 . 1

WTI and Brent Oil Prices, 2004 – 2008



Source: Energy Information Administration (EIA)

While much of the rapid rise in oil prices during the first half of 2008 can be attributed to market response to tight supply and geopolitical events, the second half of 2008 became a market focused on falling demand. The rapidly intensifying financial and credit crisis caused tremendous wealth destruction in the U.S. and around the world and resulted in greatly reduced economic activity. By early fall, most economists believed that the world was on the brink of a serious economic downturn. At the end of September, global crude oil inventories began to build and WTI had fallen to about US$100/bbl. In an effort to stem this effect, OPEC met in October 2008 and agreed to a substantial production cut of 238 000 m^3/d (1.5 MMb/d) and on 17 December 2008 agreed to a further cut of 349 000 m^3/d (2.2 MMb/d), effective 1 January 2009. Despite OPEC's announced production cuts and as the economic outlook worsened, prices continued to fall and inventories continued to build. The WTI near-month contract ended the year at US$45/bbl.

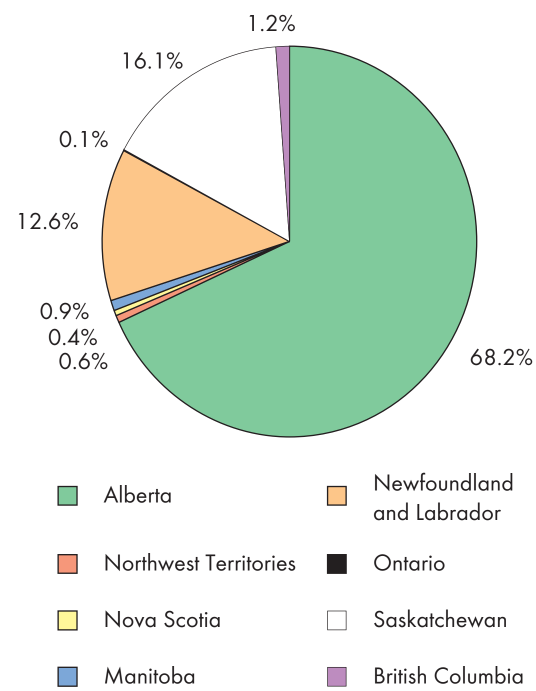
4.2 Canadian Oil Production and Reserves Replacement

In 2008, Canadian production of crude oil and equivalent averaged 429 000 m^3/d (2.7 MMb/d), a decrease of nearly two per cent from 2007 levels. Oil sands production grew by only 2.5 per cent, because of considerable down time for maintenance and tying in new facilities. This was more than offset by falling conventional crude oil production in the WCSB and on the east coast offshore where production decreased by eight per cent, reflecting natural pool decline as well as some maintenance down time at the Terra Nova field. Figure 4.2 illustrates crude oil production by province.

In 2008, production offshore Newfoundland and Labrador was 54 400 m^3/d (341 Mb/d), down from 58 600 (369 Mb/d) because of natural pool declines. Figure 4.3 illustrates east coast production. In western Canada, crude oil and equivalent supply remained essentially unchanged from 2007 levels. Conventional light crude oil production also remained steady, with production buoyed by higher oil prices in the first half of the year, and with new production from the Bakken play in Saskatchewan reversing previous decline trends. Conventional heavy crude oil production levels decreased by four per cent, in line with the general decline that has developed since production peaked in 2001. Figure 4.4 illustrates crude oil production by type.

FIGURE 4.2

Crude Oil and Equivalent Production by Province



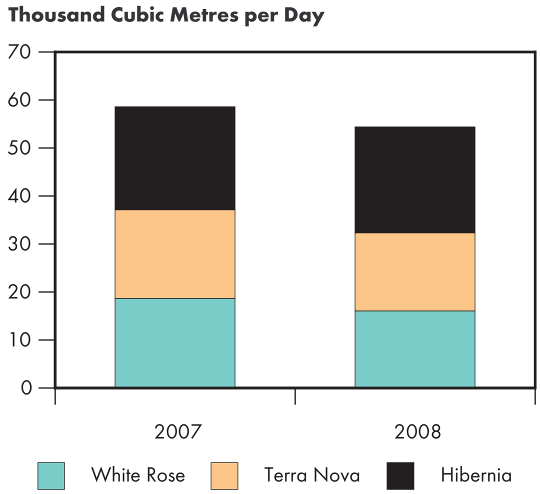
Source: NEB

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 2002 to 2006, cumulative additions to established reserves of conventional light and heavy crude oil replaced 84 per cent of production (Table 4.1). In 2007, 66 per cent of production of conventional crude oil was replaced.

The NEB's estimate of total remaining Canadian conventional crude oil and crude bitumen reserves at year-end 2007 (the last year for which nearly-complete data is available) is 28.1 billion cubic

FIGURE 4.3

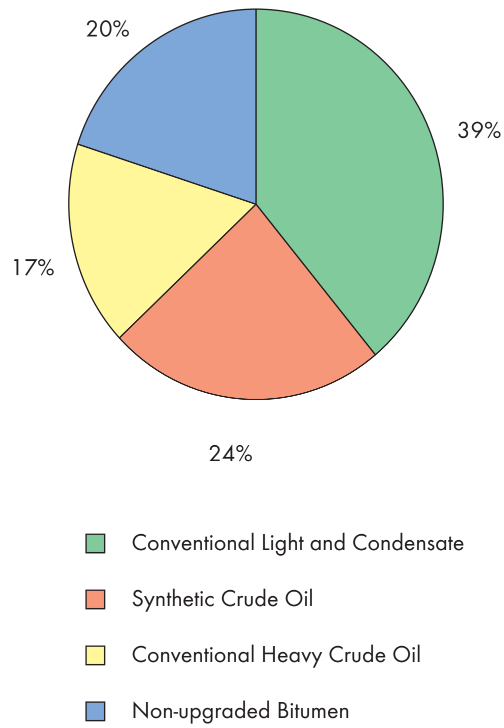
East Coast Production, 2007 – 2008



Source: Canada – Newfoundland and Labrador Offshore Petroleum Board

FIGURE 4.4

Crude Oil and Equivalent Production by Type



Source: NEB

metres (176.8 billion barrels), an increase of less than one per cent compared with 2006. Estimates of remaining established conventional crude oil reserves in Canada decreased by four per cent to 614.4 million cubic metres (3 871 million barrels) for 2007. Most of this decrease can be attributed to production significantly outpacing reserves additions in 2007. The remaining established crude bitumen reserves decreased slightly to 27.5 billion cubic metres (172.9 billion barrels) reflecting 2007 bitumen production (Table 4.2).

Reserves and Production Terminology

Crude oil can vary greatly in its composition and characteristics, and a distinction is made based on method of extraction from underground reservoirs.

Conventional crude oil is liquid in its natural state and can flow freely to a well bore and can be recovered using normal production practices.

Unconventional crude oil, or crude bitumen, is usually found in a semi-solid, viscous state, will not flow freely to a well, and requires the application of heat or dilution with solvents to be recovered. When deposited close to the surface, crude bitumen contained in oil sands can be recovered using direct mining methods. These terms are often used to describe established reserves and annual production data.

TABLE 4.1

Conventional Crude Oil Reserves, Additions and Production, 2003 – 2007 (million cubic metres)

	2003	2004	2005	2006	2007	Total
Additions[(a)]	60.8	66.9	134.7	27	50	339.4
Production	85.6	82.7	78.8	82.1	76	405.2
Total Remaining Reserves	**663**	**640**	**696**	**640**	**614**	
Total Remaining Reserves (millions of barrels)	**4 172**	**4 027**	**4 382**	**4 033**	**3 871**	

(a) White Rose added in 2002

Source: Provincial Energy Agencies, Offshore Petroleum Boards, NEB

TABLE 4.2

Estimates of Established Reserves of Crude Oil and Bitumen at 31 December 2007 (million cubic metres)

Conventional Crude Oil	**Initial**	**Remaining**
British Columbia[(a)]	129.0	19.7
Alberta[(b)]	2 751.4	240.5
Saskatchewan[(c)]	890.1	170.0
Manitoba[(d)]	45.8	7.7
Ontario[(e)]	14.8	1.6
Northwest Territories, Nunavut and Yukon		
Arctic Islands and Eastern Arctic	0.5	0.0
Mainland Territories – Norman Wells and Cameron Hills	52.9	13.7
Nova Scotia – Cohasset and Panuke[(d)]	7.0	0.0
Newfoundland – Hibernia, Terra Nova and White Rose[(d)]	299.1	161.2
Total	**4 190.6**	**614.4**
Total (millions of barrels)	**26 400.8**	**3 870.7**
Crude Bitumen		
Oil Sands – Minable Upgraded Crude[(f)]	5 590.0	4 962.0
Oil Sands – Bitumen[(f)]	22 802.0	22 486.0
Total	**28 392.0**	**27 448.0**
Total (millions of barrels)	**178 870.0**	**172 922.0**
Total Conventional and Bitumen	**32 582.6**	**28 062.4**
Total Conventional and Bitumen (millions of barrels)	**205 270.4**	**176 793.1**

(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 2006.

(d) Provincial Agencies or Offshore Boards, NEB estimate for Manitoba 2006.

(e) Canadian Association of Petroleum Producers.

(f) ERCB Report – ST 98 2008.

Note: totals may not add due to rounding.

4.3 Oil Sands

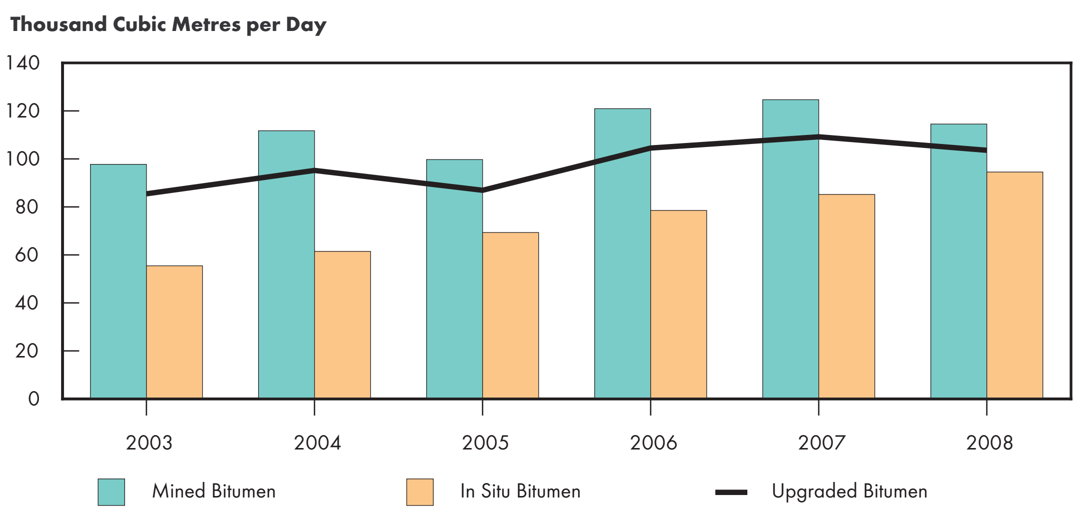
In early 2008, oil sands production in Alberta continued to expand and attract investments from domestic and foreign sources. Investment in Canada's oil sands has been appealing given the size of the resource, the stable political and investment climate, and the diminishing number of investment opportunities in other oil producing countries, owed part to increasing resource nationalization. High crude oil prices facilitated oil sands development for the majority of the year; however, volatile financial markets, increased capital costs and an abrupt fall in oil prices late in the third quarter slowed down several projects and initiated many project postponements. Oil sands spending in 2008 is estimated to be about $17.3 billion.

In 2007, adjustments to Alberta royalties and changes to federal taxation measures altered the economic conditions of oil sands projects. Royalty rates are now to be determined by a sliding scale based on WTI prices, expressed in terms of real Canadian dollars. At prices up to Cdn$55/bbl, royalty rates remain identical to the previous royalty scheme, at one per cent pre-payout and 25 per cent post-payout. At prices above this point, rates increase, reaching a maximum of nine per cent pre-payout and 40 per cent post-payout at Cdn$120/bbl. All royalty payments remain both tax-deductible and eligible as expenditures for the purposes of calculating payout. Both Suncor Energy Inc. and Syncrude Canada Ltd. had prior long-term contracts, signed in 1997 with the Alberta Government, but have come to terms with the province regarding application of the new royalty rates. The new royalty regime was implemented in January 2009.

In 2008, bitumen production from mining and in situ operations totalled 209 000 m^3/d (1.3 MMb/d), down less than one per cent compared with 2007. In situ bitumen production increased by 11 per cent to 94 600 m^3/d (596 Mb/d) (Figure 4.5), while bitumen from mining operations decreased by eight per cent to 115 000 m^3/d (721 Mb/d). The amount of bitumen production that was upgraded to synthetic crude oil decreased by five per cent to 104 000 m^3/d (653 Mb/d). Non-upgraded bitumen is blended with other heavy and light crudes and condensate for transport by pipeline to refineries. Despite rising construction costs, labour shortages and the economic downturn, several in situ and mining projects commenced operations in 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 synthetic gas (syngas)

FIGURE 4.5

Crude Bitumen Production, 2003 – 2008



Source: Energy Resources Conservation Board (ERCB) within the upgrader, hence minimizing the need to purchase and use natural gas for steam generation. In early 2009, OPTI/Nexen began first production of sweet synthetic crude at Long Lake. Canadian Natural Resources Limited Horizon mining project was brought online in the third quarter of 2008, but because of escalating costs and volatile oil prices, further expansions have been delayed. The Horizon project is expected to produce up to 17 500 m^3/d (110 Mb/d) within the next year to 18 months.

