National Energy Board

Office national de l'énergie

Canada's Energy Future

REFERENCE CASE AND SCENARIOS TO 2030

AN ENERGY MARKET ASSESSMENT NOVEMBER 2007

Canada

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* This edition of Canada's Energy Future includes minor revisions and an expanded Appendices. The National Energy Board has issued an Errata for Canada's Energy Future, available on the National Energy Board web site at www.neb-one.gc.ca. Please refer to this Errata for details of significant revisions. The Board apologizes for any inconvenience caused by these changes.

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ACCA	Accelerated Capital Cost Allowance
ACR	Advanced CANDU reactor
EUB	Alberta Energy and Utilities Board
API	American Petroleum Institute
CANDU	Canadian Deuterium (nuclear reactor)
CANMET	Canada Centre for Mineral and Energy Technology
CAODC	Canadian Association of Oilwell Drilling Contractors
CBIP	Commercial Building Incentive Program
CBM	Coalbed methane
CCS	Carbon dioxide capture and storage
CETC	CANMET Energy Technology Centre
CFL	Compact fluorescent light bulb
CHP	Combined heat and power
CNG	Compressed natural gas
CO	Carbon monoxide
CO_2	Carbon dioxide
CSS	Cyclic steam stimulation
CVT	Continuously variable transmission
DSM	Demand-side management
EGH	EnerGuide for Houses
EMA	Energy Market Assessment
GDP	Gross Domestic Product
GeoPOS	GeoPower in the Oil Sands
GHG	Greenhouse gas
GSC	Geological Survey of Canada
H_2	Hydrogen gas
ICE	Internal combustion engine
IEA	International Energy Agency
IEEP	Incremental Ethane Extraction Policy
IGCC	Integrated Gasification Combined Cycle
IOR	Improved Oil Recovery
IPCC	Intergovernmental Panel on Climate Change

LEED®	Leadership in Energy and Environmental Design
LNG	Liquefied natural gas
MNECB	Model National Energy Code for Buildings
MSAR	Multiphase Superfine Atomized Residue
NAFTA	North American Free Trade Agreement
NEB	National Energy Board
NGL	Natural gas liquid
NIT	Nova Inventory Transfer
NOx	Nitrogen oxides
NRCan	Natural Resources Canada
NYMEX	New York Mercantile Exchange
OECD	Organization for Economic Cooperation and Development
OPEC	Organization of the Petroleum Exporting Countries
PIHV	Plug-in hybrid vehicle
PM	Particulate matter
R, D & D	Research, development and demonstration
RFO	Residual fuel oil
SAGD	Steam assisted gravity drainage
SO_x	Sulphur oxides
StatCan	Statistics Canada
SUV	Sport Utility Vehicle
THAI™	Toe-to-heel air injection
UPS	Uninterruptible power supply
U.S.	United States
VAPEX	Vapourized extraction
VKT	Vehicle kilometres traveled
VOCs	Volatile organic compounds
WCS	Western Canadian Select
WCSB	Western Canada Sedimentary Basin
WTI	West Texas Intermediate

LIST OF UNITS

Units

bbl	barrels
b/d	barrels per day
Bcf	billion cubic feet
Bcf/d	billion cubic feet per day
GJ	gigajoule
GW	gigawatt
GW.h	gigawatt hour
kW.h	kilowatt hour
m^3	cubic metre
m^3/d	cubic metres per day
Mb/d	thousand barrels per day
Mcf	thousand cubic feet
Mcf/d	thousand cubic feet per day
MMb/d	million barrels per day
MMBtu	million British thermal units
Mt	megatonne
MW	megawatt
$ or Cdn$	Canadian dollars
US$	U.S. dollars
Tcf	trillion cubic feet
TW.h	terawatt hour

Executive Summary

Energy has and always will be extremely important to Canadians. With our northern climate, huge land mass and vast natural resources, we use energy to heat our homes, provide transport, develop our resources and produce goods and services. Energy is essential to our comfort and our economic prosperity.

At the same time, there is growing awareness of the consequences of energy use to our physical environment, the air quality in our cities, our health and the potential impact on the climate of our planet. Finding ways to produce and use energy that minimize the impacts on our environment is one of the key challenges Canadians face in the 21st century.

This report, *Canada's Energy Future*, allows the National Energy Board (NEB or Board) to communicate with Canadians about energy issues. Providing this information is part of the NEB's overall goal that Canadians benefit from efficient energy infrastructure and markets.

Canada's Energy Future highlights the issues Canadians face with respect to energy, as well as brings to light future implications for Canadian energy producers and consumers.

While the report focuses on trends in energy supply and demand, it does not offer specific policy direction as to what programs or actions would be required to meet certain objectives. It is up to us as Canadians, the energy industry and policy-makers to determine the desired outcome and the tools required to get us there. It is our hope that this report will be a positive contribution to the growing discussion many Canadians are having about energy and our environment.

The report examines different possible energy futures that may unfold for Canadians up to the year 2030. This includes a baseline projection, called the Reference Case, which is the Board's view of the most likely outcome up to the year 2015. Three different scenarios, each with its own internally consistent set of assumptions, such as economic growth, action on environmental issues and energy prices, are then used to examine Canada's energy future to 2030:

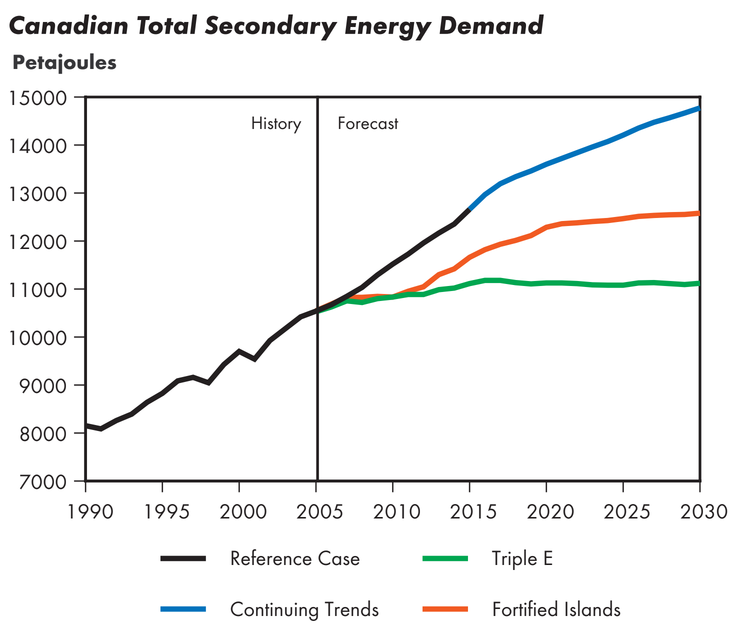
- **Continuing Trends Scenario:** Trends that are apparent at the beginning of the outlook period are maintained throughout the entire forecast and extend the Reference Case over the long-term.
- **Triple E Scenario:** A balancing of economic, environmental and energy objectives means this scenario has well-functioning energy markets, cooperative international agreements and the most rigorous energy demand management policies of the three scenarios.
- **Fortified Islands Scenario:** Security concerns dominate this scenario with geopolitical unrest, a lack of international cooperation and trust, and protectionist government policies.

The main findings of this report are as follows:

Energy demand in Canada will continue to grow for the next 30 years.

- Energy demand will remain primarily a function of population and economic growth. With these two factors on the rise, energy demand is growing (Figure ES.1). The way Canadians use energy will change, but slowly. This is because our office buildings, homes and vehicles are not replaced or upgraded on a regular basis to take advantage of the latest energy efficient technologies. Over the long-term, there will be opportunities for Canadians to reduce their energy demand as improvements in energy efficiency and technology take effect.

FIGURE ES.1



- Canadians will continue to use automobiles for personal transportation. Although these vehicles are becoming more energy efficient, they will still rely primarily on fossil fuels.
- Energy efficiency across the economy will continue to improve. The rate of improvement will depend on government policies and Canadians' commitment to managing the growth in energy demand.
- There will be a continued demand for natural gas including the need for gas in oil sands processing and electricity generation. However, there is also a move toward gas alternatives including substitution to other forms of energy and improved efficiency. This is especially true in the Triple E Scenario.

Canadians will have enough energy supplies in the forecasted future.

- Fossil fuels will continue to be the dominant source of energy supply for Canadians through to 2030. New emerging technologies and renewable energy resources, such as wind power and small hydro power projects, will be increasingly used.
- Oil sands production will grow in all three scenarios and the production will contribute to increased exports and Canadian economic growth. Large volumes of crude coming from the oil sands will be moved to market and will require appropriate infrastructure to do so.
- Natural gas production from the Western Canada Sedimentary Basin (WCSB) will decline. In fact, in two of the three scenarios, total natural gas production declines. However, there are opportunities for development of gas reserves in northern and offshore regions.

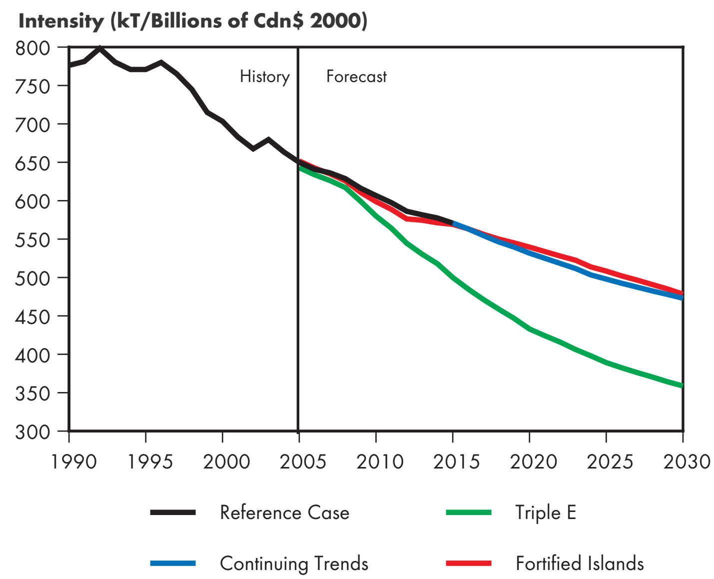
- Imports of liquefied natural gas (LNG) will increase in both the Continuing Trends and Triple E Scenarios. In the Triple E Scenario, LNG imports will account for half of Canada's gas needs by 2030.

Controlling greenhouse gas (GHG) emissions will be challenging.

- In the three scenarios studied, GHG emissions increase or decline slightly. In the Continuing Trends and Fortified Islands Scenarios, GHG emissions increase as a result of continued economic and energy demand growth. Under the Triple E Scenario, GHG emissions decline modestly as a result of energy demand management programs. Further changes by Canadians in lifestyle choices and more ambitious energy reduction programs, will be required to achieve additional reductions in GHG emissions.
- In order to achieve the Canadian government's target of a 20 percent reduction in GHG emissions by 2020, the full spectrum of GHG reduction strategies will need to be considered. Elements of solution, amongst others, will be found in agriculture and forestry carbon sinks and international emissions trading. This report, being focused on energy in Canada, did not seek to analyze these broader strategies.

FIGURE ES.2

Canadian GHG Emissions Intensity



GHG emission intensity is declining.

- Overall GHG emission intensity in Canada is declining. This means fewer GHG emissions to produce the same amount of goods and services (Figure ES.2). The future rate of decline differs depending on the policies and programs that are adopted.

Getting key buildings blocks in place will help to meet future challenges and take advantage of opportunities in the energy sector.

- Technology can offer solutions to many challenges that we face today. The type of technology choice will depend on the scenario that will unfold in the future. Seizing technology opportunities requires a combination of market mechanisms and incentives.
- The markets will continue to work well, balancing energy demand and supply. However, a 'smart' policy is needed to help optimize the multiple objectives of economic growth, environmental sustainability, and responsible development of the energy sector. A proactive

approach will be important due to the wide regional differences with respect to energy and emissions, evolving energy supply systems, and a changing global environment.

- Major investments are needed in the near future to develop new sources of energy and meet the growth in energy demand as well as replace the ageing infrastructure. With our abundant supply of energy, including northern and offshore resources and wind power, infrastructure is needed to bring it to market. There will also be a need for increased infrastructure between provinces for electricity generation. The infrastructure investments will require public engagement, buy-in and acceptance for these initiatives.
- Appropriate and adequate analysis of energy issues will continue to guide decision making. Such analysis is prefaced on high quality data.

Conclusion

The debate in Canada over the future of Canada's energy resources and our environment is growing. As Canadians plan for the future, they will face many decisions about what kind of a lifestyle they want to live and how that lifestyle reflects the broader issues impacting Canada's economy and environment.

A long-term energy vision and strategy for Canada is needed to balance multiple objectives. This plan must be well integrated at the regional level, consider environmental issues and economic growth, and be developed with input from Canadians. Only then will we be able to overcome the challenges ahead and take advantage of the opportunities available.

The NEB plans to contribute to this debate by continuing to pursue our vision of being an active, effective and knowledgeable partner engaging Canadians in the discussion of Canada's energy future.

ANALYTICAL OVERVIEW

This section provides an overview of the quantitative results contained within the report. A more detailed exploration of these results is discussed in subsequent chapters. As well, detailed provincial data tables can be found in the appendices.

Energy issues have an important influence on the lives of Canadians and have become more important in recent years. Rapidly increasing energy prices have given rise to concerns about whether or not energy supply will remain available in sufficient quantities and at reasonable prices. These energy security concerns are underpinned by international geopolitical tensions and conflicts, the apparent peaking of conventional resources in some parts of the world, and a rapid increase in global energy demand due to the pace of growth in developing countries. Furthermore, as evidence of the environmental impacts of energy production and use mount, Canadians are also paying greater attention to the sustainability of the energy system.

In response to these issues, the National Energy Board (NEB or the Board) has developed the latest in its series of long-term energy demand and supply outlooks. *Canada's Energy Future* depicts the analytical results of four different energy demand and supply cases representing the period 2005 to 2030. The report presents possible energy futures only and does not predict outcomes of regulatory decisions by the Board. The Board presents these cases to enable Canadians to discuss Canada's energy future.

Overview of Reference Case and Scenarios

Reference Case (2005-2015)

The Reference Case is a medium-term outlook for the time period 2005 to 2015. The Reference Case is the NEB's view of the most likely development of energy demand and supply over the immediate decade, assuming current energy market trends, the macroeconomic outlook, assumed energy prices and the existing suite of government programs. Overall energy production, consumption, and greenhouse gas (GHG) emissions continue to grow.

Long-Term Scenarios (2005-2030)

The other three cases are alternative long-term scenarios, which endeavour to capture a broader range of energy system outcomes. The analysis for these three cases covers the period from 2005 to 2030. Long lead times for project development and stock turnover imply that for differences in outcomes to occur by 2030, key decisions need to be taken early. Therefore, the scenario analysis begins in 2005 and overlaps the Reference Case period. The three scenarios are:

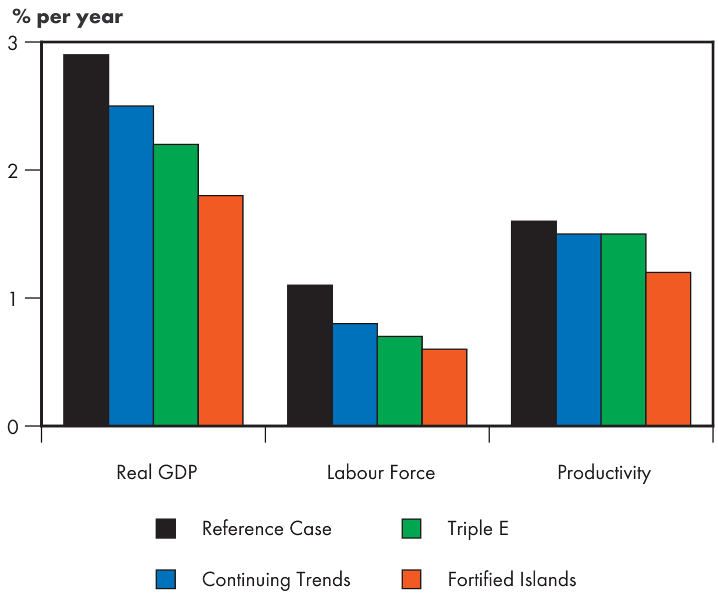
- ***Continuing Trends, which is characterized by the maintenance of significant trends apparent at the beginning of the outlook period through the forecast period.*** This scenario is one of little change. In Continuing Trends, Canada experiences the most rapid economic growth and moderate oil and gas prices. As a result, energy demand, energy production and GHG emissions growth continue to be high.

- ***Triple E is characterized by well-functioning global energy markets, cooperative international agreements and effective environmental policies.*** The scenario seeks a balance of economic, environmental, and energy (Triple E) objectives. This scenario is the mid-case for Canadian economic growth, has the lowest oil and gas commodity prices, and includes numerous energy demand management programs and policies. Consequently, energy demand growth flattens. This is the lowest energy production scenario and GHG emissions decline.

- ***Fortified Islands is the scenario wherein national energy security concerns are emphasized.*** Geopolitical unrest, a lack of international cooperation and trust, and protectionist government policies characterize this scenario. Fortified Islands reflects the lowest Canadian economic growth and the highest oil and gas prices. This combination of factors ensures that this scenario has lower energy demand growth and lower GHG emissions growth than the Continuing Trends Scenario. It also results in the strongest domestic oil and gas production scenario.

FIGURE AO.1

Annual Average Growth Rate of Real GDP, Labour Force and Productivity – Reference Case 2004-2015 and Scenarios 2004-2030



Each of the scenarios provides value by exploring a plausible future. It is unlikely that any one of these scenarios would come true in its entirety. Canadians will probably see a future that contains elements of all the different scenarios.

Overview of Key Assumptions and Quantitative Results

Assumptions

Macroeconomic

Macroeconomic projections are a key driver in the report on Canada's Energy Future. Macroeconomic variables including economic growth, gross output, and personal disposable income are used to develop the supply and demand outlooks. The structure of the Canadian economy (i.e., goods production versus service sector) and the regional distribution of gross domestic product (GDP) will influence demand trends.

In the Reference Case, real GDP growth is 2.9 percent from 2004 to 2015[1] and ranges from 1.8 percent to 2.5 percent from 2004 to 2030 across the three scenarios (Figure AO.1). Long-term economic growth is dependent on labour force and productivity assumptions. The higher the labour

1 The growth rate is the average annual growth rate with 2004 as the base year.

force or productivity improvements, the higher the economic growth, with all other factors held constant. In addition, the macroeconomic forecasts are also strongly influenced by scenario storylines.

A common thread across the three scenarios is a notable deceleration of growth in the labour force, which intensifies over the long-term. This outcome is driven by demographic factors, such as an ageing population and lower birth rates. This results in slower average economic growth projections over all three scenarios than has been experienced in the recent past. Labour force growth varies between 0.6 percent and 1.1 percent over the Reference Case and scenarios (Figure AO.1). Altering levels of immigration across scenarios provide variations in the demography, but does not reverse overall trends. Productivity assumptions range between 1.2 percent and 1.6 percent. Productivity growth in the scenarios matches, or is modestly close to, growth in the recent past.

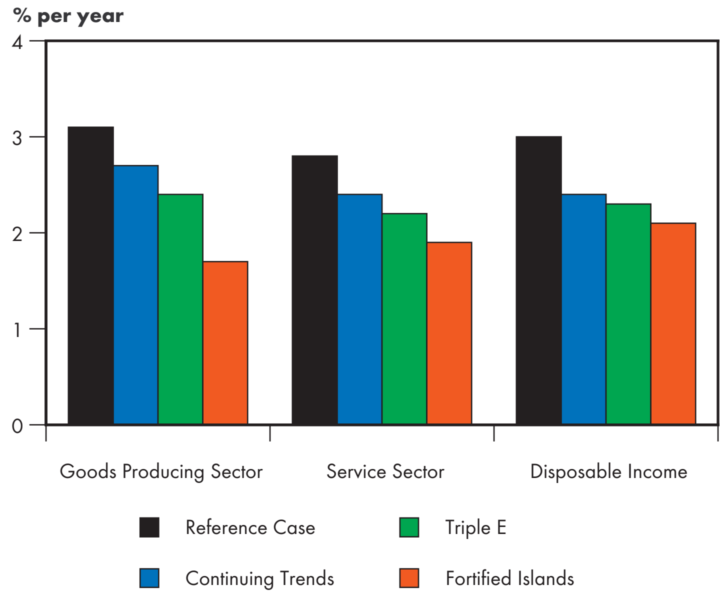
All factors considered, the Reference Case projects continued strong economic growth. This is maintained into Continuing Trends which reflects the highest economic growth of the three scenarios. Fortified Islands is the low economic growth scenario and Triple E falls in the middle. In 2030, the Triple E economy is 7 percent smaller and Fortified Islands is 10 percent smaller than the Continuing Trends economy.

Economic growth is linked to energy consumption. This is particularly evident in energy-intensive industries within the goods producing sector. In Continuing Trends and Triple E, the goods producing sector maintains its current share of GDP. Slower export demand for manufactured goods and marginally higher exchange rates in Fortified Islands lowers the goods producing share while the service sector share grows slightly.

Personal disposable income growth also influences energy demand trends, particularly in the residential sector and in personal transportation. Across the Reference Case and the scenarios, there is a range of personal disposable income growth rates that reflect the overall health of the respective economies (Figure AO.2).

F I G U R E A O . 2

Annual Average Growth Rate of Goods Producing Sector, Service Sector and Personal Disposable Income – Reference Case 2004-2015 and Scenarios 2004-2030



Some scenarios result in changes in the relative share of regional GDPs (Figure AO.3). In Continuing Trends, the share of regional GDP changes little from current shares. In Triple E, the shift in economic growth favouring central Canada is a result of relatively strong growth of manufacturing stemming from strong export demand. The opposite effect occurs in Fortified Islands where slow manufacturing export demand and high oil and gas prices hinder the manufacturing regions, but produce a boom in the oil and gas producing regions.

FIGURE AO.3

Regional Composition of GDP, 2004 and 2030

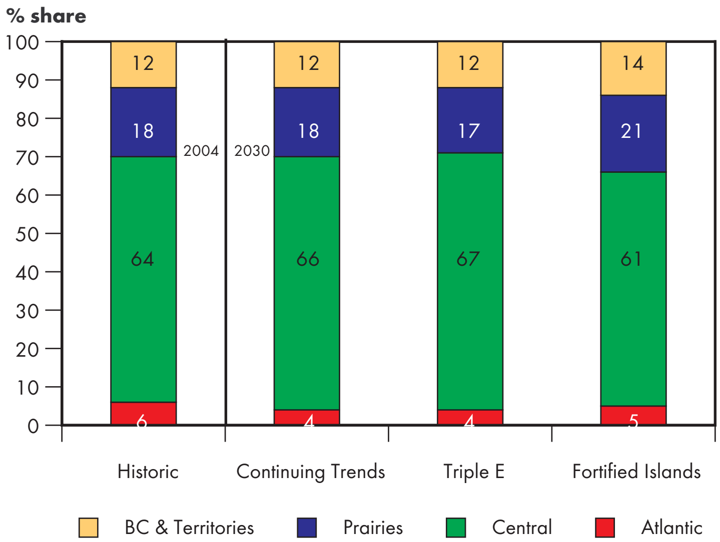
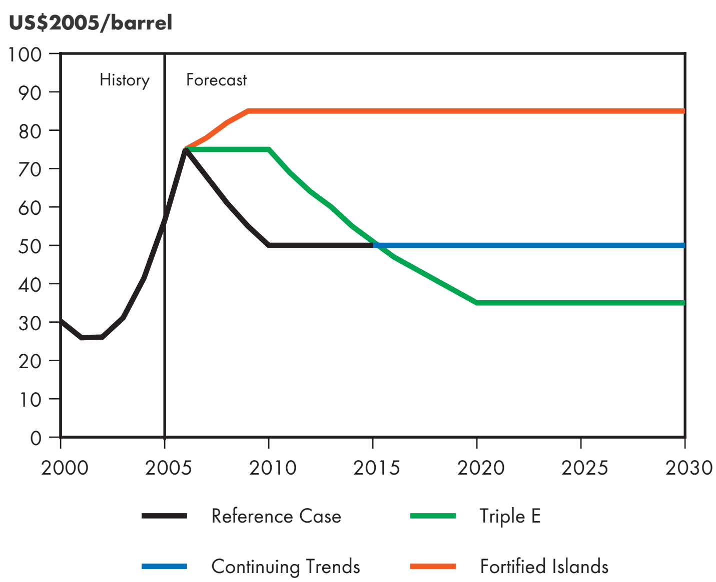


FIGURE AO.4

West Texas Intermediate Crude Oil Price at Cushing, Oklahoma



Energy Prices

The wide range of energy prices considered in Canada's Energy Future reflects the uncertainty of future prices (Figure AO.4 and AO.5). The West Texas Intermediate (WTI) crude oil price ranges from US$35.00 to US$85.00/barrel[2]. The Henry Hub price of natural gas ranges from US$5.25 to $11.40/GJ (US$5.50 to $12.00/MMBtu). Natural gas prices typically move in relation to crude oil prices over the long-term, although usually at a slight discount on an energy-equivalent basis, resulting in a natural gas to oil price ratio of around 0.84. Short-term fluctuations in this ratio can be quite wide. To reflect greater sensitivity to the lower carbon content of natural gas, the natural gas to crude oil price ratio increases to 0.94 in the Triple E Scenario.

Quantitative Results

Energy Demand

Secondary Energy Demand

Total secondary (end-use) energy demand in Canada has increased an average of 1.8 percent per year from 1990 to 2004. This is maintained in the Reference Case scenario, with a growth rate of 1.8 percent from 2004 to 2015 (Figure AO.6). Despite the higher oil and gas prices in the outlook period, the expectation is that energy demand will remain robust as income and GDP continue to put upward pressure on demand for energy-related goods and services.

Growth in energy demand ranges from 0.3 percent to 1.4 percent per year across the three scenarios. As Continuing Trends extends the Reference Case out to 2030, the same assumptions apply,

2 Prices are reported in US$2005 unless otherwise specified.

continuing the trends of the recent history into the future. As the forecast progresses to 2030, however, there is a slight slowdown in Canadian economic growth, personal disposable income and population, as described in the previous section. As a result, the energy demand growth rate for the Continuing Trends Scenario slows to 1.4 percent per year.

Economic growth and personal disposable income growth in Triple E is moderate. While commodity prices are lowest in this case, the assumed carbon dioxide (CO_2) price drives up delivered fuel prices comparable to Continuing Trends. Thus, 'dual' pricing exists in this scenario, with producers facing the lower commodity price (Figure AO.4 and AO.5) and consumers seeing the higher delivered price[3]. Energy efficiency and environment influences are strongest in this case, with numerous government policies and programs assumed. This results in the slowest growth in Triple E, with an average annual growth rate of 0.3 percent per year from 2004 to 2030.

FIGURE AO.5

Natural Gas Price at Henry Hub, Louisiana

US$2005/MMBtu

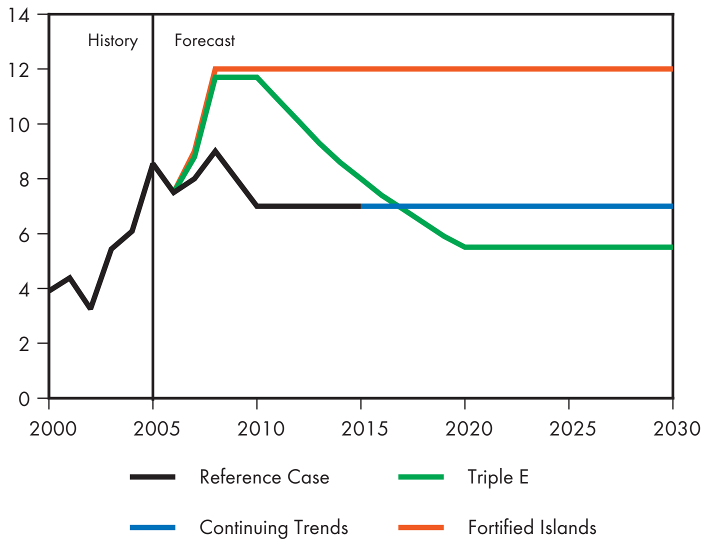
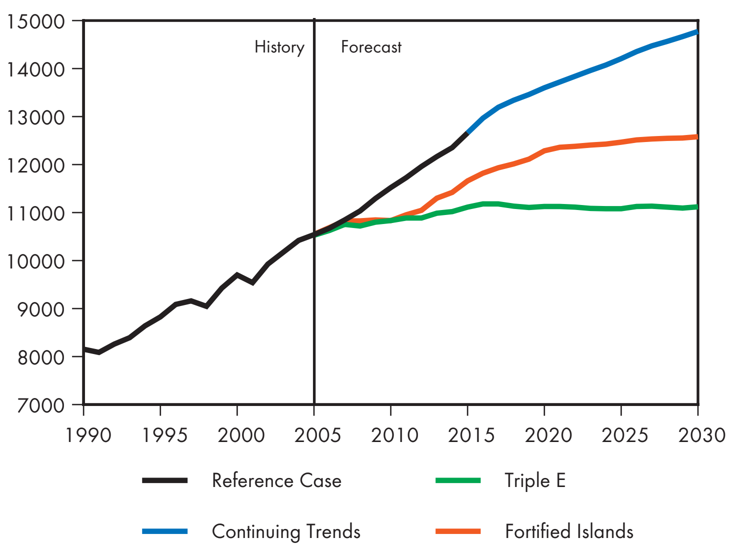


FIGURE AO.6

Canadian Total Secondary Energy Demand

Petajoules

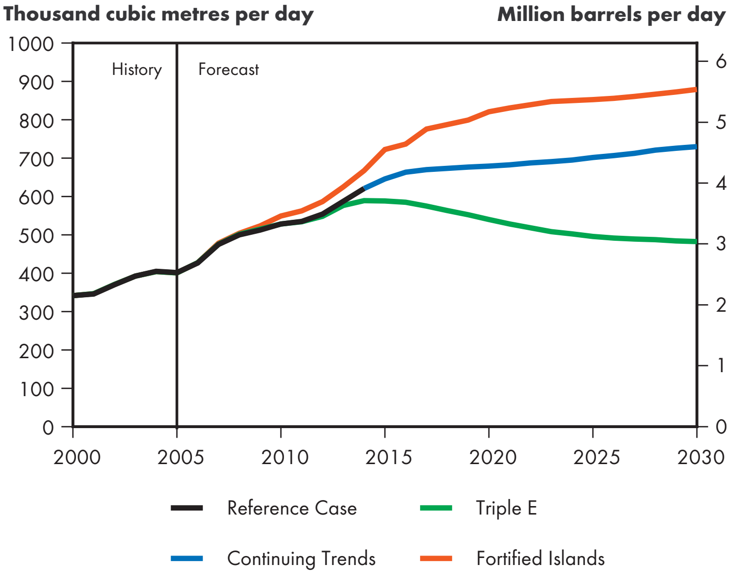


In Fortified Islands, total energy demand grows at 0.7 percent per year. This scenario is characterized by slower economic growth and higher commodity prices. This supports a deceleration in total energy demand compared to Continuing Trends and to historical rates due to the dampening income and price effect.

3 The end-use or delivered price will vary by fuel. Details on end-use prices are contained in the appendices.

FIGURE AO.7

Canadian Crude Oil Production Outlook



Energy Supply

Crude Oil

The crude oil production profiles developed for the Reference Case and the three scenarios result in a range of outcomes (Figure AO.7). All scenarios are characterized by declining conventional oil production in the Western Canada Sedimentary Basin (WCSB), moderate growth followed by rapid decline on the east coast offshore, and the increasingly dominant role of oil sands production.

Both light and heavy conventional crude oil in the WCSB are in a long-term decline. This decline is somewhat softened by the influence of higher oil prices in the Fortified Islands Scenario and by government support for CO_2-based improved oil recovery (IOR)[4] in the Triple E Scenario. The lower price in Triple E discourages development on marginal plays. Noticeable areas of impact include east coast offshore and oil sands. As a result, output declines in the latter half of the analysis timeframe. Conversely, high oil prices in Fortified Islands encourage development resulting in significant additional production.

All scenarios reflect an increasing share of oil sands production. The mid-range oil price in the Reference Case and Continuing Trends Scenario is sufficient to support relatively high levels of oil sands development. The cost pressures currently experienced by oil sands developers are expected to moderate over time. Oil sands production growth is based on the assumption that there will be timely development of additional markets and pipeline capacity, as well as the sourcing of adequate supplies of condensate or other diluent for use as a blending agent for heavy oil. It is also assumed that industry can economically adopt future environmental obligations. To the extent that these assumptions are not realized, the projected levels of oil sands production may not be achieved.

As a result of declining volumes of light conventional crude and increasing oil sands output, the composition of the feedstock supply available to refineries is changing; therefore, refinery modifications will be required to process these new crude oil types. Refinery investments are highly capital-intensive and investment requires market certainty. The scenarios not only shape production volumes, but influence decisions on downstream processing and upgrading options. Although it is assumed there is always a market for all oil production, the share, or composition, of domestic product varies by scenario.

Total crude oil exports increase or remain at the current levels (Figure AO.8 and AO.9). Continuing Trends shows minor increases in domestic demand for light crude oil and some displacement of conventional light crude oil in the feedstock slate to synthetic crude oil. The Triple E Scenario shows a marginal decline in exports in the latter portion of the outlook period compared to the beginning

4 Increased oil recovery (IOR) is also referred to as enhanced oil recovery (EOR).

of the outlook as a result of a slowing supply forecast. In Fortified Islands, the highest volume of exports is forecast with the possibility of Quebec refineries obtaining access to western Canadian crude oil. Overall, both light and heavy crude oil exports decline in the Triple E Scenario. In Fortified Islands, there is the highest growth in the three scenarios for both light and heavy crude oil exports. In the Continuing Trends Scenario, there is little change in the light crude oil exports over the forecast period and moderate growth in heavy oil exports. Overall, light crude oil exports exceed heavy oil exports in all scenarios.

FIGURE AO.8

Canadian Light Crude Oil Exports

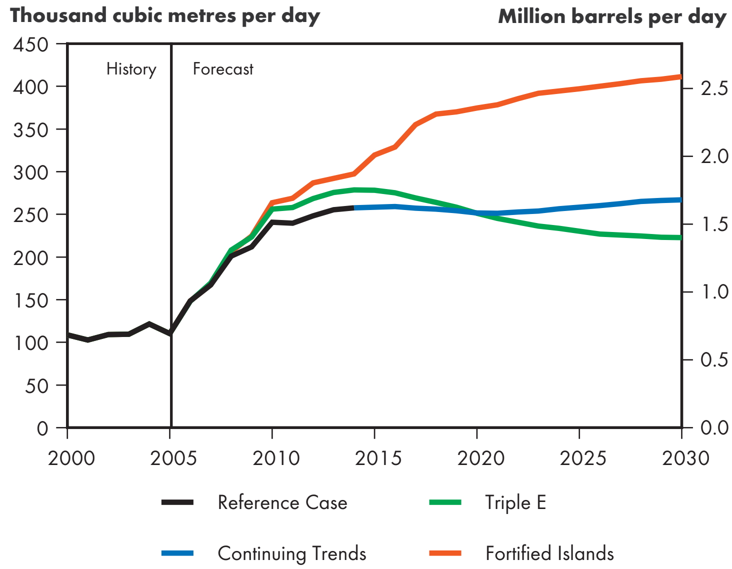
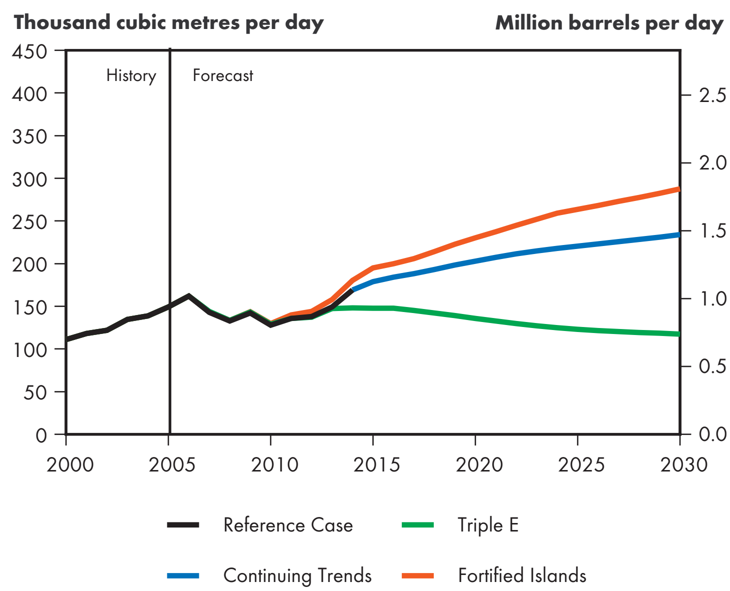


FIGURE AO.9

Canadian Heavy Crude Oil Exports



Natural Gas

The mid-range price in the Reference Case and Continuing Trends Scenario leads to gradual declines in Canadian natural gas production, while the high prices in Fortified Islands cause production to rise significantly (Figure AO.10). An influx of imported liquified natural gas (LNG) in the Triple E Scenario maintains low prices, and ends up as the source for just over half of Canadian natural gas requirements by 2030. Liquefied natural gas imports are more modest in Continuing Trends and unavailable for much of the Fortified Islands Scenario.

Canadian natural gas demand also varies widely. Together, the demand and supply trends lead to a wide range of natural gas exports (Figure AO.11). Continuing Trends maintains similar growth in demand to recent years based on the strength of gas use for oil sands and electricity generation. The Continuing Trends outlook of increasing demand and gradually declining production reduces the net

FIGURE AO.10

Canadian Natural Gas Production Outlook

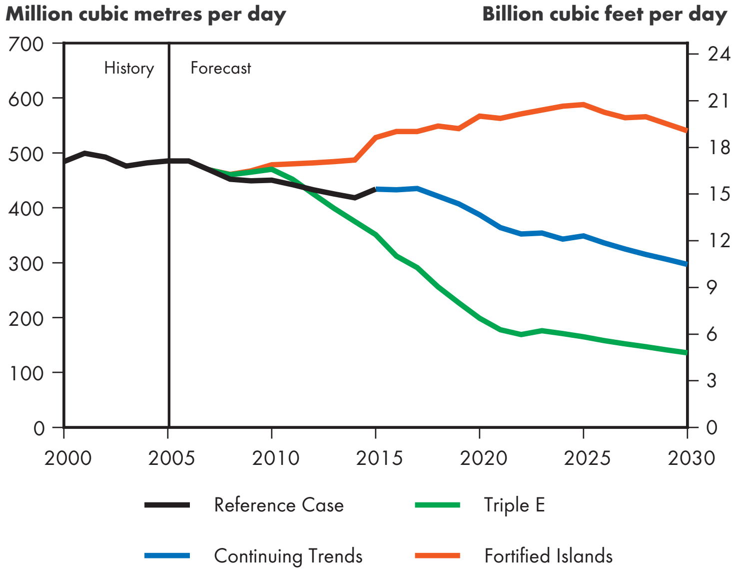
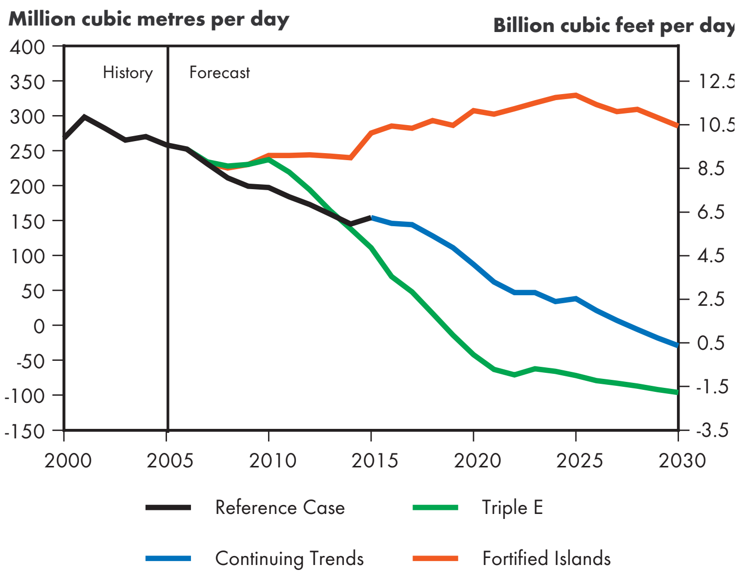


FIGURE AO.11

Canadian Natural Gas Net Exports



exports to zero by 2028, as more LNG enters Canada than conventional natural gas exported. In the later years of the outlook, Canada becomes a net gas importer, reliant on LNG imports[5].

Total Canadian gas demand growth is lower in Triple E and Fortified Islands. In Triple E this is due to increased efficiency and lower demand for gas from oil sands projects; in Fortified Islands it is a result of higher energy prices and slower economic growth. In the Fortified Islands Scenario, the amount of potential net exports erodes slightly until 2015. At this point, frontier gas production comes on-stream and enables new records to be established for net annual natural gas exports.