> ***Land Reclamation***
>
> Syncrude Canada's Gateway Hill, a 104 hectare parcel of land, received the first ever industry certification of reclamation from the Alberta government in 2008.
>
> A reclamation certificate is only issued when the land is no longer used for any oil sands purposes and is fully reclaimed meaning it can sustain vegetation and wildlife. This parcel of land, once used for oil sands mining processes, is now a popular area for hikers, who hike the Matcheetawin trail to experience the integrated forest and wetlands of the reclaimed land.
>
> Reclamation at Gateway Hill began in 1983 and continued through 2008. Currently, Syncrude leads the oil sands industry in land reclamation and has reclaimed over 500 hectares of land.

In 2008, Syncrude production volumes decreased because of operational disruptions, severe weather conditions and scheduled maintenance in the third quarter. Annual production is estimated to be 45 900 m^3/d (289 Mb/d). This is a 5.2 per cent decrease from 2007 production.

Suncor oil sands production averaged 36 249 m^3/d (228 Mb/d) in 2008, compared with 37 400 m^3/d (236 Mb/d) in 2007. This decrease primarily reflects the impact of scheduled and unscheduled maintenance, labour shortages and a November fire in Suncor's Upgrader 2 vacuum unit. Suncor completed an expansion of its Millennium Coker project in 2008 and expects to increase production in 2009.

Production at the Athabasca Oil Sands Project, a company consisting of Shell Canada Limited (60 per cent), Marathon Oil Canada Corporation and Chevron Canada (20 per cent each) is estimated to be 19 866 m^3/d (125 Mb/d) in 2008, a decline of three per cent compared with 2007. Planned and unplanned maintenance as well as operational issues were the main reasons cited for the decline in production.

4.4 Crude Oil Exports and Imports

Canada is a net crude oil exporter with the bulk of its exports going to the U.S. Canadian refineries in British Columbia, Alberta, Saskatchewan and Ontario receive crude oil supplies from western Canada with the balance exported, mainly by pipeline, to markets in the U.S. Refineries in Ontario, Quebec, and Atlantic provinces import some crude oil to meet demand because it is more economic to do so. As a result, some Atlantic crude oil production is consumed domestically with the balance exported primarily to the U.S.

In 2008, crude oil exports averaged approximately 285 000 m^3/d (1.79 MMb/d) which represents a year-on-year decrease of less than one per cent. Light crude oil exports, which include pentanes plus and synthetic crude oil (upgraded bitumen), represented 28 per cent of all exports with the remaining 72 per cent comprised of exports of heavy crude oil[10].

10 The NEB updated the crude characteristics in the Oil Export System to accurately reflect changes in sulphur content and API gravity. Some light crude oil streams became medium crude oil streams because their API gravities fell below the 30 degree API threshold. This has increased the relative volume of medium/heavy exports and decreased the relative volume of light exports.

The estimated value of crude oil exports for 2008 is $60 billion compared with $44 billion in 2007. The estimate is based on approximated export prices of $641 and $540/m^3 (Cdn$102 and Cdn$86/bbl) for light crude oil and heavy crude oil, respectively (Figure 4.6).

Heavy and light crude oils are traded in separate markets, and accordingly the prices for each vary as a result of the supply and demand for each crude type. Heavy crude has a smaller market, higher refining costs, yields lower volumes of higher valued products such as gasoline and, as a result, is usually discounted. The differential typically narrows in the summer months because of the higher demand for heavy crude oil during asphalt season and widens again in September.

Oil Pipeline Capacity Expansions

Construction began in 2008 on two Board approved crude oil pipelines.

Enbridge began construction on its Clipper pipeline which, when it is slated to begin operation in 2010, will have an initial capacity of about 71 500 m^3/d (450 Mb/d). TransCanada began construction on its 94 000 m^3/d (591 Mb/d) Keystone pipeline system which is also expected to begin operations in 2010.

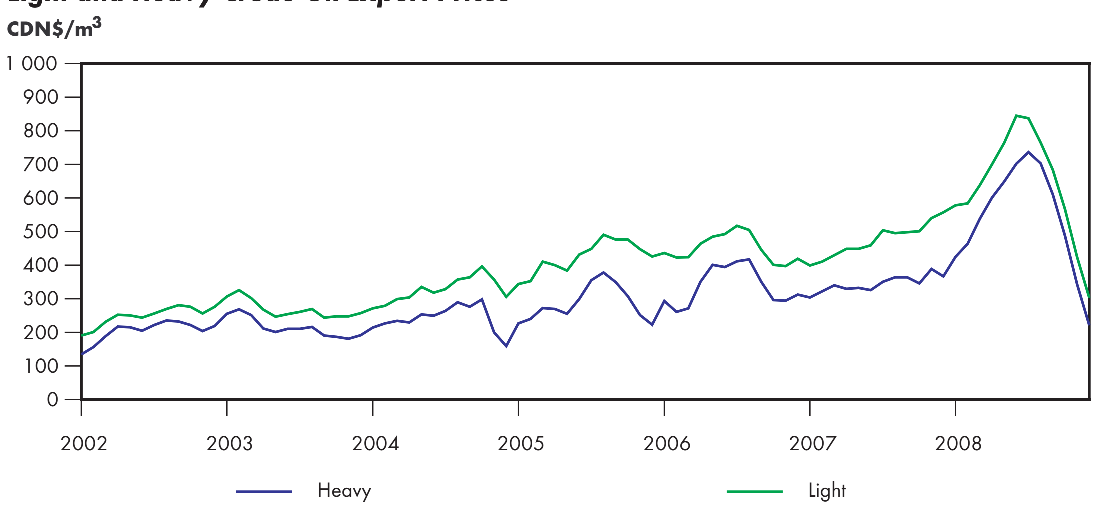
In addition to the commencement of construction on these two major export pipelines, Kinder Morgan expanded capacity on its Trans Mountain pipeline by 6 400 m^3/d (40 Mb/d). Industry and government are working in partnership to ensure that responsible and economic development of resources can occur by gaining access to new and existing markets through pipeline capacity expansions.

On a dollar basis, the light–heavy differential averaged $101/m^3 (Cdn$16/bbl) during 2008, wider than the typical level as many road improvement projects were deferred because of record crude prices. Since the summer, the differential has narrowed as a result of sharply declining crude prices and lower light crude prices due to weak gasoline demand.

Anticipated and actual capacity constraints on major oil export pipelines also contributed to the widening differential. The Enbridge, Express/Platte and Trans Mountain systems were operating at or near capacity throughout 2008 with some apportionment experienced in the first and last quarters of the year. When refiners in the U.S. expect or anticipate pipeline capacity constraints, which can result in not having crude when it is needed, they tend to offer a lower price for that crude oil.

FIGURE 4.6

Light and Heavy Crude Oil Export Prices



Source: NEB

In 2008, the Board approved a number of oil pipeline applications, including Enbridge Southern Lights (OH-3-2007), Alberta Clipper (OH-4-2007) and the Line 4 Extension (OH-5-2007). TransCanada's Keystone Cushing Extension (OH-1-2008) project, which will allow Canadian crude oil to reach Cushing, Oklahoma, was also approved.

Other pipeline projects proposed in 2008 included the Enbridge Gateway project which proposes to ship Canadian crude to new markets in Asia using oil tankers, the Enbridge Trailbreaker project which proposed a re-reversal of the Enbridge Line 9 pipeline to carry Canadian crude to the U.S. east coast and Gulf Coast, and the TransCanada Keystone XL project which proposes a pipeline to the U.S. Gulf Coast. Due to lack of shipper support, Enbridge Trailbreaker was subsequently postponed.

Canada remained the number one supplier of crude oil to the U.S. followed by Saudi Arabia and Mexico[11]. According to the EIA, the U.S. imported an average of 1.5 million m^3/d (9.7 MMb/d) giving Canada approximately 20 per cent of the import market. Canada became the number one supplier of heavy crude oil to the U.S., surpassing Mexico which continues to experience declines in production. Sixty per cent of total Canadian crude exports went to the U.S. Midwest (PADD II) market, making it the largest consuming export market for Canadian crude oil.

Over 90 per cent of eastern Canadian crude oil exports were delivered to the U.S. east coast (PADD I). The remaining eastern Canadian exports were delivered to the U.S. Gulf Coast (six per cent) and the Caribbean (three per cent). Given the proximity and relationship Canada has with the U.S., the U.S. will remain a major export market in the future. Table 4.3 contains a breakdown of crude oil exports by type and destination.

TABLE 4.3

Crude Oil Exports by Type and Destinations – 2008 (volume – m^3/d)

Market	Light	Medium	Heavy	Synthetic	Blended Bitumen	Total
PADD I	24 068.9	219.5	5 539	1 249.6	278.3	31 355.3
PADD II	12 027.3	19 647.0	67 312.7	37 468.4	39 694.8	176 150.2
PADD III	1 791.5	268.8	4 011.4	256.3	7 914.2	14 242.2
PADD IV	3 916.2	3 115.6	20 947.4	6 816	3 108.6	37 903.8
PADD V	14 201.5	0.0	0.0	7 173.9	2 750.2	24 125.6
Total U.S.	**56 005.4**	**23 250.9**	**97 810.5**	**52 964.2**	**53 746.1**	**283 777.1**
Other	633.9	0.0	0.0	415.4	250.5	1 299.8
Total	**56 639.3**	**23 250.9**	**97 810.5**	**53 379.6**	**53 996.6**	**285 076.9**

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

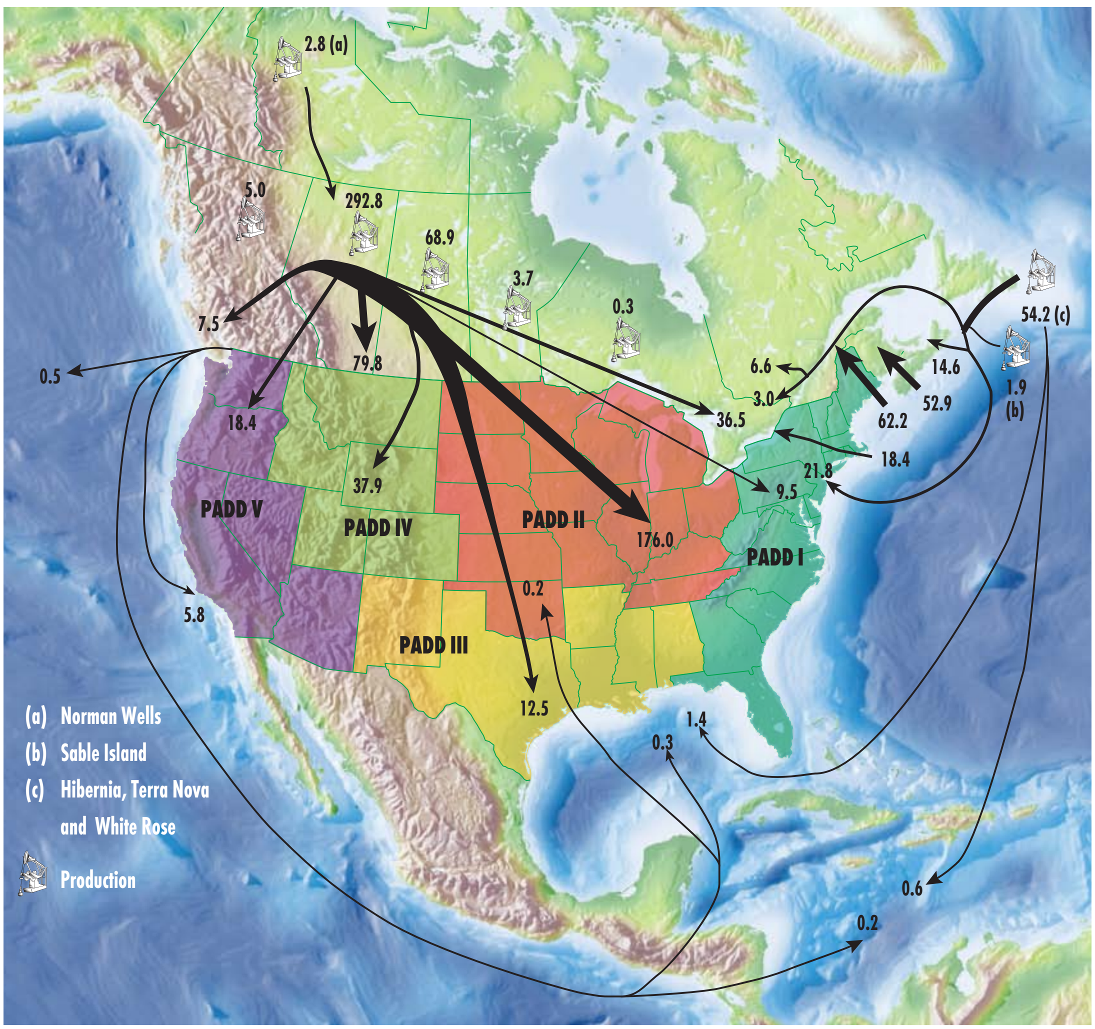
11 Canada accounted for 20 per cent of U.S. imports, Saudi Arabia accounted for 16 per cent and Mexico accounted for 12 per cent.

Although Canada is a net crude oil exporter, imports account for a significant portion of Canadian refinery demand. Refineries located in Ontario, Quebec and Atlantic Canada source a portion of their crude oil from abroad, while western Canadian refineries are fully supplied by domestic production.

In 2008, crude oil imports are estimated to be 133 000 m^3/d (840 Mb/d). This is a decrease of approximately 2.3 per cent compared with 2007 and represents 47 per cent of total Canadian refinery feedstock. OPEC countries supplied 59 per cent of imports and 34 per cent was delivered from the North Sea. The remaining seven per cent was sourced from our NAFTA partners (U.S. and Mexico) and other countries. An estimated 78 per cent of the Atlantic refining requirements were met by imports and the remaining 22 per cent with eastern Canadian production. Quebec remained the largest regional importer of crude oil with 90 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.