Natural Gas Liquids

Projections of natural gas liquid (NGL) gas plant supplies are based on projections of natural gas production. These may be further augmented by liquids extracted from Mackenzie Delta gas, oil sands off-gas, as well as enhanced deep-cut expansion at Alberta straddle plants. Alaskan gas may begin to be imported into or transit Canada at some time before 2030. Depending on the configuration and contractual arrangements, natural gas liquids contained in an Alaska gas stream may potentially be extracted within Canada to supplement domestic supplies. An alternative concept might see Alaskan gas shipped as LNG and bypass Canada. As the timing, scale and configuration of a potential Alaskan gas project are highly uncertain at this point, Alaskan gas volumes have not been included in the projections.

5 It should be noted that net gas exports is the amount of Canadian gas production in excess of Canadian natural gas consumption. Actual gas flows across Canada's international borders will exceed this value by any amounts of gas that are imported for consumption in Canada or that are imported for re-export.

Long-term ethane supply becomes less reliable in the forecast. By the end of the outlook period in both the Continuing Trends and Triple E Scenarios, ethane demand exceeds supply. This is a direct result of gas production decreases due to lower prices and continued growth in demand from the Alberta petrochemical sector. In Fortified Islands, ethane supply exceeds demand in the longer term owing to significant increments of supply from oil sands off-gas, straddle plant expansions and Mackenzie Delta gas.

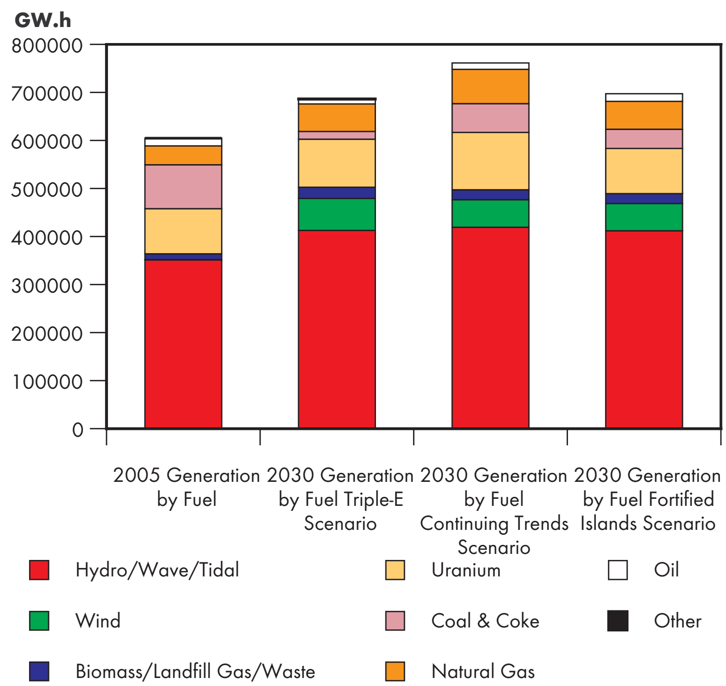
Excess volumes of propane and butane are available for export throughout the projection period under all scenarios. However, under the Tripe E Scenario, the propane and butane supply and demand balance becomes tight near the end of the outlook period as lower commodity prices cause natural gas production to decrease.

Electricity

Significant changes are expected in the electricity supply sector, with many of them resulting from recent decisions on electricity generation and transmission (Figure AO.12). While conventional generation continues to provide the majority of energy in all scenarios, the emerging technologies begin to have a noticeable impact on the generation mix across Canada. In Ontario, existing coal plants are retired by 2015, replaced by a mixture of gas, nuclear, wind and other emerging technologies. Nuclear generation sees a renaissance in all three scenarios, as five new nuclear plants are constructed to replace retiring coal units and older nuclear plants. Emerging technologies are also used for coal-fired generation, with Integrated Gasification Combined Cycle (IGCC) becoming available after 2015. All scenarios assume an expanded use of bitumen for cogeneration in the Alberta oil sands. Since the amount of cogeneration is linked to oil sands production, cogeneration is highest in the Fortified Islands Scenario and lowest in Triple E.

FIGURE AO.12

Electric Generation by Fuel and Scenario



High natural gas prices and concerns about security of supply favours coal-fired generation in the Fortified Islands Scenario, while lower natural gas prices and concern about emissions favour natural gas generation in the Triple E Scenario. The Triple E Scenario also favours the development of alternative sources of energy, with more wind and biomass than the other scenarios as well as pilot projects for wave and tidal power. This scenario also includes IGCC power plants with CO_2 capture and storage (CCS) technology in Alberta and Saskatchewan after 2019.

Interprovincial exchanges of energy and exports to the United States increase in most scenarios. With demand peaking and then beginning to decline, exports and interprovincial trade increases dramatically in the Fortified Islands and Triple E Scenarios, although the drivers are dissimilar. In Fortified Islands, wind and hydro power are seen as safe and secure from high fossil fuel prices. In Triple E, the advantage of wind and hydro power stems from their being a GHG-neutral form of generation. Higher demand in Continuing Trends is met primarily with increased hydro generation. A general tightening in domestic supply reduces opportunities for export in this scenario.

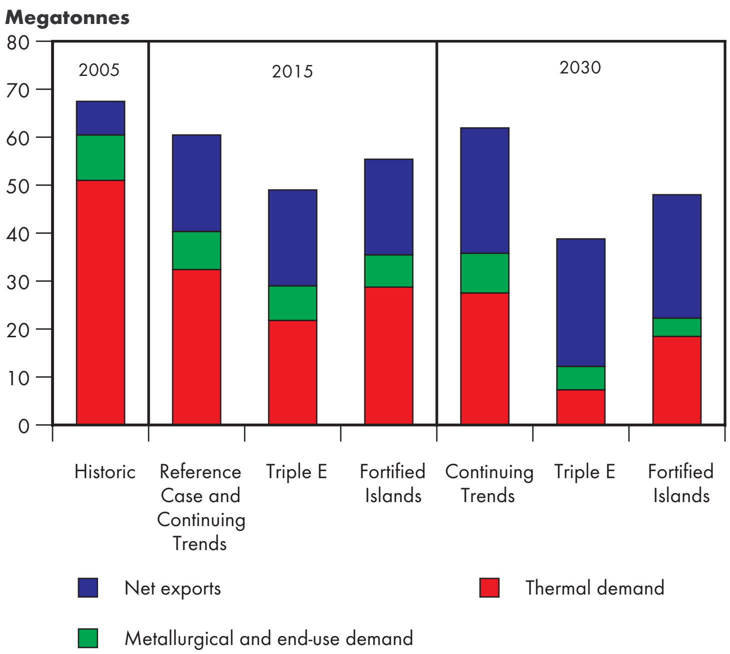
New transmission is required in all scenarios – within provinces to support new generation, between provinces to enable increased interprovincial interchange, and, between Canada and the United States to enable increased exports. In all scenarios, some new construction is included as existing plants reach the end of their 40-year economic life. Large hydro developments in Newfoundland and Labrador, Quebec, Manitoba and British Columbia may arise, requiring substantial and unprecedented additions to transmission systems.

Coal

Overall, Canadian coal demand decreases and net exports increase resulting in a decline in Canadian production across all three scenarios (Figure AO.13). Both total production and demand is highest in the Continuing Trends Scenario. In Triple E, thermal demand is lower and utilizes IGCC and CO_2 capture and storage. Low economic growth and high prices lead to lower thermal demand in Fortified Islands. The closure of Ontario's coal-fired plants is a key influence on the short- and long-term imports of thermal coal, while exports of metallurgical coal are expected to grow with the expansion in the international iron and steel industry. The potential for IGCC and CCS, and the success of other new coal technologies to address environmental concerns, depends on cost and acceptability relative to generation alternatives. Net exports remain positive and increase in all scenarios.

FIGURE AO.13

Canadian Coal Production and Disposition, 2005, 2015 and 2030



(The sum of Canadian thermal, metallurgical, and end-use coal demand as well as exports is equal to Canadian production).

Greenhouse Gas Emissions[6]

To a large extent, GHG emissions are an outcome of energy demand trends, therefore, GHG emissions increase with growing demand. Growth in GHG emissions ranges between -0.1 to 1.5 percent per year (Figure AO.14). Energy demand is rigid in the short to

6 The historic GHG emissions numbers are aligned with Canada's GHG Emission Inventory, which includes both energy and non-energy emissions. In the outlook period, non-energy emissions are grown at the rate of the economy and included in the other category.

medium term as it is shaped by established industries, devices, services, and habits. In the Reference Case, GHG emissions are expected to increase by 1.5 percent per year. In Continuing Trends, GHG emissions grow at 1.2 percent per year, reflecting the slightly lower economic growth. In the Fortified Islands Scenario, GHG emissions are expected to grow at 0.6 percent per year. The slower growth in this scenario, compared to history, is a direct result of higher energy prices and slower income and economic growth in the Canadian economy, excluding the oil and gas producing sector. In the Triple E Scenario, GHG emissions are expected to decrease by 0.1 percent per year between 2004 and 2030. This decrease is a result of policies directed at balancing energy use, environmental impacts, and economic growth.

GHG emissions intensity across the Reference Case and all scenarios continues to decline implying fewer GHG emissions are released to produce the same amount of goods and services (Figure AO.15).

FIGURE AO.14

Canadian Total GHG Emissions

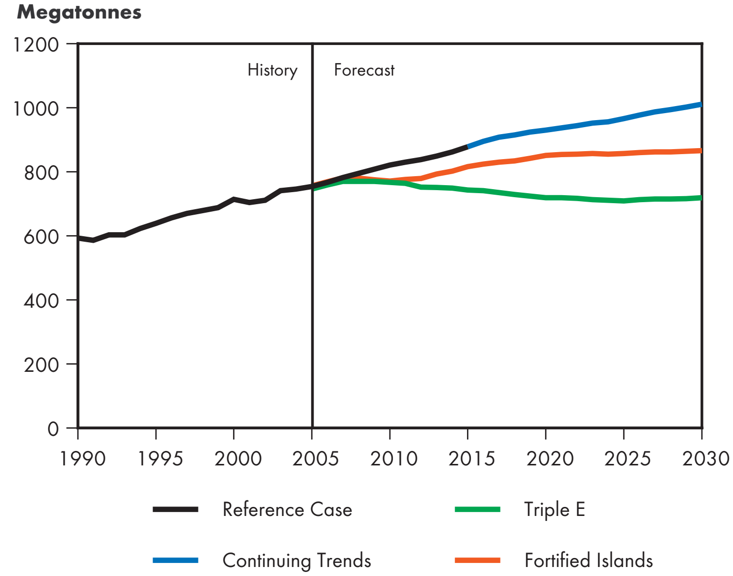
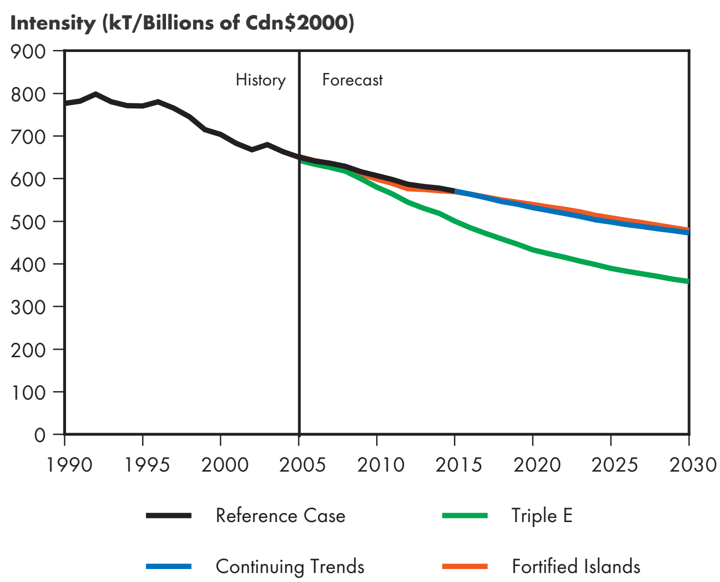


FIGURE AO.15

Canadian GHG Emissions Intensity



Recent federal government announcements have targeted a reduction in Canadian GHG emissions by 20 percent below 2006 levels by the year 2020. There are considerable uncertainties surrounding the means to achieve this reduction. In all scenarios examined, Canada partially achieves the '20 percent by 2020' goal set by the Government. There are numerous paths to GHG emission reductions. These paths will have potentially major impacts on technological choices, configuration of our cities and energy systems, as well as consumer behaviour. Identification of the specific mechanisms that will allow us to achieve this target has proven to be unattainable in the context of this analysis.

This report is an analysis of Canada's possible energy futures. As such, the report focuses strictly on GHG emission reductions from energy-related activities in Canada (e.g., energy efficiency measures, improved energy management systems or investment in CO_2 capture and storage). The analysis does not directly focus on GHG emission reduction strategies. For example, the analysis does not incorporate two potential sources of GHG emissions reductions: (a) non-energy-related emission reductions such as carbon sequestration in agriculture and forestry; and (b) GHG emission reductions from international mechanisms such as access to Kyoto's Clean Development Mechanism, or international CO_2 emissions trading regimes. Consideration of these and others as part of a full spectrum of GHG reduction strategies could go a long way in contributing to Canada meeting its target of 20 percent by 2020.

It is important to note that significant uncertainty exists over how consumers and technology will react to energy demand management and GHG emission programs and policies. At the time of writing, the most up-to-date information was included in the analysis; however, climate policy and technological advancements rapidly evolve. More rapid progression of technology than assumed in this report, or a higher willingness of consumers and industry to make significant lifestyle and production changes, would result in a more ambitious GHG emission reduction profile than reflected in the current analysis.

Our conclusions on GHGs demonstrate clearly that for Canada to achieve its 2020 goals, important and fundamental changes in the way we live and in the way we produce goods and services need to take place. Ultimately the path pursued will be the subject of major societal and political debates over the next few years in order to balance priorities on economic, environment and energy issues.

Conclusions

Canada's Energy Future highlights the many challenges and opportunities facing both the energy sector and individual Canadians, both today and in the future. The scenarios considered explore a wide range of potential energy market outcomes. A high level overview of the key assumptions and quantitative results is captured in Table AO.1.

TABLE AO.1

Summary of Key Assumptions and Quantitative Results

	Real GDP	Energy Prices	Energy Demand	Oil & Gas Production	GHG Emissions
Reference Case (2004-2015)	2.9%	Oil: $50/bbl Gas: $7/MMBtu	1.8%	Oil: 4.4% Gas: -0.9%	1.5%
Continuing Trends	2.5%	Oil: $50/bbl Gas: $7/MMBtu	1.4%	Oil: 2.3% Gas: -1.8%	1.2%
Triple E	2.2%	Oil: $35/bbl Gas: $5.50/MMBtu	0.3%	Oil: 0.7% Gas: -4.8%	-0.1%
Fortified Islands	1.8%	Oil: $85/bbl Gas: $12/MMBtu	0.7%	Oil: 3.0 Gas: 0.4%	0.6%

(Annual Average Growth Rate from 2004 to 2030 [% per year] unless otherwise specified)

Key insights garnered from the analysis can be summarized under five major themes.

1. Energy Markets and Resources

Canadian energy markets are expected to function well with energy prices acting to ensure there is sufficient energy supply to meet energy demand. Prices in the long-term are expected to be higher than those experienced historically. Overall, it appears that North American and global economies are adjusting to higher prices recently experienced.

Availability of energy resources in the future is not expected to be an issue. The type and mix of energy resources will be determined by the level of energy prices. Overall, Canadian energy supply and the fuel mix is quite price-responsive, creating a broad range of outcomes in response to alternative price trajectories and the socioeconomic environment modeled in the three scenarios.

2. Energy Supply, Demand and Exports

Fossil fuel energy continues to be the dominant source of supply, although non-conventional and non-fossil fuel supplies begin to play a larger role. Continued fuel diversity is expected to be part of the energy balance in Canada. All scenarios depict a fuel mix that is mostly conventional at the base, but varies in terms of additions from emerging and alternative technologies and fuels.

The mix of electric power generation will see significant changes as the use of wind power, nuclear power and clean coal technologies are all expected to grow.

While energy supply is quite price-responsive, energy demand is not. Demand continues to be inelastic in the short term due to the long life of the existing stock of buildings, vehicles and urban design of Canadian cities. However, in the long-term, there is opportunity for demand reductions in response to targeted policies and programs, including improvements in energy efficiency.

Total Canadian net energy exports are expected to increase in the future. However, growth varies by commodity and scenario. Oil and electricity exports increase in all scenarios, while natural gas net exports increase only in Fortified Islands. The increase in oil exports is a direct result of growing oil sands production in all scenarios. These changes will have implications for supply infrastructure.

3. Energy Interactions with the Economy and Environment

The state of the economy continues to be an important driver for the energy system, and alternative macroeconomic projections in the three scenarios lead to different energy outcomes, especially in energy demand. Macroeconomic growth in all scenarios is lower than observed in recent history, largely due to decelerating population growth and its implications for adequate labour and skill sets. These will need to be compensated by improvements in productivity and/or increased immigration.

Canadians are concerned about climate change. Numerous policies and programs are being developed at the federal and provincial levels to reduce GHG emissions. Addressing climate change in a meaningful way in Canada requires early action and utilization of all the strategies at our disposal. The GHG emissions per unit of energy used declines in all scenarios, but the rate of decline varies based on policies and programs considered.

4. Building Blocks for Canada's Energy Future

Technology can offer solutions to many challenges in the energy system. While technology makes incremental inroads into Canada's energy future, the direction, pace, and extent of these changes vary across scenarios. The technology push in Fortified Islands is most evident on the supply side. In Triple E, technology is inextricably tied to efficiency and GHG emission reductions.

'Smart' policy is required to help optimize multiple objectives of economic growth, environmental sustainability, and responsible development of the energy sector. Policy frameworks that extend (within and beyond) provincial borders will need to be constructed to consider wide regional differences with respect to energy and emissions, evolving energy supply systems, and a changing global environment. Canadians have a critical role to play in developing future policy by providing direction in terms of the objectives we would like to see pursued.

Major investments are needed in the next decade to develop new sources of energy and meet the growth in energy demand as well as replace the ageing infrastructure. Over the longer term, the infrastructure requirements and issues are more influenced by circumstances of the scenario, including implications arising from continued diversity of fuel mix. All infrastructure developments will need to take into account broad environmental concerns during construction and operation. New approaches are required to resolve differences between developers and local interests in order to improve the predictability of project completion. In some cases, this may include improving clarity in the regulatory and public engagement processes, while in other cases it may require more use of 'single window' approaches when several jurisdictions are involved.

As the requirement to renew and expand our energy infrastructure increases to meet the growing and diverse needs for energy, greater public engagement and acceptance for these initiatives will be needed. A balance will need to be established between public acceptance and the need for timely decision making. In addition, all stakeholders, including industry and governments, will need to work together to secure that greater acceptance.

High-quality data forms a solid foundation for supply and demand analysis, such as the analysis for Canada's Energy Future. As energy issues become increasingly complex, there emerges a need for enhancements and improvements to existing statistical databases to empower decision-making.

5. Canada's Energy Future

The analysis suggests significant change in several elements of the energy system[7]. A long-term energy vision and strategy for Canada is needed to balance multiple objectives. This plan must be well integrated at the regional level, consider environmental issues and economic growth, and be developed with input from Canadians. Only then will we be able to overcome the challenges ahead and take advantage of the opportunities available.

The NEB plans to contribute to this debate by continuing to pursue our vision of being an active, effective and knowledgeable partner engaging Canada in the discussion of Canada's energy future.

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7 The energy system is defined as how Canadians produce and consume energy.

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 main functions of the NEB include regulating the construction and operation of pipelines that cross international or provincial borders, as well as tolls and tariffs. Another key role is to regulate international power lines and designated interprovincial power lines. The NEB also regulates natural gas imports and exports, oil, natural gas liquids, and electricity exports, and some oil and gas exploration on frontier lands, particularly in Canada's North and certain offshore areas.

The NEB collects and analyzes information about Canadian energy markets through regulatory processes and market monitoring. From these efforts, the Board produces publications, statistical reports and speeches that address various market aspects of Canada's energy commodities. The Energy Market Assessment (EMA) reports published by the Board provide analyses of the major energy commodities. Through these EMAs, Canadians are informed about the outlook for energy supplies and demand in order to develop an understanding of the issues underlying energy-related decisions.

This EMA report, titled *Canada's Energy Future*, examines the long-term energy demand and supply possibilities within Canada. The main objectives of this report are to:

- provide unbiased, relevant, comprehensive, expert analysis on energy supply, demand and its economic and environmental implications to serve as a standard of reference for parties interested in Canadian energy issues and trends;
- provide stimulus for discussion with and amongst stakeholders, both during and after the completion of the report on emerging energy issues of national importance; and,
- inform decision makers of key risks and uncertainties facing the energy future and advise them of regulatory and other issues that need to be addressed.

While preparing this report, the NEB conducted a series of formal and informal meetings with energy market experts and other interested parties. The NEB appreciates the information and comments provided and would like to thank all participants for their time and expertise. The NEB would also like to thank the numerous dedicated staff members that contributed directly and indirectly to the completion of this report.

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

Questions and comments regarding this EMA can be directed to the following:

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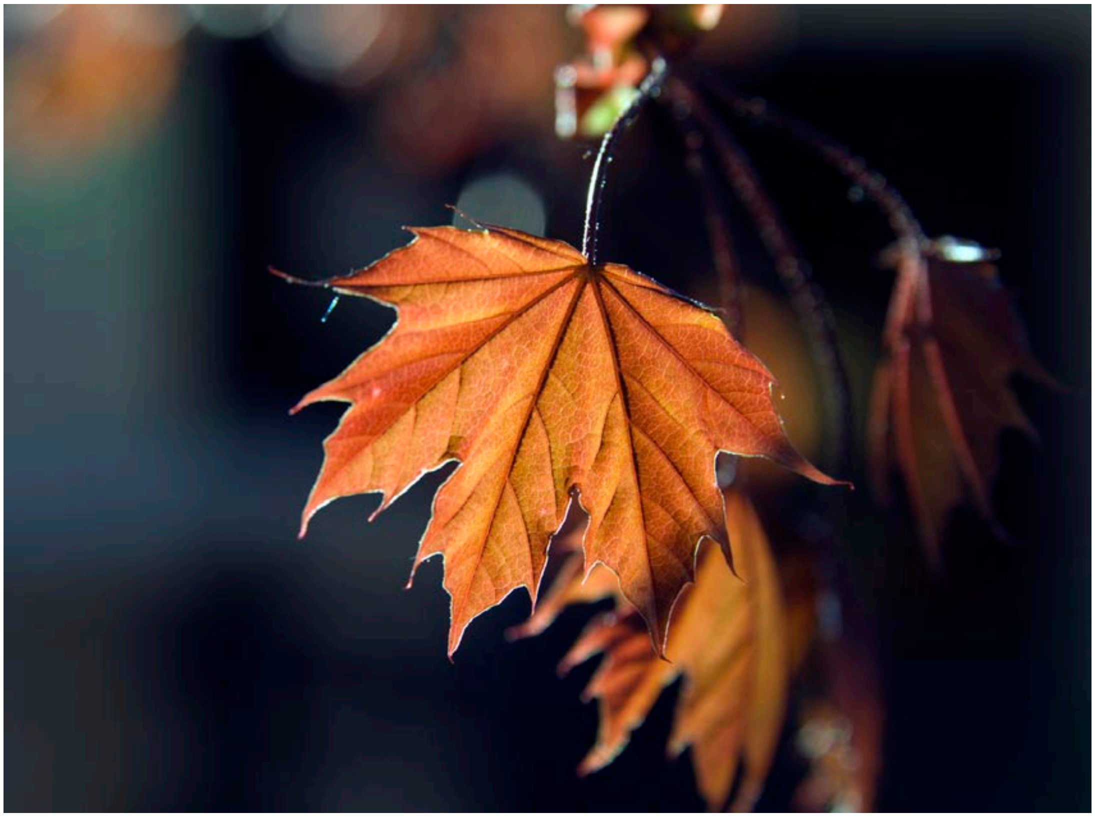


Introduction

The 2007 Energy Futures Report, *Canada's Energy Future*, is firmly grounded in today's energy realities. It is also a call for the engagement of Canadians in confronting pressing energy issues before us. The challenges ahead include: high and volatile energy prices; continuing geopolitical unrest; decreasing conventional reserves; the need to diversify supply; an ageing and constrained delivery infrastructure; and growing environmental concern. All of these considerations have contributed to the National Energy Board's (NEB or the Board) development of *Canada's Energy Future*.

To better respond to the needs of its varied stakeholders, the Board has adopted a hybrid approach in this report. The hybrid approach is a combination of a near-term outlook and long-term scenarios. It is a progression from the previous report[8], which used two contrasting scenarios: 'Supply Push' and 'Techno-Vert'. The methodological change is in response to stakeholder comments on the previous report, which recommended incorporating a baseline Reference Case and investigating a broader scope of uncertainties and issues in scenarios.

Scenarios – What are they and why are they useful?

A scenario is a self-contained story about how the future could unfold. A scenario is much different than a sensitivity analysis, which investigates how outcomes will change based on changes in key assumptions. In a scenario, all the key assumptions are subject to change. Scenarios help create plausible actions and outcomes based on context. It encourages cause and effect thinking. This, in turn, supports a long-term, coordinated response.

8 *Canada's Energy Future: Scenarios for Supply and Demand to 2025*. National Energy Board, 2003. Available at: http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/spplydmnd/spplydmnd-eng.html.

Canada's Energy Future: The 2007 Approach

Because certainty diminishes over time, the 2007 hybrid approach identifies varied analytical timeframes for the Reference Case and scenarios. The Reference Case, defined as the most likely case, is the most meaningful in the short to medium term. The timeframe for the Reference Case analysis is 2005-2015. The term scenario itself reflects uncertainty. Scenarios are more appropriate in the longer term. The timeframe for scenario analysis in *Canada's Energy Future* is 2005-2030[9].

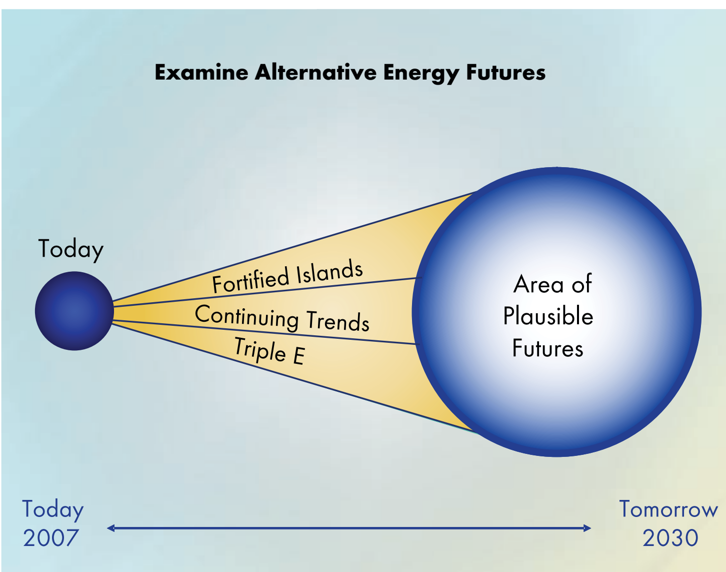
Scenarios Used in this Report

The use of scenarios provides varying perspectives on Canada's energy evolution. Energy scenarios are not forecasts or predictions, but rather plausible outcomes that describe a range of potential futures. There are many scenarios that could represent plausible energy market futures. Three scenarios were chosen to represent three distinct settings for the storylines presented in the 2007 report (Figure 1.1). These three scenarios are designed to:

- encourage discussion and debate on how Canada's energy system might evolve over the next 25 years;
- encourage energy stakeholders to consider possible responses to a given scenario; and,
- enable stakeholders and decision-makers to define the elements of a desirable energy outcome.

FIGURE 1.1

NEB Energy Futures Scenarios



The three scenarios vary according to government policies and programs, geopolitical context, societal values, energy prices, macroeconomic growth rates, and the pace and type of technological developments. However, significant trends and relationships are maintained across all scenarios. Some of the commonalities include a desire for forward progression on environmental issues, continued importance of the Canada-U.S. trading relationship, the role of governments in Canada, increasing global demand for energy using goods and services, and the continued decline of energy supply within Organization for Economic Cooperation and Development (OECD) countries. No individual scenario was considered to be more probable than the others.

9 In this report, 2005 is the first forecast year.

The scenarios in this report are:

- ***Continuing Trends***, characterized by the maintenance of significant trends apparent at the beginning of the outlook period through the forecast period. This scenario extends the Reference Case over the long-term.
- ***Triple E***, a scenario characterized by well-functioning energy markets, cooperative international agreements and effective environmental policies. It seeks to balance economic, environmental and energy (Triple E) objectives.
- ***Fortified Islands***, a setting wherein security is at the forefront of public concern. Geopolitical unrest, a lack of international cooperation and trust, and protectionist government policies characterize this scenario.

Many of the drivers used in the 2003 report are still relevant today and therefore, continue to influence the selected scenarios in 2007. The distinguishing factor in this analysis is the strong influence of the global context. Scenarios are characterized by prevailing world views, rather than a distinctly Canadian setting. Energy commodities are traded on international markets and Canada is subject to the same risks and benefits as others. These are incorporated in the analysis through variant price trajectories for energy commodities.

Greater detail on each of the three scenarios is provided in later chapters.

Stakeholder Input

The Board sought the views of Canadian energy experts and interested stakeholders through a series of consultation sessions across Canada in 2006 and early 2007, including representatives from the energy industry, government, environmental non-governmental organizations, and academia. The views collected helped shape the report methodology, assumptions and analysis. Through these consultation sessions, valuable background information was gained[10].

Report Structure

The structure of this report reflects the analytical approach adopted. The 'Energy Context' provides a backdrop to the report, through a brief discussion of issues of importance currently facing the energy sector in Canada. The Reference Case and scenario analyses are detailed under four separate chapters. Each of these chapters contains extensive results for individual energy commodities and related issues, including economic context and environmental implications. Finally, the last chapter summarizes key insights and implications under five major themes. Detailed tables on various energy demand and supply elements for each provincial and territorial jurisdiction are available in the appendices.

10 Consultation summaries are available on the NEB website at www.neb-one.gc.ca.

Energy Context

This section provides background on key issues currently impacting Canada's energy system. Energy context includes a discussion on energy prices, global factors, energy and environmental policy, demand response, emerging technologies, infrastructure, energy in the Canadian economy, energy exports, and reserves.

Price of Energy

Recent high energy prices are being driven by exceptional demand growth in developing countries; shortages in materials, equipment, labour, and engineering services; and geopolitical tensions.

Crude oil prices have been on the rise since January 1999, when WTI prices averaged approximately US$12 per barrel. Less than a decade later, crude oil has traded over US$80 per barrel due to record demand for gasoline, coupled with instability in the refining sector and tight supply and demand conditions. Low spare production capacity and geopolitical concerns surrounding the major producing countries of Iraq, Iran, Nigeria and Saudi Arabia also place upward pressure on the price of crude oil.

North American natural gas prices have trended upward under the influence of the significant increase in world crude oil prices and a tight balance between natural gas supply and demand. The price for natural gas at Henry Hub has increased from approximately US$2.25/GJ (or US$2.35/MMBtu) in January 2000 to around US$6.65/GJ (US$7.00/MMBtu) in 2007. Additionally, hurricane-related supply disruptions have resulted in brief price spikes as high as US$13.30/GJ (US$14.00/MMBtu), while a recent string of mild winters have helped to dampen prices from even higher levels. Except for brief periods when natural gas markets are particularly imbalanced (such as hurricane-related supply disruptions, weather extremes, or if approaching upper or lower limits of storage capacity), natural gas prices have tended to move in relation to oil prices. This relationship typically has gas prices in the lower half of a price range bounded at the bottom by residual fuel oil and at the top by distillate (No. 2 fuel oil) on an energy-equivalent basis. These fuel oil grades represent substitutes for natural gas, in particular in power generation and space heating applications.

With massive coal reserves, not only in North America, but also globally, coal prices have historically risen at very modest rates of one to two percent per year. Since 2003 however, the trend has changed dramatically with coal prices rising at double-digit rates annually. The change coincides with China, one of the top coal-producing countries, becoming a net importer rather than net exporter of coal due to rising internal demand. In 2006, China accounted for 70 percent of global growth in coal consumption.

North American electricity prices have also trended upward under the influence of higher fuel costs for coal, oil, uranium and natural gas; costs of meeting tighter emissions standards; and costs to improve the transmission grid to enhance reliability. Electricity prices can vary between regions depending on the mix of fuels for generation, reserve margins and load growth.

Global Context

In recent years, global growth in energy demand has been led by developing countries, most notably China and India. Energy supply has struggled to keep pace with rising demand. Conventional oil and gas producing regions are maturing and, as they become less productive, are requiring increasing levels of activity and technological intervention to maintain or slow declines in output.

Global oil and gas production and consumption are located in different parts of the world (Figure 2.1). Much of the world's resources are concentrated in politically unstable regions. For instance, geopolitical tensions, economic and political nationalism, and local opposition to development have restricted access to new resources in key regions around the world. This translates into security of supply concerns for large-consuming countries.

In 2006, the world consumed 10.8 billion tonnes (79.7 billion barrels) in oil equivalent energy, comprised of 36 percent oil, 24 percent natural gas, 28 percent coal, 6 percent nuclear and 6 percent hydro electric energy (Figure 2.2).

Oil Supply

Currently, Saudi Arabia is the world's top oil producer, producing 1.7 million m^3/d (10.8 million b/d) of oil. The U.S. and Canada rank third and seventh, respectively. Only 15 countries[11] are expected to account for up to 84 percent of the net growth in global oil production capacity in the next ten years. In order of absolute growth in capacity, the top five from the list are Russia, Saudi Arabia, Canada, Iraq and Brazil. The U.S. is by far the world's largest market for oil, making up almost 25 percent of total oil demand (3.27 million m^3/d or 20.6 million b/d). Canada accounts for only 2.5 percent of total world oil demand (353 thousand m^3/d or 2.2 million b/d).

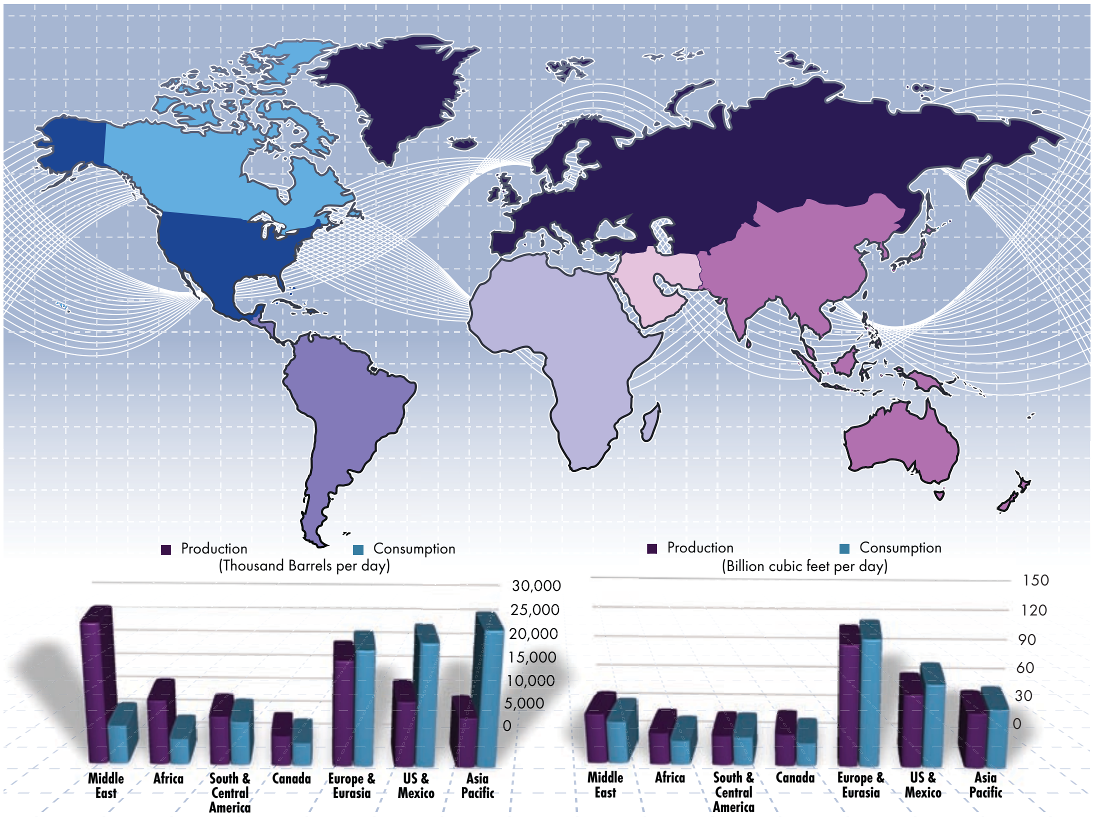
Gas Supply

Almost 60 percent of the world's natural gas reserves are located in Russia, Iran and Qatar. In 2006, Russia remained the world's largest producer of natural gas, accounting for 21 percent, at

11 The top 15 are Russia, Saudi Arabia, Canada, Iraq, Brazil, Kazakhstan, Iran, Kuwait, Algeria, Qatar, Libya, Nigeria, UAE, Angola and Azerbaijan.

FIGURE 2.1

Global Production and Consumption of Oil and Gas by Area, 2006

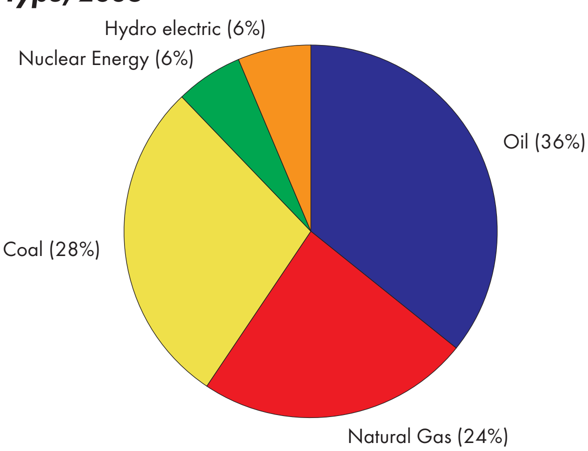


Source: BP Statistical Review of World Energy, 2007

1.67 million m³/d (59.2 Bcf/d) of the total. The U.S. is the second largest producer, but most of the production is consumed domestically. Canada ranks as the third largest producer, responsible for over six percent, but future production is expected to remain flat or decline. Asia is the largest regional market for liquified natural gas (LNG), acquiring 64 percent of total world imports, with Japan importing the bulk of these supplies.

FIGURE 2.2

World Primary Energy Consumption by Fuel Type, 2006



Source: BP Statistical Review of World Energy, 2007

Coal Supply

Unlike oil and gas reserves, coal is widely distributed throughout the world. Coal is also abundantly available. Worldwide, the reserve-to-production ratio for coal is estimated to be 147 years, whereas the reserve-to-production ratio for oil is 40.5 years and natural gas is 63.3 years. Coal is the world's fastest growing fuel in terms of both world consumption and production. The bulk of this fuel is consumed and produced by China. Canada accounts for only one percent of the world's supply and demand for coal.

In 2006, five countries, U.S., China, Russia, Japan and India, accounted for over 50 percent of the world's primary energy demand[12]. Canada accounted for approximately three percent. In 2006, compared to 2000, China and India's collective share increased by almost six percent, while shares in the other countries declined modestly. Many developed countries are attempting to reduce the rate of increase in energy demand. However, consumption in developing countries, such as China, is increasing in order to fuel rapidly expanding economies.

Energy and Environmental Policy Developments

Energy and environmental policy responsibilities within Canada are divided between federal and provincial governments. There has recently been an unprecedented level of activity in this area. With the growing importance of energy issues, the provinces have responded with the release of energy strategies and policy directives. In early 2007, British Columbia released its *Vision for Clean Energy Leadership*, focusing on energy efficiency, electricity self-sufficiency, net zero emissions from thermal generation, renewable portfolio standards, and alternative fuels. Alberta's *Climate Change and Emissions Management Amendment Act* and the *Nine Point Bio-Energy Strategy* focus on emission intensity reductions from large final emitters and expanding the bio-energy industry. Ontario's recent policy initiative released in April 2007 focuses on energy efficiency and electric sector changes. Several other policy directives have been announced previously, highlighting conservation, small-scale alternative energy projects, net metering, and infrastructure financing, all to promote efficiency in the use of energy while reducing emissions. The key elements of Quebec's energy strategy released in 2006 include accelerated development of hydroelectric resources and wind power, energy efficiency for all forms and uses, and innovation. Nova Scotia has also released several policy directives focusing on alternative energy sources, including tidal power and hybrid transit, energy efficiency, and greenhouse gas (GHG) emission reductions.

Between 1990 and 2004, Canada's GHG emissions increased by 26 percent. This increase is a result of a number of factors, including increasing population and economic growth. Growth in energy-intensive sectors of the economy, such as in oil production, have been a major influence on fuel consumption and emissions increases. In addition to energy policy directives, there have also been several climate change[13] action plans released by provinces including British Columbia, Alberta, Manitoba, Quebec, Nova Scotia, Newfoundland and Labrador, and the Northwest Territories.

Canadians are beginning to recognize a personal responsibility for environmental action[14]. This public concern is driving more robust policies and programs. Although not currently implemented, the federal government has recently announced a number of policies that will require emissions reductions from the industrial sector. The federal government's 2007 plan, *Turning the Corner: An Action Plan to Reduce Greenhouse Gases and Air Pollution*, targets absolute reductions in GHGs by 20 percent from 2006 levels by the year 2020. In addition, the plan calls for reduction of industrial air pollution by one half by 2015[15].

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12 *BP Statistical Review of World Energy*, 2007. U.S., China, Russia, Japan and India make up 52.1 percent of world primary energy demand.

13 Climate change is an altering of long-term weather patterns that includes temperatures and precipitation. The international scientific community agrees that climate change is occurring as a result of human activity, including the burning of fossil fuels which emit greenhouse gases into the atmosphere. For further information see: http://www.ipcc.ch/

14 For example 91 percent of respondents claim "I feel a moral responsibility to improve the environment for future generations" Decima Research, *The Mood of Canada*, September 2006. Anderson, Bruce. Decima Insights, January 12, 2007.

15 Air pollution includes nitrogen oxides (NO_x), sulphur oxides (SO_x), volatile organic compounds (VOCs), and particulate matter (PM). It can also include other air pollutants, such as benzene and mercury. Air pollution contributes to health and environmental impacts, such as smog and acid rain.

The policy developments at both provincial and federal levels constitute important steps in the achievement of Canada's energy and environment objectives. These developments are still a work-in-progress. Not all provinces are at a similar stage of policy development, and not all sectors are equally targeted for improvements in energy consumption and GHG emission reductions. Policies and programs that achieve broad support will need to balance economic, energy and environmental objectives.

Demand Response[16]

High energy prices would intuitively suggest a decrease in demand. However, demand response in energy use is relatively inflexible, particularly in the short term. This has been a subject of some discussion especially in the context of high energy prices. The pattern of energy consumption is largely predetermined by the make-up of the existing stock of energy-using devices. Since this stock has long life, the possibilities for demand reductions are limited. In addition, as consumers' incomes increase, they purchase more energy-using goods and services, which contributes to energy demand growth. Generally, this is what is being reflected in aggregate demand data available to date.

Despite the inherent inflexibility and the contribution to energy demand growth from the income effect, there are some indications that consumers are reacting to higher prices. Recent qualitative evidence suggests Canadians are responding to increased energy costs by adjusting lifestyles and spending habits. Although the total volume of gasoline sold in Canada continues to increase, there are indications that high and volatile prices are impacting vehicle purchasing trends. In fact, in 2006, for the first time ever, more than half of all retail car buyers bought small fuel-efficient vehicles[17]. However, this trend will take years to make a sizable impact on demand due to the turnover rate of vehicles. As well, energy efficiency improvements do not necessarily translate directly into energy demand reductions as decreased operating costs from improved fuel economy could lead to increased vehicle kilometers traveled (VKT).

There are also many low-cost investments that could yield significant savings within the existing energy system, which may become evident in the future. Homeowners are actively looking for ways to reduce energy costs. A recent survey in Ontario found 9 out of 10 home buyers in Toronto and Ottawa in 2006 were looking for increased energy efficiency[18]. Similarly, interest in programs offered by Natural Resources Canada (NRCan) for industrial, commercial and residential energy efficiency are on the rise.

In the longer term, consumers have more flexibility to react to higher energy prices, government programs and societal value changes as established stock can be replaced with more efficient energy-using equipment, and behaviours can be shaped to reduce demand.

New and Emerging Technologies

Technology is seen as an important part of the solution for energy supply and environmental challenges. There have been rapid technology advances in the last few decades, and this trend is

16 For purpose of this discussion, demand response refers to market forces and the relationship between energy prices, income and energy consumption. This is distinguished from electricity demand response, which refers to negotiated or voluntary intermittent electricity reduction.

17 Van Praet, Nicolas. *Smaller cars a bigger draw as drivers seek greater fuel economy*. National Post, March 1, 2007.

18 Energy Evolution, 2006. *Builders Say Energy Efficiency Targets Will Affect Affordability*. September 25, 2006. http://www.energyevolution.ca

not likely to diminish. On the supply side, technological advances are pursued to maintain current levels of conventional production, gain access to unconventional resources, and develop alternative sources of energy. On the demand side, more energy-efficient technologies are being developed. The main consideration is what technologies should be supported, to what extent, and to what ultimate end-goal.

In many ways, Canada is a leader in energy innovation. The extraction of unconventional oil and gas, Advanced Canadian Deuterium (CANDU) Reactors (ACR), alternative fuels, fuel cell research, and cold-climate building design, are examples demonstrating Canadian innovation. Over 30 years ago, unique public–private investment strategies led to the development of oil sands research facilities and operating oil sands plays. Over the next 30 years, technologies such as the large-scale deployment of nuclear power generation, clean coal, oil sands gasification with carbon dioxide (CO_2) capture and storage, bio-based alternative fuels, advanced transportation technologies, and aggressive energy efficiency improvements are possible. Although not explored in this report, it is also possible that breakthrough technologies could result in fundamental changes to the way Canadians produce or consume energy. Examples include the development of a cost-effective method to tap into Canada's large gas hydrate resources, the evolution of a hydrogen economy or a breakthrough in fusion.

The development of technologies is shaped by future social and political priorities. In recent years, energy research has not kept pace with economic growth[19]. The scenarios in *Canada's Energy Future* depict the possible context for exploring technology opportunities.

Infrastructure

New infrastructure requirements and accompanying implications reflect the diversity and extensive nature of Canada's energy economy. While the oil, natural gas and electricity sectors indicate unique challenges, all sectors face opposition to siting new facilities, no matter the energy source. Additions to infrastructure ranging from oil sands developments to electricity generation and transmission also need to be undertaken in consideration of immediate air quality issues and the longer-term need to reduce GHG emissions. Other factors impacting timely execution of new infrastructure plans include the availability of skilled labour and professional services, as well as escalating costs for materials and services.

Given current and anticipated oil prices and substantial commitments already made by developers, the oil sands seem destined to dominate upstream development for many more years. Uncertainty remains about the extent and timing of development given concerns about availability of water for processing, rising costs, availability of skills, and availability of sufficient diluent for blending bitumen. The substantial increase in oil sands output suggests that new markets will need to be accessed. In this context, there are many new pipeline proposals currently under consideration which will supply areas in the U.S. beyond traditional markets. Industry could also turn their attention in the future towards reaching offshore markets. Refiners need to address changes in crude oil slates brought about by greatly increased oil sands output through increased investment. Sustained higher oil prices are causing resource owners, particularly provinces themselves, to reconsider royalty regimes. This could also pose implications for the completion and timing of new resource developments in conventional areas and in frontier areas.

19 Private research and development investment energy sector: 0 .75percent revenue; non-energy sector 3.8 percent. For more information see Natural Resources Canada, *Powerful Connections – Priorities and Directions in Energy Science and Technology in Canada*, National Advisory Panel on Sustainable Energy Science and Technology, 2006.

The North American gas market is evolving from one of self-sufficiency to an increasing requirement for offshore LNG. The scope of imports into North America will depend to some extent on the success of gas projects in Alaska, Mackenzie Delta, the East Coast, and non-conventional developments, such as coalbed methane (CBM) in Western Canada and the U.S. Rockies, with additional implications for the current and emerging pipeline infrastructure. Recent cost escalation for northern projects adds to the uncertainty about in-service dates and raises concerns about whether these projects will proceed. Simultaneously, natural gas demand is expected to experience continued growth, particularly in power generation, which will create demand for new gas services to the power sector, including gas storage. Another area of growth is the demand for gas in oil sands production, which also presents an opportunity for the efficient production of electricity from waste heat recovery (cogeneration).

Across Canada, provincial energy strategies generally, and the electricity strategies specifically, are under ongoing review to ensure adequacy of generation and environmental objectives. Substantial new generation infrastructure for conventional generation and emerging technologies (e.g., wind, small hydro and biomass) is either planned or under development. How each province plans to meet its unique needs varies according to its market structure and generation resources (for example, Newfoundland and Labrador, Quebec, Manitoba and British Columbia tend to be dominated by hydro developments, whereas other provinces have a mix of thermal and hydro resources). Currently, after many years of little or no growth in transmission, significant investments in intra-provincial projects (e.g., Alberta, Ontario) and interprovincial interconnections (e.g., Quebec to Ontario, Manitoba to Ontario) are contemplated. Additionally, expanded U.S. interconnections are also under consideration.

Energy in the Canadian Economy

Canadians use energy at one of the highest rates per capita in the world. This can be largely attributed to our climate[20], type of industries, and vast land area to transport people and goods. Canada is also an industrious country. In 2005, Canada was ranked 14th out of all countries in the world in gross domestic product (GDP) per capita.[21]

The energy industry plays a vital role in the Canadian economy. The energy industry[22] directly accounted for 9.9 percent[23] of Canada's GDP in 2005 and directly employed 2.3 percent of Canada's labour force[24] in 2005. Energy export revenue totaled $87.0 billion in 2005, which accounted for 20 percent of the value of all Canadian goods and services exported. This energy proportion has continually increased since 1998, when energy exports accounted for 8.1 percent of the value of total exports. Net energy exports in 2005 were considerable at $48.1 billion and have continuously grown since the 1990 level of $6.7 billion[25]. There are also many indirect and spin-off effects of the energy

20 Canada is in the top ten countries in the world for heating degree days. Climate Analysis Indicators Tool: http://cait.wri.org/downloads/DN-HCDD.pdf ; takes into account the population densities across each country.

21 International Monetary Fund: http://www.imf.org/. Canada averages US$35, 105 per capita in 2005 dollars.

22 Including all oil and gas and support activities, coal mining, electric and natural gas utilities, refineries, the oil and gas pipeline sector and the petrochemical sector.

23 In current 1997 dollars, it is six percent. The percent is lower in 1997 dollars because some of the commodity prices used to calculate GDP in 1997 dollars are much lower than the 2005 prices (higher inflation rates from 1997 to 2005).

24 This is 365,400 people. If gasoline stations are excluded it is 290,400 people. Source: *Labour Force Survey*, Statistics Canada.

25 The 1990 net export dollar value is from *Statistics Canada's Energy Statistics Handbook*, Table 3.2.

industry, affecting activities and work loads in sectors like government, finance, construction, metal and aluminium, emerging technologies and research, consulting, and numerous other local effects.

Energy Exports

Canada has very large supplies of oil, natural gas, electricity and coal relative to the size of its domestic energy markets. With wide fluctuations in weather-induced demand and the vast physical distances between supply sources and markets, the development of interconnecting pipeline and transmission infrastructure would not have been economically viable without the inclusion of export volumes to absorb a share of the costs. In 2006, for the first time in many years, the value of Canadian net oil exports to the U.S. exceeded that of natural gas net exports. Growing oil exports are the result of production increases from oil sands and frontier oil off the East Coast.

An ongoing issue for oil and natural gas liquids is the extent to which energy is exported in its lower-value raw form rather than processed within Canada into a higher value product for export. The latter generates higher export revenues; however, it also incurs the costs of developing processing infrastructure and challenges traditional economic rationale, which suggests benefits to processing goods closer to the end-use market rather than at the point of extraction.

Natural gas export volumes have recently dropped due to declining production from mature fields and increasing domestic demand. Should this trend continue, there may be costs associated with underutilized infrastructure.

Electricity exports are a consequence of infrastructure sized to accommodate winter peaks, which opens up the potential to be underutilized for the remainder of the year. The ability to export and import during off-peak and peak periods enhances reliability and system efficiency. The concept of developing more east–west transmission capacity could result in less north–south trade with the U.S. Similarly, drier and warmer conditions could result in lower exports due to less hydroelectric power being available for export and higher consumption of electricity for air conditioning during the summer.

Canadian coal imports and exports are affected by electricity generation capacity additions, generation choices and the competitiveness of Canadian coal in international markets. Canadian imports of thermal coal are impacted by the closure of Ontario's coal-fired capacity, and Canadian exports of metallurgical coal will be impacted by the state of the iron and steel industry abroad and competitiveness of Canadian producers.

Canadian Reserves

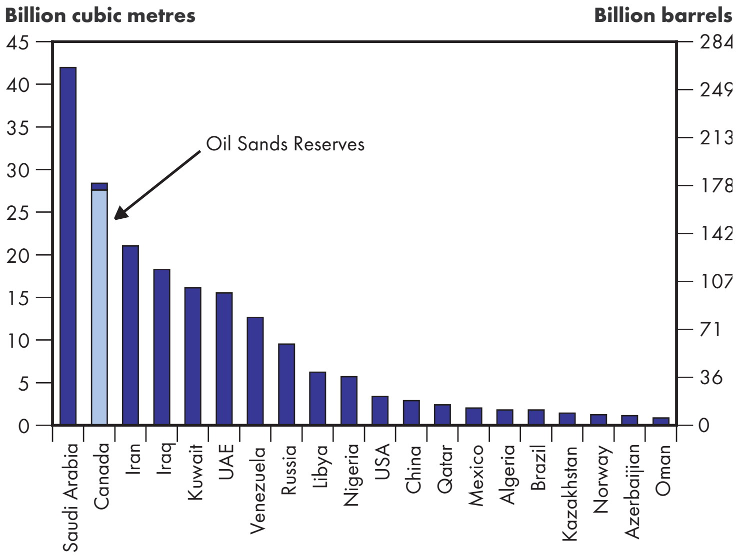
The starting point for developing long-term projections of crude oil and natural gas production is to review the reserve potential. Conventional resources for oil and natural gas are based on estimates published by provincial energy agencies, offshore petroleum boards, the Geological Survey of Canada (GSC), and the NEB. Bitumen resource estimates are adopted from the Alberta Energy Utilities Board (EUB)[26].

As of year-end 2005, Canada's remaining oil reserves stood at 28.2 billion cubic metres (178 billion barrels), composed of 27.5 billion cubic metres (173 billion barrels) of bitumen reserves and

26 Both the *Oil & Gas Journal* (Pennwell Petroleum Group) and the *BP Statistical Review of World Energy* recognized the EUB estimates for established reserves of bitumen in their listing of world oil reserves.

FIGURE 2.3

Estimated Proved Oil Reserves, 2005



Source: BP Statistical Review of World Energy, 2007

0.7 billion cubic metres (4.2 billion barrels) of conventional crude oil reserves (Figure 2.3).

Based on Canada's immense volume of recoverable reserves of oil sands bitumen, Canada ranks second in the world in terms of oil reserves, behind Saudi Arabia.

According to the *BP Statistical Review of World Energy 2007*, Canada accounts for 0.9 percent of the world's proven natural gas reserves and 6.7 percent of world production. The NEB's estimate of remaining marketable gas reserves at the end of 2005 is 1 619 billion m^3 (57.2 Tcf). Reserve additions were 212 billion m^3 (7.5 Tcf) in 2005 and replaced 125 percent of annual production. The rise in remaining reserves reflected increased exploration and improved recovery in known gas fields, as a consequence of the strong increase in natural gas prices during 2005. Initial reserves increased in Alberta, British Columbia and Saskatchewan in 2005, while Ontario and frontier regions were down slightly. With the decline in natural gas prices in 2006, some of the price-related increase in reserves during 2005 may be reversed in 2006[27]. Since natural gas markets were deregulated in the mid-1980s, the ratio of remaining gas reserves to annual production (or reserves life index) has declined from over 20 to be maintained at a relatively stable 8 to 10 since 1999.

Coal reserves are abundant throughout the world and account for over half of remaining hydrocarbon reserves. Canada also has large coal reserves (Table 2.1). At current prices, coal reserves are approximately eight percent of resources, sufficient to meet demand for about a century at the current rate of production, compared to a decade for natural gas and conventional oil. Oil sands reserves are sufficient to meet demand for almost five centuries at the current rate of production, but this is expected to drop as oil sands production is increasing rapidly.

TABLE 2.1

Canadian Coal Resources

(million tonnes)	Anthracite	Bituminous	Sub-Bituminous	Lignite	Total
Western Canada[1]	2 515	29 255	34 470	10 975	77 215
Eastern Canada[2]	0	1 480	180	0	1 660
Total	2 515	30 735	34 650	10 975	78 875

1. Saskatchewan, Alberta, British Columbia and the Territories.
2. Nova Scotia, New Brunswick and Ontario.

Source: Coal Resources of Canada, Geological Survey of Canada, 1989

27 Complete data for 2006 unavailable at time of writing.

REFERENCE CASE

Reference Case Overview (2005-2015)

The Reference Case is the National Energy Board's (the NEB or the Board) view of the most likely development of energy demand and supply over the next ten years given current energy market trends, the assumed macroeconomic outlook, assumed energy prices and the existing suite of government programs[28].

Macroeconomic Outlook

The macroeconomic outlook provides information on the Canadian economy necessary to develop energy demand and supply projections. Key drivers include total goods and services produced, disposable income, population, productivity and financial indicators[29].

28 The government programs considered are only those that are fully articulated and currently employed. Announced programs, such as the federal government's intention to finalize regulations for industrial air emissions by 2010, are not included in the Reference Case. New programs will be considered in the Reference Case of subsequent reports of *Canada's Energy Future* as they are adopted. In this report, consideration of these announced programs are only accounted for in the Triple E Scenario.

29 Using inputs such as the Reference Case assumptions and scenario storylines, as outlined in Chapters 3 to 6, Informetrica Limited provided the macroeconomic forecast for the Reference Case and scenarios.

Canadian long-term economic growth is dependent on labour force and productivity assumptions. The more rapidly the labour force or productivity levels grow, the higher the pace of economic growth, all other factors held constant. A common thread across the three scenarios is a notable deceleration of growth in the labour force that intensifies over the projection period. This result is driven by demographic factors, such as an ageing population and low birth rates. Altering levels of immigration across scenarios provide variations in the demography, but it does not reverse the overall trend.

In the Reference Case, it is assumed that population growth slows over the next 10 years to 0.8 percent per year from 1.0 percent per year from 1990 to 2004 (Table 3.1). This poses implications for labour force growth, which also slows to 1.1 percent per year from 1.3 percent per year. It is also assumed that productivity, measured as output per employee, improves to 1.6 percent per year over the Reference Case period.

TABLE 3.1

Key Macroeconomic Variables – Reference Case 2004-2015

	1990-2004	2004-2015
Population	1.0	0.8
Labour force	1.3	1.1
Productivity	1.4	1.6
Gross domestic product	2.8	2.9
Goods	2.5	3.1
Service	3.0	2.8
Real disposable income	1.6	3.0
Exchange rate (average cents US/Cdn dollar)	74	93
Inflation Rate (average %)	2.3	1.7

1 Comparing personal disposable income growth over the forecast period to the historic period of 1990 to 2004 is somewhat misleading because this historic time period captures two relatively low periods of growth, including the recession in the early 1990s, and Federal and provincial government policies of actively reducing Canadian debt.

(Annual Average Growth Rate (% per year) unless otherwise specified).

As a result, there is continued strong growth in Canadian gross domestic product (GDP) of 2.9 percent per year. The continued strong economic growth translates into personal disposable income growth of 3.0 percent per year.

By 2015, there is no change in the relative share of the goods producing industry or service sector compared to 2004 levels. The goods producing industry continues to account for roughly one-third of gross domestic product (GDP) and the service sector accounts for two-thirds. The regional distribution of Canadian economic growth has important implications for the energy demand projection because industries and regions have built-in biases for certain fuels.

The Reference Case shows economic growth in Canada being led by Ontario, Alberta, Northwest Territories and British Columbia consistent with trends over the last 15 years (Figure 3.1).

Energy Prices

Crude Oil Prices

Although Canada is ranked as one of the largest oil producers in the world, Canada produces less than three percent of total daily world production and is therefore a price-taker. The West Texas intermediate (WTI) crude oil price at Cushing, Oklahoma is one of the major world benchmarks for crude oil. Canadian crude is priced relative to WTI because the U.S. has traditionally been Canada's main export market. The U.S. is also the world's largest market for crude oil.

Crude oil prices are determined by the interaction of energy supply and demand. As discussed in Chapter 2, there has been a significant increase in energy prices in recent years as a result of high global energy demand and tight energy supply. It is expected that higher energy prices would encourage conservation and bring on additional supplies of energy leading to a moderation of energy prices in the near term. The Reference Case assumes that real crude oil prices will decrease from the high levels experienced in recent years to US$50/barrel and remain at this level until the end of the reference period (Figure 3.2).

Conventional heavy oil and bitumen blends command a lower market value than light oil because they are more difficult to refine and yield fewer high-value products. The light/heavy oil differential varies depending on supply and demand conditions and refining values in major markets. The assumption of a light/heavy differential of 30 percent is based on the historical average over the last decade and is applied in the Reference Case and all three scenarios.

FIGURE 3.1

Real GDP Growth Rates – Reference Case 2004-2015

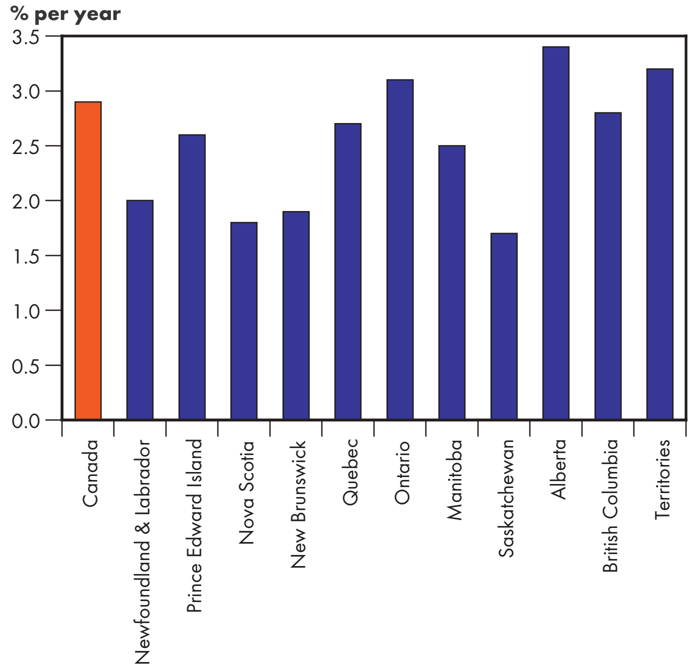
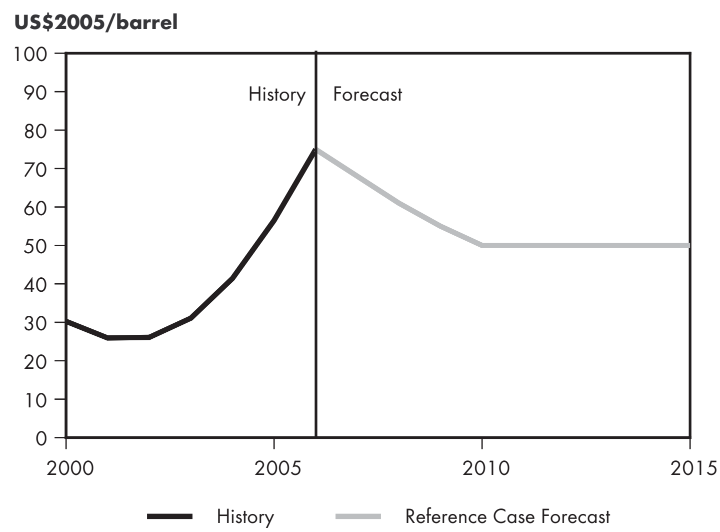


FIGURE 3.2

West Texas Intermediate Crude Oil Price at Cushing, Oklahoma – Reference Case

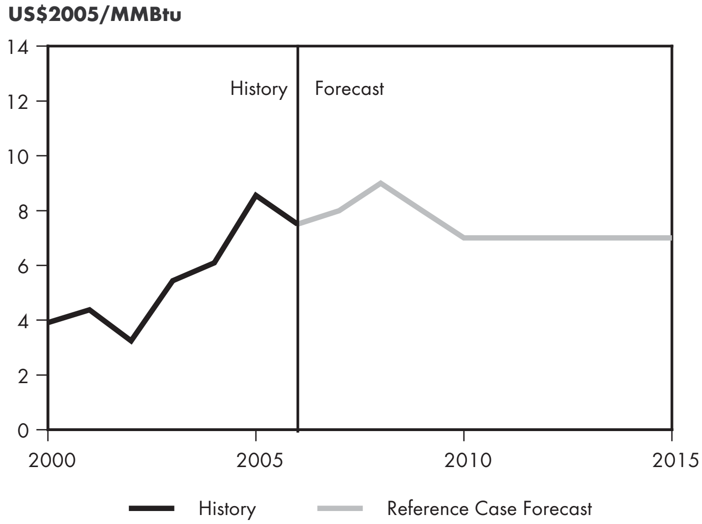


Natural Gas Prices

Natural gas prices are primarily determined on a continental basis as a result of the integrated nature of the North American natural gas demand and supply market, and limited import capacity and liquidity in the global liquefied natural gas (LNG) market. Demand is primarily affected by weather and competing fuel prices. Some industrial demand has the capability to switch between using oil or natural gas, particularly in the U.S. Northeast. As a result, natural gas prices tend to track crude oil

FIGURE 3.3

Natural Gas Price at Henry Hub, Louisiana – Reference Case



prices[30]. In the Reference Case, the historic relationship between natural gas and crude oil continues with natural gas at 84 percent of the crude oil price, at a 6:1 energy content parity (roughly 6 MMBtu of natural gas per barrel of crude oil). This results in a Henry Hub (Louisiana) price of natural gas at US$6.65/GJ (US$7/MMBtu).

This assumed natural gas price level is relatively close to the average index price for Canadian gas supply over the 2003 to 2006 period (measured by the Nova Inventory Transfer [NIT] price in Alberta). This level of pricing is considerably higher than average annual price over the last decade and reflects the expectation of tighter North American supply and demand balance.

Electricity Prices

Electricity prices are determined in regional markets. Consumer prices for electricity are composed of generation, transmission and distribution costs. Prices are lowest in the hydro-based provinces (e.g., British Columbia, Manitoba, and Quebec), which benefit from a high proportion of low-cost heritage assets, such as hydro generating stations that are often many decades old and whose capital costs are largely amortised[31]. For example, in Quebec the supply price of the heritage portion (165 TW.h) is set by law at 2.79 cents/kW.h. In 2006-2007, this heritage portion will account for 95 percent of the electricity distributed by Hydro-Québec, and the cost of the remaining 5 percent will reflect market prices.

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 heritage costs, 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.

30 No. 2 heating oil generally provides an upper bound, while 1 percent sulphur residual fuel oil (RFO) generally provides a lower bound.

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

Within a given province, prices tend to be higher for residential customers and lower for large volume commercial and industrial customers, reflecting the cost of serving these markets. In addition, large customers may have access to power at lower costs than can be obtained from the provincial or municipal electric utility. This requires open access to transmission systems (or wholesale access). All provinces have some form of wholesale access.

In the Reference Case, prices rise steadily as increasing demand requires new generation to be added at higher cost. Depending on the province, new generation facilities include a diversity of conventional technologies, including natural-gas-fired generation, coal-fired units, and nuclear refurbishments as well as alternative or emerging technologies, including wind or biomass.

Coal Prices

Canadian coal prices for power generation vary substantially by region, with prices in Western Canada being generally lower, reflecting the cost of integrated mining and power generation (mine mouth power plants). Prices of coal imported to Nova Scotia, New Brunswick and Ontario reflect the competitive international market. Western Canadian coal is not usually competitive in Ontario, after taking into account quality differences and transportation costs.

In the near term, high oil and gas prices inflate coal prices. However, through the Reference period it is expected competitive pressures and productivity increases in mining and rail transportation will result in price declines.

Energy Demand

The outlook for energy demand is determined by the macroeconomic environment, energy prices, energy efficiency improvements, government policies and the weather[32]. The Reference Case is based primarily on historic trends. There has been an unprecedented rate of technological change in the last few decades and this trend is expected to continue. The trajectory of future technological improvements is based on the historical rate of change.

The Reference Case acknowledges literally hundreds of energy efficiency, demand management, research and development, emerging or alternative energy programs and policies that were in place in Canada at the start of the outlook period.

Total Secondary Energy Demand Trends

Canadian total secondary (or end-use) energy demand for the Reference Case grows at 1.8 percent over the 2004 to 2015 period and the energy intensity of the Canadian economy improves by 1.1 percent per year (Figure 3.4). This intensity improvement reflects higher energy prices in the Reference Case than has been historically experienced. As a result, there is an increase in the uptake of the more readily-accessible energy efficiency improvements, as well as more energy conservation action than witnessed in the last 15 years. Despite this, energy demand continues to be robust. Overall, energy demand remains defined by established devices, industries, services and habits. Projected strong economic and income growth maintain energy demand growth levels.

One of the fastest and most significant areas of energy demand growth is projected to be in the energy producing sector, particularly in the oil sands. As a result, Alberta's share of total Canadian

32 Weather assumptions are based on climate normals, which assume a 30-year historical average.

FIGURE 3.4

Canadian Total Secondary Energy Demand Intensity – Reference Case

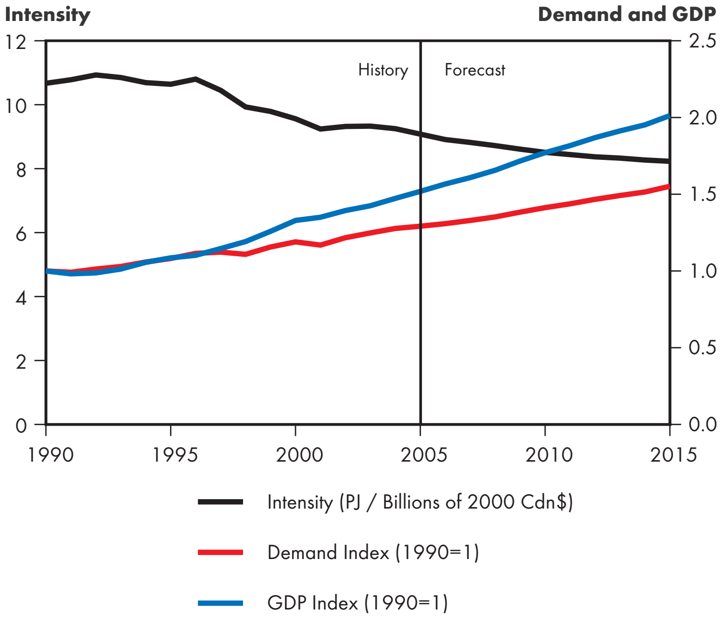
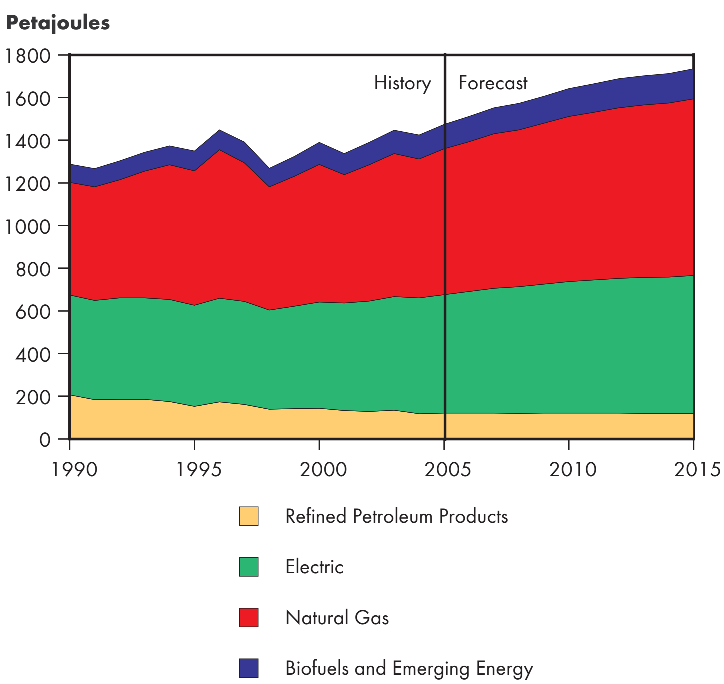


FIGURE 3.5

Canadian Residential Secondary Energy Demand by Fuel – Reference Case



energy demand in 2015 shows the greatest increase, from 26 to 30 percent, which puts Alberta's energy demand on par with Ontario, also at 30 percent[33].

Residential Secondary Energy Demand

Canadian residential secondary energy demand grows at 1.8 percent per year over the Reference Case (Figure 3.5). Higher personal disposable income translates into increased consumer spending on larger homes, appliances, electronics, and lighting. This profusion of consumer goods outweighs energy efficiency gains and leads to residential energy demand growth.

Regional availability of fuel, energy prices, and end-use demand determines the mix of fuel that is used across Canada. Space and water heating account for approximately 80 percent of residential energy demand. In Atlantic Canada, residential demand has been met with electricity, oil and biomass as natural gas was historically unavailable. Hydro-rich provinces, such as Quebec, Ontario, Manitoba and British Columbia, rely more heavily on electricity to meet residential energy demand than other provinces, as electricity prices tend to be competitive with other fuels. Similarly, Alberta and Saskatchewan rely more heavily on natural gas than other regions as there is an abundant supply of this fuel in the region.

33 Appendix 2 contains detailed energy demand information by province.

Some fuel-switching occurs over the Reference Case. Higher electricity prices in the forecast moderate some of the electricity demand growth that would occur as a result of higher personal disposable income. Moderate natural gas prices encourage further expansion of gas networks.

In recent years, residential and commercial natural gas infrastructure has been constructed in Nova Scotia and New Brunswick. High natural gas prices in 2005 and 2006 as a result of Hurricanes Katrina and Rita resulted in a slowing of natural gas demand in the provinces. However, the more moderate natural gas prices in the Reference Case are assumed to allow for further penetration of natural gas in the residential market. By 2015, natural gas accounts for two percent of residential energy demand in Nova Scotia and five percent in New Brunswick.

Residential energy demand is highly influenced by weather trends. A warmer winter will result in decreased energy demand as space heating requirements are lower and a warmer summer will result in increased demand for space cooling. This influence can be seen in the jagged historic energy demand profile for the residential sector in Figure 3.5. It is important to note that the NEB assumes normal weather patterns, which is to say weather follows the 30-year historic average. Over the last decade, Canadian temperatures have been warmer than the 30-year average would suggest. Therefore, residential energy demand could be incorrectly estimated if weather patterns during the outlook period are more similar to the past 10 years than they are to the 30-year historic average.[34]

Commercial Secondary Energy Demand

Canadian commercial secondary energy demand is projected to grow at 1.4 percent per year over the 2004 to 2015 period (Figure 3.6). More moderate service industry economic growth and higher energy prices drive this result. Energy prices in the Reference Case are expected to trigger an energy demand response in the commercial sector where there is still considerable energy efficiency potential.

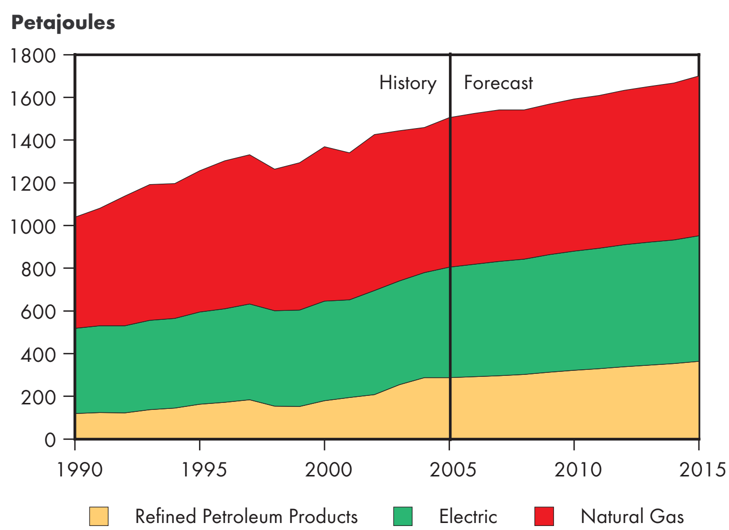
As with the residential sector, fuel shares reflect regional availability and markets. Generally, the fuel shares over the forecast period remain fairly constant, although there is some shifting into natural gas demand as a result of the higher electricity prices[35].

Industrial Secondary Energy Demand

Canadian industrial secondary energy demand grows at a moderate rate of two percent per year over the 2004 to 2015 period (Figure 3.7).

FIGURE 3.6

Canadian Commercial Secondary Energy Demand by Fuel – Reference Case

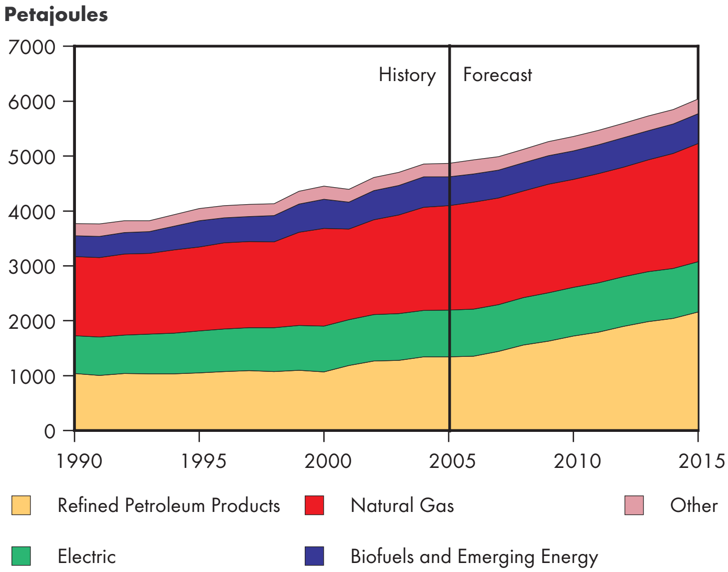


34 An exact estimate of the degree of error is unavailable. However, the Office of Energy Efficiency estimates that changes in weather accounted for between a 2 percent decrease and a 4 percent increase in residential energy demand between 1997 and 2004.

35 Some commercial sector data allocation issues may also distort fuel shares. Historically, the commercial sector acts as a catch-all for miscellaneous energy demands and, as a result, commercial oil shares have been increasing over the last few years.

FIGURE 3.7

Canadian Industrial Secondary Energy Demand by Fuel – Reference Case



('Other' fuel includes coal, coke, coke oven gas, steam, naphtha)

The industrial sector consists of energy demand from manufacturing, forestry, fisheries, agriculture, construction, and mining. The majority of industrial energy demand is found in a handful of energy-intensive industries, such as iron and steel, aluminium manufacturing, cement manufacturing, chemicals and fertilizers, pulp and paper, petroleum refining, and oil and gas extraction[36]. These relatively mature industries are facing increasing global competition and higher Canadian exchange rates. These economic factors temper energy demand growth.

One notable exception to the large-industry demand trend is the oil and gas industry. The strength of this industry drives much of the industrial sector energy demand growth. Oil sands operations are energy intensive, requiring significant amounts of natural gas, as well as other fuels, such as oil (e.g., still gas, petroleum coke, diesel[37]) and electricity. Energy demand expectations are dependent on the oil sands production outlook, which is discussed in more detail in the oil section. A discussion of energy requirements for the oil sands industry can also be found in this section.

In 2015, Alberta accounts for 44 percent of industrial energy demand in Canada and 86 percent of this demand is from the oil and gas industries. Ontario is the second largest at 24 percent and Quebec follows at 15 percent. Fuel shares by province vary significantly, depending on the types of industries and their energy intensities, along with the availability of fuels.

Transportation Energy Demand

Canadian transportation energy demand grows at 1.6 percent per year over the 2004 to 2015 period (Figure 3.8). This is slightly lower than the historical rate of 1.9 percent, and indicates energy efficiency effects tempering increased personal income and GDP growth effects. This sector is driven by macroeconomic conditions, energy prices and government standards.

The transportation sector is split into six different modes, including passenger transportation, on-road freight transportation, off-road transportation, rail, air and marine (Figure 3.9). Passenger transportation is the largest subsector and is primarily fueled by motor gasoline. Ethanol and other transportation fuels make up a very small component of passenger transportation demand. The

36 In 2004, energy-intensive industries accounted for 80 percent of industrial energy demand. Industries outside of energy-intensive industries, such as light manufacturing, agriculture, forestry and construction, each account for a relatively small proportion of industrial energy demand, but taken together they account for about 20 percent.

37 For the purposes of this report, diesel fuel use is captured under off-road transportation.

ethanol share grows from near zero percent to one percent by 2015 due to the planned ethanol policies in Ontario and Saskatchewan[38]. The moderate energy prices in the Reference Case combined with strong personal disposable income growth leads to strong passenger transportation and gasoline demand growth.

On-road freight and off-road transportation is primarily fueled by diesel. Strong industrial growth drives an increase in freight volumes, which in turn increases diesel consumption. Off-road transportation includes vehicle use that takes place primarily off paved or public roads, such as in agriculture, construction and mining activities. The off-road share remains strong due to projected growth in the oil sands, agriculture and construction industries.

In 2004, air, rail and marine demand accounted for roughly 14 percent of transportation energy demand. These shares are not expected to undergo significant changes over the Reference Case outlook.