FIGURE 4.7

Crude Oil Supply and Disposition – 2008
(thousand cubic metres per day)



4.5 Oil Refining

There were 19 Canadian refineries operating at the end of 2008 with a total refinery capacity (distillation) of 335 000 m^3/d (2.1 MMb/d), up from 325 000 m^3/d (2.0 MMb/d) in 2007. The refineries and their locations are included in Table 4.4.

Canadian demand for petroleum products in 2008 is estimated to be 264 000 m^3/d (1.7 MMb/d), roughly the same as 2007. The lack of growth reflects slumping demand because of very high prices during the summer and reduced economic activity in the third and fourth quarters of 2008. Refinery runs of crude oil in Canada in 2008 are estimated to be 284 000 m^3/d (1.8 MMb/d), a decline of two per cent over 2007 levels of 290 000 m^3/d (1.8 MMb/d). Refinery capacity utilization also decreased from 90 per cent in 2007 to 88 per cent in 2008. Refinery receipts of domestic crude oil declined by 6.2 per cent in 2008 to 148 000 m^3/d (935 Mb/d), largely because of the reduction in refinery runs due to the price driven decline in demand for petroleum products during the summer. Spring and summer refinery outages and maintenance activity in western Canada resulted in gasoline and diesel fuel shortages, as well as reduced crude oil usage at those facilities.

TABLE 4.4

Refineries in Canada

Company	Location	Capacity (m^3/d)	Capacity (b/d)
Atlantic Canada		**76 600**	**482 600**
Imperial Oil Limited	Dartmouth, N.S.	13 000	81 900
Irving Oil Limited	Saint John, N.B.	45 300	285 400
North Atlantic Refining (Harvest Energy)	Come-by-Chance, Nfld.	18 300	115 300
Quebec		**83 500**	**526 000**
Petro-Canada	Montreal	20 700	130 400
Shell Canada Limited	Montreal	20 700	130 400
Ultramar Limited	St. Romuald	42 100	265 200
Ontario		**74 800**	**471 200**
Imperial Oil Limited	Nanticoke	17 800	112 100
Imperial Oil Limited	Sarnia	19 200	121 000
Shell Canada Limited	Sarnia	11 400	71 800
NOVA Chemicals	Sarnia	13 200	83 200
Suncor Energy Products Inc.	Sarnia	13 200	83 200
Western Canada		**99 800**	**628 900**
Consumers Co-operative Refineries Ltd.	Regina, Sask.	15 600	98 300
Husky Energy Marketing Inc.	Lloydminster, Alta.	4 000	25 200
Imperial Oil Limited	Strathcona, Alta.	29 700	187 100
Moose Jaw Asphalt	Moose Jaw, Sask.	2 500	15 800
Petro-Canada	Edmonton, Alta.	21 900	138 000
Shell Canada Limited	Scotford, Alta.	15 900	100 200
Chevron Canada Limited	Burnaby, B.C.	8 300	52 300
Husky Energy Marketing Inc.	Prince George, B.C.	1 900	12 000
Total		**334 700**	**2 109 000**

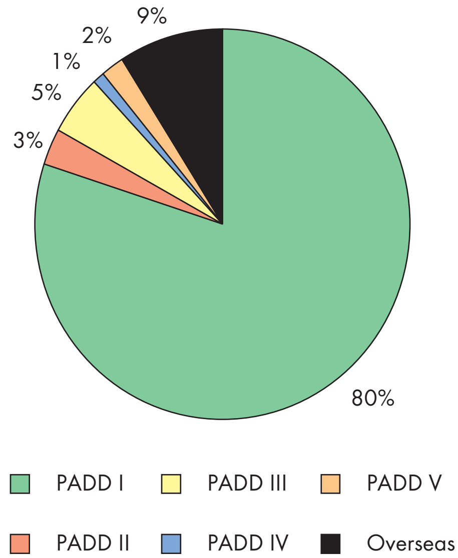
Source: NEB

4.6 Main Petroleum Product Exports and Imports

Canada continued to be a net exporter of petroleum products, with the U.S. as its principal customer. Exports of main petroleum products in 2008 are estimated to be 52 540 m^3/d (331 Mb/d), a marginal increase from 2007. Exports were primarily destined for the U.S. east coast market (PADD I) with overseas exports being the second largest market. Figure 4.8 illustrates the destination for main petroleum product exports.

FIGURE 4.8

Product Exports by Destination – 2008



Source: NEB (Data available to October 2008)

The estimated revenue in 2008 from exports of main petroleum products, including partially processed oil, was $11 billion, up from about $9 billion in 2007. Very high crude oil prices supported by tight markets in the first half of 2008 were key drivers behind the jump in revenues. A strong global distillate market kept diesel prices high throughout the year and distillate production was critical to keeping refineries profitable. Stagnant gasoline demand and rising crude oil prices had a negative effect on gasoline margins in the first half of 2008.

Canadian imports, primarily from the U.S., were up by 25 per cent on a year-on-year basis. This increase reflects the drop in Canadian production caused in part by unplanned refinery outages. Year-on-year growth in domestic sales of petroleum products was negligible meaning that while product balances and consumption remained the same, production setbacks were off-set by higher imports.

4.7 Product Prices

According to Natural Resources Canada (NRCan)[12], average Canadian retail product prices were approximately 23 per cent higher in 2008 compared with 2007, reflecting increases in world crude oil prices. Retail gasoline prices in Canada increased from 102 cents/litre in 2007 to 114 cents/litre in 2008 (Table 4.5). Because of a tight global distillate market, diesel and furnace oil prices increased at a greater rate than gasoline. 2008 prices for diesel and furnace oil averaged 125 cents/litre and 113 cents/litre, respectively, which is an average increase of 29 per cent from 2007.

TABLE 4.5

World Oil and Canadian Products Prices

Product	2008 (cents/litre)	2007 (cents/litre)	Change	Change (%)
Gasoline	114.0	101.8	+12.2	12.0
Diesel	124.9	99.8	+25.1	25.2
Furnace oil	113.2	85.7	+27.5	32.1
WTI (US$/bbl, Cushing, OK)	99.67	72.34	+27.3	37.8
Edmonton Par (Cdn$/bbl)	102.87	76.97	+25.9	33.6

Source: NRCan, EIA, NEB

World crude oil prices were volatile in 2008 and product price movements typically respond to crude oil prices; however, gasoline prices were

12 Natural Resources Canada, *Fuel Focus, 2008 Annual Review*, 11 January 2009.

softened by stagnant demand and did not rise in direct proportion to the rise in crude oil prices. This negatively affected the profitability of refineries. A combination of tight global supply–demand and volatile crude oil prices caused diesel prices to rise rapidly. Refineries geared production, as much as possible, to maximize distillate (diesel) output. Refinery and upgrader problems in Alberta at times caused pro-rationing of both gasoline and diesel, further tightening the situation and increasing prices in western Canada. The demand reduction experienced in the second half of 2008, however, caused year-end inventories of both gasoline and distillate to exceed 2007 levels.

4.8 Looking Ahead

Crude oil prices reached unprecedented levels in the summer of 2008 but had declined substantially by year-end in response to the global economic downturn. In order to stimulate their economies, central banks around the world have cut interest rates and governments have announced major stimulus spending packages. 2009 is expected to be a difficult year for the global economy and this, in turn, will result in reduced crude oil demand. Accordingly, forecasters are predicting low crude oil prices for 2009 reflecting poor GDP growth in developed countries and slower growth in developing countries such as China and India. Because of the low crude oil price environment anticipated in 2009, Canada can expect lower crude oil export revenues.

Continued volatility and uncertainty will be a challenge for both consumers and producers in the coming year. Given the challenging global economic conditions, numerous capital investment projects have been deferred or cancelled. These projects were primarily aimed at increasing production and refining capacity. In Canada, the list of cancelled or deferred projects is growing and until the price of crude oil rebounds to a level that provides economic incentive for investment, incremental production volumes and refining capacity will remain in doubt.

Increasing links between the environment, energy and the economy will continue to be part of the Canadian dialogue in 2009. How this will impact the Canadian oil industry remains uncertain; however, a shift in policy in major consuming regions around the globe could spur technological advancements which in turn would allow for cleaner, more sustainable growth. In this context, Canada, with its large endowment of natural resources and growing importance in the global energy picture, will be well positioned to seize opportunities to achieve sustainable energy development.

Natural Gas

5.1 North American Natural Gas Markets

In 2008, about one-quarter of the natural gas produced in North America came from Canada. About 97 per cent of Canadian gas continues to be produced from the WCSB with Alberta producing roughly 78 per cent. British Columbia and Saskatchewan contribute approximately 16 and four per cent, respectively, of total WCSB production. Daily production from the WCSB remained steady through the first three quarters of the year at 445 10^6m^3/d (15.7 Bcf/d) before rapidly declining in the fourth quarter to 428 10^6m^3/d (15.1 Bcf/d) as early cold winter weather caused freezeoffs at the wellhead.

Together, the Canadian and U.S. natural gas markets operate as one large integrated market. This means that events in any one region such as changes in transportation costs, infrastructure constraints or weather will affect the other regions. The majority of Canadian and U.S. natural gas production continues to come from areas roughly following the continental divide, from the Gulf of Mexico to the Northwest Territories. New production has tended to come from unconventional sources, especially shale gas, whose development expanded rapidly in Canada during 2008. Demand is spread across the continent but is concentrated in densely populated areas and in areas of intense industrial activity. North American demand declined in 2008 primarily as a result of decreased industrial demand brought on by the economic downturn. Canadian gas production is connected to the North American gas market through a network of thousands of kilometres of pipeline that allows buyers to purchase and transport natural gas from a number of supply sources across the continent.

Natural gas prices have been volatile in recent years and this volatility continued in 2008 (Figure 5.1). New highs were reached early in July before the economic downturn decreased demand at the same time that new domestic supply was coming on stream. Those two factors combined to drop the price to less than $6.00/MMBtu in the last part of 2008. Additionally, the price of natural gas is particularly sensitive to real and anticipated weather events and this can result in large seasonal swings. A lack of spare productive capacity in North America resulted in tight market conditions that have contributed to high and volatile natural gas prices since 2001. However, growing production from shale and other unconventional gas resources in North America has helped to offset the ongoing decline in conventional production, easing the tight supply–demand balance and contributing to the decline in gas prices in the second half of 2008.

Natural gas prices can also be sensitive to crude oil prices; however, in 2008 this price relationship became increasingly disconnected as gas prices were well below oil on an energy equivalent basis. Some consumers can switch between natural gas and fuel oil for their heating needs, particularly in the U.S. northeast and southeast. This competition provides a link, albeit imperfect, between oil prices and natural gas prices, such that an increase in crude oil prices can support an increase in the price of natural gas. The rapid fall in oil prices and the global financial crisis in the second half of 2008 had a significant impact on natural gas prices this year. Natural gas prices in North America, as measured by the three-day average at the Henry Hub, rose to a high of around $13/MMBtu in

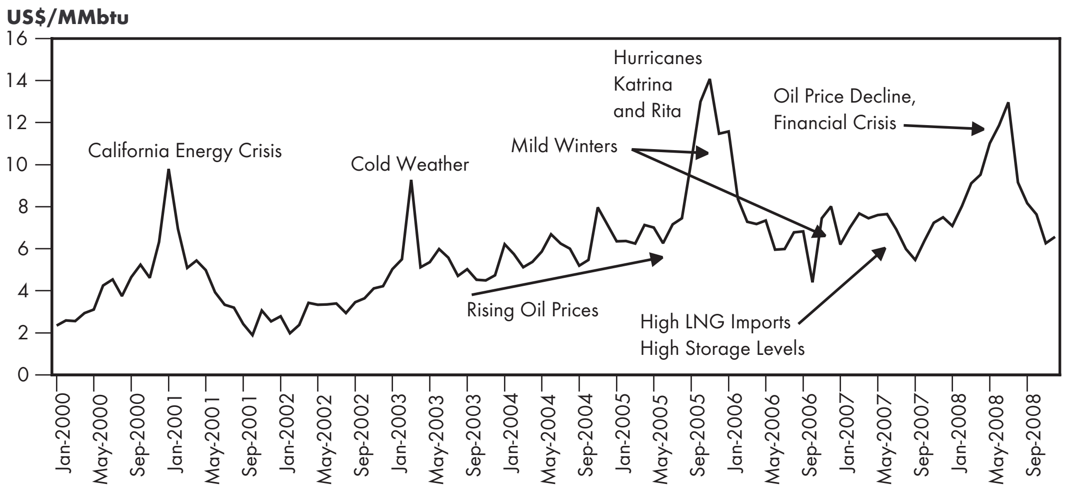
July 2008 and subsequently fell by about 50 per cent by the end of the year. Natural gas prices for 2008 averaged US$9/MMBtu, almost 30 per cent higher than 2007.

Natural gas is produced at a relatively steady rate throughout the year whereas its consumption is seasonal. To balance supply with demand, gas is injected into underground storage in the summer and withdrawn in the winter months. April is the beginning of the typical storage injection season (Figure 5.2). Temperatures in early 2008 were very cold throughout the U.S. northeast and eastern Canada. With these being large consuming regions, a previous storage surplus was depleted. Storage levels began the injection season below 2007 levels and below the five-year average. However, in 2008, storage levels steadily grew to the end of October, almost reaching the record high of 2007 before entering the 2008–2009 winter heating season in November.

U.S. gas production increased significantly in 2008, offsetting reductions in LNG imports (which were less than half of the levels reached in 2007) and Canadian gas production. Considerably milder

FIGURE 5.1

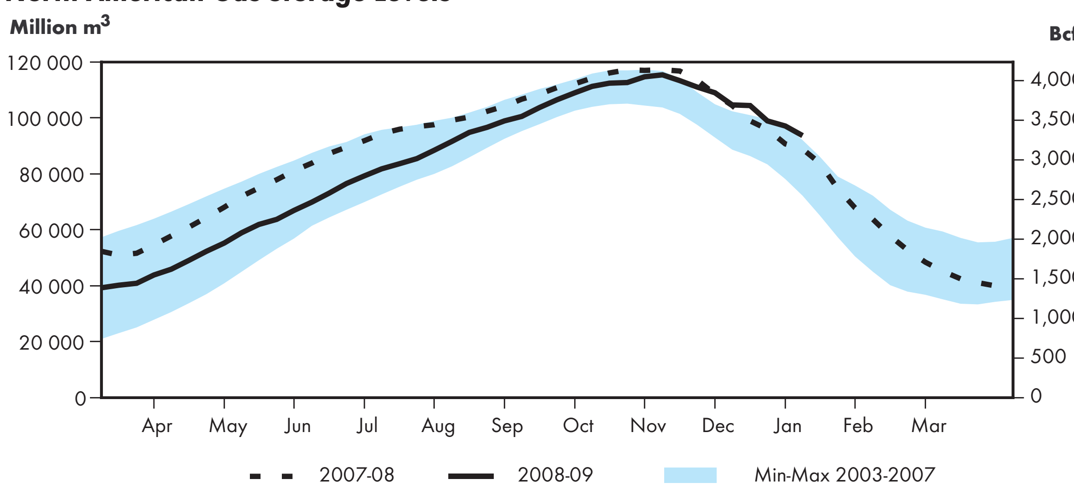
North American Gas Price Trends – Henry Hub (Monthly average)



Source: GLJ Publications Inc.

FIGURE 5.2

North American Gas Storage Levels



Source: Canadian Enerdata Ltd., NEB estimates, U.S. Energy Information Administration temperatures in the summer and fall, compared to 2007, allowed for steady injections into storage in 2008.

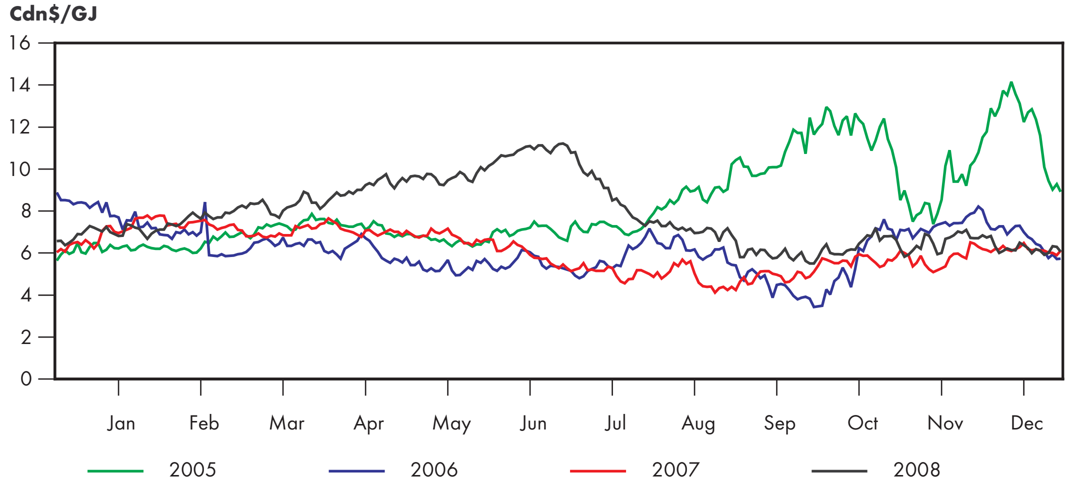
Western Canadian natural gas prices, measured at the AECO hub in Alberta, which is located near a number of natural gas storage fields near the southern border of Alberta and Saskatchewan, began 2007 at $6.57/GJ and reached an all-time mid-summer high of $11.22/GJ in July and a pre-heating season low of $5.50/GJ in September before closing the year at $6.07/GJ, following the trend of the U.S. Henry Hub price (Figure 5.3). Although prices in 2005 reached higher levels than 2008 because of hurricane supply disruptions, the average price of 2008 was, overall, five per cent higher than the 2005 average.

Prices in eastern Canadian markets are cited at the Dawn Hub, which is located near underground storage facilities in southwestern Ontario, and include a component of transportation and storage costs. The Dawn price began the year at US$8.05/MMBtu and reached a high of US$13.63/MMBtu in early July (Figure 5.4). Similar to the AECO price, the Dawn price, in Ontario, declined through

FIGURE 5.3

Daily AECO-C Price

Cdn$/GJ

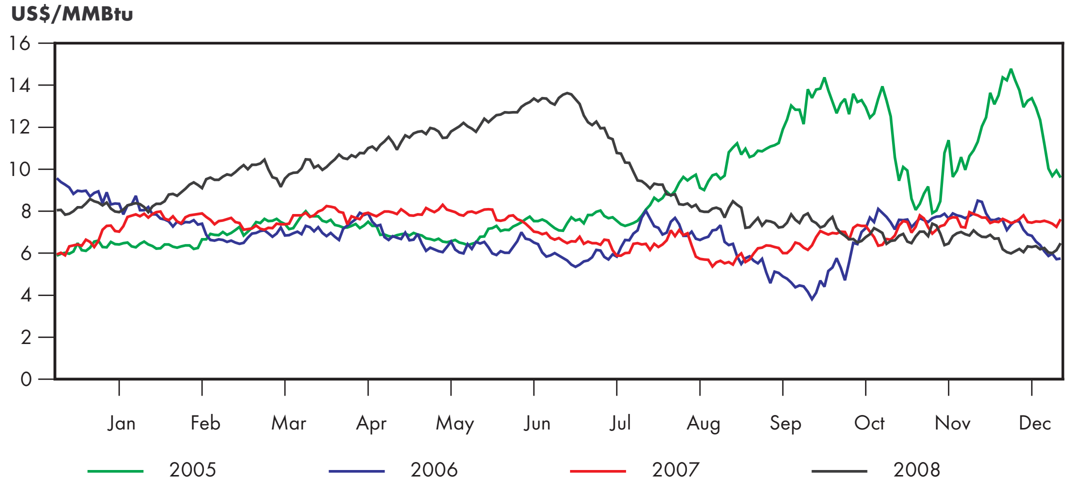


Source: Platts

FIGURE 5.4

Daily Dawn Price

US$/MMBtu



Source: Platts

the fall and early winter of 2008 to close the year at US$6.20/MMBtu. Falling commodity prices, including natural gas, contributed to the decline in the Canadian dollar in the second half of 2008. However, Canadian natural gas prices remained well-connected to North American gas prices overall.

5.2 North American Natural Gas Supply

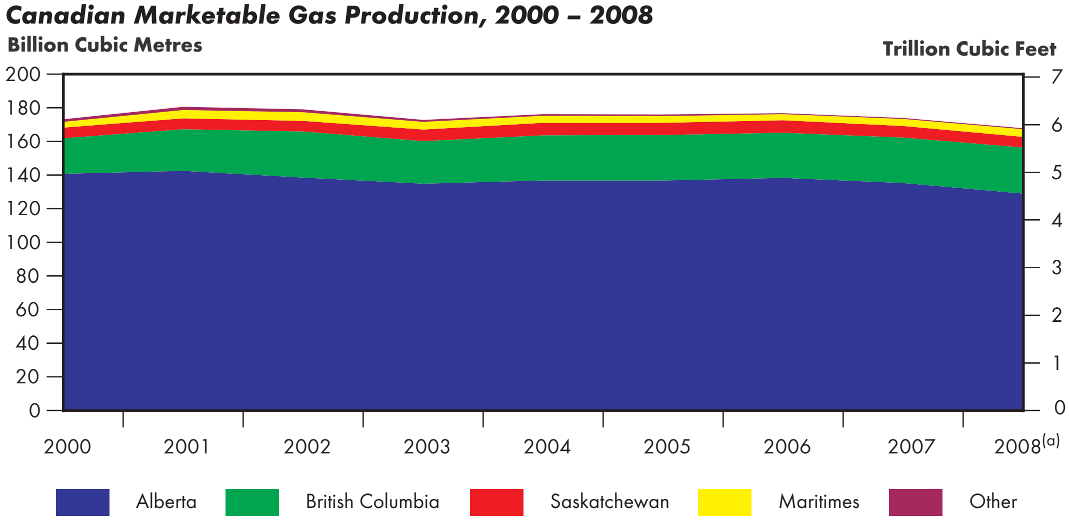
2008 Canadian natural gas production averaged 458 million m^3/d (16.2 Bcf/d), ranking Canada behind the U.S. and Russia as the world's third largest gas producer, the same position Canada has had since 1982. 2008 production was roughly four per cent or 18 million m^3/d (0.65 Bcf/d) less than in 2007 (Figure 5.5). Alberta led the decline with production falling five per cent from 2007 levels. The only regions to show increases in 2008 were British Columbia and the Maritimes, whose production rose by one and seven per cent from 2007, respectively. The overall Canadian production decline since 2006 can be linked to a pullback in drilling activity in western Canada which started that year.

In 2008 there was recognition of and significant public attention drawn toward large potential shale gas resources in several areas of Canada, including Quebec, Alberta and British Columbia (Figure 5.6). While positive exploration results were released in those areas, only the Montney Formation of British Columbia has been under development and producing significant amounts of shale gas over the past few years, approximately 8.5 million m^3/d (300 MMcf/d) by year-end 2008, 62 per cent higher than 2007 production. Shale gas from the Horn River Basin of British Columbia was producing around 1.4 million m^3/d (50 MMcf/d), all of it added during 2008.

There remains significant resource potential in coalbed methane (CBM) even though industry has focused its efforts on Canadian shale gas. Production of CBM in 2008 averaged approximately 21.4 million m^3/d (757 MMcf/d)[13], an 11 per cent increase over 2007. However, CBM development outside of the WCSB still faces challenges. In 2008, Shell Canada voluntarily imposed a drilling moratorium in the Klappan area of northwestern British Columbia over the concern of residents about the footprint of oil and gas operations. Since then, the British Columbia government has

FIGURE 5.5

Canadian Marketable Gas Production, 2000 – 2008



(a) Estimate

Source: Provincial and territorial regulatory agencies

13 CBM production is sometimes mingled with other shallow non-coal formations with no method to differentiate the source of production, therefore CBM production reported here is likely overestimated to a small extent.

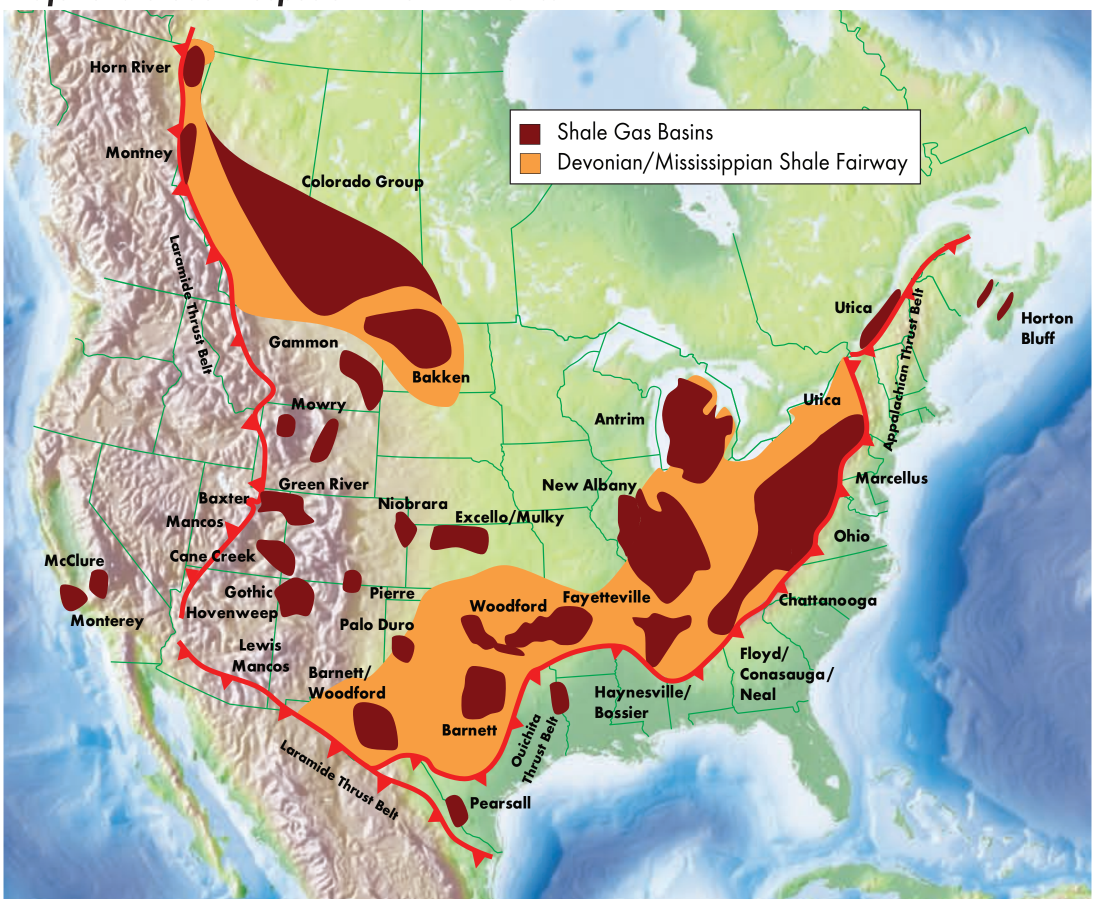
imposed a two-year moratorium on CBM activity in the Klappan area. Consultations continue between industry, government and community groups.