FIGURE 3.8

Canadian Transportation Energy Demand by Fuel – Reference Case

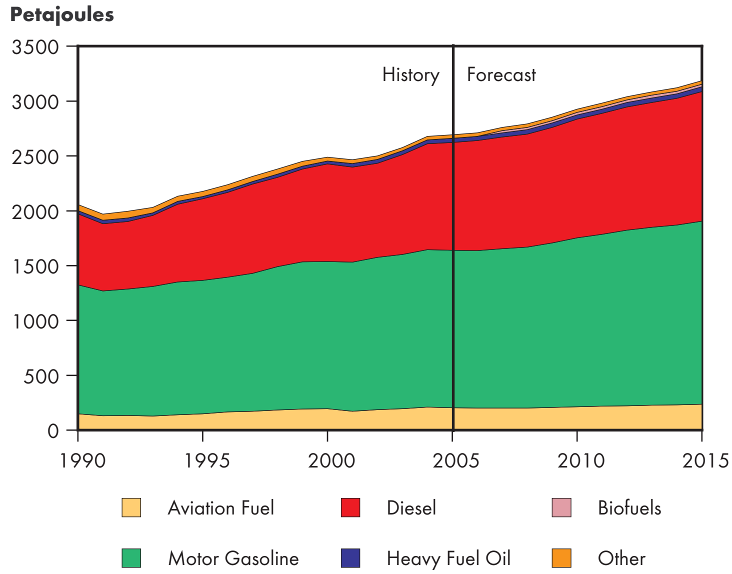
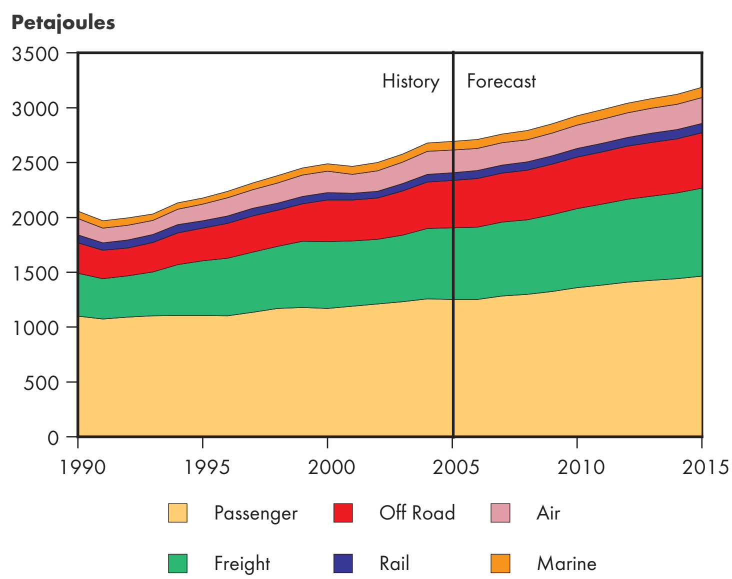


FIGURE 3.9

Canadian Transportation Energy Demand by Mode – Reference Case



Oil Supply

Crude Oil and Equivalent

Crude Oil and Bitumen Resources

Canadian crude oil and bitumen resources remain constant in the Reference Case and in all three scenarios. Current estimates place Canada's remaining established oil reserves at

38 The Ontario assumption is 5 percent ethanol volume (3.4 percent energy) of total gasoline use in the province by 2007. The Saskatchewan assumption is 7.5 percent ethanol volume (5.1 percent energy) of total gasoline use in the province by 2007.

28.2 billion cubic metres (178 billion barrels), with Alberta's oil sands deposits accounting for 27.5 billion cubic metres (173 billion barrels), and conventional oil reserves in the WCSB at 483 million cubic metres (3.0 billion barrels). At current rates of Canadian production, this equates to 181 years of supply. Eastern Canada and Frontier Area resources are estimated to be 211 million cubic metres (1.3 billion barrels)[39].

Total Canadian Oil Production

In the Reference Case, oil prices remain sufficiently buoyant and oil sands supply expands steadily. Declining Western Canada Sedimentary Basin (WCSB) conventional oil production is more than offset by increasing oil sands and east coast production. The east coast allotment would include connection of several satellite pools, as well as a new 80 million m^3 (500 million b) discovery. By 2015, the Reference Case production levels increase by 61 percent above 2005 levels, reaching 642 000 m^3/d (4.05 million b/d), which in today's terms would rank Canada as the world's fourth largest producer (Figure 3.10).

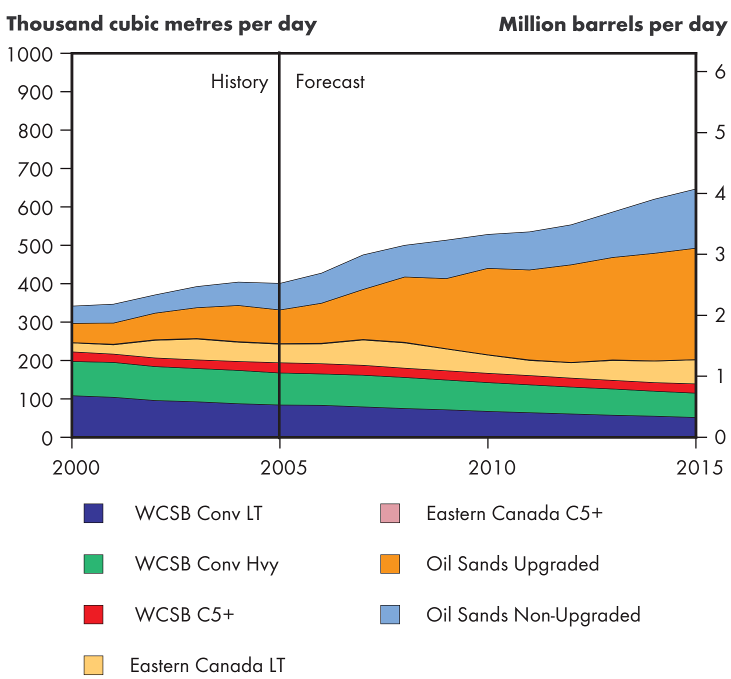
Conventional Crude Oil – WCSB

The projections in the Reference Case are based on extrapolation of historical decline trends, consideration of remaining reserves, potential for new discoveries, potential for improved oil recovery (IOR) and trends in initial production rates for new wells.

The high oil-to-gas price ratio has resulted in a shift to more oil-directed drilling. As well, recent success in exploiting the Bakken oil deposits of the Williston Basin in southeast Saskatchewan and in southwestern Manitoba has led to increased light crude oil production. The effect of these events is a softening of the production decline in the WCSB for several years, after which historical decline trends are expected to resume, consistent with a mature supply basin and the level of remaining reserves.

FIGURE 3.10

Total Canada Oil Production – Reference Case



Due to the WCSB being a mature supply basin, exploration efforts yield increasingly smaller pools, but development drilling and IOR, primarily waterflooding, make up a larger portion of reserves additions.

Following the success of IOR through carbon dioxide (CO_2) flooding at the Weyburn and Midale Fields in

39 Further detail on Canada's oil resources can be found in Appendix 3.

Saskatchewan, it is expected that CO_2 flooding in mature oil reservoirs will increase across the WCSB.

In the Reference Case, production of conventional crude oil and equivalent from the WCSB is projected to resume its decline in the 2009-2010 timeframe, for both light and heavy crude oil, with 2015 production levels of 52 000 m^3/d (328 thousand b/d) for conventional light crude oil and 63 300 m^3/d (399 thousand b/d) for conventional heavy crude oil (Figure 3.11). By 2015, conventional crude oil from the WCSB has declined by about 30 percent compared to 2005 production levels. Condensate is derived primarily from the processing of natural gas; therefore, projections of condensate production are consistent with the natural gas production projections. In the Reference Case, condensate production levels decline to 22 300 m^3/d. (140 thousand b/d) by 2015.

FIGURE 3.11

WCSB Conventional Oil Production – Reference Case

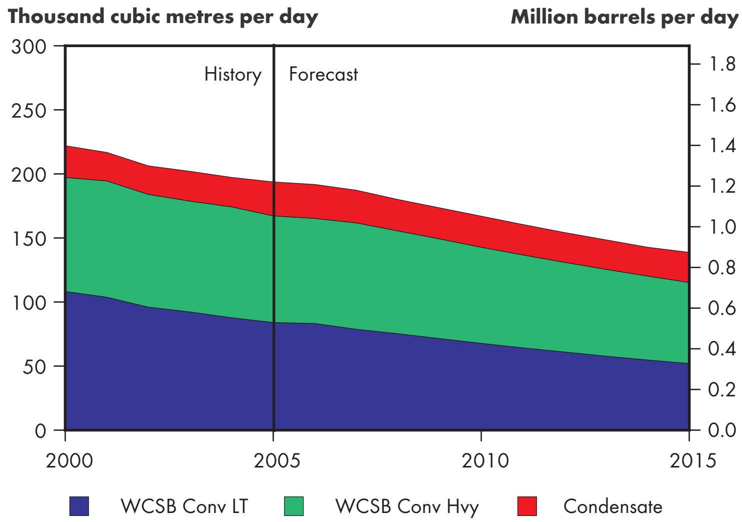
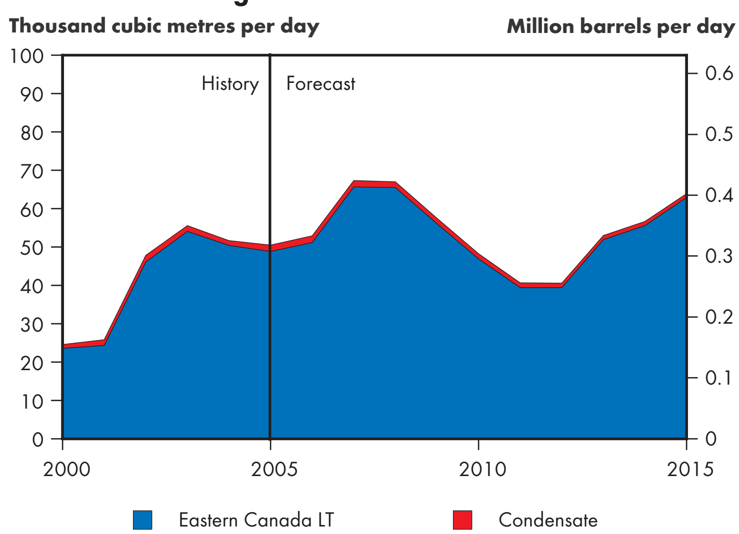


FIGURE 3.12

Eastern Canada Light Crude Production – Reference Case



Eastern Canada Light Crude Production

Projections for eastern Canada oil production are dominated by the east coast offshore, with only minor amounts of production expected from Ontario.

The White Rose Field offshore Newfoundland and Labrador became the third producing field in 2005, after Hibernia and Terra Nova. Total production levels are predicted to reach 66 000 m^3/d (416 thousand b/d) in 2007, as White Rose expands and Terra Nova returns to full capacity after maintenance work in 2006 (Figure 3.12). The Hebron Field begins production in 2013. Contributions from smaller satellite pools in the Jeanne d'Arc Basin are also included, beginning in 2010[40].

40 The estimates presented above reflect the thinking at the time of analysis. Some of these estimates are speculative and may need revisions as more information is received. These revisions will be reflected in the Board's future analyses.

It is also assumed that a new 80 million m^3 (500 million b) field is found in the relatively unexplored regions of the East Coast, potentially in the Flemish Pass region or in the Deepwater Scotian Shelf. The pool comes on-stream in 2015, increasing production levels to 75 000 m^3/d (473 thousand b/d).

Oil Sands Supply

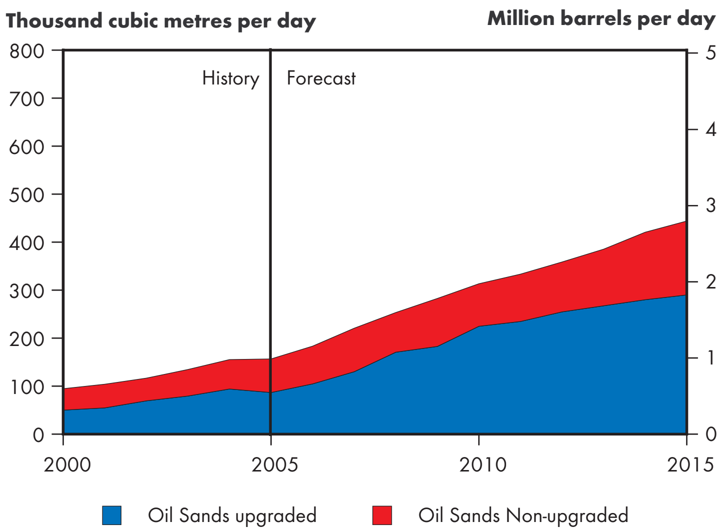
The projections of oil sands derived production in the Reference Case are largely based on the June 2006 NEB Energy Market Assessment (EMA) titled, *Canada's Oil Sands - Opportunities and Challenges to 2015: An Update*.

The energy prices assumed in the Reference Case generate sufficient cash flow for oil sands operators to actively expand production levels. Bitumen supply is derived from surface mining and in-situ recovery operations. The bulk of in-situ supply comes from steam assisted gravity drainage (SAGD) and cyclic steam stimulation (CSS) thermal processes, while the contribution from the toe-to-heel air injection (THAI™) and vapourized extraction (VAPEX) processes is anticipated to increase over time. Primary or 'cold production' levels are assumed to increase at an annual rate of one percent over the course of the projection.

Upgraded bitumen supply includes bitumen from mining, in-situ and primary sources. This upgraded supply includes shipments to dedicated (on-site) and stand-alone (Edmonton refinery corridor) upgraders. Upgraded bitumen levels expand to 290 000 m^3/d (1.82 million b/d) by 2015 and represent 65 percent of total bitumen supply (Figure 3.13). The non-upgraded bitumen supply falls as a result of additional upgrading capacity coming on-stream. In the Reference Case, non-upgraded bitumen levels expand to 154 000 m^3/d (970 thousand b/d) by 2015.

FIGURE 3.13

Canadian Oil Sands Production – Reference Case



The oil sands industry is a large user of natural gas and has been seeking ways to reduce its dependence on this fuel. Over the past decade, the energy efficiency in oil sands operations has improved on the order of one percent annually. In the Reference Case, this rate of improvement is maintained to 2015. In addition, the adoption of alternative fuels in certain new projects is considered. Bitumen gasification will provide the bulk of the fuel requirements and feedstock for the OPTI/Nexen Long Lake SAGD/Upgrader project, scheduled to begin operations in 2007. It is assumed that the application of bitumen gasification will gradually gain momentum in both in-situ and upgrading operations. As well, the application of the THAI™ and Multiphase Superfine Atomized Residue (MSAR) technologies will begin to play a role in the 2010-2012 timeframe. In the Reference Case, the purchased natural gas intensity is reduced from 0.67 Mcf/b in 2005 to 0.59 Mcf/b in 2015. Total purchased natural gas requirements, excluding on-site electricity requirements, increase from 18.4 million m^3/d (0.65 Bcf/d) in 2005 to 51.0 million m^3/d (1.8 Bcf/d) by 2015.

Supply and Demand Balances

The crude oil feedstock requirements for Canadian refineries are based on projected demand and assumed levels of exports and imports of petroleum products. Total domestic demand for petroleum products was 290 900 m^3/d (1.83 million b/d) in 2005. By 2015, it increases to 392 400 m^3/d (2.47 million b/d).

Canada's refineries are located in four main regions: Western Canada, Ontario, Quebec and Atlantic Canada. There is very little spare processing capacity in Canada. Two of the three refineries in Atlantic Canada produce petroleum products primarily destined for the export market. With the exception of Shell Canada's refinery in Scotford, Alberta, most Canadian refineries are over 30 years old. The Reference Case assumes most companies will focus on optimizing production and flow-through at existing refineries rather than investing in new refineries.

Refineries in Quebec and the Atlantic do not have access to western Canadian crude oil and rely on imports for most of their feedstock requirements. East Coast offshore production can reach Ontario and Quebec; however, the suitability of the crude quality and stability of supply, combined with import economics, will limit the displacement of imported volumes in these markets.

Oil Sands Opportunities and Challenges

Worldwide economic growth and the consequent construction boom that has resulted in sharp increases in demand for labour and in prices of construction materials, especially steel and cement, combined with a very active construction environment in Alberta, has led to increased construction costs in the province. Oil sands developers are acutely aware of the challenges in construction and commissioning of large facilities. An overheated economy has resulted in shortages of engineers, project managers, skilled labour, trades and even materials. In addition, the influx of capital and people have severely strained supporting infrastructure, as shortage of schools, housing, healthcare and other essentials have impacted budgets and timelines. The result has been an escalation in capital costs for oil sands producers in the order of 40 to 50 percent over the last two years. For example, capital costs for adding integrated mining and upgrading capacity, to come on in the 2010-2011 timeframe, are estimated to be in the range of $80 000 to $100 000 per flowing barrel.

Volatile oil and gas prices, as well as volatile light/heavy crude oil price differentials, add considerable risk in predicting rates of return on investment for oil sands projects. In addition, because the oil price is denominated in U.S. dollars, a stronger Canadian dollar has a significant negative impact on project economics. Recent changes in tax policy, concerning removal of the Accelerated Capital Cost Allowance (ACCA) have also had an effect.

The oil sands industry faces additional uncertainties regarding environmental compliance, as both provincial and federal government regulations regarding greenhouse gas (GHG) emissions are not yet fully defined. Provincial regulations concerning water use, air quality, and land use are also not yet fully defined. As well, Alberta's provincial government has undertaken a review of oil and gas royalties, including oil sands royalties, with a final report to be released in the fall of 2007.

These challenges have slowed the pace of activity somewhat, and a number of companies are reassessing the economics of their projects.

The challenges faced by the oil sands industry are counter-balanced by the opportunities. At a time of increasing resource nationalism around the world, Canada's huge oil sands reserves, set in a climate of relatively stable political and economic policy, represent an attractive target for investment. The potential for technological innovation to reduce the costs of bitumen extraction and upgrading is an additional attraction. Given the outlook for continued higher oil prices, return on investment should be sufficient to drive oil sands expansion.

Light Crude Oil[41] – Supply and Demand Balance

Exports of light crude oil increase steeply from 110 200 m³/d (694 thousand b/d) in 2005 to 258 300 m³/d (1.63 million b/d) in 2015 (Figure 3.14). Most of the refineries in Western Canada will run greater volumes of synthetic crude oil, which will displace potentially 11 700 m³/d (74 thousand b/d) of conventional light crude oil that could, in turn, be exported.

FIGURE 3.14

Supply and Demand Balance, Light Crude Oil – Reference Case

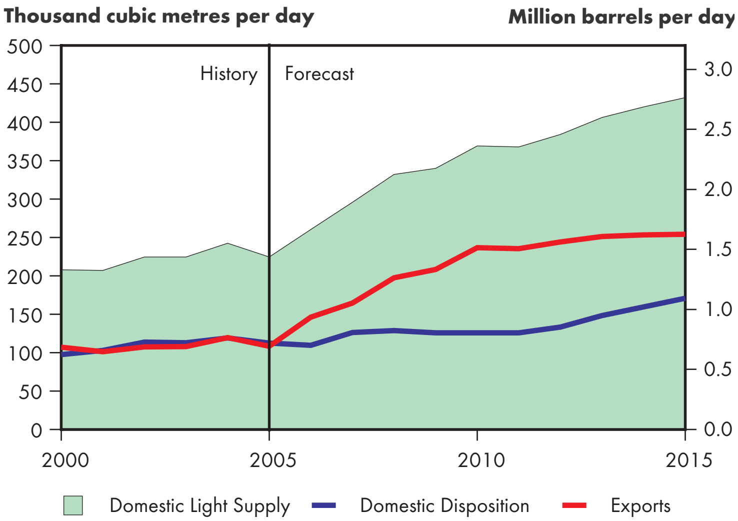
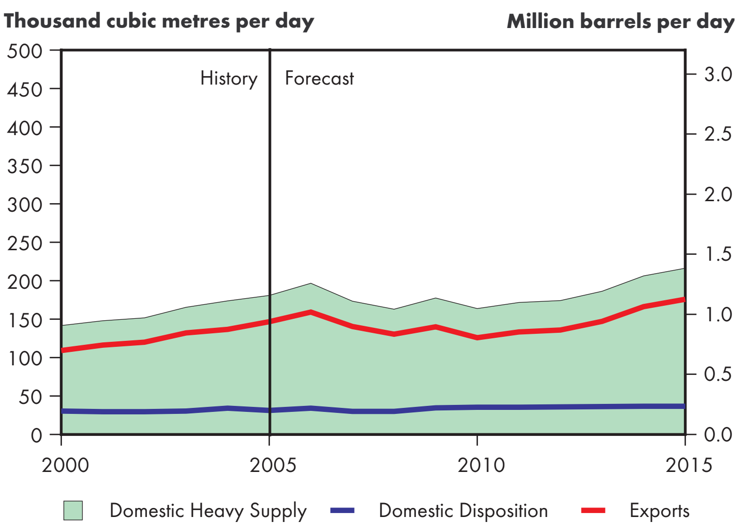


FIGURE 3.15

Supply and Demand Balance, Heavy Crude Oil – Reference Case



Heavy Crude Oil – Supply and Demand Balance

Exports of heavy crude oil increase from 149 200 m³/d (940 thousand b/d) in 2005 to 178 900 m³/d (1.13 million b/d) in 2015 but vary somewhat during the forecast period (Figure 3.15). It is assumed that some of the refineries in Western Canada will also be able to process some bitumen directly, which translates into increased domestic demand for heavy crude oil.

Natural Gas Supply

Canadian Natural Gas Resource Base

Under the pricing conditions of the Reference Case, Canada's remaining marketable natural gas resource base is estimated at 12 011 billion cubic metres (424 trillion cubic feet). Conventional gas in Western Canada represents almost a third of the remaining resource base and is expected to be the source of almost 80 percent of projected Canadian natural gas production through 2015.

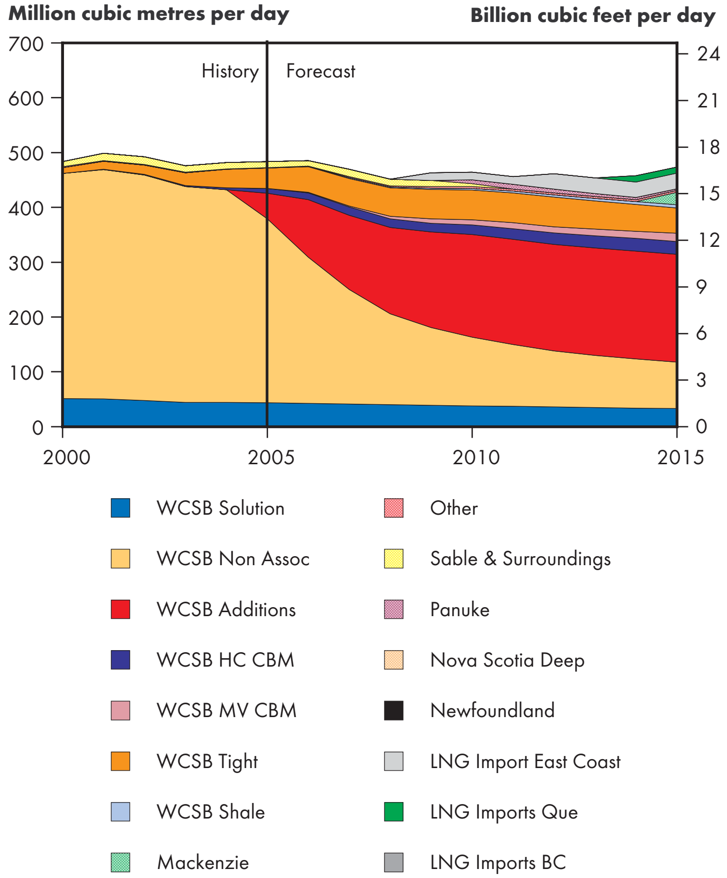
41 To remain consistent with Statistics Canada (StatCan) data, 'light crude oil' refers to all crude oil of 26 API and greater while 'heavy crude oil' refers to all crude less than 26 API. This report reclassifies the export statistics currently available on the NEB website, which combines medium crude oil, with an API between 25 and 30, with heavy crude oil.

Western Canada also contains significant unconventional natural gas resources, including coalbed methane (CBM), tight gas and shale gas. These unconventional natural gas resources comprise 1 841 billion cubic metres (65 trillion cubic feet) or 15 percent of estimated remaining natural gas resources.

Other natural gas resources are designated as frontier supply. Frontier resource areas are estimated to contain 6 374 billion cubic metres (225 trillion cubic feet) or 53 percent of Canada's remaining marketable natural gas resources, but only minor amounts are likely to be accessible within the time period of the Reference Case[42].

FIGURE 3.16

Natural Gas Production Outlook – Reference Case



Production and LNG Imports

The Reference Case estimate of Canadian marketable natural gas production and LNG imports is indicated in Figure 3.16. Western Canada is expected to continue to be the primary source of gas production in the Reference Case. After lagging from 2006 to 2008, natural gas drilling in Western Canada recovers to roughly 18 000 gas wells per year by 2009 and will maintain that level through 2015. Natural gas drilling slowed in the second half of 2006 and into 2007 due to reduced margins resulting from escalating drilling costs and softening gas prices. A gradual recovery in natural gas drilling activity is expected to begin in 2008 as drilling costs weaken due to lower utilization (compounded by growth in the drilling rig fleet) and natural gas prices strengthen.

Despite the resumption of strong drilling activity, a continued downward trend in new well productivity leads to a gradual decline in production over the period, as shown in Figure 3.16. Coalbed methane production in Western Canada increases steadily, reaching 38 million m^3/d (1.4 Bcf/d) by 2015.

Conventional natural gas production from the East Coast contributes an average of 12.2 million m^3/d (0.43 Bcf/d) over the Reference Case period and includes the Sable project offshore Nova Scotia, the onshore McCully field in New Brunswick, and CBM production in Nova Scotia. Also included is offshore production from the proposed Deep Panuke project starting in 2010, subject to

42 A detailed breakdown of Canada's remaining marketable natural gas resource base is provided in Appendix 4.

Unconventional Natural Gas

Unconventional gas includes CBM, tight gas, shale, and gas hydrates.

Coalbed methane consists of methane bonded or adsorbed into the large internal surface area of the coal. CBM resources are primarily located in the shallow Horseshoe Canyon Formation and the deeper Mannville Formation in Alberta.

Canada does not currently have a specific definition for tight gas. The usual practice has been to incorporate the estimated 368 billion cubic metres (13 trillion cubic feet) of resources in the low permeability or tight gas plays that are currently producing gas as conventional gas. For the purposes of this report, it is useful to recognize these volumes separately and the conventional category has been reduced accordingly. Further, the NEB believes that the gas resources attributed to these producing plays understates additional volumes that could also be recognized as tight gas and so has increased the remaining marketable natural gas resource estimate for the Reference Case to a total of 595 billion cubic metres (21 trillion cubic feet). Tight gas is expected to be producible from along the mountain front of Alberta and British Columbia in a region known as the 'Deep Basin', in the Jean Marie Formation of northeast B.C., and possibly in the shallow gas deposits of southeastern Alberta and southwestern Saskatchewan.

At present, there are no large scale production programs from shale horizons in Canada. Several shales in Western Canada qualify as targets and there is some ongoing testing of shales in select locations. Fracturing, both natural and induced, is generally required to provide flow pathways to the well bore. There are occasional wells in Alberta that do produce gas or oil from highly fractured shales. For the Reference Case, 244 billion cubic metres (8.6 trillion cubic feet) of remaining marketable resources have been assigned to shale gas.

Gas hydrates are another potential source of unconventional natural gas. Gas hydrates consist of methane molecules trapped in and encased by a cage of frozen water molecules. Gas hydrates are found at the ocean bottom or on land under permafrost areas. The likelihood of achieving commercial methane production from gas hydrates by 2030 is very low and so has not been included in the unconventional resource estimate.

the project obtaining regulatory approval and a commercial decision to proceed. Significant volumes of discovered gas are associated with offshore oil projects on the Grand Banks of Newfoundland, but this gas is expected to be used for reservoir pressure maintenance or otherwise stored in reservoirs until oil production slows down beyond the end of the Reference Case.

Three LNG import terminals are expected to be operational by 2015 with annual import volumes assumed to average 39.7 million m^3/d (1.4 Bcf/d). Currently one LNG facility, and its connecting pipeline, has approvals and construction is under way with deliveries expected to start in 2008.

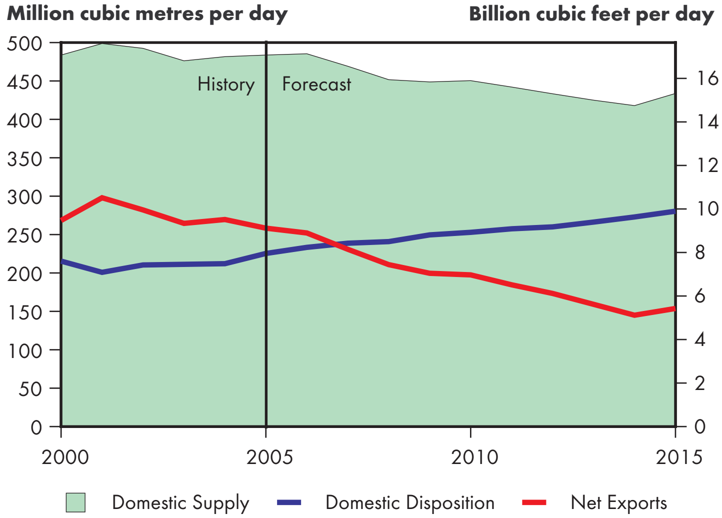
Supply and Demand Balance

Demand for natural gas increases steadily in the Reference Case, led by gas use in expanding oil sands operations and greater use as a fuel to generate electricity. With production initially declining and then remaining relatively flat for much of the period, rising gas demand results in a gradual tightening between supply and demand (Figure 3.17). While physical export and import flows of natural gas between Canada and the U.S. will likely vary from year to year and between specific regions on the basis of relative market conditions, a gradual reduction in net natural gas export capability is a consequence of the Canadian production and demand projections in the Reference Case.

Although not part of the analysis for this report, any reduction in net Canadian gas exports over the period is likely to be offset by increased LNG imports into the U.S. and by growing U.S. unconventional gas production. As a result, relatively balanced supply and demand conditions are expected to persist in North American natural gas markets over the Reference Case period and maintain an average gas price of $6.65/GJ (US$7.00/ MMBtu).

FIGURE 3.17

Supply and Demand Balance, Natural Gas – Reference Case



Natural Gas Liquids

Supply and Disposition

The natural gas liquids supply outlooks are primarily derived from the natural gas production outlooks[43]. However, a portion of propane and butane supply comes from oil refining. Therefore, as gas declines and oil production increases in all scenarios, the share of natural gas liquids (NGL) from oil increases.

Under all scenarios, extraction of liquids from natural gas is assumed to be economic over the long-term given the price assumptions. In addition, NGL volumes are augmented by liquids extracted from Mackenzie Delta gas, (subject to regulatory approval and a commercial decision to proceed), oil sands off-gas, as well as enhanced deep-cut expansion at Alberta straddle plants. The enhanced deep-cut and off-gas sources reflect the Alberta government's Incremental Ethane Extraction Policy (IEEP) introduced in 2006.

In the Reference Case, excess volumes of propane and butane are available for export throughout the entire projection period. The butane supply and demand balance becomes tight in the middle of the outlook period; however, demand for butane as bitumen diluent is assumed to disappear around 2015. The commencement of service on one or two of the currently proposed condensate import lines would result in the loss of butane diluent demand[44].

Ethane Supply and Demand Balances

The ethane supply and demand balance is expected to be tight early in the period, as supply declines with the decrease in conventional WCSB natural gas production and little incremental supply is available from oil sands off-gas or extraction facility expansions (Figure 3.18). The tightness is likely to ease by 2010, as new ethane extraction facilities and oil sands off-gas add about 5 800 m^3/d (36 thousand b/d) of incremental ethane with another 6 600 m^3/d (42 thousand b/d) added in 2015. Consequently, a small amount of excess supply is available for export during the period of 2010 to 2015.

The ethane supply outlook does not include ethane from the East Coast, British Columbia offshore, or Arctic Islands resources – this is the case under all scenarios. In addition, there is insufficient ethane to support development of a petrochemical industry in the Atlantic Provinces. As a result, in the Reference Case and the scenarios, ethane is left in the natural gas streams in these areas.

43 Liquids associated with LNG are assumed to remain in the natural gas stream and therefore do not contribute to Canadian NGL supply in any scenario.

44 Further detail on propane and butane supply, demand and potential exports can be found in Appendix 3.

FIGURE 3.18

Canadian Ethane Supply and Demand Balance – Reference Case

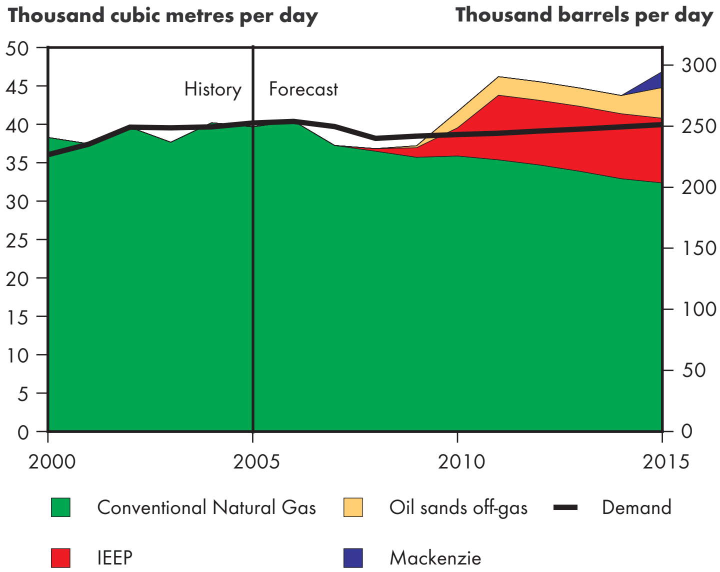
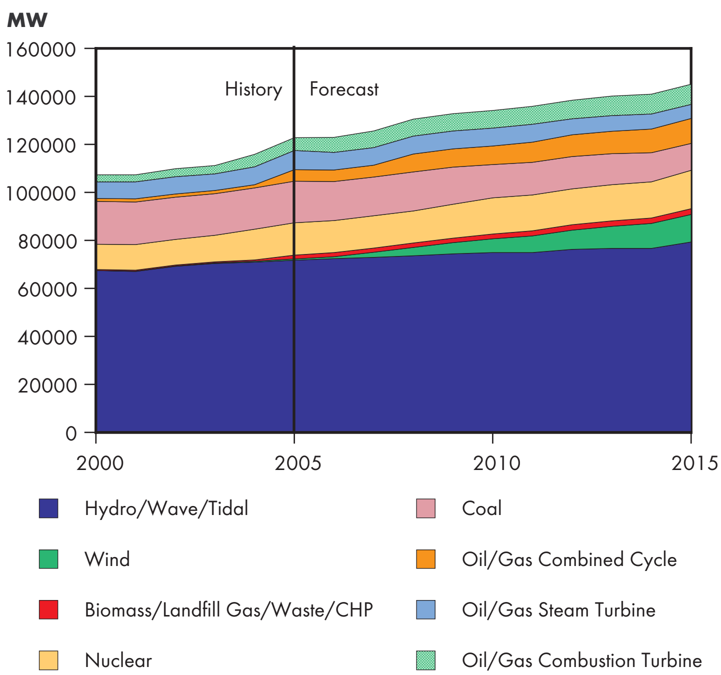


FIGURE 3.19

Canadian Generating Capacity – Reference Case



Of the ethane extracted in 2005, about 94 percent was consumed by the Alberta petrochemical sector as feedstock to produce ethylene, with the remaining volume used for IOR miscible flood projects or shipped to other provinces. Demand for ethane is projected to grow at a slow rate, as the ethylene market in North America is considered to be saturated; therefore, it is assumed that no new ethylene plants will be built during the forecast period under all scenarios. Some volumes of propane are currently being used to supplement ethane supplies at petrochemical facilities, and this is expected to continue through the forecast period.

Electricity Supply

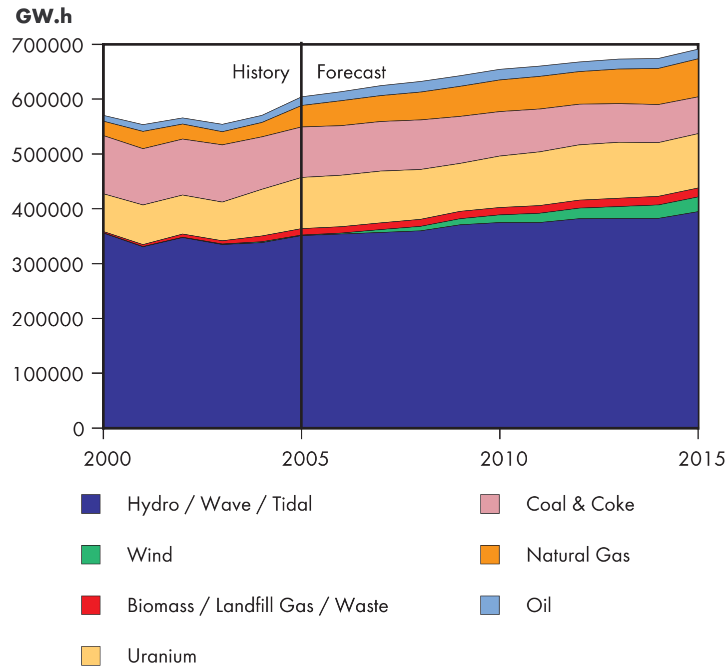
Capacity and Generation

Generation capacity increases by 18 percent between 2005 and 2015 (Figure 3.19). These capacity additions are required to meet projected load requirements during peak periods, while maintaining adequate reserve margins for reliability. Generation growth averages two percent annually over the period, with new electricity supply coming from both traditional and emerging sources. Investment requirements are being examined using a portfolio approach that considers a variety of factors in addition to cost, such as environmental impact, fuel price volatility and security of supply. This approach will enable investments in projects of all types, including conventional sources such as large hydro, nuclear, natural gas, coal and oil emerging technologies such as wind, biomass, solar, tidal and small hydro.

Hydro

FIGURE 3.20

Canadian Generation – Reference Case



Hydroelectric generation will continue to be the major source of electricity during the Reference Case timeframe, increasing its share from about 60 percent of Canadian electricity generation to 65 percent (Figure 3.20). Hydro-based capacity, excluding small hydro is projected to reach 79 300 MW by 2015, an increase of roughly 7 600 MW from 2005.

There will be extensive development of new hydro projects in Quebec, Manitoba, British Columbia and Newfoundland and Labrador and smaller hydroelectric projects in Alberta and Ontario. The Reference Case assumes that the 2 260 MW Lower Churchill facility in Newfoundland and the 200 MW Wuskwatim project in Manitoba are built, and that announced hydro projects, including expansion of existing facilities, in Quebec (3 194 MW) and British Columbia (1 389 MW) are constructed.

Many of these projects are located far from the customer base and will require major transmission investments.

Nuclear

Total nuclear capacity increases by 2 650 MW (20 percent) during the period of the Reference Case. Nuclear additions occur in Ontario, with the return to service of two 825 MW Bruce A units in 2009 and 2010, and the subsequent construction of a 1 000 MW Advanced Canadian Deuterium (CANDU) reactor (ACR) in 2015 to replace retiring coal units. It is assumed that the Point Lepreau (New Brunswick) and Gentilly-2 (Quebec) generating stations will be refurbished.

Natural gas-fired

Investment in natural gas-fired generation is forecast to increase despite the rise in the relative level and volatility of natural gas prices. The following increments are forecast to occur during the period of the Reference Case: an additional 5 000 MW of combined-cycle generation; 3 000 MW of combustion turbine/cogeneration facilities; and a decrease of 1 400 MW of steam turbine generation. Such investments illustrate that natural gas will continue to be relied on to meet increased electricity demand. Annual natural gas-fired generation output is forecast to increase from 39 000 GW.h to 69 000 GW.h over the forecast period, increasing its share of total generation from seven percent to 11 percent.

In the near term, investment in combined-cycle generation is planned for Ontario, British Columbia, Saskatchewan and Newfoundland and Labrador. In Ontario, combined-cycle gas will be relied on to help meet demand following the phase out of coal-fired generation. In British Columbia, the Burrard steam turbine generator will either be converted to combined-cycle units or replaced with new combined-cycle generation. In Newfoundland, oil steam units will be replaced by a 360 MW combined-cycle oil-fired facility in 2012.

There is a general decrease in natural gas-fired steam generation as older plants are replaced by more efficient combined-cycle facilities, except in Ontario where some coal-fired generation is converted to natural gas.

Combustion turbine generation will be added in the Northwest Territories as part of the Mackenzie Valley pipeline project starting in 2015.

Also included in the combustion turbine total is cogeneration. Cogeneration units will be added in Alberta, Ontario and Quebec. Of note, 1 500 MW of natural gas and bitumen-fired cogeneration facilities are developed in Alberta in conjunction with the growing number of oil sands and in-situ bitumen projects. In Quebec, Bécancour is the only gas-fired generation addition.

Coal-fired

Total coal-fired generation capacity is projected to decrease by 36 percent or 6 300 MW in the Reference Case. As a result, coal's share of total generation will fall from 14 percent in 2005 to 8 percent in 2015. Output from coal-fired generation will decrease 27 percent. The largest change occurs in Ontario, as coal-fired generation decreases by 87 percent or 6 600 MW. During the period of the Reference Case, new conventional coal-fired generation will be constructed in Alberta and Nova Scotia.