On the east coast, Sable production averaged 11.7 million m^3/d (400 MMcf/d) or about four per cent less than 2007 production. Production from the onshore McCully field in New Brunswick has remained stable at about six per cent of the region's production or 0.8 million m^3/d (26.6 MMcf/d).

In 2008, hurricanes Gustav and Ike each shut in almost 200 million m^3/d (7.0 Bcf/d) in the Gulf of Mexico; by year-end, approximately 42 million m^3/d (1.5 Bcf/d) was still shut in[14]. Despite this, U.S. dry gas production, which averaged 1.5 billion m^3/d (52.3 Bcf/d) in 2007, grew to 1.6 billion m^3/d (56.2 Bcf/d) in 2008, an astonishing 7.5 per cent increase, mainly from growth in the Barnett, Fayetteville and Haynesville shale gas plays of Texas, Louisiana and Arkansas (Figure 5.5) and tight sands in Texas and the Rocky Mountain basins. This supply glut has been a substantial factor in the

FIGURE 5.6

Major Shale Gas Prospects in North America



Developing: Barnett, Fayetteville, Haynesville, Woodford, Marcellus, Montney and Horn River.
Evaluating: Barnett/Woodford, Utica and Gothic.
New Shale Plays: Growth in Medium to Long Term.

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 land mass that has been overridden by the mountains (i.e. a thrust fault).

14 EIA, *Impact of the 2008 Hurricanes on the Natural Gas Industry*, 2009.

Unconventional Natural Gas in Canada

As additional reserves of conventional natural gas become increasingly difficult to find in mature areas like the WCSB, exploration companies have been shifting their focus to a wide variety of unconventional resources. These are generally found in widespread, low permeability deposits (permeability is defined as the ability of a fluid to move through a porous and/or fractured solid). These unconventional resources require special drilling and hydraulic fracturing techniques as well as an increased number of wells drilled per unit area.

Two types of shallow unconventional resources are shallow gas and CBM, which are normally only exploited when less than one kilometre deep and through closely spaced vertical wells, although CBM wells may be drilled horizontally. Shallow gas originates from muddy sandstones and has been exploited in the region near Medicine Hat, Alberta for more than 100 years. CBM is natural gas produced from within coal cleats (i.e. fractures in the coal). While water is produced from some coals, others are dry and produce no water. For example, the Horseshoe Canyon Formation coals of central Alberta are by far the largest producer of CBM in Canada and produce almost no water. Rates from individual wells in these shallow resources tend to be low, around 1 500 m^3/d (0.05 MMcf/d), but may last for several decades. Recently, producers have also stepped out into some sandy shales for shallow shale gas production.

Two types of deep unconventional resources are tight gas and shale gas, normally found around two kilometres in depth or deeper. Tight gas consists of low permeability conglomerates and sandstones (for example, the Cadomin Formation of west-central Alberta and northeast British Columbia) or limestones and dolostones (for example, the Jean Marie Formation of northeast British Columbia). Shale gas comes from organic rich mudstones where some of the organic material has been converted to methane. An example of this is found in northeast British Columbia in the Horn River Basin.

A hybrid between tight gas and shale gas is a sandy mudstone called the Montney Formation, found in northeast British Columbia and west-central Alberta. After horizontal drilling and hydraulic fracturing, these tight gas and shale gas reservoirs typically produce from 30 000 m^3/d (1.1 MMcf/d) to 350 000 m^3/d (12.3 MMcf/d) before declining to around 8 000 m^3/d (0.3 MMcf/d) for ten years or more.

significant drop in natural gas prices and the subsequent decrease in drilling across the continent, including Canada.

LNG import capacity into the U.S. increased substantially in 2008 through the addition of two new terminals and the expansion of existing facilities. At the end of 2008, import capacity into the U.S. was over 300 million m^3/d (10 Bcf/d), from eight terminals. Despite this capacity increase, U.S. LNG imports averaged only 27 million m^3/d (1.0 Bcf/d), less than half of the average level of LNG imported in 2007 (60 million m^3/d or 2.1 Bcf/d). The drop in LNG imports in 2008 reflects the higher demand and prices received for LNG in other global markets during the year. Those markets attract supplies away from the U.S. Canada's first LNG facility was under construction throughout 2008 and is expected to become operational in 2009. This facility will primarily import natural gas as LNG and ship the regasified natural gas to the New England market.

5.3 Natural Gas Reserves

Despite Canada's number three ranking in terms of natural gas production, Canada ranks 21st in the world in terms of reserves, defined as the total amount of marketable gas in discovered pools that can be extracted in current economic conditions. The NEB's estimate of remaining marketable gas reserves at the end of 2007 is 1 607 billion m^3 (56.3 Tcf) (Table 5.1). Reserve additions were 139 billion m^3 (4.9 Tcf) in 2007 and replaced only 78 per cent of annual production. The decrease

TABLE 5.1

Canadian Natural Gas Reserves

($10^9 m^3$) At Year-end 2007	Natural Gas Reserves		
	Initial Reserves	**Cumulative Production**	**Remaining Established Reserves**
British Columbia	940.1	545.9	394.2
Alberta	4 893.3	3 823.9	1 069.3
Saskatchewan	271.0	181.8	89.2
Subtotal – WCSB	**6 104.4**	**4 551.6**	**1 552.7**
Ontario	54.3	34.3	20.0
Nova Scotia Offshore	55.0	34.1	20.9
Mainland NWT & Yukon	29.1	16.1	13.0
Mackenzie Delta	0.3	0.1	0.2
Subtotal – Frontier	**84.4**	**50.3**	**34.1**
Total Canada	**6 243.1**	**4 636.2**	**1 606.8**
Total Canada (Tcf)	**220.4**	**163.7**	**56.3**

Sources: Various regulatory and industry bodies.

in remaining reserves reflects the pullback in drilling by exploration companies from 2005 highs. Initial reserves, the cumulative total of reserves discovered in Canada up to year-end 2007 with no subtractions for production, increased in Alberta, British Columbia and Saskatchewan, while frontier regions and Ontario remained largely unchanged.

5.4 Canadian Natural Gas Consumption

Approximately one-quarter of all energy consumed by Canadians is natural gas. This amounts to an estimated consumption in 2008 of about 216 million m^3/d (7.6 Bcf/d), or about 47 per cent of Canadian production. Canada ranks among the top five natural gas consuming nations, accounting for about three per cent of world consumption.

Natural gas is primarily consumed in the residential and commercial sectors for space heating, in the industrial sector for process heat, as a building block in chemical production, and to produce electricity. Canadian gas demand for heating, industrial use and electric power generation (included within "direct sales") has been fairly flat since 2000 (Figure 5.7).

Despite continuing growth in residential and commercial floor

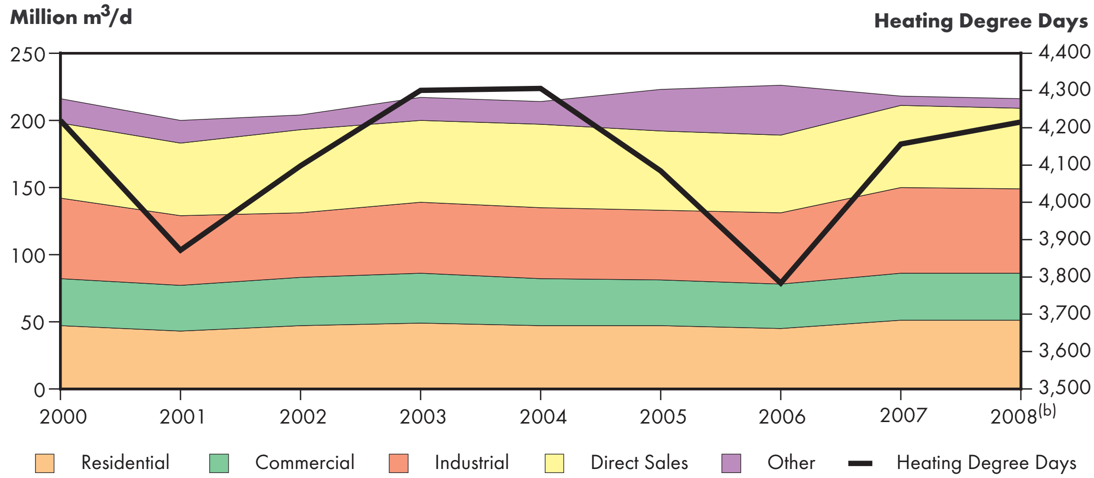
Canadian Natural Gas Reserves – How Much Gas is There?

Canada is the third largest natural gas producer in the world behind Russia and the U.S. However, Canada is 21st in terms of reserves. While remaining established reserves are reduced by production each year, new discoveries, extensions to existing pools and revisions to reserves estimates usually add to reserves. As a result, the changes in reserves annually from production are generally much less than the annual production volume.

Currently, if these additions are not considered, our reserves life is one of the lowest in the world at 9.1 years, meaning it would take only 9.1 years to exhaust our proven reserves at the current production rate. But, if experience is any indicator, Canada will not run out of natural gas any time soon. The U.S. has maintained a 10-year reserve life for the past 25 years, lately through reserve additions of shale gas, which Canada is just beginning to exploit.

FIGURE 5.7

Canadian Total Gas Consumption and Heating Degree Days[(a)]



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

(b) Estimate

Source: Statistics Canada, NEB Estimates, and Canadian Gas Association

space, actual natural gas consumption in this sector has changed little since 2000, growing by approximately 0.7 per cent annually on average. This is attributed, at least in part, to mild winter weather over the past few years. Four of the past eight years rank among Canada's top 10 warmest years[15]. 2008 was slightly colder than the previous year, but still 0.7 Celsius above normal, according to Environment Canada. Besides weather effects, higher and more volatile natural gas prices moderated natural gas consumption, particularly in the price-sensitive industrial sectors, in recent years.

The most significant impact on natural gas consumption was the emergence of major economic turmoil in the global financial markets seen in 2008. The economic recession in the U.S. has resulted in lower industrial activity, collapsing commodity prices and tight credit conditions. Canadian manufacturing and industrial sectors have been impacted by these recessionary forces and gas consumption in these sectors was estimated to have declined by three per cent in 2008.

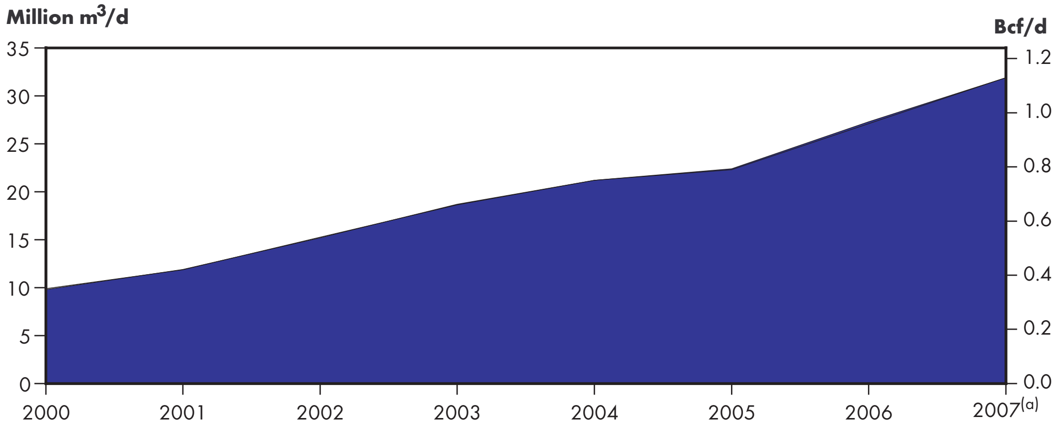
Natural gas is used in both the generation of electricity and steam. Steam is used for in situ oil production and in the production of hydrogen to upgrade bitumen into synthetic crude oil blends. A fast-growing sector for natural gas consumption over the past few years has been the Alberta oil sands (Figure 5.8). Consumption of natural gas in 2008 was almost 30 million m³/d (1.1 Bcf/d) – over three times the amount of gas used in 2000. While upgrader production declined by two per cent in the latter half, compared to 2007 levels, in situ production had increased overall in 2008.

Although the oil sands industry is a large natural gas user, efforts are underway to reduce its dependence on this fuel. This includes pursuing energy efficiency improvements as well as the adoption of alternative fuels and technologies, such as bitumen gasification, which will provide the bulk of fuel requirements and feedstock in the OPTI/Nexen Long Lake SAGD/Upgrader project, which began production operations in late 2008.

15 Environment Canada, *Climate Trends and Variations Bulletin*, *Annual 2008*, 19 January 2009.

F I G U R E 5 . 8

Average Annual Natural Gas Requirements for Oil Sands Operations



(a) Estimate

Source: NEB and ERCB

In the longer term, it is expected that the application of bitumen gasification will gradually gain momentum in both in situ and upgrading operations if it can be shown to be an economic alternative to natural gas. As well, improvements and modifications to SAGD methods, and the application of other technologies such as toe-to-heel air injection (THAI™) will begin to play a larger role. THAI™ combustion technology for in situ bitumen recovery combines a vertical air injection well (toe), with a horizontal production well (heel). Most of the heat required to mobilize the bitumen is derived from the combustion process within the reservoir, thus reducing the need for natural gas compared with other thermal recovery methods. Therefore, although natural gas demand in oil sands applications is expected to increase, it will not increase at the same rate as oil sands production.

5.5 Canadian Natural Gas Exports and Imports

2008 natural gas exports were about 282 million m^3/d (10 Bcf/d) or 16 per cent of estimated U.S. consumption. The U.S. Central/Midwest and the U.S. Northeast regions are Canada's largest export markets. Overall, exports of natural gas to the U.S. were lower in most months of 2008 than in 2007 (Figure 5.9). Although the U.S. National Climatic Data Center reported that in 2008 the U.S. experienced its coolest year in more than 10 years[16], economic weakness and growing U.S. natural gas production in 2008 reduced the requirement for Canadian gas imports.

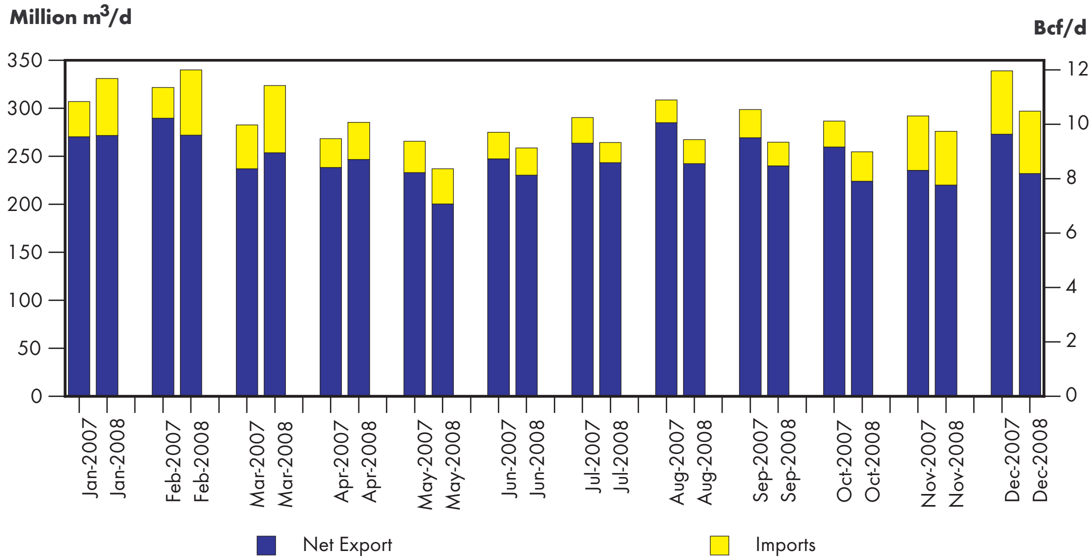
The gross volume of Canadian gas exported to the U.S. was four per cent lower compared with 2007. Net exports (gross exports less imports) for 2008 were 239 million m^3/d (8.4 Bcf/d), about eight per cent lower than the 2007 net export volume of 258 million m^3/d (9.1 Bcf/d).

Canadian revenues from gas exports increased significantly in 2008 over 2007. Although there was a decrease in export volumes, the average export price was about 20 per cent higher in 2008 than in 2007 because of extremely high prices in the first half of 2008. This resulted in net export revenues of about $28 billion, 15 per cent higher than in 2007. 2009 average natural gas prices are not expected to be as high as the 2008 average price. With lower expected Canadian gas requirements in the U.S., because of both lower economic activity and growing U.S. production, the Board, therefore, does not expect 2009 net export revenues to increase from 2008.

16 2008 Annual Climate Review U.S. Summary, National Climatic Data Center, 20 January 2009.

FIGURE 5.9

Monthly Natural Gas Export and Import Volumes



Source: NEB

Pipeline infrastructure allows gas to flow along a choice of pipeline options when destined to eastern markets. As a result, natural gas may be imported through import points in Ontario, if it is economic. Although Canada is a net exporter of natural gas, an estimated 44 million m³/d (1.5 Bcf/d) of gas was imported into Ontario from the U.S. in 2008 (Figure 5.10).

5.6 Natural Gas Liquids (excluding Pentanes Plus)

NGLs are light hydrocarbons produced from natural gas as liquids through an extraction process in gas processing plants or as a by-product of crude oil refining and upgrading. Natural gas liquids, for the purpose of discussion here, include ethane, propane and butanes. Natural gasoline, also known as pentanes plus or condensate, is discussed in Section 4.

Propane and butane prices climbed during the first half of 2008, buoyed by skyrocketing oil prices and petrochemical demand in North America. However, during the second half of the year, propane and butanes prices followed the free fall of crude prices. Propane price at Mont Belvieu, the main NGL trading hub in the United States, fell from an historical monthly average record of 169.3 U.S. cents per gallon in August 2008 to 69.5 U.S. cents per gallon in December.

Canadian propane production in 2008 is projected to be 31 300 m³/d (197.2 Mb/d), a decrease of 0.8 per cent over 2007 production. Propane from gas plants in 2008 is estimated to be 27 694 m³/d (174.5 Mb/d), slightly lower (-0.2 per cent) than last year. Estimated propane production from refineries declined 5.7 per cent to 3 516 m³/d (22.2 Mb/d) as a consequence of lower refinery runs compared with 2007.

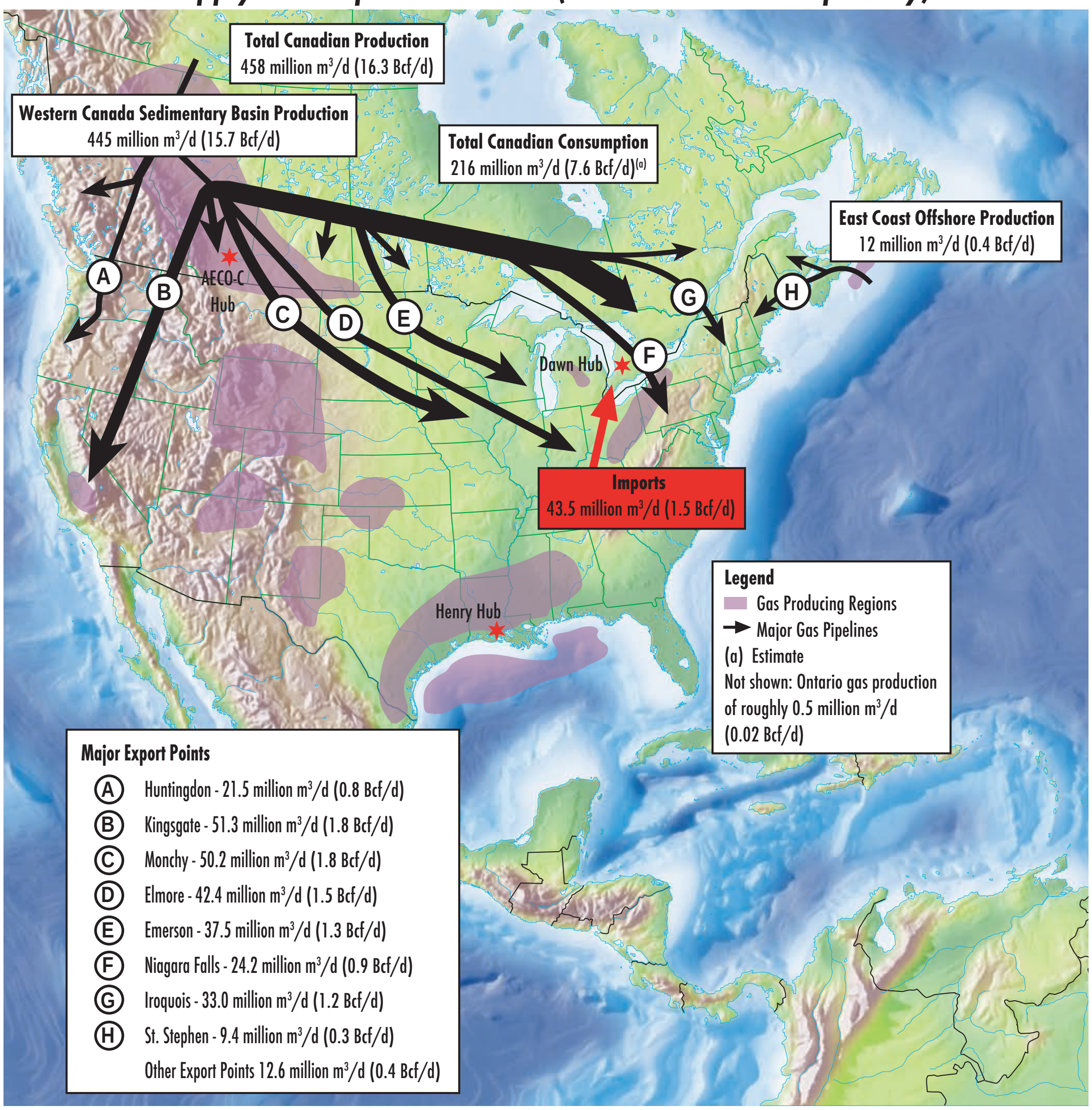
2008 ethane production from gas plants is estimated to be 37 969 m³/d (239.2 Mb/d), a 0.9 per cent reduction as the economic downturn in the United States depressed demand for petrochemical feedstocks. Butane production in Canada in 2008 is projected to be 24 974 m³/d (157.3 Mb/d), an increase of 1.9 per cent over 2007 figures. Refinery production of butane is estimated to be 8 003 m³/d (50.4 Mb/d), while butanes from gas plants is estimated to be 16 050 m³/d (101.1 Mb/d), an increase of 6.7 per cent and 1.6 per cent respectively over the previous year.

Exports of propane in 2008 are estimated to be 17 663 m^3/d (111.3 Mb/d), declining five per cent from 2007. Butane exports in 2008 were 4 164 m^3/d (26.2 Mb/d), an increase of 9.1 per cent over last year. PADD II (Midwest) was the most important destination for propane and butane exports with 57.8 per cent and 54.4 per cent of total exports of each product, followed by the U.S. east coast (PADD I) with 23.9 per cent and 31.6 per cent, respectively. The decrease in propane exports is associated with lower propane production and higher domestic demand, while the increase in butane exports is mostly related to higher production and lower Canadian demand for refinery feedstock.

Even though propane export volumes were lower in 2008, record propane prices helped to increase the estimated export revenue for the year by 17.1 per cent to $2.7 billion. Butane export revenues were also up 35.5 per cent to $748 million, supported by record prices and higher export volumes. Export revenue for the two commodities totaled almost $3.4 billion.

FIGURE 5.10

Natural Gas Supply and Disposition – 2008 (million cubic metres per day)



5.7 Looking Ahead

Shale Gas

With the prevalence of shale deposits throughout North America (Figure 5.6), there has been much optimism and an increase in recent industry activity to pursue potential development of similar resources in Canada. Today, efforts are ongoing to assess shale gas prospects in northeast British Columbia (Horn River Basin and the Montney Formation), southern Alberta and Saskatchewan (Colorado shale), Quebec (Utica shale), and Atlantic Canada (Windsor Group shales). Each shale is in various stages of development or experimentation. There was significant growth in Montney shale gas production in 2008, along with the first production from Horn River Basin shales. While growth is expected to continue into 2009 as shale gas continues to attract industry attention even in the recent downturn, growth is not expected to be as dramatic as that seen in 2008.

While having significant potential, the full extent of commercial development of shale resources is still uncertain. The near-term contribution of Canadian shale development may also be constrained by the need to assess viability, optimize operations and build the necessary connecting infrastructure to access major pipelines. Other considerations include the environment because of high water usage in shale gas operations. Furthermore, Horn River Basin shale gas is 12 per cent CO_2 and its production has the potential to significantly increase Canadian CO_2 emissions unless the CO_2 is re-injected. Local operators are planning for sequestration of the CO_2 into porous formations several kilometres below the surface.

Finally, should Canadian shale gas become a reliable, long-term supply for the North America energy mix, it could become used much more extensively as a substitute for oil and coal in an effort to reduce GHG emissions and to improve energy security.

Liquefied Natural Gas

Global LNG trade enables the development and movement of significant natural gas resources around the world to supplement domestic production. Proven reserves of natural gas worldwide are about 20 times larger than the proven natural gas reserves of North America. Despite being the world's largest producer of natural gas, North America has historically used LNG imports to supplement its indigenous production and provide an important option to ensure that reliable and secure gas supplies are available.

Although the current economic downturn and lower and volatile energy prices will likely reduce the demand for natural gas and the requirement for new LNG import terminals in North America, the long-term requirement for energy and natural gas is still projected to grow. Greater production from shale and other unconventional gas resources have also helped to offset the ongoing decline in conventional production and may reduce or set back the immediate requirement for LNG imports.

In the longer term, economic recovery and environmental initiatives to reduce the combustion of other fossil fuels and GHG emissions may result in significant demand for natural gas and LNG. The extent to which North America pursues various alternate energy sources to natural gas will greatly influence the overall need for LNG. The Board recently published an Energy Market Assessment on the dynamics of global natural gas and LNG markets, the likelihood and availability of future LNG imports to North America and the potential implications for Canadian natural gas markets and LNG development[17].

17 NEB, *Liquefied Natural Gas – "A Canadian Perspective"*, 2008.

In anticipation of growing natural gas requirements in North America, there are numerous proposals to expand existing terminals in the U.S. and Mexico and construct new LNG receiving facilities. Given the integrated nature of the North American natural gas market and infrastructure, Canadian import LNG terminals will likely serve markets in both Canada and the U.S. The extent to which North American LNG facilities will be used and whether long-term supply is available will be determined largely by competitive factors such as market conditions and the stakeholders involved, including their respective contractual arrangements for supply and markets and the requirement for LNG in other global regions.

The first Canadian LNG import terminal (Canaport LNG in Saint John, New Brunswick) is expected to become operational in mid-2009. With prospects for significant future production from shale gas development, and potentially lower requirements for gas exports to the U.S., there are now two proposals to develop an LNG export terminal at Kitimat, British Columbia The eventual number of LNG projects to be developed in Canada is not certain. In general, proposed and existing Canadian LNG projects are located competitively with other North American and global terminals.