At the time of writing, SaskPower (a Crown Corporation that is the principal supplier of electricity in Saskatchewan) was working on an innovative Clean Coal Project that would result in the construction of a 300 MW coal power plant that would have up to 90 percent of its CO_2 emissions captured. Our analysis assumes that this unit comes into service in 2012. The experience gained will allow the addition of carbon capture and storage (CCS) systems to coal power plants built after 2018, although for economic reasons this technology is only widely employed in the Triple E Scenario.

Oil-fired

Oil-fired power facilities provide generation during peak demand periods or in areas where other fossil fuelled generation is not available, such as the Yukon, Nunavut and Northwest Territories. The Reference Case indicates declining shares of oil-fired generation, as older steam units are replaced with natural gas-fuelled combined-cycle generation.

Emerging Technologies

The term 'emerging technologies' includes all alternatives to traditional generation sources such as coal, hydro with storage, natural gas, oil and nuclear. The share of installed unconventional generation remains small relative to the more centralized conventional sources, yet large changes are expected to occur. Wind power experiences exceptionally strong growth, and total wind power capacity is projected to grow from 495 MW in 2005 to 11 400 MW by 2015. During the outlook period, the largest volume of wind power additions occur in Quebec (4 365 MW), Ontario (2 852 MW) and Alberta (1 140 MW). Output from wind generation shows a corresponding increase, from 945 GW.h in 2005 to 29 605 GW.h in 2015.

Other generation technologies, such as biomass, landfill gas, waste heat, solar and tidal grow by 50 percent to 812 MW. The majority of this output is from biomass.

Exports, Imports and Interprovincial Transfers

Canadian net exports increase by 32 per cent from 2006 to 37 600 GW.h in 2015, due in large part to the commissioning of the Lower Churchill hydro development in Labrador (Figure 3.21). This also leads to an increase in interprovincial transfers as this power must be wheeled through Quebec before it can be exported.

Coal

Canadian Resources and Reserves

Coal resources include those deposits that occur in coal seams within specified limits of thickness and reflect the technical feasibility of exploitation and probable ultimate use. Ninety-eight percent of Canadian coal resources are found in Western Canada, of which over half consists of sub-bituminous deposits in Alberta (45 percent) and lignite in Saskatchewan (14 percent). Approximately 41 percent of western coal reserves are from bituminous and anthracite coal resources.

Market-Based Prices for Electricity

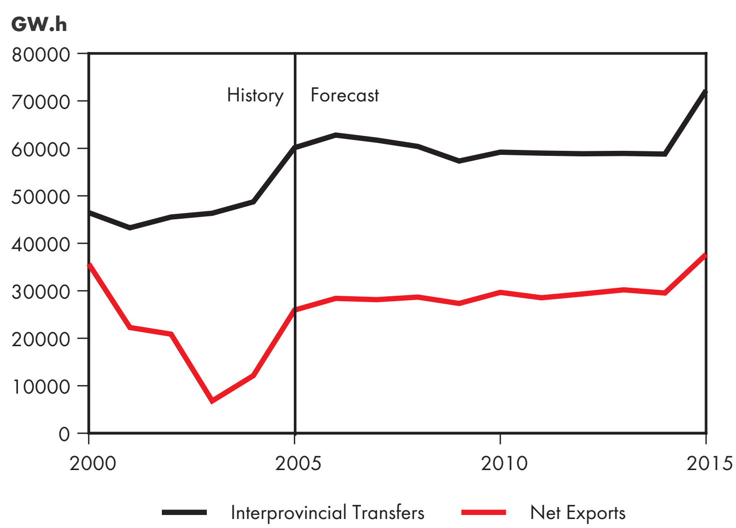
Although there are some exceptions, the prices Canadians pay for electricity are based on regulated rates approved by provincial public utility boards. Such rates tend to be based on the historical costs of power developments (heritage assets) and are thus lower than the replacement, or marginal cost. With a preponderance of low-cost heritage hydro resources, this enables Canadians to enjoy among the lowest electricity prices in the developed countries. In contrast, electricity sales in interprovincial and international trade, occur at market-based prices, which are higher than provincially-regulated prices.

Regulated prices can be justified on the basis of the provincial market structure, where there is limited competition (in many provinces, electricity generation is dominated by Crown corporations) and a desire to maintain stable and reasonable prices. Some provinces have encouraged the development and use of low-cost power as an economic development strategy for attracting electric-intensive industry.

Proponents of market-based pricing argue that both consumers and producers need market signals to encourage efficient outcomes. For example, anticipated supply shortages would cause increasing prices, thus encouraging development of new supply and providing a signal to consumers to reduce consumption. Currently, Alberta and Ontario have made the most progress toward implementing market pricing for electricity consumers.

FIGURE 3.21

Interprovincial Transfers and Net Exports – Reference Case



Supply and Demand

Global demand for total coal appears to have started slowing down in 2005. However, global thermal coal demand continues to be strong, particularly in developing countries that use coal for heat and electricity generation. Canada's 2005 domestic demand for coal is estimated to be slightly higher than the average level of the past decade. In 2005, Canadian electricity generation consumed about 51 Mt, of which 34 Mt was sourced domestically and 17 Mt was imported. Canada's steel, cement and other industries consumed about 4 Mt of coal. Canada produced about 68 Mt of coal in 2005, a slight increase over the past decade's coal production of 62 Mt. Canada exported 28.2 Mt of coal, a decrease from mid-1990 levels of 34 Mt.

Both nationally and internationally, there does not appear to be significant resource constraints on coal production. Canadian coal production is projected to decrease by about four percent by 2015. This decrease is primarily driven by a lower domestic demand in power generation, which accounts for 80 percent of Canadian coal consumption in 2015. Metallurgical coal production is forecast to increase by 13 percent between 2005 and 2015, while end-use and net exports are slated to increase by 16 and 59 percent respectively. Overall, Canadian production decreases to 60 Mt in 2015 from 68 Mt in 2005. Canadian coal production will be affected by power generation choices and the competitiveness of Canadian coal in international markets.

Between 2005 and 2015, the reduction of coal-fired generating capacity in Ontario leads to a decrease in domestic demand from 55 Mt in 2005 to 39 Mt in 2015. Canadian net exports of coal are expected to increase 65 percent between 2005 and 2015. The majority of increased exports will come from metallurgical coal used in the iron and steel industry.

In 2005, Canada exported coal to 21 countries on five continents, with an annual value of approximately $2 billion. Global thermal coal demand continues to be strong, particularly in developing countries that use coal for heat and electricity generation.

Greenhouse Gas Emissions

Heightened concern over climate change in recent years has led governments to develop policies to manage emissions. In addition, research and development is underway in an effort to develop more energy efficient equipment and other technological solutions, such as CCS, to reduce GHG emissions. In Canada, many of these programs, policies and technologies are still in the development phase and are therefore not included in the Reference Case or in the Continuing Trends Scenario. Instead, the significant impact that these programs will have on future energy demand and supply trends is explored in the Triple E Scenario.

Greenhouse gas emissions are a function of population, economic growth and energy demand decisions. In the Reference Case, increasing population and economic growth lead to increases in energy demand. As well, GHG intensive fuels, such as refined petroleum products continue to play a dominant role in meeting Canadian's growing need for energy. This results in increased GHG emissions. Total GHG emissions in the Reference Case grow at 1.5 percent annually between 2004 and 2015, close to the historical growth rate of 1.7 percent from 1990 to 2004. The industrial sector has the most rapid GHG emissions growth rate (Figure 3.22). A large portion of this growth can be attributed to expanding oil sands extraction and upgrading. The electric generation sector has the slowest GHG emissions growth (a negative growth rate) as a result of retiring coal-fired generation units.

Greenhouse gas shares and growth rates vary by province. The three largest GHG emitters are Alberta, Ontario and Quebec. In 1990, Alberta accounted for 28 percent of total Canadian GHG emissions. This share increases to 35 percent in 2015. Ontario's share was 30 percent in 1990 and declines to 26 percent in 2015, while Quebec's share drops slightly from 15 to 13 percent.

Overall, GHG emissions levels increase in Canada over the Reference Case; however, GHG emissions intensity, measured as megatonnes of GHG emissions per unit of GDP, declines (Figure 3.23). This implies that fewer GHGs are emitted to produce the same amount of goods and services. This reflects improvements in energy efficiency and a shift towards less GHG intensive fuels (e.g., retiring of Ontario's coal plants). During the Reference Case timeframe, the GHG intensity level declines at 1.4 percent per year, slightly higher than the historical decline rate of 1.1 percent. This increased rate occurs as clean energy technology and efficiency improvements gain momentum.

FIGURE 3.22

Canadian Total GHG Emissions by Sector – Reference Case

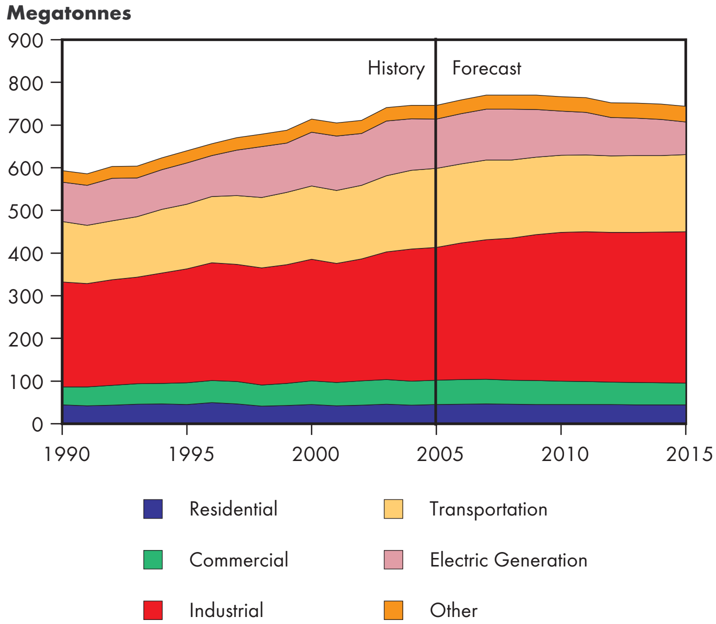
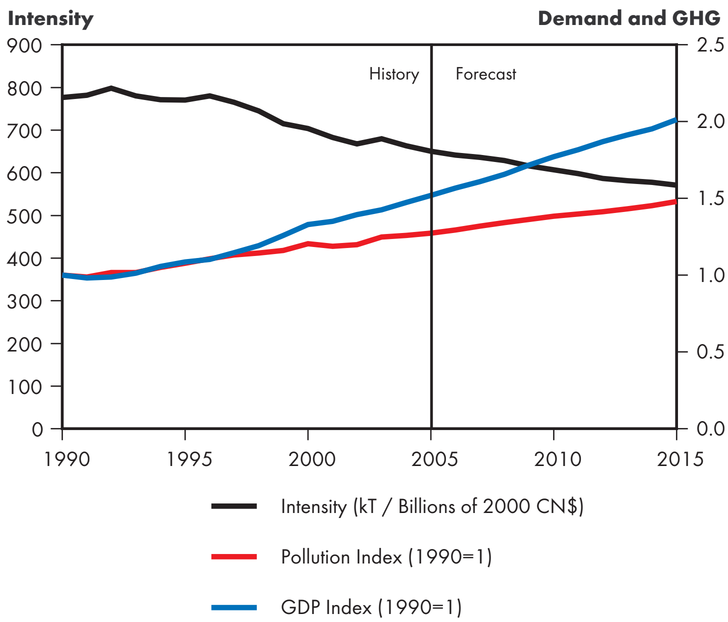


FIGURE 3.23

Canadian Total GHG Intensity – Reference Case



Reference Case Issues and Implications

- Despite higher energy prices than experienced throughout the 1990s, energy demand growth is expected to be robust. This is a result of strong economic performance and growth in personal disposable income. As well, significant changes to energy demand are restricted by established energy using stock.

- Over the immediate decade, Canadians will witness the impact of energy supply decisions and realities, including the following:
  - Rapidly expanding oil sands developments. Changes to refinery configurations will be required to process the synthetic crude oil and bitumen blends produced from the oil sands. As well, this will have implications for pipeline infrastructure.
  - Canada has a large remaining natural gas resource base, but because of the long lead times to access frontier resources, we will remain largely reliant on producing areas of Western Canada.
  - It is expected that coal will be phased out in Ontario and nuclear capacity will be largely restored. Emerging technologies, particularly wind energy, will begin to have a noticeable impact on the generation mix across Canada. Decisions will also be made with respect to large hydro developments in Newfoundland and Labrador, Quebec, Manitoba and British Columbia, posing implications for substantial and unprecedented additions to transmission systems.
- The changing energy landscape during the Reference Case has implications for energy consumers, producers, governments and regulators. Effective development of resources will require goodwill and consideration from all participants.
- The key risks and uncertainties surrounding the Reference Case outlook include the following:
  - An additional 80 million m^3 (500 million b) field is assumed to be found in the relatively unexplored regions of the East Coast, potentially in the Flemish Pass region or in the Deepwater Scotian Shelf, coming on stream in 2015. While these regions have been assigned considerable undiscovered potential, the discovery of such a field, and its timing, is somewhat speculative and depends in large part on the availability of suitable drilling rigs.
  - A pipeline to access gas from the Mackenzie Delta is assumed to begin operating near the end of the period, but such a pipeline will be subject to both obtaining regulatory approval and a commercial decision to proceed.
  - Energy and environmental programs in place today are included in the energy supply and demand projections. This includes Alberta's *Climate Change and Emissions Management Act* scheduled to come into effect on 1 July 2007, which requires existing large industrial facilities to reduce their GHG emissions intensity by 12 percent. However, announced programs or plans for policy development, such as the federal government's plan to introduce industrial GHG emissions targets by 2010, are not included in the Reference Case[45]. The adoption of these programs could have implications for Canada's energy market and the Reference Case outlook.

  - Generation additions reflect the latest information available at the time the analysis was conducted. If Saskatchewan decides not to proceed with the proposed clean-coal project, the province will need an additional source of generation, such as natural gas-fired units. A decision to move ahead with nuclear generation in Alberta would displace other base load generation in the province, either natural gas-fired co-generation or coal-fired units.

45 These programs are given consideration in the Triple E Scenario and will be included in future Reference Cases as more details become available.

CONTINUING TRENDS

Significant trends apparent at the beginning of the outlook period are maintained throughout the scenario in Continuing Trends. This scenario is characterized by little change and, as such, reflects an expansion of the Reference Case over the long-term.

Scenario Overview (2005-2030)

Global Forces

At the beginning of the Continuing Trends Scenario, high energy prices spur investment in energy supplies and infrastructure around the world. As a result of increasing supply, energy prices moderate. Prices do not return to the low levels of the 1990s due to higher exploration and production costs for unconventional energy and ever-increasing world energy demand.

Over the scenario time frame, a number of significant events occur; however, nothing is momentous enough to significantly alter the path that the world was on in 2005. The world continues to consume enormous, and increasing, amounts of energy, most of which is based on fossil fuels. The link between economic growth and energy use is still strong, albeit weakening due to the continuing trend of energy efficiency improvements.

There continues to be an uneven distribution of energy production and consumption. Energy supplies are concentrated in a few countries and large energy-consuming regions continue to be dependent on these supplies. Despite this concentration, markets are generally reliable and competitive. Energy sellers and consumers recognize the economic benefits of an expanded market. However, geopolitical incidents continue to cause energy market volatility.

The demand for environmental improvements continues to grow globally. It is difficult and time consuming to negotiate international agreements. As a result, environmental issues are largely dealt with in isolation and there are few institutional frameworks to deal with environmental, social and economic issues in unison. Reductions in environmental emissions are largely achieved through business-as-usual improvements in energy efficiency and stock turnover rates.

Canadian Outcomes

The global forces in this scenario are reflected in the Canadian outcomes. Continuing Trends continues to see strong Canadian energy demand growth as well as robust energy production outlooks.

TABLE 4.1

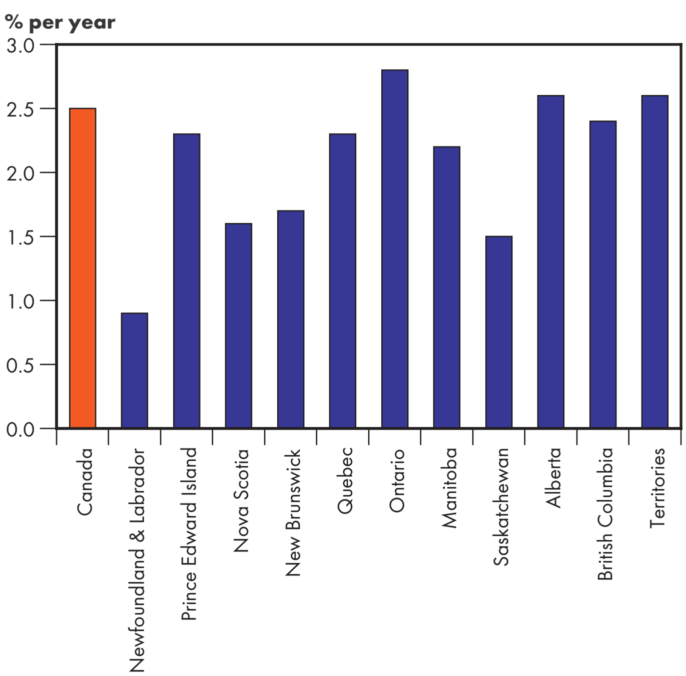
Key Macroeconomic Variables – Continuing Trends 2004-2030

	1990-2004	2004-2030
Population	1.0	0.7
Labour force	1.3	0.8
Productivity	1.4	1.5
Gross domestic product	2.8	2.5
Goods	2.5	2.7
Service	3.0	2.4
Real disposable income	3.6	4.2
Exchange rate (average cents US/Cdn dollar)	74	101
Inflation rate (average %)	2.3	1.7

(Annual Average Growth Rate (% per year) unless otherwise specified).

FIGURE 4.1

Real GDP Growth Rates – Continuing Trends 2004-2030



Macroeconomic Outlook

In the Continuing Trends Scenario, population growth slows to 0.7 percent per year (Table 4.1). The slowing population growth and retirements by the baby-boom generation result in a deceleration in labour force growth. Over the outlook period, labour force growth averages 0.8 percent per year. Productivity measured as output per employee improves to 1.5 percent per year over the next 25 years. These two factors combined result in Canadian gross domestic product (GDP) averaging 2.5 percent per year growth (Figure 4.1). This is slightly slower than historic rates as increased productivity does not fully compensate for the lower labour force growth. To achieve a higher growth rate or to maintain economic growth at current levels would require much more aggressive improvements in productivity or increases in immigration levels.

The structure of the Canadian economy remains fairly stable. By

2030, the goods producing sector continues to account for one-third of the GDP and the service sector accounts for two-thirds.

The regional distribution of Canadian economic growth also remains constant with Ontario, Alberta, British Columbia and the Territories leading economic growth in the country.

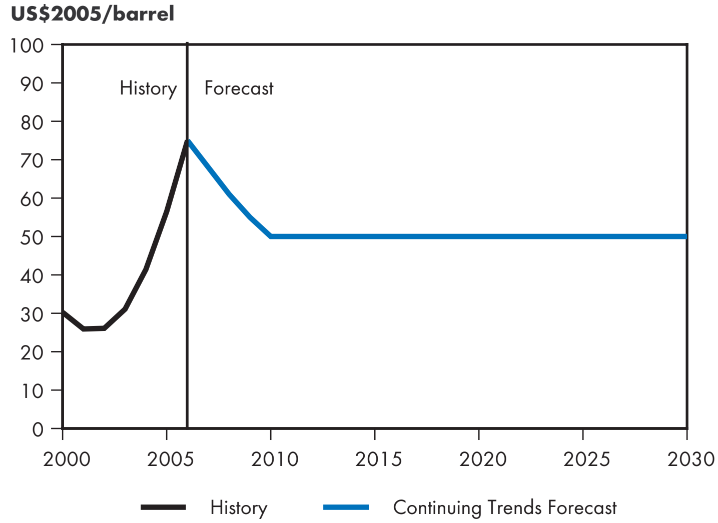
Energy Prices

Crude Oil Prices

Recent high crude oil prices encourage consumers to curb energy demand and bring on additional supplies of energy leading to a moderation of prices. The Reference Case assumes that crude oil prices will fall to US$50/barrel and remain at this level until the end of the reference period. The Continuing Trends Scenario maintains this assumption past the Reference Case time horizon to 2030 (Figure 4.2).

FIGURE 4.2

West Texas Intermediate Crude Oil Price at Cushing, Oklahoma – Continuing Trends

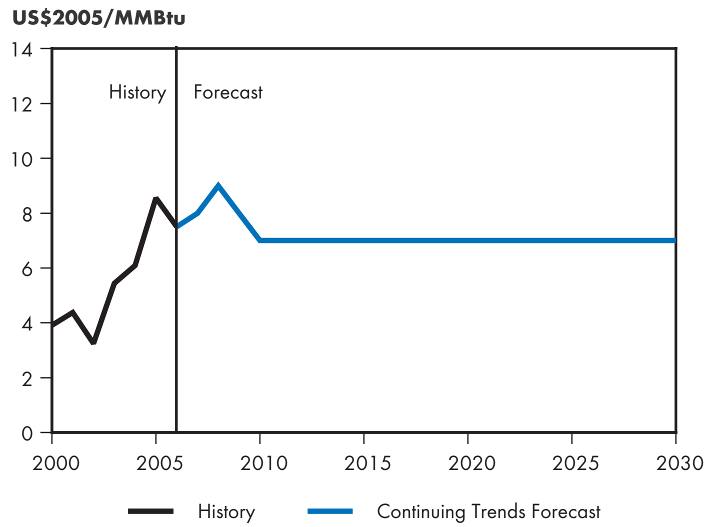


Natural Gas Prices

In Continuing Trends, the historic relationship between crude oil and natural gas prices is maintained. As a result, natural gas prices for the majority of the scenario remain at US$6.65/GJ (US$7/MMBtu) (Figure 4.3).

FIGURE 4.3

Natural Gas Price at Henry Hub, Louisiana – Continuing Trends



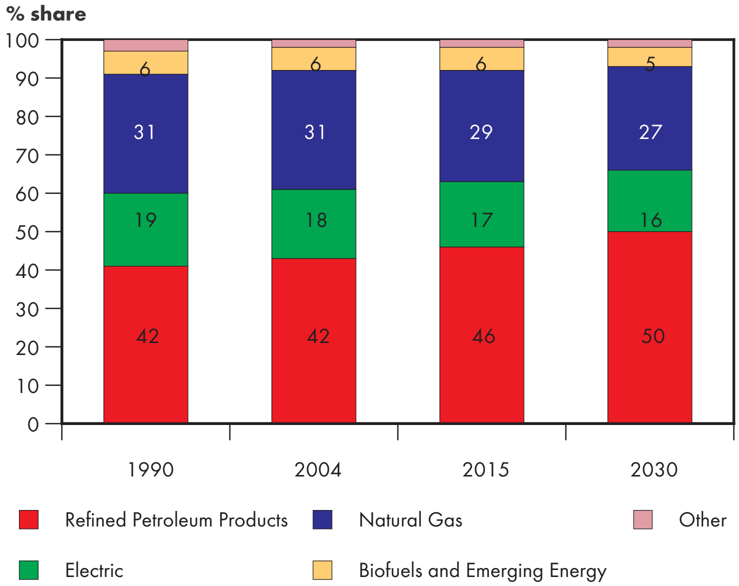
Electricity Prices

In Continuing Trends, prices continue to rise with the need for new generation assets to accommodate growth (e.g., gas-fired, hydro, wind and biomass) and the need to replace ageing facilities (e.g., nuclear assets in Ontario)[46].

46 Regional prices are provided in Appendix 5.

FIGURE 4.4

Canadian Total Secondary Energy Demand by Fuel – Continuing Trends



('Other' includes coal, coke, coke oven gas, and steam)

Demand Management Programs

Demand management programs include demand-side management (DSM), specifically energy conservation and energy efficiency, as well as demand response (DR). Demand-side management refers to long-term, sustainable load reduction. The concepts of DSM have existed for decades. Previous programs were generally low-tech, such as turning down the thermostat, and relied on publicly-funded information campaigns. New technology, particularly in automation and controls, is already defining the possibilities for future demand-side management programs. Many new homes are already wired as 'smart homes' where lights, security systems, heating or cooling, and major appliances can all be computer controlled. Energy use can be optimized to match the need. A simple household 120V power bar is now available that shuts off all loads automatically when loads have been inactive for more than an hour.

Demand response, also known as load shedding or load shifting, is desirable in a constrained supply market where occasional load reduction is preferable to sourcing new generation. Demand response programs are available for large power users, generally in the industrial sector, who have the option of temporarily reducing power consumption. These programs offer the customer a financial incentive to offer committed power back into the grid. Due to the relative inelasticity of the electric market, peak load power costs can be up to ten times the base load price. Reducing loads during these times improves grid reliability and market efficiency.

Coal Prices

After the uplift accounted for by higher oil and gas prices in recent years, coal prices are projected to decline gradually in the near term as the result of competitive pressures and continuing productivity increases in mining and rail transportation. However, as opportunities for resource development become more costly, prices rise gradually through the remainder of this scenario.

Energy Demand

Continuing Trends extends the assumptions made in the Reference Case out to 2030.

Total Secondary Energy Demand Trends

Canadian total secondary energy demand in the Continuing Trends Scenario grows at a rate of 1.0 percent per year over the 2015 to 2030 period (Figure 4.4). The decrease in energy demand growth from the Reference Case is primarily due to slower economic growth in the latter years of the Continuing Trends forecast. The overall Canadian demand intensity improvements are 1.1 percent per year over the scenario outlook.

As of 2030, the three largest energy consumers are Ontario, Alberta and Quebec. Ontario accounts for 31 percent of total secondary energy demand in Canada, Alberta accounts for 30 percent and Quebec 18 percent. Provincial population, personal disposable income and economic activity assumptions, as described in the macroeconomic section of this chapter, all affect provincial energy demand. Total secondary energy demand growth rates vary by province, with Alberta, Ontario and the Territories all having growth rates higher than the Canadian average.

Continuing on a trend established in the Reference period, oil's share of the fuel mix continues to increase (Figure 4.4). This increase is primarily attributable to the rapid expansion of oil sands activity in Western Canada with the use of oil by-products as an on-site fuel source. Natural gas and electricity energy demand continue to grow over the forecast, but not at the same rate as oil. As well, there is some moderating of electricity demand growth as a result of increasing electricity prices. The absolute value of biofuels and emerging energy demand increases, but its share decreases from six percent in 2004 to five percent by 2030.

Residential Secondary Energy Demand

Canadian residential secondary energy demand grows at a rate of 1.0 percent per year over the 2004 to 2030 period (Figure 4.6). Higher personal disposable income enhances a continuation of the trends for consumer goods and services. Energy efficiency simply cannot compete with the income effect. However, in the latter years of the Continuing Trends Scenario, energy demand moderates to 0.5 percent per year as a result of decelerating population growth and slower income growth. Fuel shares by province vary and follow the same patterns as the Reference Case.

FIGURE 4.5

Canadian Total Secondary Energy Demand Intensity – Continuing Trends

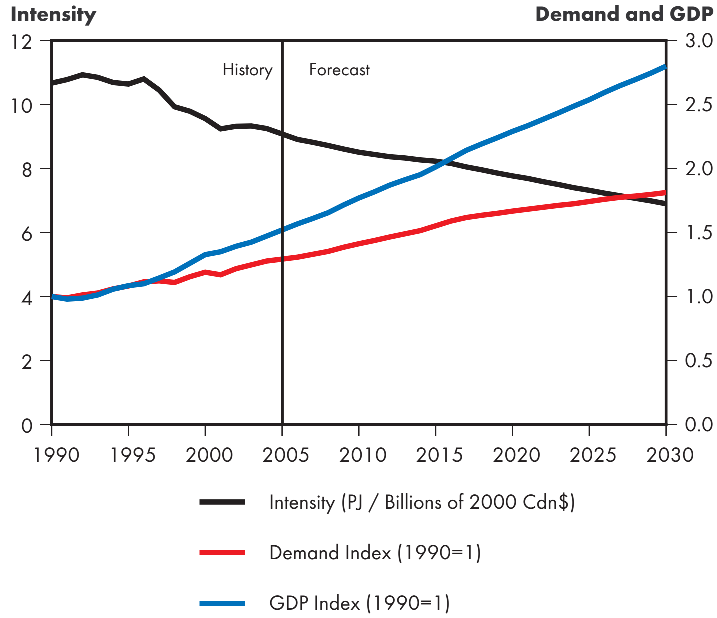


FIGURE 4.6

Canadian Residential Secondary Energy Demand by Fuel – Continuing Trends

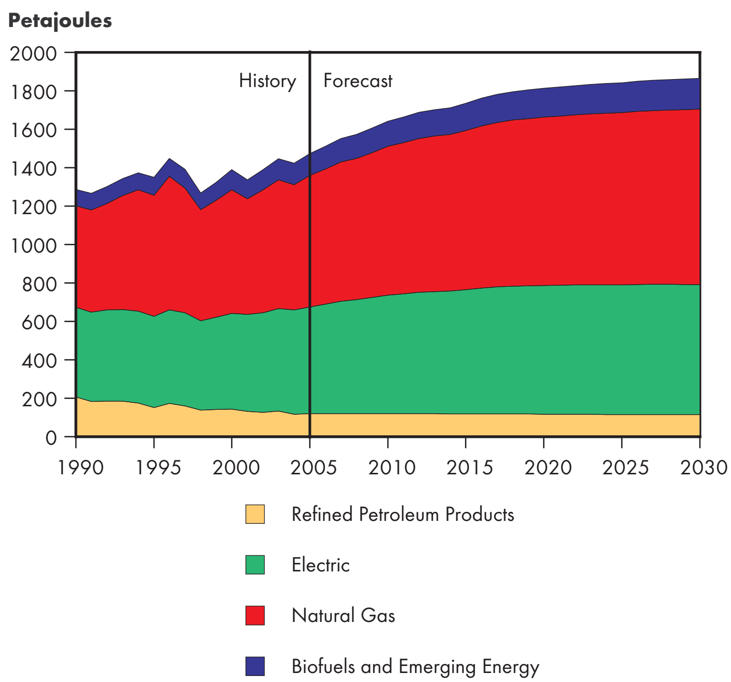


FIGURE 4.7

Canadian Commercial Secondary Energy Demand by Fuel – Continuing Trends

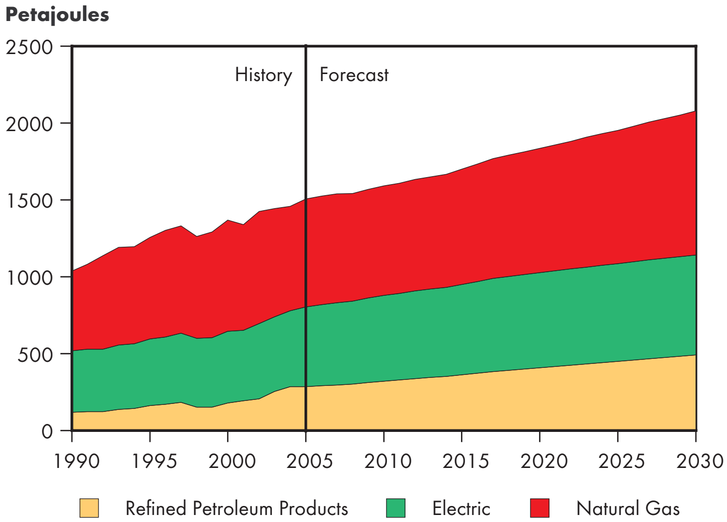
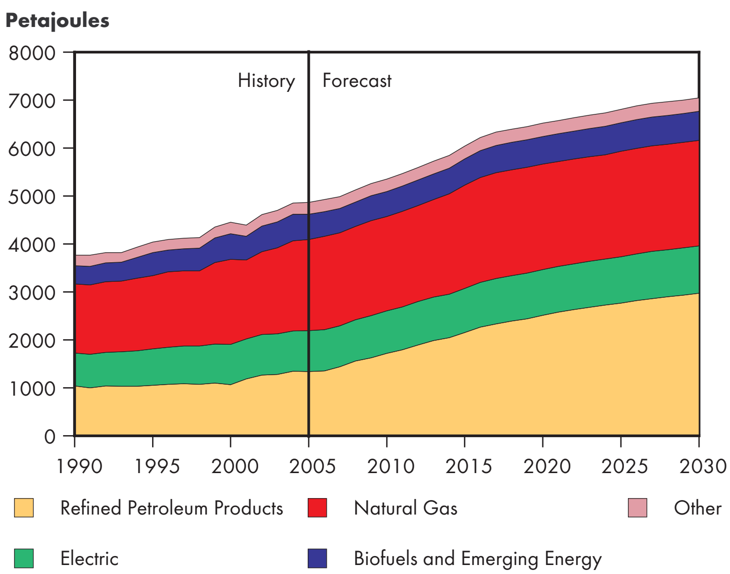


FIGURE 4.8

Canadian Industrial Secondary Energy Demand by Fuel – Continuing Trends



('Other' fuel includes coal, coke, coke oven gas, steam, naphtha)

Commercial Secondary Energy Demand

Canadian commercial secondary energy demand grows at an average rate of 1.4 percent per year over the entire 2004 to 2030 period (Figure 4.7). Population is a primary driver of service sector growth, which determines commercial energy demand. The decelerating population assumption leads to lower growth expectations in the service sector. This economic assumption, combined with higher electricity prices and the backlog of energy efficiency prospects in commercial buildings (mostly lighting and recommissioning), results in slower than historical energy demand growth.

The demand shares by fuel for Canada from 2004 to 2030 indicate some fuel-switching into oil from natural gas and electricity, although, some commercial sector data allocation issues could distort fuel shares.

Industrial Secondary Energy Demand

Economic growth in the goods producing sector combined with a favourable oil sands production profile result in Canadian industrial secondary energy demand growth of 1.1 percent per year over the 2004 to 2030 period. As can be seen in Figure 4.8, energy demand growth is slower in the latter part of the scenario. This is a consequence of slowing economic growth and more moderate expansion of oil sands activity.

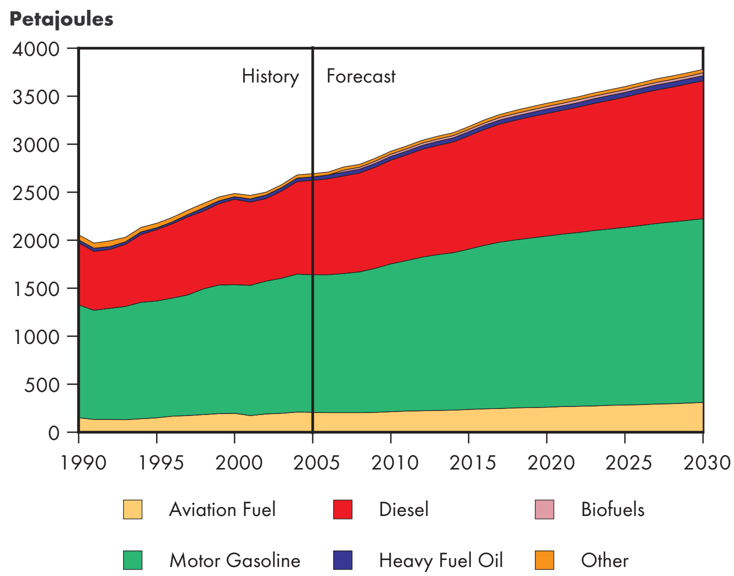
In 2030, the largest provincial energy consumer in the industrial sector is Alberta, accounting for 43 percent of industrial energy demand in Canada. Ontario accounts for 26 percent and Quebec follows at 16 percent of industrial demand.

Transportation Energy Demand

Canadian transportation energy demand grows at 1.3 percent per year over the 2004 to 2030 timeframe and at 1.1 percent per year over the 2015 to 2030 period (Figure 4.9). Higher commodity prices, slightly lower economic growth rates, and efficiency improvements result in lower transportation energy demand in the future. The renewables share increases from near zero to one percent by 2030 due to the assumed ethanol policies in Ontario and Saskatchewan[47]. The off-road share remains strong at 16 percent over the forecast with robust activity in the oil sands, agriculture and construction industries.

FIGURE 4.9

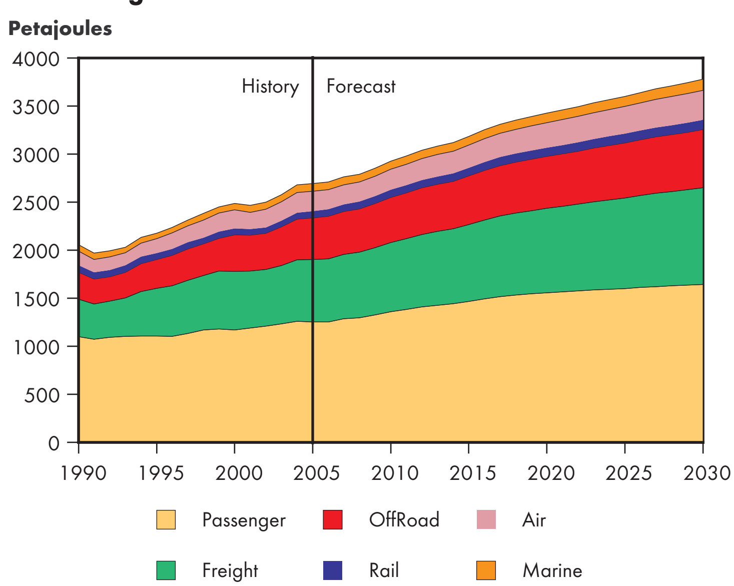
Canadian Transportation Energy Demand by Fuel – Continuing Trends



('Other' includes electricity, LPG, lubricants and natural gas)

FIGURE 4.10

Canadian Transportation Energy Demand by Mode – Continuing Trends



Oil Supply

Crude Oil and Equivalent

In Continuing Trends, the extrapolation of existing trends combined with reasonably attractive oil prices allows for the preservation of historical declines in WCSB conventional crude oil production and east coast offshore production. Expansion in oil sands production levels also continue.

Crude Oil and Bitumen Resources

Canadian crude oil and bitumen resources are the same in the Reference Case and all three scenarios[48].

47 The Ontario assumption is 5 percent ethanol volume (3.4 percent energy) of total gasoline use in the province by 2007. The Saskatchewan assumption is 7.5 percent ethanol volume (5.1 percent energy) of total gasoline use in the province by 2007.

48 Canadian crude oil and bitumen resources are detailed in Chapter 3 and in Appendix 3.

FIGURE 4.11

Total Canada Oil Production – Continuing Trends

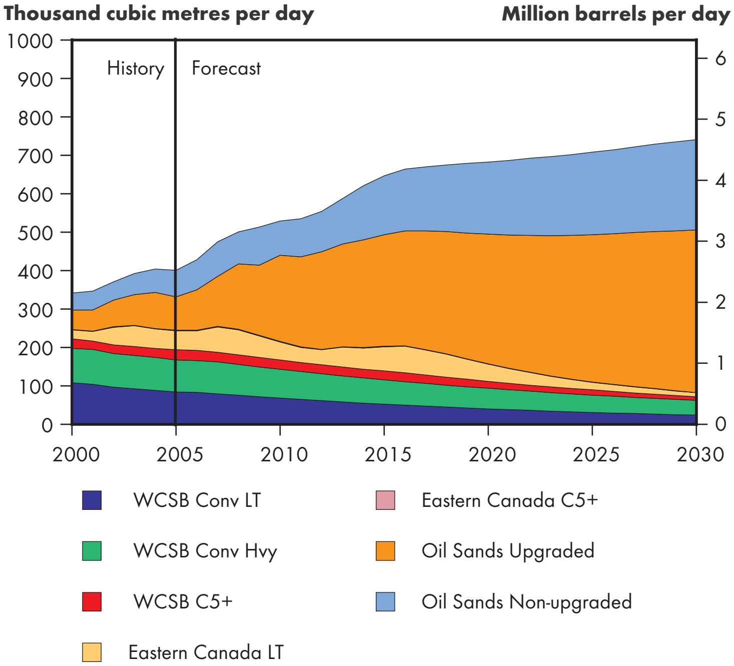
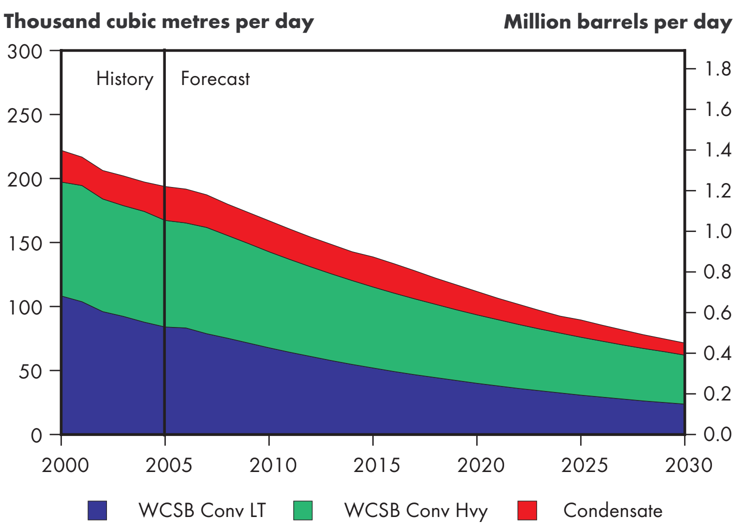


FIGURE 4.12

WCSB Conventional Oil Production – Continuing Trends



Total Canada Oil Production

In the Continuing Trends Scenario, production expands by about 2.0 percent per year until 2015, supported by increasing oil sands mining, in-situ production and by the east coast offshore activity (Figure 4.11). Production expansion gradually declines to about 0.7 percent per year by 2030, with production reaching 740 000 m³/d (4.66 million b/d). Oil sands production plays an increasingly dominant role, accounting for 90 percent of total Canadian oil production by 2030.