Electricity

6.1 Regional Initiatives

Electricity industry activity during 2008 included new infrastructure and also many efforts to maintain adequate supply and reliable operation. Initiatives included new infrastructure additions and also many institutional and governmental initiatives, announcements and clean energy programs across the country.

Western Canada

BC Hydro announced it would pursue a Bioenergy Call to independent power producers to utilize forest-based biomass, including sawmill residue and logging debris. The utility also launched a Standing Offer Program for renewable generation projects up to 10 MW and launched the Clean Power Call for large renewable projects, with the intent of acquiring up to 5 000 GW.h annually.

The Alberta government introduced a regulation aimed at promoting the development of micro-generation. Customers in Alberta can now run their own small-scale "environmentally friendly" generation projects and receive credit for any power they supply to the grid, in excess of their own needs. The micro-generation units must be less than one MW in size and employ a renewable technology, such as wind, solar, biomass or small-scale hydro.

SaskPower announced that it will pursue a demonstration CCS project at its Boundary Dam coal facility. The project will be pursued as a

SaskPower's Boundary Dam Carbon Capture and Storage Demonstration Project

Saskatchewan's public electric utility, SaskPower, has partnered with the Government of Canada, the Government of Saskatchewan and private industry to fund and develop a CCS demonstration project at SaskPower's Boundary Dam coal-fired generating station, near Estevan, Saskatchewan.

The project is expected to cost $1.4 billion and involves the refurbishment of Boundary Dam Unit #3, originally built in 1960 and otherwise scheduled for retirement in 2013, and retrofitting post combustion carbon capture technology, thereby extending the plant life by as much as 30 years.

The project is to be undertaken in two phases. Phase 1, scheduled for 2011 to 2013, would result in emissions from Unit #3 being reduced to levels comparable to a conventional natural gas combined cycle plant and a reduction in the net-to-grid output of Unit #3 from 139 MW to 120 MW. Phase 2 of the project, from 2013 to 2015, would further reduce the plant output to 100 MW and reduce emissions to near zero, capturing nearly one million tonnes of CO_2 annually. A process is currently underway to select a vendor for the CCS technology.

Once captured, the CO_2 would be compressed into liquid form and shipped via pipeline to nearby oilfields where it would be injected into oil reservoirs. Injection of CO_2 into oil reservoirs allows more oil to be extracted (enhanced oil recovery) and serves as permanent storage for the liquefied CO_2. Securing a buyer for the captured CO_2 and developing the pipeline transmission infrastructure from Boundary Dam to the oilfields will be critical to the success of the project.

Ontario's Smart Meters

Ontario is introducing smart meters – along with a "time-of-use" electricity price structure – to help customers manage their electricity costs, while helping Ontario to build a more efficient and environmentally sound electricity system. So far in Ontario, more than two million smart meters have been installed – almost half the target number. Every home and small business should have a smart meter installed by 2010.

A smart meter can record and report electricity consumption information automatically. In Ontario, smart meters will record electricity consumption on an hourly basis and, typically, report that information via wireless technology.

Electricity prices paid by consumers can vary during different hours of the day, which reflects the way prices are established in the electricity market. This will encourage consumers to think more about how and when they use electricity. As they move consumption away from the more expensive (peak) times of the day, consumers can help Ontario reduce its peak demand, which can help limit the construction and operation of peak-generating facilities.

Smart meters – plus time-of-use rates – will provide customers with a cost-management tool.

government and industry partnership to rebuild and retrofit the existing Boundary Dam Unit #3 with carbon capture technology. This project will demonstrate the technical, environmental and economic benefits of CCS.

Manitoba Hydro continued to expand its Power Smart programs in 2008, particularly with the introduction of new biomass electric production incentives. This program will assist users with potential to utilize biomass for distributed generation by providing feasibility assessment and generation construction services.

Ontario and Quebec

Ontario set the stage during 2008 for renewable energy developers to bid on 500 more MW of new green energy supply. The final contract rules have been set for a competition to award new contracts for projects larger than 10 MW. This bidding will mark the first phase of a Renewable Energy Supply procurement process, one that is intended to combat climate change by adding 2 000 MW of new green power to Ontario's electricity supply.

Hydro-Québec's goal of saving eight TW.h of electricity by 2015 has been increased to saving 11 TW.h, or about six per cent of annual customers' forecasted consumption. The target of 4.3 TW.h in 2010 is now established at five TW.h. If Quebec reaches its savings by 2015, it would be equivalent to saving the annual consumption of about 550,000 houses in the province.

Atlantic Canada

In 2008, the New Brunswick government initiated an analysis of the province's current electricity market. The final report will consider the structure of the electricity market and its impact on the structure and governance of the NB Power group of companies. New Brunswick also released a preliminary report exploring various models for developing community wind energy, as well as the province's *Strategic Environmental Assessment Report on In-Stream Tidal Energy Generation*. The report suggests that tidal energy generation could become a reality on New Brunswick shores of the Bay of Fundy.

The P.E.I government released a three-part Environment and Energy Policy Series entitled *Securing Our Future*. The first volume sets out a ten-point plan on how to meet the goal of growing wind to 500 MW by 2013, as well as to explore issues pertaining to the intermittency of wind power and how to back up this volume of wind capacity. The second volume explores biofuels and biomass and sets out a provincial energy strategy and vision, while the third volume speaks to climate change and global warming. As the province imports nearly 85 per cent of its energy needs, which are primarily petroleum based, the P.E.I. strategy targets diminishing dependence on imported oil.

6.2 Electricity Prices

Canadian electricity prices are determined in regional markets. Prices in most jurisdictions are 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," must also be approved and rolled in, resulting in higher average costs. This model is followed in all provinces and the 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 prices for new generation.

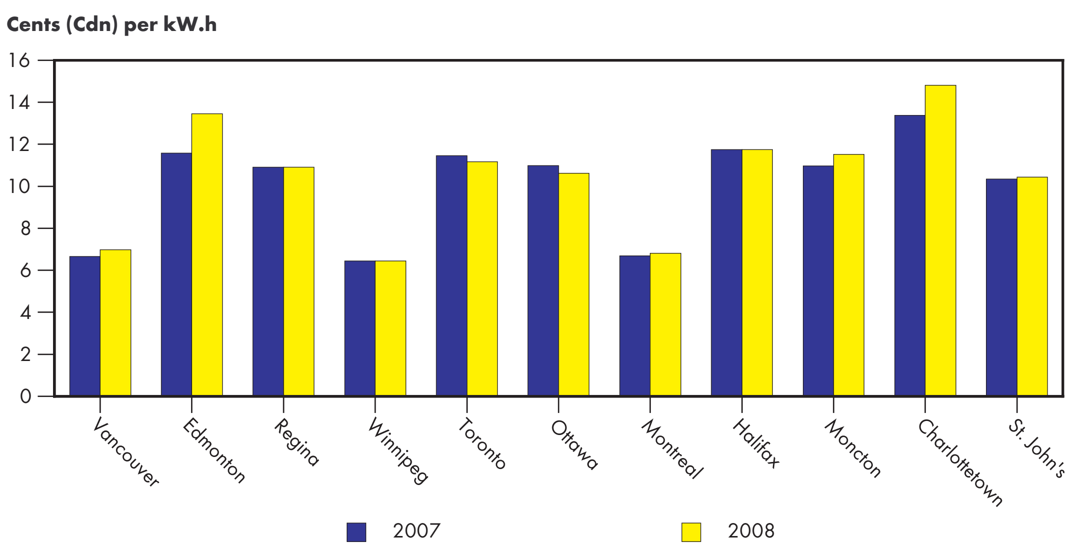
Prices tend to be lowest in hydro-based provinces such as British Columbia, Manitoba and Quebec, which benefit from a high proportion of low-cost heritage assets, such as hydro-generating facilities that have minimal fuel costs and largely amortized capital costs. Electricity prices are most volatile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

Figure 6.1 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. Prices in Charlottetown and Edmonton increased significantly, while prices in Ontario cities decreased.

The cost of electricity for residents in P.E.I. is based largely on a fixed energy rate and a variable Energy Cost Adjustment Mechanism (ECAM). The ECAM adds to the overall cost when fossil fuel prices are high, and because such fuels were more expensive in the spring of 2008 than a year earlier, the prices in P.E.I. increased year-over-year.

F I G U R E 6 . 1

Canadian Residential Electricity Prices
(Based on 1 April rates and consumption level of 1 000 kW.h per month)



Source: Hydro-Québec: Comparison of Electricity Prices in Major North American Cities

Residents in Alberta have the option to pay either a competitive contract rate or the default Regulated Rate Option (RRO) which is set monthly. Every year until 2010, the RRO will be based more on the next-month projected cost of electricity and less on the long-term projection. The difference in the RRO from April 2007 to April 2008 represents most of the increase shown for Edmonton prices.

Residents in Ontario also have the option to pay either a contract rate or pay according to the Regulated Price Plan (RPP) which is set annually. The RPP is based on a forecast of wholesale prices and generation from regulated facilities. The RPP prices in effect for most of 2008 were lower than the previous year, which explains the decrease shown for Toronto and Ottawa prices. However, the wholesale prices averaged slightly higher, and the RPP prices were raised as of November 2008.

6.3 Electric Reliability

The reliability of the Bulk Power System (BPS) is achieved through ensuring that supply adequacy and operating reliability is maintained in generation and transmission. Operation of the BPS within the requirements of a set of reliability standards is critical to ensuring that the BPS can operate reliably despite power system disturbances and contingencies.

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 and are mandatory in Ontario and New Brunswick through the market rules governing transmission in those provinces. NERC standards are applicable in Saskatchewan and Manitoba 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 April 2008, the NEB issued letters to international power line (IPL) owners that the Board is pursuing the option of amending the National Energy Board Electricity Regulations to implement mandatory reliability standards on IPLs. The Board is exploring different possibilities for amending the regulations while recognizing regional interests.

A main driver for the implementation of mandatory reliability standards was the major power blackout that affected Ontario and the U.S. northeast in August 2003. While there is currently no single measure to indicate trends in overall electric reliability, NERC continues to work toward developing such measures. For example, the number of power system disturbances has shown a declining trend since 2003. It is NERC's view that the development of mandatory standards and the increased attention paid to reliability by the BPS operators have resulted in improved reliability in recent years.

6.4 Electricity Generation

Canadian generation decreased from 607 TW.h to 601 TW.h in 2008 (Table 6.1). Hydroelectric generation increased from 366 TW.h to 369 TW.h, the result of favourable conditions in hydroelectric-generating provinces. Thermal generation decreased from 150 TW.h in 2007 to 139 TW.h, reflecting the economic slowdown and higher fuel prices. Nuclear generation was stable overall as Ontario generation offset impacts of plant outage in New Brunswick. Wind generation increased by more than 20 per cent to 3.6 TW.h.

TABLE 6.1

Electricity Production (TW.h)

	2004	2005	2006	2007	2008
Hydroelectric	336.7	358.4	349.5	365.8	369.3
Nuclear	85.2	86.8	92.4	88.2	88.6
Thermal	154.6	157.3	147.7	149.6	139.1
Wind & Tidal	1.0	1.6	2.5	2.9	3.6
Total	**577.5**	**604.2**	**592.0**	**606.5**	**600.6**

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

Source: 2001 to 2007: Statistics Canada 57-202
2008: CanWEA, Statistics Canada 127-0002

Many forms of generation, including conventional and emerging technologies (e.g., wind, small hydro and biomass) were proposed across the country in 2008. Some significant regional power generation developments follow.

SaskPower pursued the addition of two 94 MW simple cycle gas-fired peaking generation plants in 2010 to meet the increased load driven by population and economic growth in the province. Natural gas turbines are also viewed as a “green” replacement technology, especially for jurisdictions currently dealing with oil and standard coal electricity generation plans.

Going Green: Evolving Electricity Generation

Canadians are increasingly interested in the impact of energy and our environment. More and more, one cannot be mentioned without the other in mind. While Canadians increasingly feel more personal responsibility for their environment, change happens slowly. The development of green energy options answers Canadian environmental concerns, such as air quality and global warming.

Electric generation is one area in which emerging technologies, including wind power, small hydro, biomass, geothermal energy, fuel cells, solar cells, ocean energy and clean coal increasingly pose significant potential for cleaner, greener energy. Implementing new technology, while promoting local economic growth and protecting the environment does not come without its challenges. Collectively referred to as “renewables”, greener options include:

Wind Power: *A commercially viable source of power, wind involves no fuel cost, emissions or waste. However, wind does not always blow and most wind farms operated at between 25 to 35 per cent capacity.*

Biomass: *Landfill gas and waste products are used to create electricity, reducing greenhouse gases. However, high start-up and operating costs pose a challenge.*

Small Hydro: *This well established technology is Canada’s largest contributor to “going green”. With low capital costs and many possible sites available in Canada, small hydro poses a much smaller environmental impact than larger hydro options. However, small hydro can be costly and time consuming given associated regulatory approvals, and local opposition to development can delay the growth of this technology.*

Other emerging technologies, including solar, geothermal and wave power continue to evolve.

Construction of the Wuskwatim Generating Station in Manitoba progressed last year with the completion of the first phase of excavation and a transmission line. This project represents the first collaboration in Canada for construction and ownership of a large hydroelectric generation facility between a First Nations group and a public utility.

In Ontario, two major gas-fired generators came online in high value locations (Sarnia and Toronto), with a combined output near 1 500 MW. These facilities will form part of the capacity needed to phase out coal-fired generators in the province. Coal-fired electricity generation dropped to a level unseen in the last decade, whereas wind and gas-fired generation continued to rise in both installed capacity and energy output.