Conventional Crude Oil – WCSB

While reasonably attractive oil prices allow for significant reserves additions from new discoveries, infill drilling and improved recovery techniques, these additions are only sufficient to maintain production at the long-term decline trends shown.

For conventional light crude oil, the long-term declining trend of five percent per year is maintained, consistent with a mature supply basin.

Alberta and Saskatchewan are the primary sources of conventional heavy crude oil, with British Columbia contributing minor amounts. Similar to light oil, the long-term declining trend of 3.5 percent per year is maintained for heavy oil, consistent with a mature supply basin.

In the Continuing Trends Scenario, conventional light oil production declines to 23 700 m³/d (149 thousand b/d) and conventional heavy oil production declines to 38 300 m³/d (241 thousand b/d) by 2030 (Figure 4.12). By 2030, conventional production in the WCSB is 37 percent of 2005 rates. Condensate production levels decline to 9 500 m³/d (60 thousand b/d).

Eastern Canada Light Crude Production

Projections for eastern Canada oil production are dominated by the east coast offshore, with only minor amounts of production expected from Ontario.

As with the Reference Case, Continuing Trends includes Hebron production starting in 2013, contributions from smaller satellite pools in the Jeanne d'Arc Basin, and a 80-million cubic metre (500 million barrel) sized pool in the relatively unexplored regions of the East Coast commencing production in 2015 (Figure 4.13). Production peaks in 2016 at 69 600 m^3/d (438 thousand b/d), after which a relatively rapid decline begins. By 2030, production declines to 10 300 m^3/d (65 thousand b/d).

Oil Sands Supply

The projections of oil sands derived production in the Continuing Trends Scenario are essentially based on an extrapolation of trends presented in the Reference Case. It is assumed that cost pressures moderate over time from the current situation. Additional annual incremental capacity decreases over time, as limits to growth are approached, consistent with typical hydrocarbon resource growth curves.

These projections represent both upgraded and non-upgraded oil sands supply from mining, in-situ and primary bitumen sources (Figure 4.14). Primary or cold production levels increase one percent annually in all scenarios.

Production from Saskatchewan oil sands deposits are assumed to start in 2017, reaching a level of 10 100 m^3/d (64 thousand b/d) by 2030.

In Continuing Trends, the assumptions on price and light/heavy differentials generate sufficient cash

FIGURE 4.13

Eastern Canada Light Crude Production – Continuing Trends

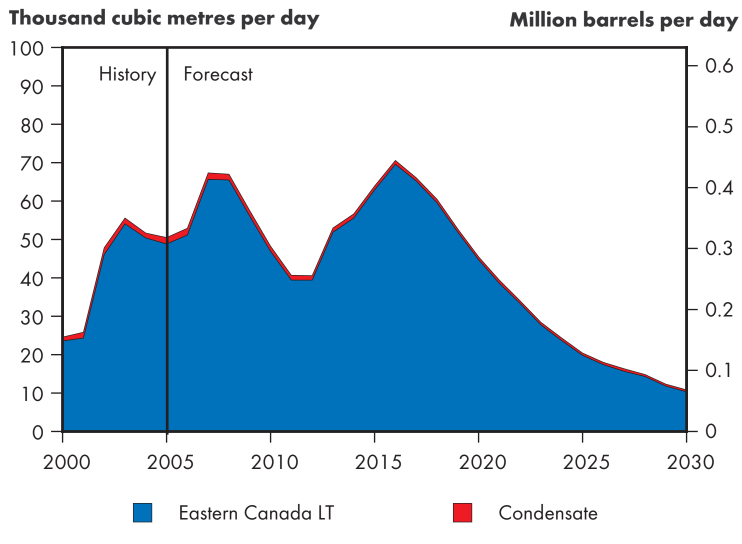
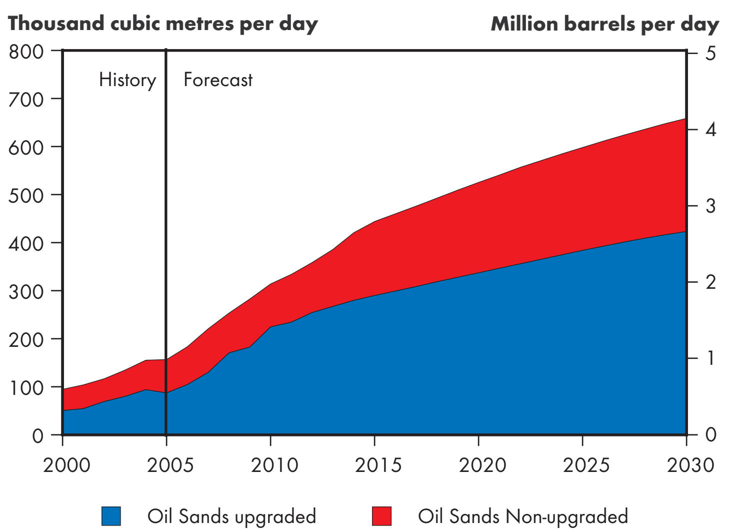


FIGURE 4.14

Canadian Oil Sands Production – Continuing Trends



flow for oil sands operators to expand production levels, with production reaching 658 000 m^3/d (4.15 million b/d) by 2030. Upgraded bitumen volumes total 423 000 m^3/d (2.67 million b/d) while non-upgraded volumes total 235 000 m^3/d (1.48 million b/d).

Regarding the natural gas requirements for oil sands operations, the trends established in the Reference Case are extended out to 2030. Thus, the assumption of a one percent annual improvement in energy efficiency for ongoing operations is maintained, and the application of bitumen gasification

Alternative Fuels for Oil Sands

The recovery and upgrading of bitumen from the oil sands is an energy-intensive endeavour. Natural gas, which is a reliable and clean-burning source of energy, and historically inexpensive, came to be relied on as the major source of energy for bitumen extraction and electricity generation, and of hydrogen required for upgrading. However, a tightening North American natural gas market has resulted in higher and more volatile gas prices. Oil sands operators are seeking ways to reduce their exposure to natural gas. Several developing alternatives to using natural gas could be available.

A number of projects are planned that feature the gasification of bitumen residue in various forms to produce hydrogen for use in upgrading and a synthetic gas for thermal extraction purposes and electricity generation. The Long Lake SAGD/Upgrader project operated by OPTI Canada and Nexen Inc. will be the first project in Canada's oil sands to utilize gasification of bitumen, while Suncor Energy Inc. is considering plans to gasify petroleum coke for its Voyageur 2 upgrader in 2012. North West Upgrading plans an independent upgrader that will use residual hydrocracked bottoms to produce hydrogen and synthetic fuel. Quadrise Canada has developed a process termed Multiphase Superfine Atomized Residue (MSAR) that features the combustion of a bitumen/water emulsion as a fuel source. This process has been tested at the TOTAL Joslyn SAGD project and offers the advantage of being a lower cost fuel than natural gas.

Petrobank Inc. has been pilot testing its in-situ combustion process, termed THAI™ (toe-to-heel air injection) at its Whitesands project. As most of the required energy is derived from the reservoir, natural gas use is significantly reduced.

In order to improve recovery and process efficiency, and thereby reduce natural gas usage, the addition of solvent to injected steam volumes in both cyclic steam stimulation (CSS) and SAGD projects has been tested by Imperial Oil and Encana, among others. Vapour extraction processes, which feature the injection of a cold solvent vapour, is being piloted in several projects. An industry consortium, GeoPower in the Oil Sands (GeoPOS) has been formed to investigate the economic and technical feasibility of employing geothermal energy for oil sands production. Geothermal energy could potentially provide a constant, predictable, price-stable source of energy that releases virtually no greenhouse gas (GHG) emissions or other airborne pollutants.

Nuclear energy for oil sands use has been proposed and, similar to geothermal, offers the advantage of a constant, reliable source of energy with little GHG emissions. However, high initial capital costs, security issues and concerns on the part of the general public regarding safe disposal of radioactive waste may preclude early implementation of this technology.

Additional information on natural gas requirements for oil sands can be located on several industry and government web sites:

www.capp.ca; www.eub.ca; www.quadrisecanada.com; www.petrobank.com; and, www.energyab.com and other technologies such as THAI™, MSAR and vaporized extraction (VAPEX), continue to gain momentum.

In Continuing Trends, the effect of ongoing efficiency improvements and adoption of alternative fuels reduces the purchased natural gas intensity from 0.67 Mcf/b in 2005 to 0.47 Mcf/b in 2030. Total purchased natural gas requirements, excluding on-site electricity requirements, reach 53.8 million m³/d (1.9 Bcf/d) by 2030.

Supply and Demand Balances

The supply and demand balances for Continuing Trends from 2000 to 2015 are the same as for the Reference Case. Petroleum product demand increases from 392 400 m³/d (2.47 million b/d) in 2015 to 486 300 m³/d (3.06 million b/d) in 2030.

Light Crude Oil – Supply and Demand Balance

Exports of light crude oil remain relatively constant from 258 300 m³/d (1.63 million b/d) in 2015 to 266 900 m³/d (1.68 million b/d) in 2030 (Figure 4.15).

Heavy Crude Oil – Supply and Demand Balance

Exports of heavy crude oil increase from 178 900 m³/d (1.1 million b/d) in 2015 to 233 900 m³/d (1.47 million b/d) in 2030 (Figure 4.16).

FIGURE 4.15

Supply and Demand Balance, Light Crude Oil – Continuing Trends

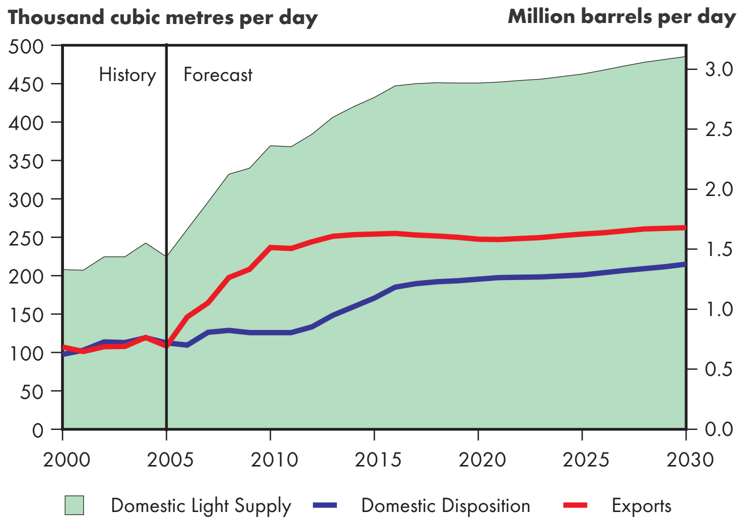
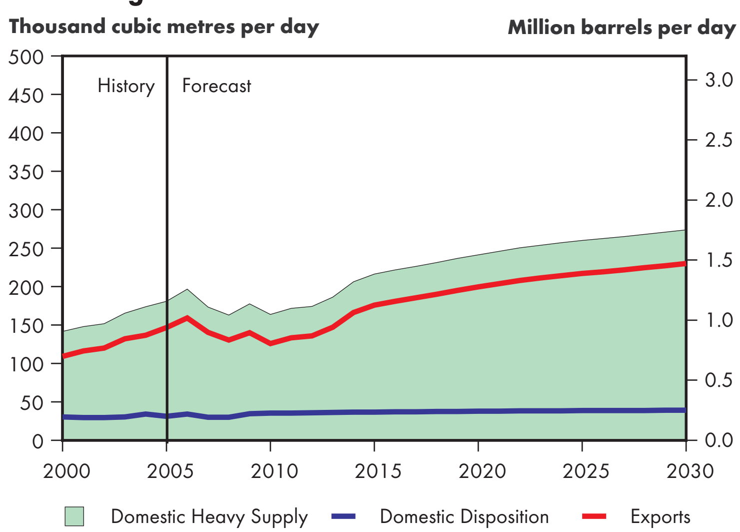


FIGURE 4.16

Supply and Demand Balance, Heavy Crude Oil – Continuing Trends



Natural Gas Supply

Canadian Natural Gas Resource Base

Continuing Trends adopts the same estimate for the Canadian natural gas resource base as the Reference Case. The relatively greater draw on conventional natural gas resources over the 2005 to

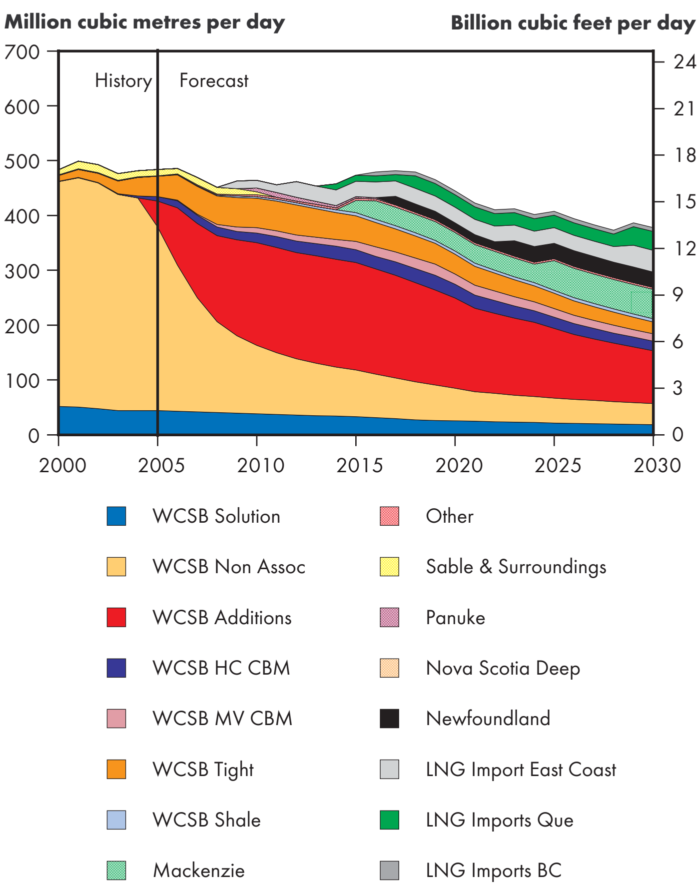
2015 period results in the remaining resource base in Western Canada at the beginning of 2016 being slightly less weighted toward conventional resources (i.e., 2 351 billion cubic metres of conventional compared to remaining unconventional resources of 1 501 trillion cubic metres [83 trillion cubic feet of conventional compared to remaining unconventional resources of 53 trillion cubic feet]). By the end of 2015, roughly 765 billion cubic metres (27 trillion cubic feet) of the original 1 416 billion cubic metres (50 trillion cubic feet) of established conventional reserves will have been consumed, with another 425 billion cubic metres (15 trillion cubic feet) used between 2016 and 2030.

Production and LNG Imports

Relative to the almost 484 million m^3/d (17.1 Bcf/d) of annual output in 2005, Canadian natural gas production is expected to decline by almost 40 percent to 297 million m^3/d (10.5 Bcf/d) by the end of 2030, as shown in Figure 4.17. The production decline represents a relatively constant level of natural gas drilling at roughly 18 000 wells drilled per year and ongoing reductions in initial well productivity. After 2015, WCSB conventional gas provides just 60 percent of production, while unconventional production accounts for 22 percent (compared to 79 percent and 12 percent, respectively, for the 2005 to 2015 period). Assuming no significant new discoveries, offshore Nova Scotia gas production (Sable and Deep Panuke[49]) would likely have ended operations by 2020.

FIGURE 4.17

Natural Gas Production Outlook – Continuing Trends



By 2017, it is assumed that sufficient oil production will have occurred from projects on the Grand Banks of Newfoundland and that the associated gas formerly retained for pressure maintenance would start to become available for market. Production volumes are projected to increase to 28 million m^3/d (1 Bcf/d) and produce almost 99 billion cubic metres (3.5 trillion cubic feet) through 2030. Possible options for delivering this gas to regional markets may include compressed natural gas (CNG) tankers, a liquified natural gas (LNG) project, or a sub-sea pipeline.

Subject to regulatory approval and a commercial decision to proceed, a Mackenzie gas pipeline is assumed to deliver 34 million m^3/d (1.2 Bcf/d) until 2025, when throughput would increase to

49 Deep Panuke project is subject to obtaining regulatory approval and a commercial decision to proceed.

54 million m^3/d (1.9 Bcf/d). Throughput in excess of 23 million m^3/d (0.8 Bcf/d) reflects production from sources outside the three anchor fields discovered in the 1970s and could include offshore projects in the Beaufort Sea.

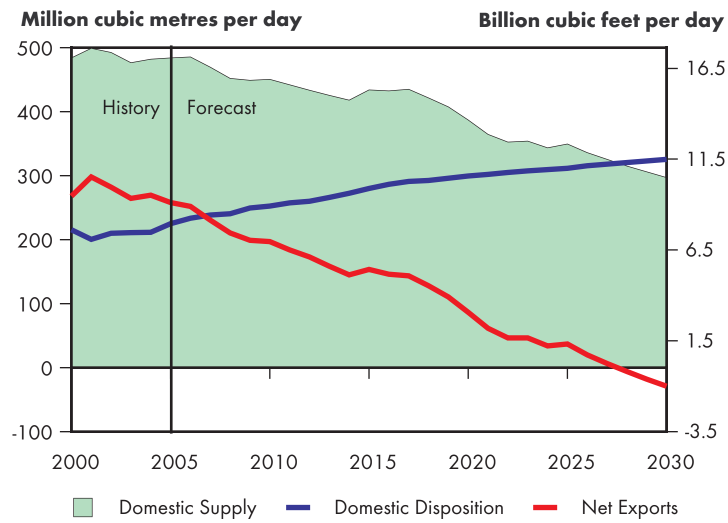
By 2030, LNG imports average 81 million m^3/d (2.9 Bcf/d) or the equivalent of roughly 27 percent of Canadian domestic natural gas production. This level of imports may be accommodated through an estimated five import terminals ranging in capacity from 14 to 28 million m^3/d (0.5 to 1.0 Bcf/d).

Supply and Demand Balance

After 2015, growth in gas demand for oil sands operations slows due to the adoption of alternative technologies and fuels in the latest generation of projects. The use of natural gas for power generation continues to increase, but slows somewhat toward the end of the scenario as new clean coal and nuclear facilities enter service.

FIGURE 4.18

Supply and Demand Balance, Natural Gas – Continuing Trends



By 2028, Canadian domestic gas consumption is estimated to be equivalent to Canadian domestic gas production and Canada's position as a net gas exporter would potentially come to an end, as shown in Figure 4.18. Physical exports and imports of natural gas between the U.S. and Canada would likely continue on a region-specific and seasonal basis in response to varying market conditions. Liquefied natural gas imports into Canada and the U.S. would supplement production in both countries to maintain balanced market conditions and enable the relatively stable pricing conditions incorporated in the scenario.

Natural Gas Liquids

Supply and Disposition

Continuing Trends indicates excess volumes of propane and butanes available for export throughout the projection period[50].

Ethane Supply and Demand Balances

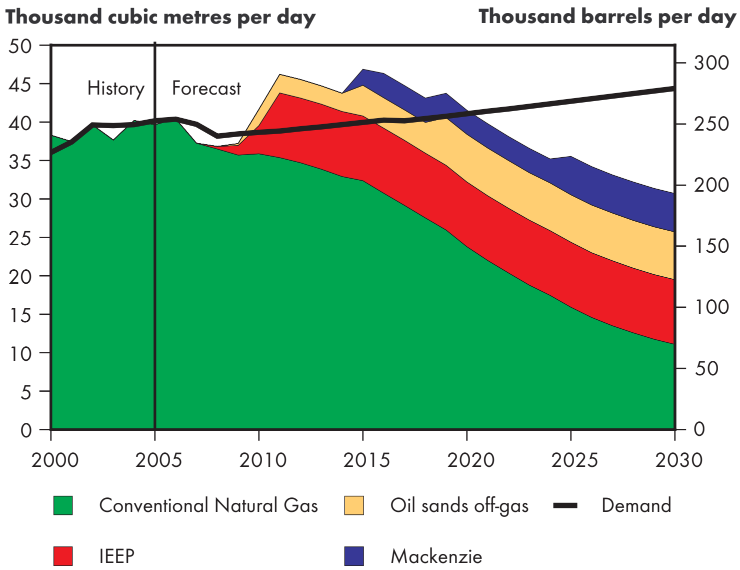
In Continuing Trends, the decline in conventional ethane supply continues through 2030, reflecting the long-term decline of WCSB natural gas production (Figure 4.19). Similarly, ethane feedstock demand is assumed to grow at the same rate as the Reference Case; however, demand for improved oil recovery (IOR) is lower in the Continuing Trends Scenario than in the Reference Case, as some of the miscible flood projects are likely to end by 2015. In addition, increments of ethane supply related

50 Further detail on propane and butane supply, demand and potential exports can be found in Appendix 3.

to straddle plant capacity expansion, oil sands off-gas and development in the Mackenzie Delta are expected to play a bigger role in supplementing supplies from conventional gas production in the longer term. In particular, it is expected that incremental ethane supplies from unconventional sources will contribute about 64 percent of total ethane supply by 2030, with about 5 000 m³/d (31 thousand b/d) from Mackenzie Delta gas (assuming the natural gas stream contains about four percent ethane and the project proceeds) and about 14 600 m³/d (92 thousand b/d) from enhanced deep-cut facilities and oil sands off-gas. However, even with incremental ethane supply, demand from Alberta ethylene plants exceeds supply by 2025, with the shortfall increasing to about 13 700 m³/d (86 thousand b/d) by 2030.

FIGURE 4.19

Canadian Ethane Supply and Demand Balance – Continuing Trends



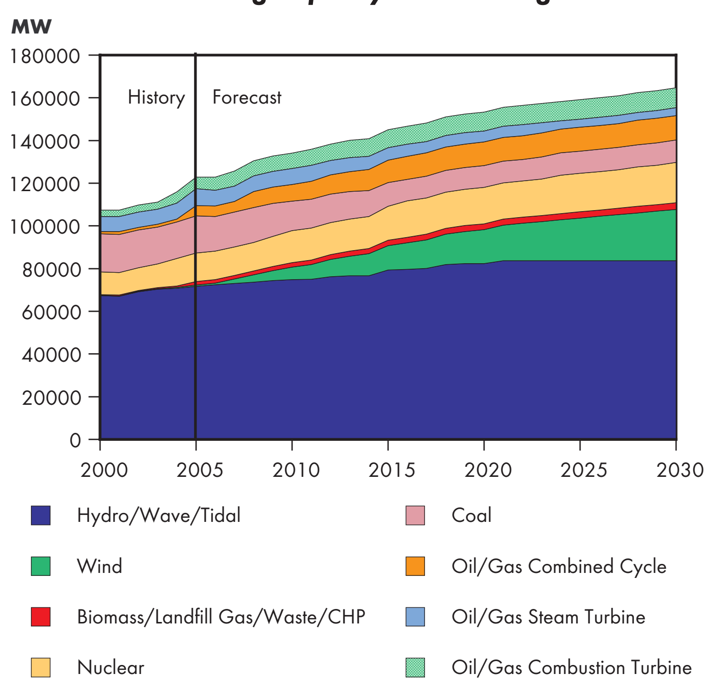
Electricity Supply

Capacity and Generation

In the Continuing Trends Scenario, demand growth encourages the development of both traditional generation sources and alternatives to conventional generation. However, generation capacity additions moderate from the relatively high growth of the Reference Case. Generation capacity will increase 34 percent between 2005 and 2030, and 12 percent, or 19 600 MW, between 2016 and 2030 (Figure 4.20). Generation growth averages one percent annually over the latter half of the forecast period (Figure 4.21).

FIGURE 4.20

Canadian Generating Capacity – Continuing Trends

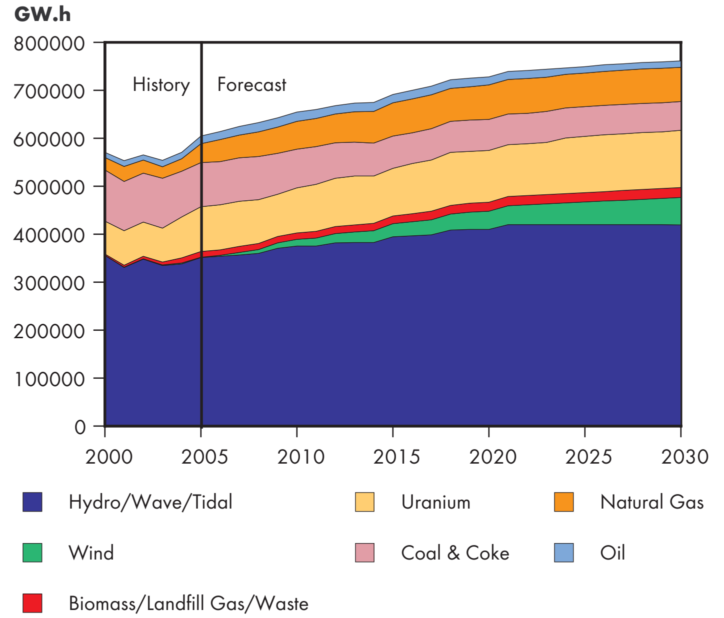


Hydro

Hydroelectric generation will continue to play an important role in meeting Canadian electricity demand, with the share of hydro-based generation increasing from 65 percent in 2016 to 68 percent in 2030. This will constitute additions of 4 400 MW between 2016 and 2030, for a total of 12 000 MW of new hydroelectric energy added between 2005 and 2030.

FIGURE 4.21

Canadian Generation – Continuing Trends



Between 2016 and 2030, several hydro facilities will be constructed, including the Peace River Site C (900 MW) in British Columbia, Conawapa (1 380 MW) and Gull/Keeyask (600 MW) in Manitoba, and 1 125 MW of new hydroelectric generation in Quebec.

Nuclear

In the Continuing Trends Scenario, nuclear additions occur in Ontario and New Brunswick. In Ontario, a 1 000 MW Advanced Canadian Deuterium (CANDU) Reactor (ACR) is added in 2016 to replace retiring coal units, and two 1 000 MW units are added in 2028 and 2030 when the units at Pickering Station A are retired. In New Brunswick, a 1 000 MW ACR is added in 2024 to replace retiring oil-fired and Orimulsion-fired steam units.

Natural gas-fired

Investment in gas-fired generation slows relative to the Reference Case, due to lower demand. Combined-cycle generation adds 790 MW. There are 910 MW of combustion turbine and cogeneration facilities constructed, and there is a decrease of 2 000 MW of steam turbine generation. From 2016 onward, the share of output from natural gas-fired generation remains constant, meaning that gas will continue to be relied upon to meet demand, but there will not be an increasing use of gas-fired generation.

Coal-fired

Total coal-fired generation capacity is projected to increase by 331 MW during the forecast period. In Alberta, new cogeneration and integrated gasification combined cycle (IGCC) generation is employed in order to help meet load requirements and to replace retiring traditional pulverized coal-fired generation. Five new 360-MW IGCC units are added in the last two decades of the outlook period. Combined with retirement of existing units, these additions result in total coal capacity in Alberta declining by 517 MW. An additional 360 MW of IGCC coal-fuelled generation is added in each of New Brunswick, Ontario and Saskatchewan and Nova Scotia.

Oil-fired

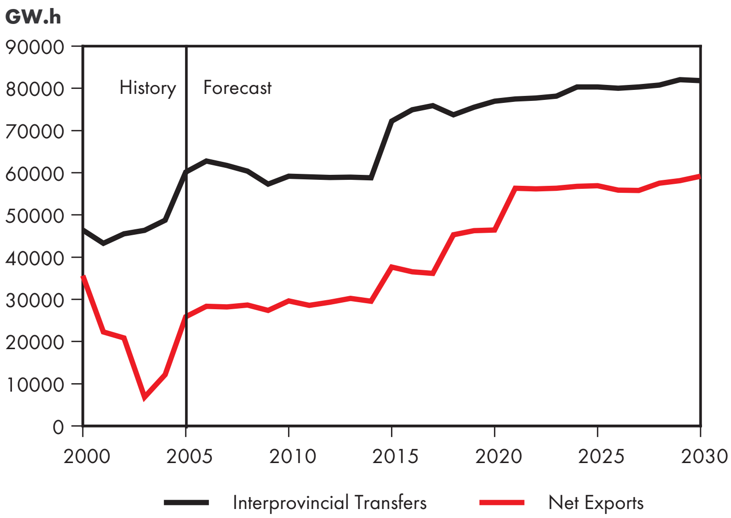
During the Continuing Trends Scenario, declines in the share of oil-fired generation continue. Older steam units continue to be replaced by natural gas-fuelled combined-cycle generation units and those remaining continue to be employed less and less frequently. Diesel internal combustion generation units continue to be the main source of energy in the Territories. In 2020, retiring oil-fired generation in Newfoundland is replaced with a 180 MW natural gas-fired combined-cycle generation unit.

Emerging Technologies

The pace of wind development is still strong in the Continuing Trends Scenario, although it slows relative to the Reference Case, as the increasing amount of wind generation makes it more of a challenge to integrate wind in the grid. Wind power almost doubles its share of the total generation mix, increasing from just over nine percent in 2016 to 20 percent in 2030. Total wind power increases from 11 400 MW in 2016 to 24 000 MW in 2030. Likewise, the rate of growth for wind power generation decreases but continues to grow. By 2030, 57 000 GW.h will be generated by wind power, whereas 29 600 GW.h are forecast for the year 2016. The pace of growth for other emerging generation technologies slows, but overall expands by 23 percent or 675 MW.

FIGURE 4.22

Interprovincial Transfers and Net Exports – Continuing Trends



Exports, Imports and Interprovincial Transfers

Canadian net exports increase by 108 percent from 2006 to 37 600 GW.h in 2030, due in large part to expansion of hydro generation in Manitoba, British Columbia and Labrador. A 30 percent increase in interprovincial transfers to 81 800 GW.h in 2030 also allows hydro provinces to buy cheap power during off peak periods, saving water in reservoirs for export sales during peak hours (Figure 4.22).

Coal

Supply and Demand

Despite economic growth, domestic demand and imports of thermal coal are down due to the eventual closure of all Ontario coal-fired generation. Also, it is assumed that new coal-fired generation utilizes advanced technology. Integrated Gasification Combined Cycle is used especially after 2019 when the technology is employed for new baseload generation, replacing ageing plants in the western provinces, Nova Scotia and New Brunswick.

Coal demand and production is highest in Continuing Trends due to the high demand. Coal production decreases to 62 Mt in 2030 from 68 Mt in 2005, which is nonetheless the highest production among the three scenarios. This growth is due to stronger metallurgical and thermal demand. Higher than historical natural gas prices, depleting gas reserves and volatile oil prices gradually drive economic decisions toward coal. The replacement of ageing coal-fired power plants, located primarily in Western Canada and parts of the Maritimes, provides the necessary dependable capacity to meet electricity needs.

The closure of Ontario's coal-fired generating plants reduces Canadian imports of thermal coal by approximately 16 percent and metallurgical coal by four percent between 2015 and 2030. Over this same period, Canadian thermal exports and metallurgical exports increase 13 percent corresponding with the increase in inter-regional trade of coal used for power generation and the high U.S. demand for coal to be used in steel production.

Exports of thermal and metallurgical coal are highest in Continuing Trends, both increasing by 12 percent between 2005 and 2015. Increasing world iron and steel production and the continued use of coal-fired generation lead to this increase. Thermal and metallurgical coal exports also grow by 12 percent between 2015 and 2030. Thermal imports increase eight percent compared to 2015 values, due to the addition of coal-fired plants in the Maritimes. Imports of metallurgical coal are up 22 percent based on strong demand in Continuing Trends. Between 2015 and 2030, Continuing Trends indicates the greatest net exports, increasing 16 percent.

Greenhouse Gas Emissions

Canadian total GHG emissions in the Continuing Trends Scenario grows at a rate of 1.5 percent over the 2004 to 2015 period and 0.9 percent over the 2015 to 2030

Wind Integration: Opportunities and Challenges

While wind power has a number of unique benefits, the intermittent nature of wind power presents a challenge in integrating large amounts of wind power into existing power systems.

Because of variability of wind resources, wind power at a specific location may not always be available. This variability may have a direct impact on electric system reliability, since wind cannot be relied upon for base-load requirements. Intermittent wind power therefore implies that some other energy source must be available to cover periods when wind is unavailable.

There are a number of measures that can mitigate wind intermittency concerns, including geographic diversity, forecasting and synergy with hydroelectric systems.

If wind turbines span a large geographic region, it is less likely that they will all be without wind at the same time. However, wind power developers want to site units in places with the highest average wind speed to maximize output. Advanced daily or hourly forecasts for wind speed and wind turbine generation are valuable, as this provides system operators with time to respond to changes.

Hydro and wind systems have a natural synergy. Hydro units can vary their output quickly, compensating for changes in wind generation. Wind power can be a useful supplement, providing energy when the wind blows, allowing hydro facilities to save water for future generations.

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

For further information on wind energy, please refer to the Board's Energy Market Assessment (EMA), *Emerging Technologies in Electricity Generation - March 2006*, available on the NEB web site at www.neb-one.gc.ca.

Cogeneration

A cogeneration, or combined heat and power, plant simultaneously produces thermal and electrical energy from the same fuel or fuels. Using the output of one process to drive the other provides substantial gains in energy efficiency compared to the independent production of both products. Construction and operating costs of a cogeneration facility are also comparable to conventional power plants and boilers. Since they are also normally connected to the provincial power grid cogeneration also increases reliability. Having several smaller plants distributed across the province means there is less likelihood of a single point of failure than one large plant, and the cogenerator benefits as they can draw on the grid if a plant encounters problems.

Cogeneration is not more prevalent primarily because it requires a facility that needs both electricity and thermal energy. Also, there must be a mechanism in place wherein the owner of the cogeneration facility can be compensated for the benefits the facility brings to the grid and for any excess power that the plant produces.

There are a number of interesting new developments in the field of cogeneration.

First is the development of a process sometimes referred to as trigeneration. Currently employed at a few commercial sites such as universities and colleges, trigeneration provides electricity, heat and cooling. Conventional air conditioners use a mechanical pump, typically driven by electricity, to provide cooling. Trigeneration adds a technology known as the absorption chiller to a regular cogeneration facility. An absorption chiller is a refrigeration or air conditioning system that is driven by waste heat from the generator instead of electricity. This is not only more efficient, but also does not require a generator and a motor, and as such has a lower capital cost. It can also improve the economics of cogeneration by providing a use for waste heat in the summer months. As cogeneration penetrates the commercial market, trigeneration will become more common.

Secondly, companies in the oil sands are starting to work on using bitumen as a fuel instead of natural gas. Raw bitumen is not a suitable fuel for the combustion turbines used in most oil sands cogeneration plants, so the proposal is to gasify bitumen to produce synthesis gas, a mixture of carbon monoxide (CO) and hydrogen (H_2). Some of the H_2 is used to upgrade the bitumen produced to more valuable synthetic crude, while the rest of the synthesis gas is used to produce steam and electricity to extract more bitumen from the oil sands.

Finally, research continues into technologies that can extend cogeneration to the residential market. Typical cogeneration facilities are much too large for residential use, but new technologies such as Stirling cycle engines, fuel cells and thermionics all offer potential for small, reliable units suitable for residential use. For more details on these possibilities please refer to the Energy Market Assessment (EMA) *Emerging Technologies in Electricity Generation - March 2006*, available at www.neb-one.gc.ca.

period (Figure 4.23). This is lower than the historical growth rate of 1.7 percent from 1990 to 2004, largely due to a lower GDP growth rate, higher commodity prices, energy efficiency improvements, the expansion of alternative energy resources (e.g., ethanol, wind power), and retiring of older fossil fuel-fired generation plants.

Greenhouse gas shares and growth rates vary by province. The three largest GHG emitters in 2030 are Alberta, Ontario and Quebec. In 2004, Alberta accounted for 31 percent of total Canadian GHG emissions, and accounts for 34 percent in 2030. Ontario's share remains 27 percent, while Quebec's share rises from 13 to 15 percent.

Greenhouse gas levels do increase in Canada but the GHG emissions intensity in Canada declines over the outlook period (Figure 4.24). In Continuing Trends, the GHG emissions intensity declines at 1.3 percent per year, which is slightly more rapid than the historical rate of 1.1 percent as energy efficiency improvements take place and alternative and emerging fuel use increases.

FIGURE 4.23

Canadian Total GHG Emissions by Sector – Continuing Trends

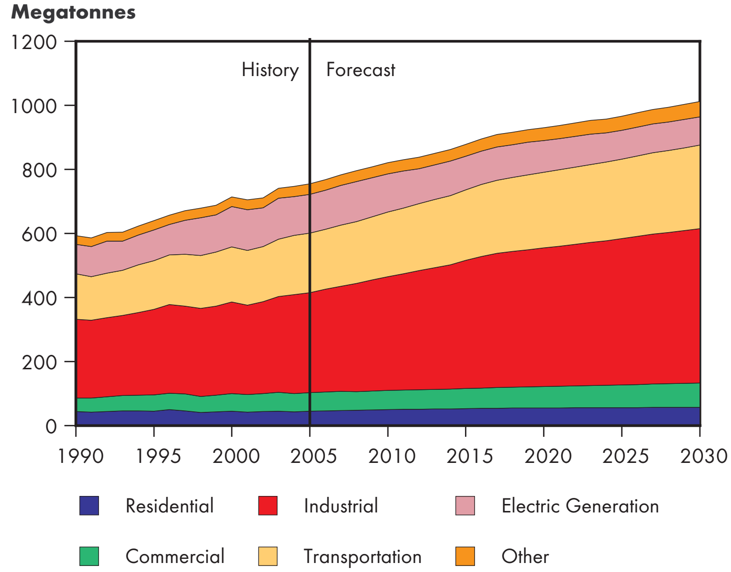
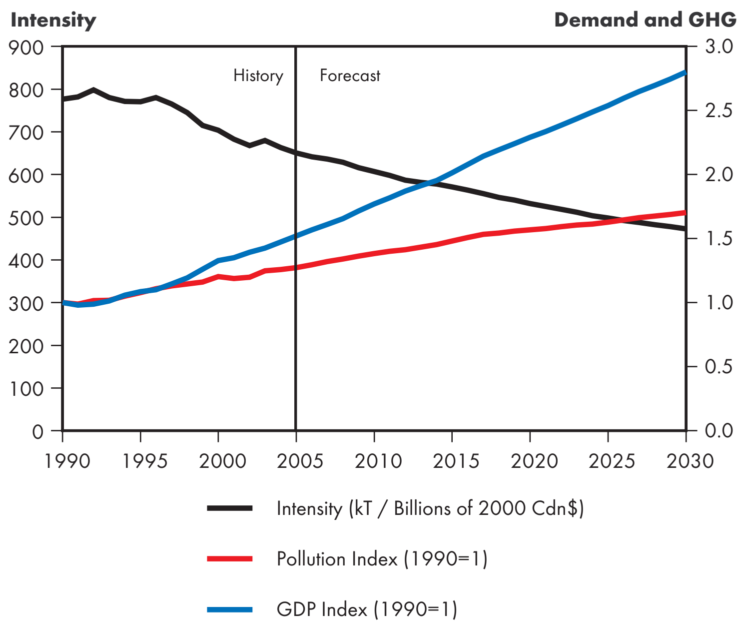


FIGURE 4.24

Canadian Total GHG Intensity – Continuing Trends



Continuing Trends Issues and Implications

- Strong energy demand growth and changing energy supply profiles will require investments in additional infrastructure. The development of this infrastructure is contingent on public acceptance.
  - Oil sands are expected to account for over 85 percent of the total Canadian oil supply by 2030 requiring sufficient take-away pipeline capacity and the development of additional markets.

    - The decline in conventional natural gas production and growing gas demand for oil sands in Western Canada result in a gradual decline in the volume of gas exiting Western Canada. Gas flows outside Western Canada might readjust as a result.
    - As well, gas flow patterns and utilization of transmission infrastructure will change across North America, as LNG imports enter coastal markets and production shifts between regions. The growing share of LNG imports will increasingly link North American natural gas markets to the rest of the world. Current LNG supplies are tight, but major capacity additions are under construction or planned.
    - Significant development of transmission lines will be required.
- Canada's role as a net gas exporter will gradually change to net importer by the end of the period. This could have implications for the balance of trade, although growing crude oil exports should compensate.
- The key risks and uncertainties surrounding the Continuing Trends outlook include:
    - Oil sands production is assumed for Saskatchewan in 2017. Although initial exploration is promising, no official reserves have been published, so this assumption remains speculative.
    - Energy demand management policies are not as well developed in this scenario as in other scenarios. Policies and programs that are in place at the beginning of the outlook period are carried forward until the end of the scenario. However, programs that are under development or are being contemplated are not included. Increased consumer awareness and support for environmental issues makes the implementation of these types of programs more likely and is a potential risk associated with the Continuing Trends Scenario.

Triple E

Triple E refers to balancing of economic, environmental and energy (triple E) objectives. This scenario is characterized by well-functioning energy markets, cooperative international agreements and the most rigorous energy demand management policies of the three scenarios.

Scenario Overview (2005-2030)

Global Forces

At the beginning of this scenario, geopolitical tensions are easing. High energy prices constrain demand as the developing world maintains rapid economic growth rates. These high energy prices lead to:

- increased international investment in previously marginal energy plays and in energy infrastructure;
- development of alternative sources of energy supply;
- slowing of international energy demand growth rates as consumers search for more efficient methods of using energy and governments introduce policies to manage demand;
- increased international co-operation to increase access to global supplies and coordinate demand; and
- continued support to deal with rising emissions levels.

By 2010, the ingredients for a low price environment are established. The combination of increased access to energy supplies and a moderation of energy demand growth leads to an energy market with some slack. As a result, energy prices fall between 2010 and 2020.

Environmental action becomes a worldwide phenomenon. The environmental movement has continued to gain momentum in the developed world and is now seen as a key policy-making consideration. Higher incomes in the developing world lead to increased demand for environmental stewardship. Despite falling global energy prices, the comprehensive energy demand and emission management policies that were introduced to combat high energy prices at the beginning of the scenario are expanded rather than abandoned.

By 2030, the gross domestic products of global economies experience significant growth and as a result, global energy demand also grows. However, energy demand has not grown as quickly as it might have in the absence of government policies and social value changes. Although not necessarily there yet, the world is on the path to achieving more sustainable growth. The link between energy demand, emissions and economic growth is weakening.

There continues to be sufficient global energy supplies to meet energy demand requirements and as a result, world energy prices remain low. The most notable achievements include increased access to global energy resources as geopolitical tensions continue to improve, the development of a large-scale liquefied natural gas (LNG) market and significant growth in global alternative and emerging energy resources. Lastly, the relative share of cleaner energy sources increases as the world places more value on green energy supplies.

Canadian Outcomes

Just as in the global context, the Canadian Triple E energy path is characterized by long-run government policies directed at balancing energy use, environmental impacts and economic growth. The policies considered include[51] the following:

- urban design (e.g., urban density requirements, stricter standards for energy use in residential and commercial building codes, smart metering, support for district energy);
- a price on emissions, which could be achieved through a number of policy programs, such as a carbon dioxide (CO_2) tax, a cap and trade system, or others;
- increased energy efficiency standards (e.g., residential and commercial appliances, engines and motors for industrial applications);
- financial incentives (e.g., residential and commercial building retrofit subsidies);
- research, development, and demonstration funding (e.g., subsidies and grants for the development of energy efficient and/or low-emission technologies, including the development of a carbon dioxide pipeline in Alberta and/or Saskatchewan to facilitate CO_2 capture and storage);
- information and voluntary programs (investment in programs and policies to make consumers aware of the energy used and environmental impacts of goods and services consumed); and
- transportation sector initiatives, including increased mass transit infrastructure, increased vehicle standards for personal and freight transportation, and renewable vehicle fuel requirements (e.g., ethanol and biodiesel).

51 It is important to note that this analysis does not include an examination of other impacts associated with the implementation of these programs, such as program cost-effectiveness, distributional impacts, or competitiveness implications. Thus, this suite of programs should not in any way be construed as a recommendation for future policy development, but rather it should be viewed as an exploration of energy efficiency and emission intensity potential within Canada, given the strong societal support inherent in the Triple E Scenario.

Abundant global energy supplies and low world energy prices result in the lowest Canadian oil and gas production outlook. This, in combination with economic-environmental trade-offs, make Triple E the moderate economic growth scenario. As a result of the comprehensive energy demand and emission management policies, this scenario sees demand stabilize and major improvements in energy intensity.

Macroeconomic Outlook

The key factors that shape the macroeconomic outlook in this scenario are well-functioning global markets and progressive energy demand and environmental management programs.

In the Triple E Scenario, population growth slows to 0.8 percent per year, slightly higher than the population growth rate in the Continuing Trends Scenario (Table 5.1). Higher immigration levels are assumed as a result of the more open nature of this scenario. Despite the higher population, labour force growth continues to slow over the outlook period, averaging 0.7 percent per year as a result of demographic trends. Productivity measured as output per employee improves to 1.5 percent per year as a result of strong energy and environmental management programs, which encourages Canadian producers and consumers to invest in more efficient equipment.

TABLE 5.1

Key Macroeconomic Variables – Triple E 2004-2030

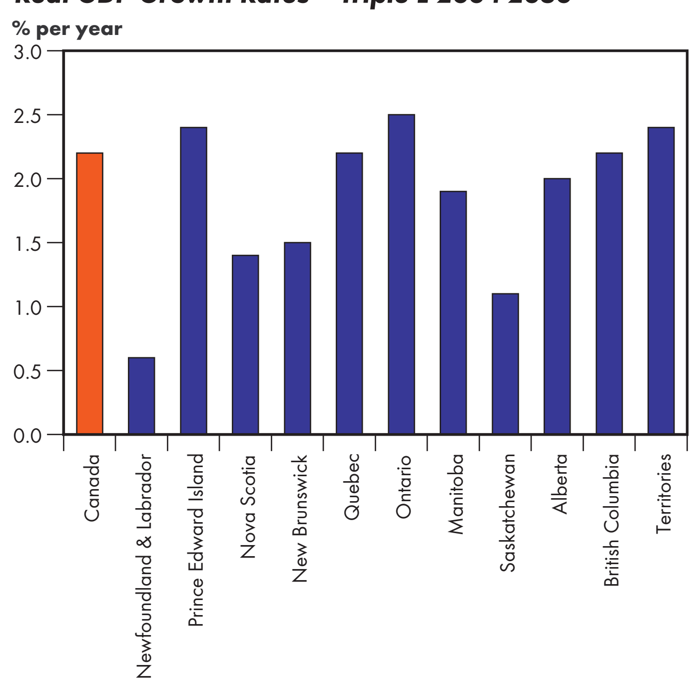
	1990-2004	2004-2030
Population	1.0	0.8
Labour force	1.3	0.7
Productivity	1.4	1.5
Gross domestic product	2.8	2.2
Goods	2.5	2.4
Service	3.0	2.2
Real disposable income	3.6	4.1
Exchange rate (average cents US/Cdn dollar)	74	98
Inflation rate (average %)	2.3	1.8

(Annual Average Growth Rate (% per year) unless otherwise specified).

Population and productivity assumptions result in Canadian gross domestic product (GDP) averaging 2.2 percent per year (Figure 5.1). This is slightly slower than historic GDP growth because increased productivity does not fully compensate for the lower labour force.

FIGURE 5.1

Real GDP Growth Rates – Triple E 2004-2030

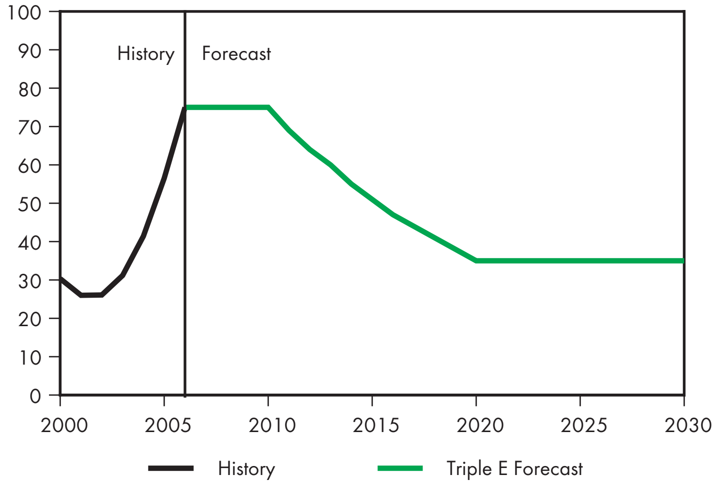


The structure of the Canadian economy remains fairly stable. By 2030, the goods producing sector continues to account for one-third of the GDP and the service sector accounts for two-thirds. However,

FIGURE 5.2

West Texas Intermediate Crude Oil Price at Cushing, Oklahoma – Triple E

US$2005/barrel



the regional distribution of Canadian economic growth changes. The manufacturing regions of Canada, specifically Ontario and Quebec, benefit from strong manufacturing export demand. However, the oil and gas producing regions of Canada face low commodity prices, which result in slower production. This is particularly apparent in Alberta where economic growth is actually below the Canadian average.

Energy Prices[52]

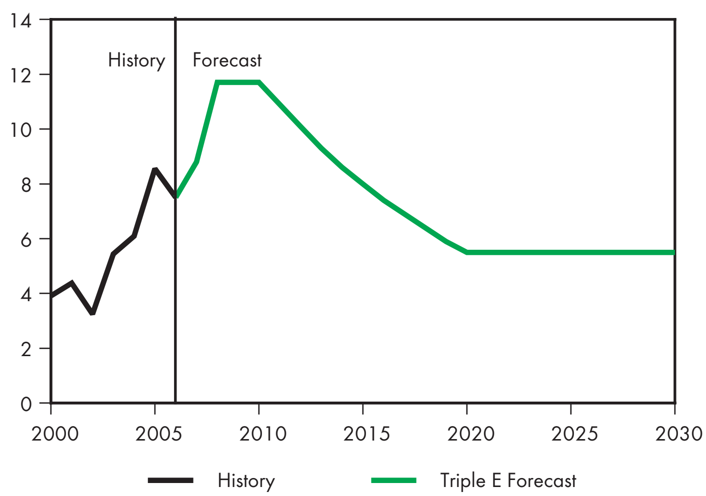
Crude Oil Prices

The Triple E Scenario assumes a gradual reduction of the security premium[53] on oil and enhanced access to world oil resources through technology, investment and cooperative international relations (Figure 5.2). Additionally, global government action and consumer value changes ease demand growth around the world. World energy prices follow this trend and by the end of the scenario, are well below levels seen in the Reference Case or in Continuing Trends.

FIGURE 5.3

Natural Gas Price at Henry Hub, Louisiana – Triple E

US$2005/MMBtu



Natural Gas Prices

High LNG imports in Triple E have a dampening effect on North American natural gas prices and cause the Henry Hub natural gas price to decline over the period to US$5.25/GJ (US$5.50/MMBtu)(Figure5.3). As the lowest carbon-content fossil fuel, natural gas commands a premium in this scenario, with a price at 94 percent of the equivalent crude oil price on an energy-equivalent basis.

52 Note in Triple E there is an assumed CO_2 price that drives up the delivered fuel prices faced by consumers. The CO_2 price is described in detail in this chapter and end-use price data are contained in the appendices. The oil and gas prices presented here are the commodity prices and do not include the CO_2 price.

53 A premium to the oil price reflecting the degree of risk of interruption in oil supply. Geopolitical events that threaten oil supplies result in higher oil prices.

Electricity Prices

Price pressures moderate in Triple E as oil and natural gas prices decline from the levels of the early 2000s putting downward pressure on the costs for fossil-fired generation. There is also a decline in the growth of new generation, as the growth in electricity demand moderates. These downward pressures are partially offset by an increasing share of higher-cost alternative or emerging technologies in the generation mix (e.g., wind, hydro and clean coal), consistent with an increased emphasis and programs focused on addressing concerns surrounding air quality and greenhouse gas (GHG) emissions[54].

Coal Prices

The world supply and demand balance is not entirely different from the Continuing Trends Scenario; thus, the commodity price of coal is the same. However, the carbon intensity and corresponding cost reduces its price advantage compared to natural gas. As a result, coal purchasers, including coal-fired power generators and industrial end users, pay a premium.

Energy Demand

The key dynamic of Triple E is moderating energy demand in the midst of robust economic activity. Achieving the balance between economic, energy, and environmental ideals in this scenario involves pursuit of a full portfolio of policies, and support of Canadians. The result is demand essentially flattens, as average growth is reduced to 0.3 percent annually. Key influences include energy efficiency and conservation and the shift to less carbon-intensive fuels, such as ethanol and biodiesel[55].

Although world energy prices are the lowest in Triple E, the end-use consumer price for fossil fuels is similar to the Continuing Trends Scenario because there is a price for CO_2 emissions. The emissions adjustment is based on carbon content of the fuel and is scaled up over time. The cost of CO_2 emissions between 2010 and 2014 is $15/tonne[56]. This price increases by $10 every five years. By the end of the outlook period, the CO_2 emissions price is $45/tonne of CO_2. Revenue collected through the CO_2 price is recycled back into the economy to support the structural shift required in the Triple E Scenario.

CO_2 Emission Price and Revenue Recycling

The benefit of pricing emissions is that it more accurately captures the full cost of energy production and use. There are a number of different programs and policies that could be implemented to create a price for CO_2 emissions, including a CO_2 tax or a GHG emissions cap and trade program. Pricing emissions allows for cost-effective emission reductions, incentives for investments in cleaner and more energy efficient technologies, and development of a pool of revenue that can be recycled back into the economy to further support policy objectives.

In the Triple E Scenario a portion of the revenue collected through the CO_2 emission price is used to support building retrofit programs, advancement of research, development and demonstration (R,D&D) that facilitates the technological shift assumed in this scenario, capital projects (e.g., support for the development of a backbone CO_2 capture and storage pipeline), and information and capacity building. Capacity building includes not only public education campaigns, but also training of qualified engineers, architects, operators and installers. These information programs result in greater energy awareness, higher levels of energy conservation and the development of improved energy systems.

54 Regional electricity prices are provided in the Appendix 5.

55 Emerging and alternative energy sources for the production of electricity, such as wind generation, are considered in the Electricity Supply section within this chapter.

56 As an example, this translates into roughly 4 cents per litre of gasoline.

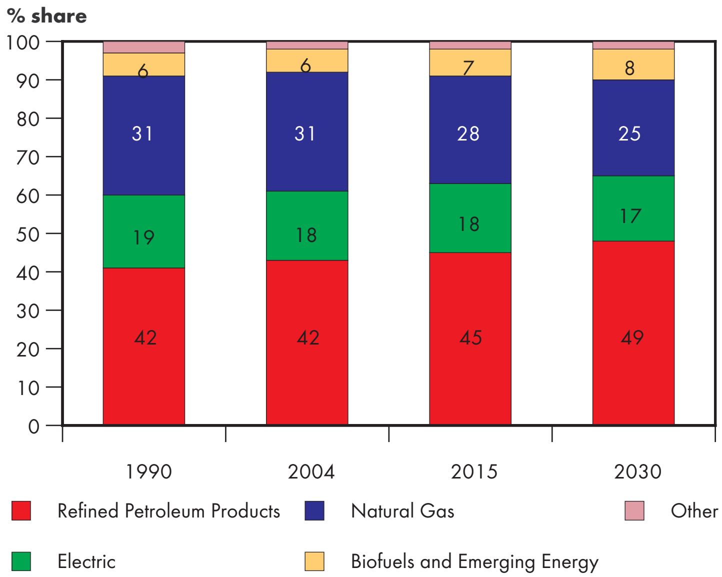
Total Secondary Energy Demand Trends

Canadian total secondary energy demand in the Triple E Scenario grows at a rate of 0.3 percent over the 2004 to 2030 period, significantly lower than the historical growth rate of 1.8 percent from 1990 to 2004. The industrial sector has limited ability to switch to cleaner and cheaper fuels, and as such, demand increases faster than in the more policy-responsive residential and commercial sectors.

Demand sector shares and growth rates vary by province. The three largest energy consumers are Ontario, Alberta and Quebec. Ontario accounts for 33 percent of total secondary energy demand in Canada, Alberta accounts for 26 percent and Quebec 19 percent. Provincial population, personal disposable income and economic activity assumptions, as described in the macroeconomic section of this chapter, all affect provincial energy demand. Total secondary demand growth rates vary by region, with Ontario, Quebec, Alberta, Prince Edward Island, the Yukon and Nunavut all having growth rates higher than the Canadian average. All other provinces, along with the Northwest Territories, show lower demand growth rates. Saskatchewan, Manitoba, Nova Scotia, New Brunswick and Newfoundland and Labrador have negative average annual growth rates over the forecast (i.e., demand in 2030 is lower than it was in 2004). This negative growth rate is a consequence of population trends, moderate economic growth and energy efficiency improvements.

FIGURE 5.4

Canadian Total Secondary Energy Demand by Fuel – Triple E



('Other' includes coal, coke, coke oven gas, and steam)

The energy demand projection shows initial high growth which slows and eventually flattens (Figure 5.4). A delicate balance is established between economic drivers (income and GDP) putting upward pressure on demand, and the countering influence of programs, policies, and societal values putting downward pressure on energy demand.

The overall Canadian demand intensity declines fastest in the Triple E Scenario, at 1.9 percent annually, well above the historical annual rate of 1.0 percent (Figure 5.5). This reduction in demand intensity is primarily caused by the assumed aggressive energy policies in this scenario.

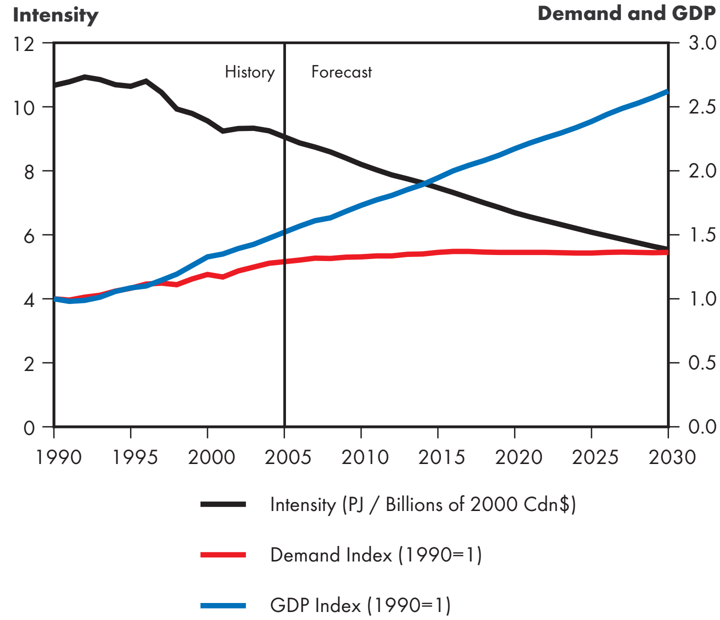
Residential Secondary Energy Demand

The residential sector is particularly responsive to a combination of policies. This assists in overcoming the historical trend of increasing demand due to a 'more and bigger' consumer mindset that essentially cancelled out past energy efficiency gains. Regulations applied uniformly across Canada bring what were formerly marginal technologies and practices into widespread application. As a result, several end-use services, such as space and water heating, see a net decrease in energy demand between 2004 and 2030. Demand reductions in the residential sector are achieved through the integration of several key policies, including the following:

- all new homes meet R-2000[57] (or equivalent) energy performance standards by 2015 (and this rate of improvement is maintained until 2030);
- all new appliances meet Energy Star approval ratings by 2015; and
- introduction of programs and policies to support energy retrofits on existing homes.

FIGURE 5.5

Canadian Total Secondary Energy Demand Intensity – Triple E



Policies for strategic urban planning, or ‘smart growth’ are emphasized. Policies specific to residential building energy use include:

- more compact urban design, including an increase in multi-density dwellings in relation to single dwellings; and
- shared walls and energy-operating systems between multiple households, including community energy (such as district heating or distributed energy).

The new housing standard in Triple E is a 30 percent improvement in energy performance over the historical average. This improvement has already been demonstrated by such building programs as R-2000, BuiltGreen[58] and Energy Star for Homes. The green building market has been experiencing rapid growth recently. There are indications of unprecedented market support and in this scenario it is assumed that these options are pursued in the majority of new homes that are built.

The 30 percent improvement target represents aggregated savings that takes into account building shell (insulation/draft-proofing), windows, heating systems, lighting and appliances. The existing home energy performance rating system in Canada, EnerGuide for Houses (EGH)[59], is a useful

57 An R-2000 Standard home meets technical requirements for new home performance beyond building codes.

58 BuiltGreen is a non-profit organization that promotes environmentally friendly home building methods and practices.

59 A net-zero energy home would be the equivalent of an EnerGuide rating of 100. A rating of EGH 90-100 is considered to include the best in home building technology, appliances and lighting and some contribution from alternative energy.

Hydrogen's Role in Canada's Energy Future

On a per capita basis, Canada is already the largest hydrogen producer within Organization for Economic Cooperation and Development (OECD) countries and is at the forefront of hydrogen research and development. The appeal of the 'hydrogen economy' is tremendous and Canada is well positioned to benefit from its development.

Hydrogen, like electricity, is simply a way of distributing energy. It is closer in character to a battery than a fuel. The production of hydrogen comes at the expense of other energy inputs. Presently, the majority of hydrogen production is produced from natural gas, in a process that releases CO_2 into the atmosphere. Alternatively, hydrogen could be generated from electrolysis of water by electricity. This electricity could come from coal, gas or nuclear generation, but the ideal long-term strategy would link renewable energy (hydro, solar, wind) with hydrogen generation. Presently it is less expensive to produce hydrogen from natural gas than electricity. The opportunities for hydrogen depend on the application. The following table lists possible applications for hydrogen along with associated benefits and challenges:

Application	Main Benefits	Main Challenges
Replacement for transportation gasoline and diesel	Efficiency improvement, CO_2 abatement, improvement in urban air quality	Replacing/adding hydrogen fuelling infrastructure, hydrogen storage, costs
Replacement for natural gas in residential and industrial markets	Uninterruptible power units/standby power, combined heat power (CHP) applications, replacement for steam methane reforming in oil sands refining and upgrading	Main markets generally not situated near source of production, adding to expense
Storage medium for buffering electrical power	Complementary to intermittent power sources (wind, solar) and ability to take advantage of grid off-peak and reserve capacity	Competing with other, rapidly advancing energy storage technologies

The difficulties the industry faces are evident by the 20 percent decrease in investment value in the last few years, as reported by the Canadian Hydrogen Association. Despite the very high costs associated with hydrogen production and use today, investment by industry, provincial and federal governments confirms that hydrogen is still very much part of regional energy policies. The widespread deployment and impact of these technologies will likely fall outside of the timeframe of this report, and therefore, are not included.

For further information on hydrogen in Canada, visit the Canadian Hydrogen Association web site at www.h2.ca.

indicator of the progression of new homes between 2004 and 2030. In the past few years, new homes had an average EGH rating of around 72. The assumed target for 2015 is a rating of EGH 80 and increases to between EGH 90 to 100 by 2030. To achieve this, a combination of technology and process improvement is applied. As an example, improvements in hot water heating can be gained through technological advancement (i.e., condensing water heater) and process improvements (i.e., low flow showerheads). Process improvements allow for efficiency improvements beyond what is technically possible on the device itself. The savings are extended further by behaviour changes. The Triple E Scenario applies a universal conservation ethos, which significantly enhances even small technology improvements.

Large home appliances maintain their historic trend of improvement and have the built-in automation necessary for participation in utility demand response programs, such as peak load reduction and time-of-use rates. Energy Star increases its market penetration and becomes the standard by 2015. The historic trend of increasing electrical demand from an onslaught of small electronics, such as computers, portable devices and entertainment devices, is mitigated by new international laws limiting standby power consumption to 1 watt on all electronics.

By the end of the scenario, the incremental advances in efficiency begin to decrease; however, the implementation of the best available technology includes an increasing contribution from alternative and emerging energy. By the end of the Triple E Scenario, many homes and communities are net-zero energy consumers. The contribution from on-site renewables offsets purchased energy.

Photovoltaic (solar PV), solar thermal and geothermal are considered as part of the home energy operating systems and as such, are modeled on the demand side. Uptake rates are based on industry association projections. The last few years have seen rapid growth in these technologies, but the curve starts from a negligible base. Achieving full potential in the EGH 90-100 range requires better technology at lower cost. These developments are assumed to occur through proactive investments in research and development.

The residential sector energy performance is limited by the large stock of existing, inefficient older homes that remain in the demand pool for decades. Major retrofits are disruptive and costly and economic benefits occur well after the average length of time people own a home. Until very recently, the official number of home energy retrofits completed under the EGH program has been small (less than 10 000 per year). Further, the leading motivation for home renovations has historically been aesthetics. To address this, Triple E allocates a portion of the revenue collected from the CO_2 price toward subsidies for energy retrofits. Approximately 5 percent of the older homes are retrofitted each year for an 18 percent reduction in energy demand. Recent statistics indicate an unprecedented number of homeowners considering home renovations in the near future[60]. The Triple E mindset assumes that any opportunity to renovate automatically includes improvements in energy use. This attitude, along with concern for indoor air quality and an added financial incentive, effectively leverages almost every home renovation project into an energy efficiency upgrade.

Perhaps the policy most indicative of the paradigm shift in Triple E concerns urban form, encompassing energy efficiency, alternative energy, urban design, distributed energy and transportation issues. As well, it reveals the complex challenges between technology and structural (zoning/codes/regulations) issues that need to be addressed. Modeling the policy started with an increased ratio of multi-dwelling (apartment, row or condominium) new home starts compared to single family dwellings. Historically, single starts have outnumbered multi-starts. The last few years have seen a marked increase in multi-starts[61], and this trend is continued and enhanced, leading to multi-dwelling homes accounting for an extra 10 percent of stock within the modeling period.

Higher density allows for reduced energy demand in the residential sector, due to shared walls and shared energy systems. It also sets off a cascading series of opportunities. The higher density developments support distributed energy and community energy system opportunities. District heating systems, large geothermal or energy storage systems, and electrical net-metering help extend efficiency ratings well beyond individual end-use devices. Urban form's biggest impact is in transportation, which is covered later in this chapter.

Awareness and education are a large part of the Triple E Scenario. The awareness concept was modeled on the results of smart metering demonstration projects where participants reduced electrical consumption by an average of six percent, in response to availability of information[62]. While the energy saving was predominately applied to electricity in existing home stock, all end-uses received at least a small input from the general concept of awareness and energy conservation characteristic of Triple E.

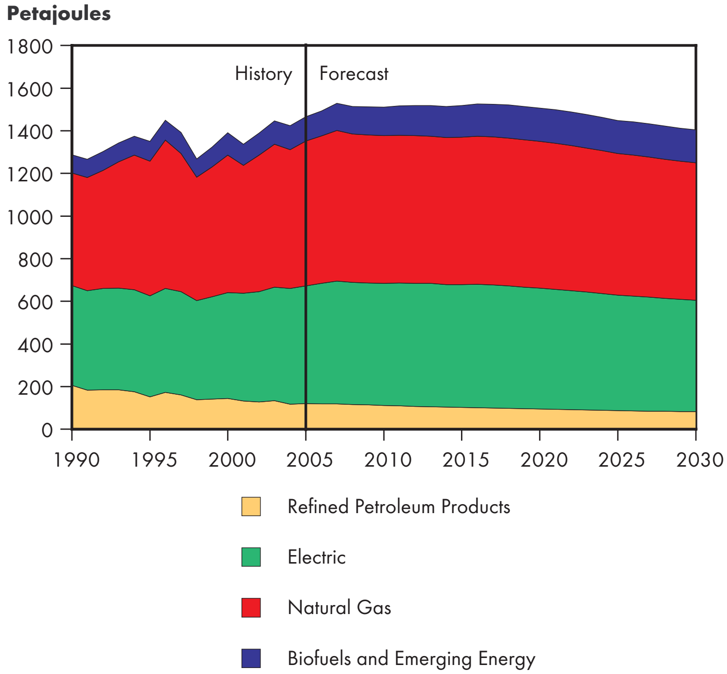
60 Canada Mortgage and Housing Corporation, *Canadian Housing Observer*, 2005.

61 Canada Mortgage and Housing Corporation, *Canadian Housing Observer*, 2005

62 Energy Evolution, 2006. *Ontario Government Approves Full Smart Metering Rollout for Chatham-Kent Hydro.* September 14, 2006.

FIGURE 5.6

Canadian Residential Secondary Energy Demand by Fuel – Triple E



Overall, Canadian residential secondary energy demand decreases at 0.1 percent over the 2004 to 2030 period (Figure 5.6).

Commercial Secondary Energy Demand

The policies, opportunities and results in the commercial sector are very similar to the residential sector. It is appropriate that these two sectors are frequently grouped together simply as the 'built' environment.

The gap between historical and future commercial building performance is addressed through the same combination of policies as in the residential sector. The most important of these policies is a tightening of building codes to raise the level of all new building energy performance to the Leadership in Energy and Environmental Design (LEED®) silver standard, which is a 25 percent improvement in energy performance by 2015. The LEED® rating system is also based on a variety of environment-friendly building technologies. Developers are free to choose the most appropriate of a wide variety of energy efficiency measures (insulation, windows, ventilation, lighting, appliances), building material, resource use (including water) and alternative energy options in order to meet minimum requirements on a project-by-project basis.

A recent surge in construction of exemplary green buildings has taken place[63]. Issues such as corporate branding, indoor air quality (improved productivity/reduced sick-days) and prestige are market forces presently driving the interest. The full impact is obtained through a regulated minimum standard across the country. Energy savings between these buildings and the reference is typically 25 to 50 percent; however, savings of 60 to 80 percent have been achieved[64].

The probability of significantly improving existing commercial building stock is even more challenging than in the residential market. This is a major issue considering 75 percent of infrastructure in place by 2030 has been built before 2005. A large part of Canada's installed buildings are relatively old[65]. Subsidized retrofit polices have proven effective. Results from the federal Commercial Building Incentive Program (CBIP) show an average improvement of 35 percent over the Model National Energy Code for Buildings (MNECB) after upgrades. In the last few years,

63 As listed by the Canadian Green Building Council, see http://www.cagbc.org/uploads/LEED_Certified_Projects_in_Canada_Updated_070605.pdf.

64 Based on recommended minimums as stated in Model National Energy Code for Buildings (MNECB).

65 31 percent are 40 to 80 years old and 28 percent are over 80 years old. The Canadian Society of Civil Engineering. *Civil infrastructure systems technology roadmap, 2003-2013*. June 2003.

improvements of 50 to 60 percent were common[66]. In modeling Triple E, an improvement of 20 percent is applied to 5 percent of the existing building stock each year. There is a pool of easily accessed 'low-hanging fruit' within the commercial building sector due to lighting improvements (fluorescent bulbs, day lighting and occupancy sensors) and improvements in building automation and controls. Although economic in any scenario, in Triple E these better opportunities are leveraged, along with the subsidies, for a more systems-based, whole building approach.

One explanation for escalating commercial demand in recent years is increasing air conditioning and plug load (computers and printers for example). Offices and retail stores are now the fastest growing sub-sector of commercial buildings, as well as being almost 100 percent likely to have air conditioning and be fully computerized. The Energy Star standard (10 to 15 percent better than average) for appliances and the new universal 1-watt standby limit is effective in the commercial market as well, as it directly targets a major source of the increasing demand.

Urban Form as Smart Growth

Many Canadian cities have adopted the concept of smart growth in order to achieve long-term economic and environmental sustainability. The essence of smart growth is a strategy of land use and urban form which promotes:

- compact design and a pattern of development to enhance travel efficiency
- reduced dependency on automobile transportation
- high density and mixed-use development based around transportation infrastructure
- green space protection
- material, energy and water conservation
- pedestrian-friendly village centres and an increased sense of community

Urban form is a major influence on reducing transportation energy demand and GHG emissions. Switching a small portion of the population to walking/bus/rail/bike transportation, or even increased telecommuting, is equivalent to a large section of population upgrading to more efficient personal vehicles. All of these options are pursued as part of the Triple E environment.

Fuel-switching to on-site alternative energy sources including geothermal, solar PV and solar thermal account for almost one-third of the total fossil-fuel energy savings of Triple E versus Continuing Trends. Geothermal contributes approximately three percent of the space heating savings. Solar thermal is applied to sub-sectors with high heat loads, such as recreation, hotels and health care, resulting in a savings of approximately 10 percent on water heating. The solar PV contribution increases exponentially but is too small (less than two percent) to be modeled individually.

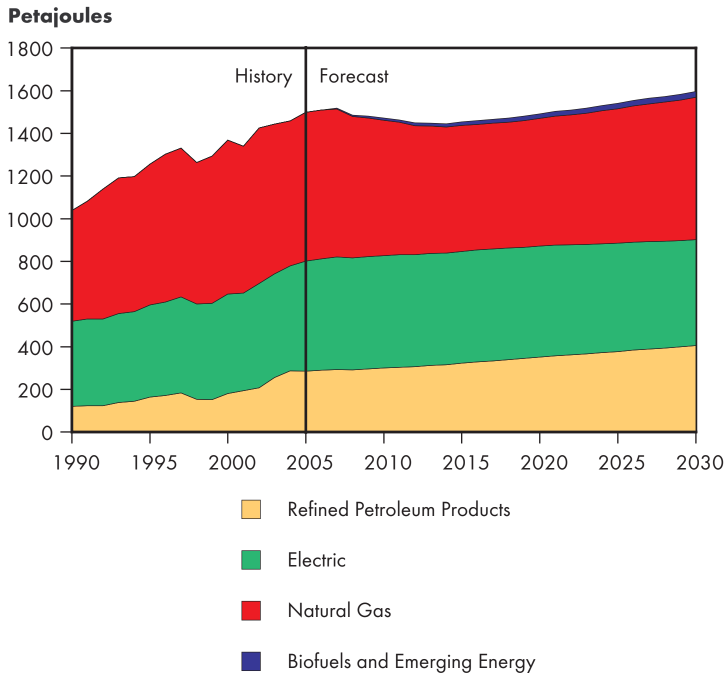
In addition to major decreases in raw material and manufacturing costs, full deployment requires time for infrastructure to be established, including interconnection standards and trained personnel. To capture its influence, an extra efficiency gain is attached to large electric appliances which effectively displaces a small amount of purchased electricity.

Additionally, on-site commercial combined heat and power grows and displaces almost two percent of the total purchased electricity demand in the commercial sector by 2030. This is accomplished through the alignment of improved technology, reduced costs and a supportive regulatory

66 Natural Resources Canada (NRCan) *Built Environment Strategic Roadmap – Commercial Buildings Technology Review*, CANMET Energy Technology Centre (CETC), 2007.

FIGURE 5.7

Canadian Commercial Secondary Energy Demand by Fuel – Triple E



environment favouring a shift to increased distributed energy.

Canadian commercial secondary energy demand grows at a rate of 0.3 percent over the 2004 to 2030 period, lower than the historical growth rate of 2.5 percent, due to the economic characteristics of Triple E and the assumed energy policies (Figure 5.7). Biofuels and emerging energy in the commercial sector have a zero percent share in 2004 and increase to a two percent share in 2030, as solar and geothermal energy policies are implemented.

Industrial Secondary Energy Demand

Industrial demand is driven predominately by macroeconomic influences. In Triple E, the demand changes vary by industry type, the most significant of these being a reduction in oil sands, mining and petroleum products activities. As well, industrial demand is influenced by the same core policies as the commercial building sector, including accelerated efficiency standards, subsidies for facility and equipment upgrades, research and development support, and the application of a carbon price. For many reasons, including competition for capital and the disruptions in production flow, energy efficiency upgrades in the industrial sector do not vary widely between scenarios. Small alternative or emerging energy is not directly modeled on the industrial demand side; however, a significant increase in on-site cogeneration, or combined heat and power, is included in the efficiency impact.

Process heat and motor systems are universal loads within all industrial subsections. Energy efficiency improvements in technology and process optimization result in an improvement of approximately one percent annually, a slight improvement on the historical trend. Triple E industrial demand distinguishes itself in the later stages of the scenario when efficiency gains a boost from major process innovation within the most energy-intensive industries. These are the least definitive technologies modeled. Technologies include improved electrolytic processes for aluminium and copper smelting; black liquor gasification for pulp and paper; and improved material handling technology, which allows a larger component of recycled material into the processing stream.

The magnitude of energy demand within the oil and gas sector warrants an analysis independent of other industries. In Triple E, all the policies come together to indicate, or favour, a particular development path in the oil and gas sector. The reduced demand for product and lower prices restricts the pursuit of the most energy intensive and expensive sources of oil and gas. Triple E determines not only what plays are developed, but how they are developed, favouring more efficient processes such as oxy-fuel or gasification for synthetic crude oil production and upgrading. An increase in gasification technology in oil sands would decrease natural gas use and could be used to produce a pure CO_2

stream for CO_2 capture and storage. This is discussed more fully in the oil section later in this chapter.

Canadian industrial secondary energy demand grows at a rate of 0.3 percent over the 2004 to 2030 period (Figure 5.8). The slower economic growth assumptions for the industrial sector as well as efficiency improvement policies keep demand growth lower than the historical growth rate of 1.8 percent. Total industrial demand grows faster in the first half of the forecast, due to strong oil and gas growth; however, it starts to decline as the oil and gas industry growth tapers off due to lower commodity prices. Non-energy related growth, at 0.6 percent over the forecast, is not adequate to keep total industrial demand increasing. The exclusion of the Mackenzie Valley Pipeline in this scenario, due to lower prices, and the accessibility of the world's best industrial process technology impacts demand.

In 2030, the largest provincial energy consumers are Alberta, accounting for 50 percent of industrial energy demand in Canada; Ontario, with 20 percent; and, Quebec following at 13 percent. Fuel shares by province vary significantly, depending on the types of industries, their energy intensities and the availability of fuels[67].

Food, Fibre and Fossil Fuel Alternatives

Ethanol is the most cited example of bio-based fuels making inroads into established fossil fuel markets. Ethanol biofuel is just one example of the larger, rapidly expanding biomass industry. The biomass (or bio-economy) network includes bioenergy, biofuels and bioproducts and processes. In addition to a petroleum gasoline alternative, bio-based feed stocks can also be found as an alternative or blend for diesel fuel, in electric power generation, in heating systems, and as a chemical feedstock for products such as plastics, paints and detergents.

The biomass industry suggests biological systems (forest and agriculture based) could provide 20 percent of Canada's energy needs by 2030. It already provides over 60 percent of the heat and power requirements in Canada's pulp and paper industry. The appeal of biofuels, particularly ethanol, includes reduced greenhouse gas emissions, energy security and agriculture incentives. For these reasons, Canada has a long history of support for the ethanol industry. Until recently, ethanol represented less than one percent of the gasoline fuel share. There are now policies in place to support a target of a five percent share by 2010. The last year has seen an unprecedented amount of activity in building ethanol capacity in North America. As witnessed recently in the U.S., the extensive promotion of corn for ethanol has wide-reaching implications. These include altering or reversing established export trade patterns, impinging on food and livestock producing enterprises and introducing related environment concerns.

Although agriculture is a fairly energy-intensive industry, a large body of peer-reviewed, scientific analysis has shown a net energy gain for fermented corn starch ethanol versus gasoline. (In the U.S., this is estimated to be about a 38 percent gain.) The biofuels industry and policy-makers consider the present situation to be part of a transition to improved efficiencies and lower cost. Ethanol is presently more expensive to produce than gasoline. To reach the Triple E target of 10 percent, it is assumed that technology continues rapid improvement. Cellulosic ethanol, or ethanol from plant fibre (as opposed to fermented grain) is moving into the commercial production stage, and Canadian companies are at the forefront of this technology. This technology has the potential to increase efficiency by a factor of ten. In addition, select crops such as poplar and switch-grass have the potential to improve output efficiency. Improved efficiencies in processes (including combustion, gasification and pyrolysis) will further aid the development of the whole biomass industry.

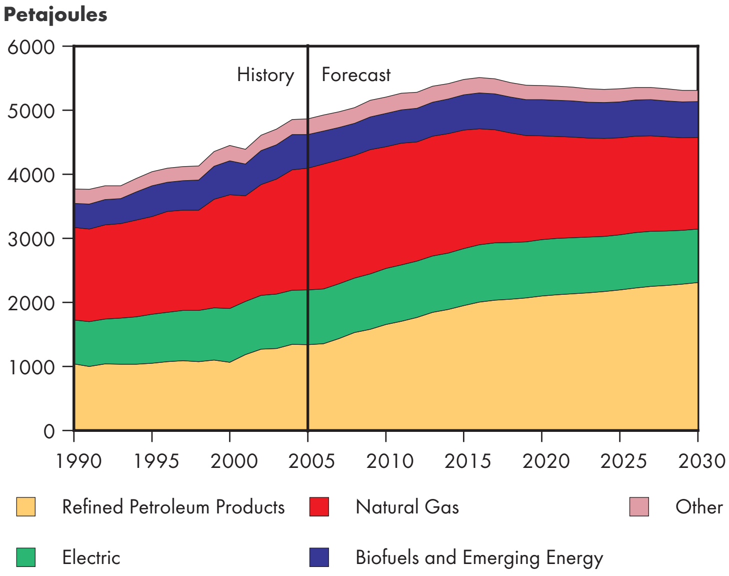
For further information see:

www.cbin-rcib.gc.ca – www1.eere.energy.gov/biomass/net_energy_balance.html – www.greenfuels.org – www.biocap.ca

67 For detailed provincial energy demand data, see Appendix 2.

FIGURE 5.8

Canadian Industrial Secondary Energy Demand by Fuel – Triple E



('Other' fuel includes coal, coke, coke oven gas, steam, naphtha)

Transportation Energy Demand

Although efficiency, expressed as fuel economy, is the pressure point for the transportation debate, Triple E incorporates a wider view of lifestyle choices and societal values, which have an equally significant impact on transportation energy demand.