In Quebec, commissioning of the Chute-Allard and Rapides-des-Cœurs hydro developments began in 2008. The two generating stations will have a total capacity of 139 MW and full operation is expected in mid-2009. The Péribonka 385-MW generating facility has also been completed in 2008 and will add about 2.2 TW.h of clean energy annually. Hydro-Québec decided to refurbish its Gentilly-2 nuclear power plant in Bécancour. The project is scheduled for late 2010 to mid-2012 at a cost of $1.9 billion. Refurbishing the 675-MW plant will extend its operation until 2040 and provides about 5.0 TW.h of low emissions annual output.

In New Brunswick, NB Power is currently refurbishing the Point Lepreau nuclear reactor. It was taken out of service in March 2008 and it is scheduled to be back in service in late 2009 or early 2010. The Point Lepreau generating station provides up to 30 per cent of New Brunswick's electricity and is one of the lowest cost generators on NB Power's electrical system. Studies of the potential for a second nuclear reactor at Point Lepreau have also reached the conclusion that a merchant model is viable under certain conditions, including long-term market commitments. A second reactor would have the potential to displace oil in New Brunswick and P.E.I., as well as coal in Nova Scotia.

Wind

According to the Canadian Wind Energy Association (CanWEA), total wind generation capacity was about 2 370 MW at the end of 2008, enough to power over 680,000 homes or equivalent to about one per cent of Canada's total electricity demand. Canada's wind generating capacity rose 34 per cent from 2007, ranking 16th in the world. It has officially become the 12th country in the world to surpass 2 000 MW.

At the end of 2008, Ontario was the leader in wind power in Canada with 782 MW of installed capacity, followed by Quebec and Alberta with 532 MW and 524 MW, respectively (Figure 6.2).

6.5 Electricity Demand

Over the past few years, electricity demand growth in Canada has shown some signs of moderating, partly from conservation and improved efficiency and partly because of slowing economic activity in some industrial sectors. In 2008, initial estimates indicated demand declined from 576 TW.h in 2007 to 568 TW.h (Table 6.2).

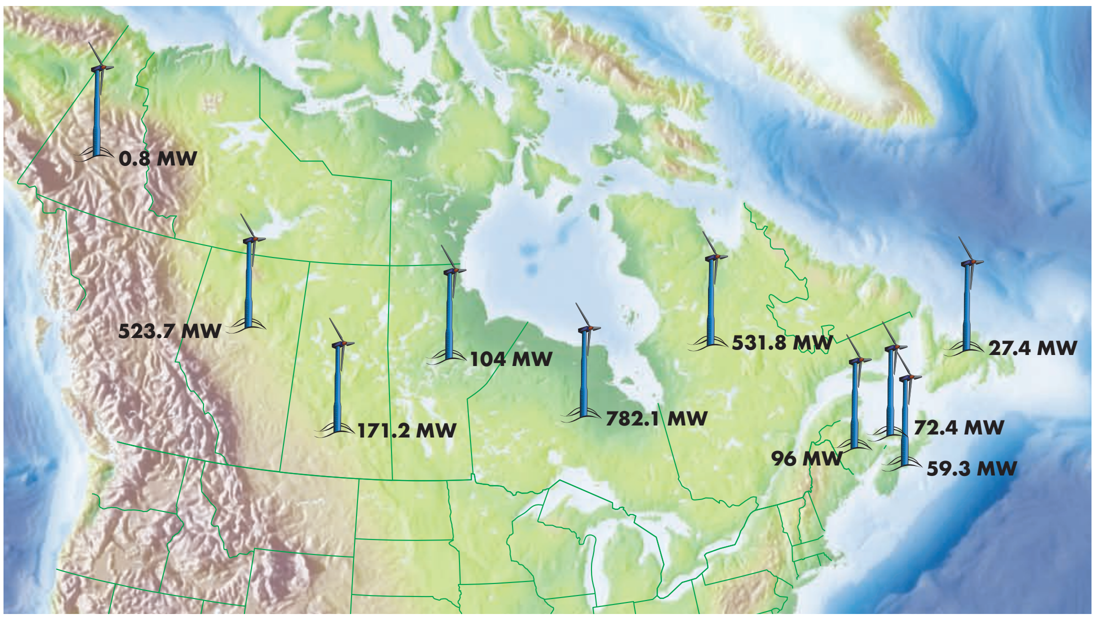
Demand growth trends varied across the country. As a result of increased conservation efforts and slowing industrial demand, British Columbia's electricity consumption dropped two per cent from the 2007 levels. Alberta consumption continued to grow, requiring increased imports from British Columbia and Saskatchewan. Consumption in Saskatchewan stayed on par with 2007. The five per cent growth in Manitoba led the nation in 2008. To meet the increased demand, Manitoba generated three per cent more electricity and exported six per cent less than in 2007.

In contrast, the economic slowdown contributed to a decline in demand of three per cent in Ontario and two per cent in Quebec. Despite this softening in demand, generation (and exports) in these provinces increased significantly.

In the eastern provinces, any concern about supply adequacy has been reduced by an economic slowdown that has reduced overall demand. The manufacturing industry has been hit hard by the slowdown and, as plants have shut down, demand has decreased. The refurbishment of Point Lepreau contributed to a 16 per cent drop in New Brunswick generation and significantly more imported electricity. Newfoundland and Labrador reported increased consumption in 2008.

FIGURE 6.2

Canadian Wind Farms



Source: CanWEA

TABLE 6.2

Electricity Generation and Disposition (TW.h)

	2004	2005	2006	2007	2008
Supply					
Total Generation	577.5	604.2	592.0	606.5	600.6
Imports	22.2	18.7	22.1	18.4	23.5
Total Supply	**599.7**	**622.8**	**614.1**	**625.0**	**624.1**
Disposition					
Demand	566.9	580.5	574.3	575.6	568.4
Exports	32.8	42.3	39.7	49.3	55.7
Total Disposition	**599.7**	**622.8**	**614.1**	**625.0**	**624.1**

Source: 2001 to 2007: Statistics Canada 57-202, NEB
2008: CanWEA, Statistics Canada 127-0003, NEB

Trends in the Territories varied. Indications are that in 2008, consumption decreased by three per cent in Yukon, remained relatively constant in the Northwest Territories, and increased by four per cent in Nunavut.

6.6 Electricity Exports and Imports

Electricity exports increased 13 per cent from 49 TW.h in 2007 to 56 TW.h and were 40 per cent above the previous five-year average of 39 TW.h. Imports increased from 18 TW.h to 24 TW.h in 2008. Imports were about 10 per cent above the previous five-year average of 21 TW.h. Canada exported approximately \$3.8 billion of electricity compared to \$3.1 billion in 2007, an increase of 22 per cent.

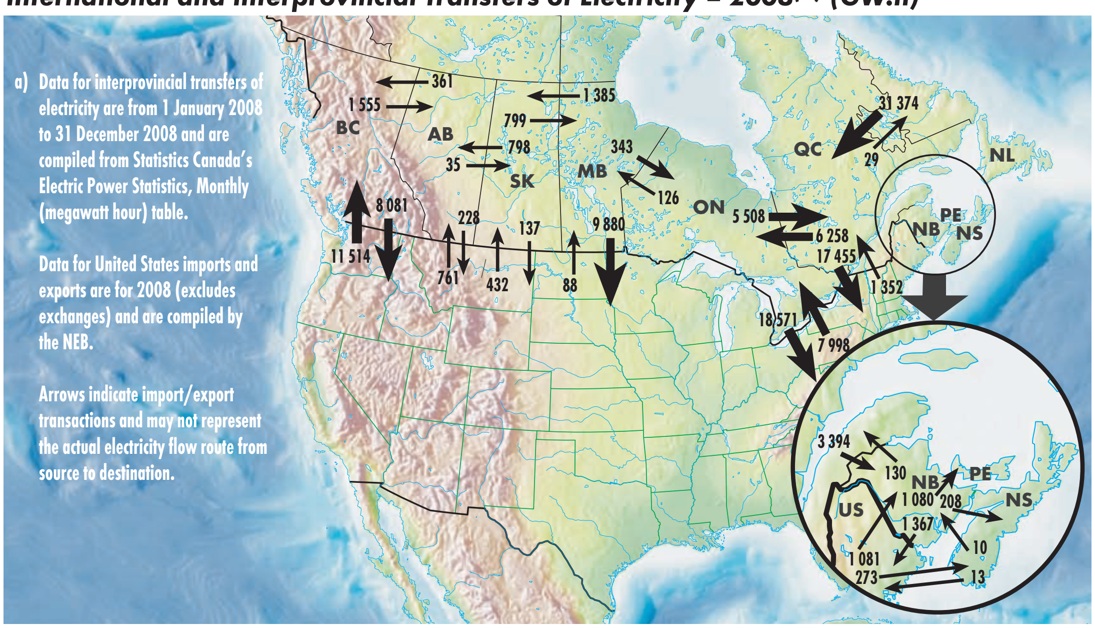
Canadian electricity jurisdictions tend to be winter-peaking systems and so the largest imports of electricity from the U.S. typically occur during the winter when local heating requirements are highest.

Net exports increased by four per cent from 31 TW.h in 2007 to 32 TW.h. Net exports were nearly double the previous five-year average of 18 TW.h. Figure 6.3 illustrates international and interprovincial transfers of electricity.

The overall increase in exports and export revenues can be attributed to favourable water conditions in hydroelectric-generating provinces and export growth in Ontario. Exports from Quebec increased from 2007 levels, while exports from British Columbia and Manitoba dropped slightly. For the first time in decades, Ontario exported the most electricity, with exports amounting to 125 per cent more than the previous five-year average. Imports into Ontario increased as well, whereas Quebec and Manitoba imported significantly less than in 2007. For the sixth consecutive year, British Columbia's trade balance alternated between net exports and net imports, as the province reported net exports of 3.1 TW.h in 2007 and net imports of 3.4 TW.h in 2008.

FIGURE 6.3

International and Interprovincial Transfers of Electricity – 2008*[a] *(GW.h)



6.7 Looking Ahead

In planning for adequacy of future supplies, utilities and their regulators are paying particular attention to renewables, conservation and efficiency improvement.

A number of wind projects are already under construction that will be fully commissioned soon. As a result, despite the poor economic outlook, 2009 installations could exceed those completed in 2008. Accordingly, Canada could pass the 3 000 MW mark for wind capacity in 2009. Integration of new wind capacity into the grid will continue to pose challenges across the country. Fortunately, Canada's large hydroelectric resources, which account for about 60 per cent of Canada's electricity, provide a complement for fluctuating wind generation, enabling the opportunity to integrate more wind energy into the system. This is an advantage Canada has over other countries in the development of the wind power.

Canadian electricity consumers face upward pressure on electricity rates, mainly driven by the development of higher-cost sources of generation. Volatile fuel prices including natural gas, oil and coal will also impact generation costs and therefore, electricity prices. Consumer prices will be generally more stable in the hydro-based provinces and where prices are established on a cost-of-service basis.

Export revenues will continue to be dominated by hydroelectric-generating provinces. Despite decreasing levels anticipated in the foreseeable future in reaction to the economic slowdown, electricity exports are expected to continue to be a significant source of revenue. Imports will provide reliability for those provinces interconnected with adjacent U.S. regions.

Jurisdictions are expected to continue initiatives toward improving interconnections both inter-provincially and internationally. One such project is the Canada to Northern California project. The Canadian portion of the line is expected to run from the Selkirk substation in southwestern British Columbia to northern Oregon, where it will connect northern California. The line is being spearheaded by California's PG&E and is designed to access incremental renewable resources in the U.S. Pacific Northwest as well as Canadian electricity.

Conclusion

The Canadian energy economy demonstrated strong growth in 2008. Despite small decreases in the production of hydrocarbons, export revenues were higher. At the same time, governments across Canada placed greater importance on environmental protection and made progress in key areas such as CCS and on policies to lower GHG emissions. Canadian conventional oil and oil sands development continued and is increasingly being seen as a critical piece of the North American energy security picture. The natural gas industry, in the midst of change, is finding new supply sources that will have an important, yet uncertain, impact in the market. Electricity generation in Canada is becoming greener.

Canada, with its vast natural resources and diverse economy, is well positioned to responsibly face current challenges and seize opportunities to be recognized as an energy leader. Energy, the environment and the economy will remain interconnected, and Canada will continue on its journey toward sustainable development of energy resources.

AECO or AECO-C	Alberta gas trading spot price.
Bitumen or crude bitumen	A highly viscous mixture, mainly hydrocarbons heavier than pentanes. In its natural state, it is not usually recoverable at a commercial rate through a well because it is too thick to flow.
Coalbed methane	Is a form of natural gas extracted from coalbeds. Coalbed methane, often referred to as CBM, is distinct from a typical sandstone or other conventional gas reservoir, as the methane is stored within the coal by a process called adsorption.
Conventional crude oil	Crude oil, which at a particular point in time, can be technically and economically produced through a well using normal production practices and without altering the natural viscous state of the oil.
Conventional gas	Refers to natural gas from all sources other than CBM.
Hub	A geographic location where large numbers of buyers and sellers trade a commodity and where physical receipts and deliveries occur.
In situ recovery	The process of recovering crude bitumen from oil sands other than by surface mining.
Marketable gas	Natural gas that has been processed to remove impurities and natural gas liquids. It is ready for market use.
Natural gas liquids	Those hydrocarbon components recovered from natural gas as liquids. These liquids include, but are not limited to, ethane, propane, butanes and pentanes plus.
Oil sands	Sand and other rock material that contains bitumen. Each particle of oil sand is coated with a layer of water and a thin film of bitumen.
Pentanes plus	A mixture mainly of pentanes and heavier hydrocarbons obtained from the processing of raw gas, condensate or crude oil.
Reserves – Established	The sum of the proven reserves and half probable reserves.
Reserves – Initial Established	Established reserves prior to deduction of any production.
Reserves – Proven	Reserves recoverable under current technology and present and anticipated economic conditions, specifically demonstrated by drill, testing or production.
Reserves – Remaining	Initial reserves less cumulative production at a given time.