Improvements in the efficiency of the basic internal combustion engine (ICE) vehicle are a starting point. The three percent annual improvement target in the first half of the scenario represents a substantial improvement over the historical rate. In addition to the efficiency improvement within each vehicle class (e.g., compact, sub-compact, light truck, med-truck), the transportation sector shows a large reduction in energy use from a shift in consumer purchasing preference toward smaller vehicles. As older vehicles are removed from stock, they are replaced by more efficient vehicles. This could be achieved by replacing a vehicle of a similar size and class with a more advanced technology (e.g., hybrid vehicles) or by replacing the current size vehicle at least one level or class better in efficiency.

Along with efficiency improvements and purchasing habits, Canadian travel behaviour changes significantly. Initially, this change in behaviour involves shifting a section of commuters out of single-occupancy vehicles and into using mass transit. Cities embrace the concept of smart growth, which supports higher densities and more options for personal mobility. This would alter the trend of increased urbanized area (urban sprawl) in Canada, which is contributing to growing personal vehicle kilometres traveled (VKT). In Triple E, a reduction of five percent in VKT due to municipal investment in mass transit options is applied. An additional 10 percent of households have a 50 percent reduction in VKT due to increased density and mixed use (work/live) neighbourhoods by 2030.

The biofuel component of the Triple E transportation policy applies existing and regional short-term targets and expands on these to 2030[68]. The five percent ethanol target presently in place is achievable with existing technology. The 10 percent target for 2030 is based on breakthroughs in biofuel processing; for example, cellulosic ethanol that would significantly improve the biomass to energy output ratio. The same applies for biodiesel. Biodiesel is assumed to make up two percent of the road

68 The Ontario assumption is 5 percent ethanol volume (3.4 percent energy) of total gasoline use in the province by 2007 and up to 10 percent ethanol volume (6.8 percent energy) by 2030. The Saskatchewan assumption is 7.5 percent ethanol volume (5.1 percent energy) of total gasoline use in the province by 2007 and up to 10 percent volume (6.8 percent energy) by 2030. For modeling purposes, the assumption was 10 percent ethanol volume of total gasoline use in Canada by 2030. The assumption is biodiesel will make up two percent volume (1.8 percent energy) of total diesel use in Canada by 2030.

diesel volume. The success of the biofuels industry in Canada benefits from high level collaboration among energy, environment and rural development strategies.

Canadian transportation energy demand grows at a rate of 0.2 percent over the 2004 to 2030 period, which is much lower than the historical growth rate due to slower economic growth, efficiency improvements and behavioural changes (Figure 5.9). The demand shares by fuel for Canada over the forecast illustrate a large drop in gasoline demand shares, resulting from efficiency improvements and the biofuels policies assumed.

FIGURE 5.9

Canadian Transportation Energy Demand by Fuel – Triple E

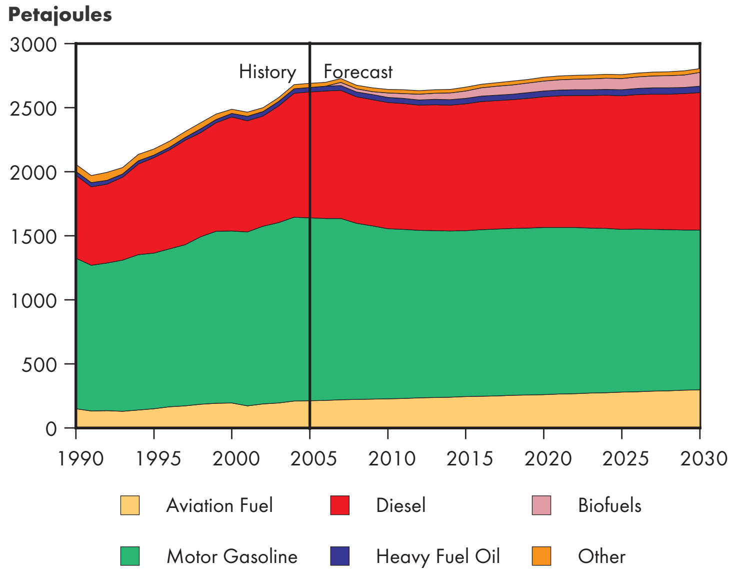
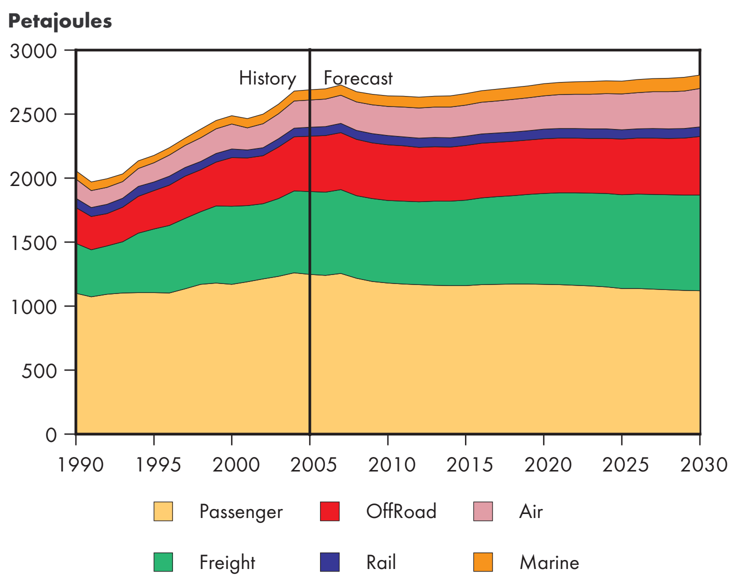


FIGURE 5.10

Canadian Transportation Energy Demand by Mode – Triple E



Oil Supply

Crude Oil and Equivalent

The Triple E Scenario, with the lowest oil price track and the greatest emphasis on environmental compliance, is the least conducive to expanding oil production levels.

Crude Oil and Bitumen Resources

Canadian crude oil and bitumen resources are the same in the Reference Case and all three scenarios[69].

Total Canada Oil Production

In the Triple E Scenario, production expands by about 1.6 percent per year until 2015 and then contracts to negative growth as lower prices and an escalating CO_2 price take effect. However,

69 Canadian crude oil and bitumen resources and are set out in Chapter 3 and in further detail in Appendix 3.

Transportation Technologies

For effective reductions in energy demand or emissions, change within the transportation sector is essential. This sector has been a major influence for increasing demand and emissions in Canada in the last 15 years. Increasing average vehicle weight, size and horsepower has essentially cancelled out overall efficiency gains achieved through better technology. However, the popularity of light trucks, including sport utility vehicles (SUVs), appears to have peaked. The market share of new passenger cars and light trucks in Canada has stabilized at approximately 62 percent and 38 percent respectively, according to Natural Resources Canada.

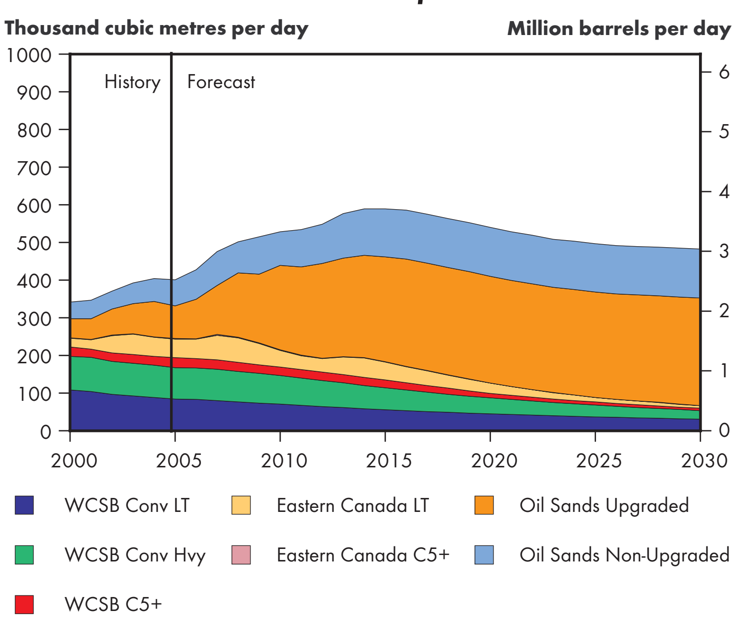
Modeling transportation energy use involves analysis of engine type, fuel type and operating environment. Road transportation, which dominates demand within the transportation sector, was reviewed in detail for potential changes. As an indication of the change that could be expected in the near future in this sector, the U.S. has recommended fuel economy improvements up to four percent a year starting in 2010. This improvement rate would be several fold over the historical rate.

The automotive industry continues to refine and perfect the performance of the internal combustion engine. The last few years have seen improvements such as cylinder deactivation, variable valve timing, Continuously Variable Transmission (CVT) and regenerative braking. Improvements evolve over many years and each may improve fuel economy by a few percentage points. Achieving significant change in transportation demand or GHG emissions would require a full slate of policy options, including consumer purchasing habits and urban planning.

The vehicles of the future could see a convergence of technologies that revolutionize energy demand. Present hybrids are seen as a transitional technology to Plug-in Hybrid vehicles (PIHV), which in turn are seen as a platform for future fuel cell vehicles. These vehicles offer the opportunity to not only 'fuel' from the utility grid, but also the possibility of supplying power to the grid. The future may see a fleet of vehicles interacting with the electrical power grid for a two-way flow of energy, charging at off-peak hours and distributing power back into the grid during critical peak loading periods.

FIGURE 5.11

Total Canada Oil Production – Triple E



government initiatives for CO_2 capture and sequestration support higher levels of improved oil recovery (IOR). Production peaks in 2014 at about 589 000 m^3/d (3.71 million b/d) and falls to 482 000 m^3/d (3.04 million b/d) by 2030 (Figure 5.11).

Conventional Crude Oil – WCSB

The low oil price in the Triple E Scenario makes it the least attractive for oil producers; however, large-scale CO_2 flooding, aided by a backbone CO_2 pipeline, proceeds with

Carbon Dioxide Capture and Storage and the Alberta Backbone CO_2 Pipeline

Carbon dioxide capture and storage (CCS) has the potential to significantly reduce GHG emissions from industrial sources and electricity generation. There are three stages to CCS:

- CO_2 Capture – CO_2 that is usually released into the atmosphere as a by-product of industrial processes is extracted and compressed into a more easily transportable form.

- CO_2 Transportation – the captured CO_2 is transported by pipeline or tanker to a storage area.

- CO_2 Storage – CO_2 is stored in geological formations (e.g., active or depleted oil and gas reservoirs, deep saline aquifers, and salt caverns), in the ocean, or in mineral carbonates. It may be permanently stored or used in industrial processes. Carbon dioxide storage in geological formations shows significant potential. Research is ongoing to determine the feasibility of CO_2 storage in the ocean or in mineral carbonates. Industrial processes are thought to have limited applications for large reductions in GHG emissions.

Alberta is a good candidate for CCS because of the proximity of large industrial sources of high purity CO_2 to the Western Canada Sedimentary Basin (WCSB) (e.g., oil sands facilities, natural gas plants, ammonia plants, and potentially in the future fossil fuel-fired electricity generating plants). The WCSB is a well understood geological basin with infrastructure in place that could be leveraged for CO_2 transportation and injection. The development of a large-scale CO_2 pipeline that would connect major industrial GHG emitters and storage sites within the province has been proposed. This 'backbone' pipeline would likely run from Fort McMurray and the Edmonton/Fort Saskatchewan area to the Swan Hills and Pembina fields. It could also connect to the Weyburn and Midale fields in Saskatchewan. The CO_2 that is captured could be used in IOR. Carbon dioxide captured in excess of IOR demand can be stored in the WCSB.

There are technological and economic challenges to the development of CCS. According to the Intergovernmental Panel on Climate Change, CCS systems can be assembled from existing technologies; however, the combination of these technologies into one system has yet to be proven. As well, there is a gap between the price that IOR industries would be willing to pay for CO_2 and the price that industries would demand to cover the costs of capturing CO_2. Government policies are likely necessary to close this gap.

Web Resources:

Intergovernmental Panel on Climate Change (IPCC) – Special Report on Carbon Dioxide Capture and Storage http://arch.rivm.nl/env/int/ipcc/pages_media/SRCCS-final/IPCCSpecialReportonCarbondioxideCaptureandStorage.htm

International Energy Agency (IEA) Greenhouse Gas R&D Programme – CO_2 Capture and Storage website http://www.co2captureandstorage.info/

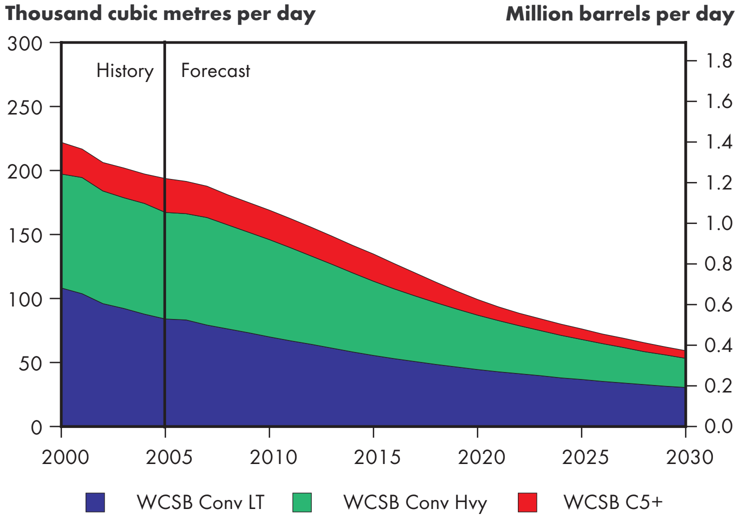
Government of Canada – Canada's CO_2 Capture and Storage Technology Roadmap http://www.nrcan.gc.ca/es/etb/cetc/combustion/co2trm/htmldocs/ccstrm_main_e.html

FIGURE 5.12

Alberta Backbone CO_2 Pipeline Schematic

FIGURE 5.13

WCSB Conventional Oil Production – Triple E



government support (see text box). Overall production levels decline, but slow growth resumes late in the scenario as costs align with changing market conditions.

The effect of the emphasis on CO_2 flooding in the Triple E Scenario is to moderate the rate of decline such that the conventional light oil decline rate is 4.2 percent compared with five percent for the Continuing Trends Scenario (Figure 5.13).

With respect to heavy conventional crude oil, in the Triple E Scenario, lower prices and the costs of more stringent environmental conditions slow the early production momentum. As well, in this more environmentally sensitive scenario, a preference for light crude oil could mean tighter markets for heavy crude. Production falls to 23 000 m^3/d (145 thousand b/d) by 2030.

Eastern Canada Light Crude Production

Projections for eastern Canada oil production are dominated by the east coast offshore, with only minor amounts of production expected from Ontario.

The oil price track in the Triple E Scenario is not conducive to oil supply expansion on the East Coast after 2015. In Triple E, no satellite pools are included, and no additional large pool is assumed. Supply peaks at 65 000 m^3/d (410 thousand b/d) in 2007 and declines to 6 700 m^3/d (42 thousand b/d) by 2030 (Figure 5.14).

Oil Sands Supply

FIGURE 5.14

Eastern Canada Crude Production – Triple E

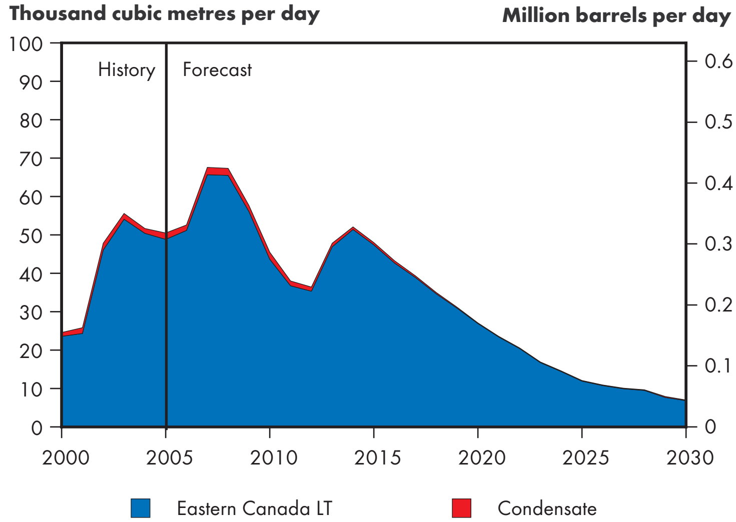
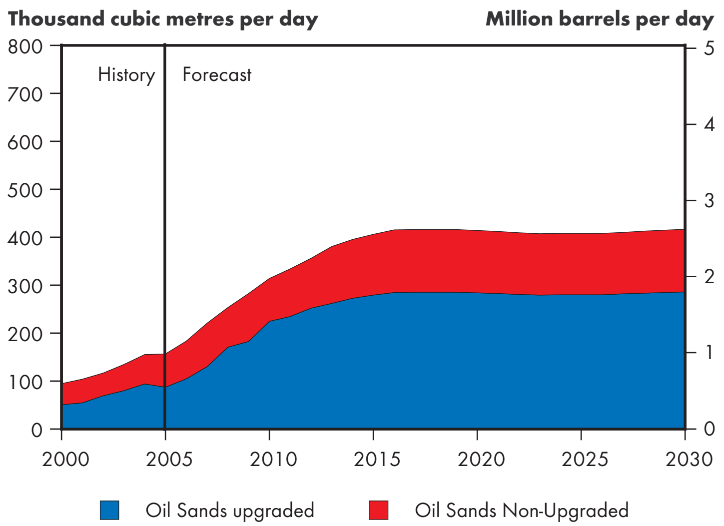


FIGURE 5.15

Canadian Oil Sands Production – Triple E



In Triple E, the lower oil prices and the higher costs of enhanced environmental conditions slow activity precipitously (Figure 5.15). By 2020, only existing projects continue to produce and production declines for several years. After a period of adjustment, slow growth appears after 2027. Production reaches 416 000 m³/d (2.62 million b/d) by 2030 in the Triple E Scenario. Upgraded bitumen volumes total 286 000 m³/d (1.80 million b/d) while non-upgraded volumes total 131 000 m³/d (825 thousand b/d). There is no oil sands production from Saskatchewan assumed in this scenario.

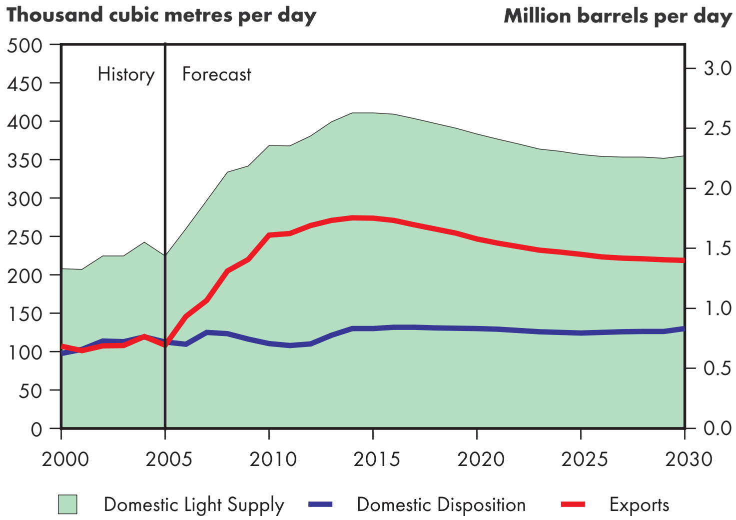
Triple E is the most environmentally conscious scenario, with government incentives in place to reward improved energy efficiency. In this scenario, annual improvement in energy efficiency is assumed to be 1.5 percent, as opposed to 1.0 percent in the other scenarios. In addition, government initiatives to support CO_2 capture and storage encourage some switching to bitumen gasification to provide energy for oil sands operations, in spite of low oil prices. In this scenario, the purchased natural gas intensity is reduced from 0.67 Mcf/b in 2005 to 0.30 Mcf/b in 2030. Total purchased natural gas requirements, excluding on-site electricity requirements, increase slightly from 0.65 Bcf/d in 2005 to 0.9 Bcf/d by 2030, in line with muted oil sands production growth.

Supply and Demand Balances

The Triple E Scenario shows a lower production forecast and the earliest decline in conventional production. The domestic demand for petroleum products in 2005 is 290 900 m³/d (1.83 million b/d) and increases to 331 800 m³/d (2.09 million b/d) in 2015. By 2030, demand is 358 600 m³/d

FIGURE 5.16

Supply and Demand Balance, Light Crude Oil – Triple E



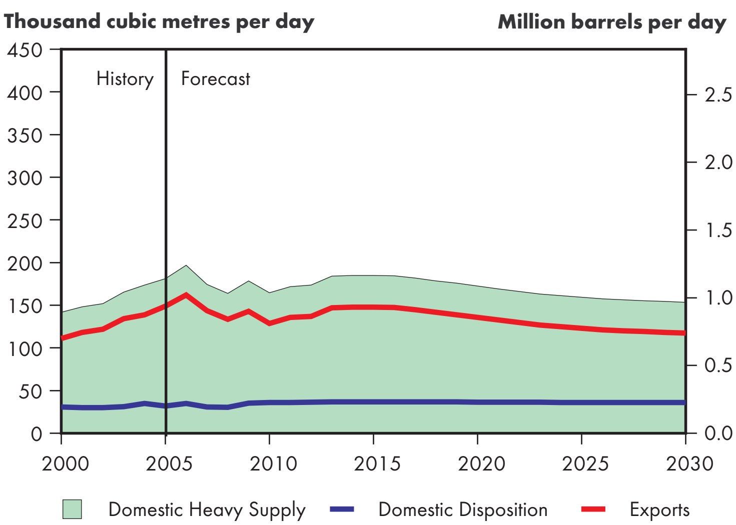
(2.26 million b/d). There is a greater focus on the production of cleaner transportation fuels and energy efficiency.

Light Crude Oil – Supply and Demand Balance

Exports of light crude oil increase sharply from 110 200 m³/d (694 thousand b/d) in 2005 to peak at 278 400 m³/d (1.75 million b/d) in 2015. Subsequently, exports drop to 222 600 m³/d (1.40 million b/d) by 2030, a direct result of the sharp decline in conventional light crude oil production and no growth in synthetic crude production (Figure 5.16).

FIGURE 5.17

Supply and Demand Balance, Heavy Crude Oil – Triple E



Heavy Crude Oil – Supply and Demand Balance

Exports of heavy crude oil in 2005 are 149 200 m³/d (940 thousand b/d), and remain around that level until 2015, at which point exports begin a steady decline to 117 500 m³/d (740 thousand b/d) by 2030 (Figure 5.17).

Natural Gas Supply

Canadian Natural Gas Resource Base

In the declining price environment of the Triple E Scenario, the more costly portions of the unconventional resource base are no longer economic to develop. Consequently, the remaining resource base for coalbed methane (CBM), tight gas and shale gas in Western Canada is reduced relative to the other scenarios[70]. Compared to the Reference Case and Continuing Trends Scenario, the estimated remaining CBM resource base is lower by 26 percent, with tight gas and shale gas remaining resources reduced by almost 40 percent each.

70 As shown in Appendix 4.

Unlike unconventional gas, the estimate of the remaining conventional resource base is unchanged from the level in the Reference Case and Continuing Trends Scenario. The estimate of the remaining conventional resource base is defined by the minimum reservoir size for each play type that is considered technically feasible for the industry to develop. Within the price range considered, the minimum reservoir sizes adopted in the resource estimate for the Reference Case and Continuing Trends Scenario remain applicable in the Triple E Scenario.

The remaining resource base for frontier projects is also unchanged in Triple E. The frontier resource estimate from the Reference Case and Continuing Trends Scenario incorporates the NEB's best current estimate of technically recoverable marketable gas and is applicable to the range of prices considered. A major challenge in a lower price environment is to overcome technical and locational cost barriers to the construction of infrastructure required to access remote frontier resources. As the likely development of frontier resources over the period to 2030 is only a minor fraction of the total frontier resource base, a downward adjustment to the estimate would be of minimal consequence to the supply outlook.

Production and LNG imports

In this scenario, strong growth in worldwide LNG supply makes imported gas a viable option for a substantial portion of Canadian natural gas requirements. Canadian gas producers may choose to also participate to varying degrees in international LNG opportunities. The availability of abundant LNG imports could eliminate the need to pursue development of some high cost conventional, unconventional and frontier supplies within Canada.

Liquefied Natural Gas

In 2005, Canada and the U.S. represented 26.3 percent of global natural gas consumption. Over 98 percent of this requirement was sourced from within the two countries. However, over 96 percent of worldwide remaining proved gas reserves are estimated to be located outside Canada and the U.S. Under certain market conditions, it may be advantageous for North America to tap into a larger share of the global natural resource base and import greater amounts in the form of ship-borne LNG. Total world LNG trade in 2005 was roughly 567 million m^3/d (20 Bcf/d), and future LNG projects either under construction or proposed could potentially increase LNG supply to around 1 700 million m^3/d (60 Bcf/d) in the next decade, according to Tristone Capital.

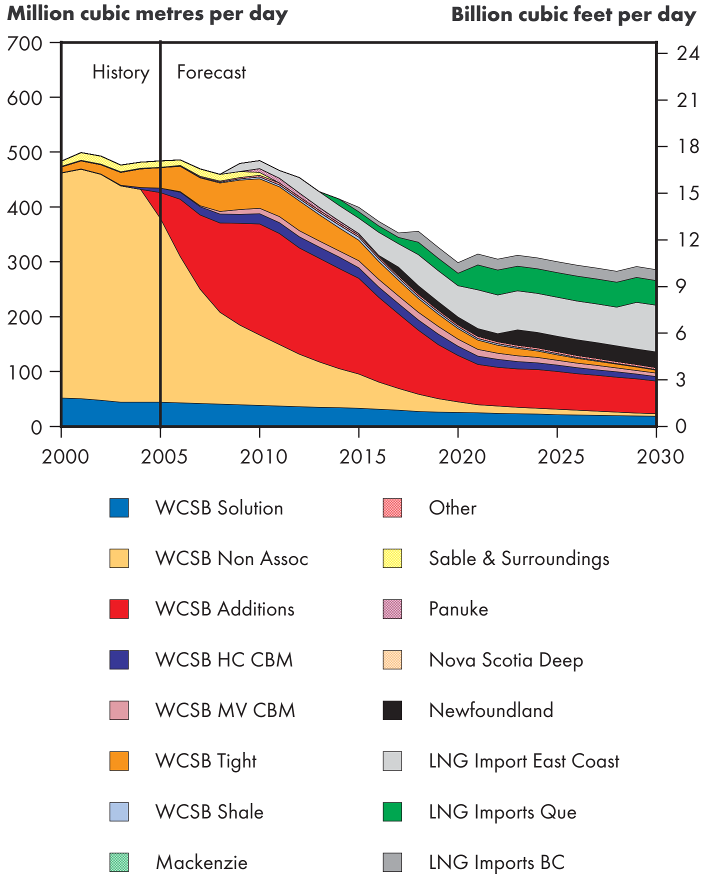
Should such a substantial build up occur, it is possible that the rise in LNG supply could exceed growth in market demand. Under such conditions, LNG suppliers may be forced to compete with each other on price to deliver volumes into already adequately supplied markets. This situation could see prices competed down to the average marginal cost of LNG, currently estimated at roughly $5.04/GJ (US$5.30/MMBtu) delivered to North America, according to Tristone Capital. At this price level, higher-cost domestic gas production would potentially be displaced by incremental LNG imports. Perhaps in recognition of the potential for such price-eroding LNG-on-LNG competition, some current and prospective LNG suppliers have begun very preliminary discussions of the potential to form a gas equivalent of OPEC to assist in cooperatively managing worldwide LNG supply.

Substantial increases in North American LNG import capacity have occurred or are currently under construction including expansions at four of the five existing terminals and seven new terminals (four on the U.S. gulf coast, two in Mexico and the Canaport project in New Brunswick). Over 40 additional import terminals have been proposed for the U.S. and Canada, but only a fraction of these might ever be built. In general, proposals for LNG terminals along the east and west coasts of the U.S. have tended to attract greater site-related local opposition than those along the Gulf coast.

Lastly, North America's large underground gas storage capacity relative to other major LNG markets (also located primarily in the northern hemisphere) may lead to greater LNG imports during the summer months than during the peak heating season.

FIGURE 5.18

Natural Gas Production Outlook – Triple E



Liquefied natural gas imports are projected to begin in 2009 at 14 million m³/d (0.5 Bcf/d) and grow steadily to 150 million m³/d (5.3 Bcf/d) by 2029, as shown in Figure 5.18. Liquefied natural gas volumes would be offloaded at an estimated seven receiving terminals, ranging in capacity from 14 to 28 million m³/d (0.5 to 1.0 Bcf/d). Import terminals could potentially be developed at appropriate coastal locations in Nova Scotia, New Brunswick, Newfoundland and Labrador, Quebec, and British Columbia. Projected LNG imports are equivalent to 50 percent of domestic production by 2020 and rise steadily to slightly exceed domestic production by the end of the outlook period.

Given the lower price environment and access to abundant imports, annual levels of gas drilling in Canada can be reduced substantially to be highly selective of prospects, maximize drilling efficiency and minimize cost escalation. In Western Canada, this would involve drilling an average of 8 000 gas wells annually from 2015 to 2030, a level of activity similar to that experienced in the late 1990s. At these lower drilling rates, conventional gas production in Western Canada would decline fairly rapidly to fall by approximately one-third by 2015 and 80 percent by 2030.

Similarly, the drilling-intensive nature of unconventional resources is not well suited to the minimal activity conditions of Triple E. Tight gas production exhibits modest growth through 2012 before gradually declining to less than 6 million m³/d (0.2 Bcf/d) by 2030. Shale gas struggles to be competitive and never rises above 6 million m³/d (0.2 Bcf/d). Coalbed methane development stabilizes at just over 28 million m³/d (1 Bcf/d) from 2010 to 2019 and then gradually declines by half over the remainder of the projection.

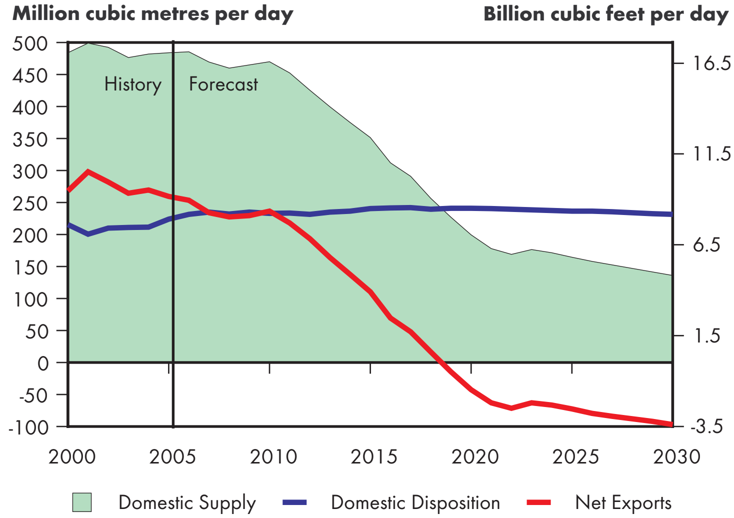
Natural gas developments associated with oil projects off Newfoundland's Grand Banks remain competitive as a substantial component of the original development costs are absorbed by the oil operations. Frontier projects in more remote locations, including Mackenzie Delta gas, are not developed in Triple E as natural gas prices are insufficient to offset the costs of building the required pipeline or shipping infrastructure to connect to markets.

Supply and Demand Balance

Lower supply costs in Triple E are achieved through a combination of declining Canadian natural gas production and rising LNG imports. This combination provides a gradual reduction in the natural gas supply available in Canada from 481 million m³/d (17 Bcf/d) in 2005 to 397 million m³/d (14 Bcf/d) in 2015 and 283 million m³/d (10 Bcf/d) by 2030. With the U.S. also increasingly served by growing LNG imports, the reduction in natural gas supply in Canada corresponds to a reduction in requirements for Canadian natural gas exports to the U.S.

FIGURE 5.19

Supply and Demand Balance, Natural Gas – Triple E



Energy efficiency improvements and reduced oil sands requirements slow Canadian natural gas demand growth to just seven percent between 2005 and 2030. Canadian demand is satisfied through a combination of Canadian domestic production and LNG imports. The remaining differential between supply and demand averages 62 million m³/d (2.2 Bcf/d) between 2020 and 2030 and would be available for export to the U.S.

In the Triple E Scenario, Canada becomes a net importer of natural gas after 2018. This reflects a conscious strategy to reduce natural gas supply costs by focusing Canadian gas development on lower cost conventional, unconventional and frontier sources, while augmenting supplies with imports of abundant LNG. With the U.S. market also amply supplied with additional LNG imports, a gradual reduction in Canadian natural gas exports to the U.S. would be accommodated under normal market behaviour as the lowest cost option for all market participants. Market imbalance conditions of the type required to invoke a North America Free Trade Agreement (NAFTA) proportionality determination are inconsistent with the low cost, stable international investment and efficient market premises of the Triple E Scenario. A more unsettled international environment is consistent with the Fortified Islands Scenario, where Canadian gas exports to the U.S. are generally increasing rather than decreasing.

Natural Gas Liquids

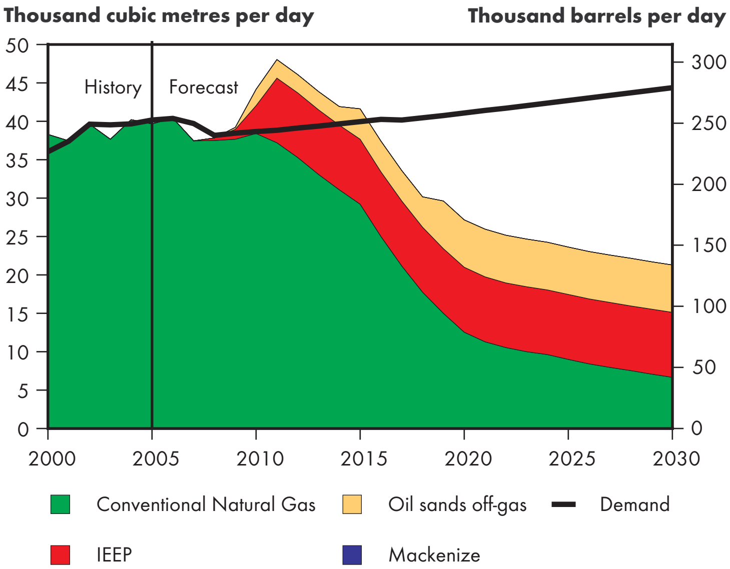
Supply and Disposition

In the Triple E Scenario, the butane supply and demand balance becomes tight near the end of the outlook period, as WCSB conventional natural gas production decreases and demand for oil sands diluent and motor gasoline blending continues to grow. As a result, no excess supply is available for export as of 2021[71].

71 Further detail on the propane and butane supply and demand balances can be found in Appendix 3.

FIGURE 5.20

Canadian Ethane Supply and Demand Balance – Triple E

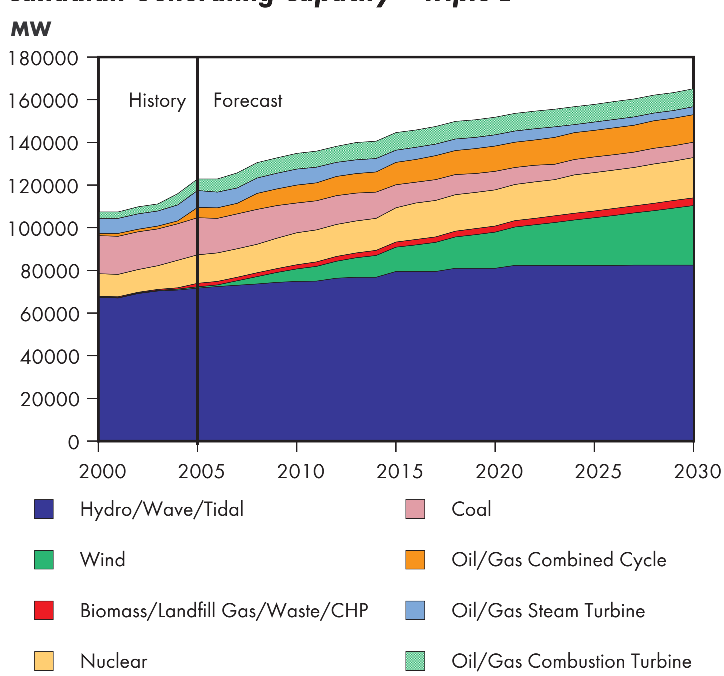


Ethane Supply and Demand Balances

Under the Triple E Scenario, demand exceeds supply early in the period, with the ethane shortfall of about 2 900 m^3/d (18 thousand b/d) commencing in 2016, increasing to about 23 000 m^3/d (145 thousand b/d) by the end of the outlook period (Figure 5.20). The ethane deficit is highest in the Triple E Scenario. This deficit is caused mainly by the significantly lower supply of conventional ethane. In this scenario, WCSB conventional natural gas production is the lowest due to the declining price environment. Moreover, there is no ethane associated with Mackenzie Delta gas, as the pipeline project is assumed to be uneconomic as a result of low natural gas prices.

FIGURE 5.21

Canadian Generating Capacity – Triple E



Electricity Supply

Capacity and Generation

In the Triple E Scenario, the combination of energy demand management policies and changes in societal values relating to energy use implies that demand for electricity will start to decline after 2016. Due to the cost of controlling CO_2 and other emissions end-use energy prices remain strong despite the decrease in electricity demand and lower crude oil and natural gas prices.

Generation capacity increases by 34 percent between 2005 and 2030 and includes large numbers of wind power facilities and other non-traditional technologies that are forecast to generate electricity intermittently (Figure 5.21). The environmental policy of the Triple E Scenario enables funding of more efficient types of generation and the development of alternatives to traditional generation. It also encourages the advancement of purely environmental applications, such as CO_2 capture and storage. Great strides are made in terms of balancing environmental, economic and energy considerations. In this respect, concern about the cost incurred to implement environmental initiatives is balanced by concern for the environment.

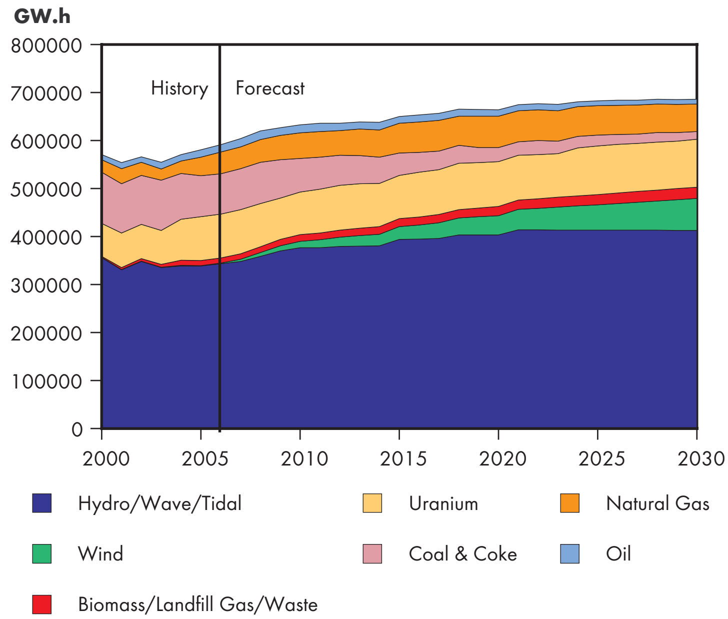
Hydro

In addition to the units listed in the Reference Case, after 2015 the following hydro facilities will be constructed: Peace River Site C (900 MW) in British Columbia and both Conawapa (1 380 MW) and Gull/Keeyask (600 MW) in Manitoba.

Hydroelectric generation will provide about 60 percent of electricity needs throughout the forecast period (Figure 5.22). Capacity expands to 82 400 MW by 2030, a further increase of 3 000 MW from 2015 and 10 000 MW from 2006.

FIGURE 5.22

Canadian Generation – Triple E



Nuclear

Total nuclear capacity increases 42 percent between 2005 and 2030, an increase of 5 500 MW from 2005. Assumptions about nuclear capacity are the same as in the Continuing Trends and Fortified Islands Scenarios.

Natural gas-fired

Due to its lower price in this scenario and increased concern about environmental effects, natural gas is the preferred fuel for conventional generation outside Alberta and Saskatchewan.

Coal-fired

Falling demand, combined with competition from natural gas and emerging technologies, indicates that installed coal capacity falls from 14 to 4.3 percent of total installed capacity by 2030. In Alberta and Saskatchewan, there is renewed interest in coal generation starting in 2019 and advanced coal plants equipped for CO_2 capture and storage come into service.

Oil-fired

Lower electricity demand, combined with switching to cleaner-burning natural gas, reduces generation from oil-fired units by 37 percent by 2030, despite the construction of 640 MW of bitumen-fired oil sands cogeneration plants in Alberta. In 2020 retiring oil-fired generation in Newfoundland is replaced with a 180 MW natural gas-fired combined-cycle generation.

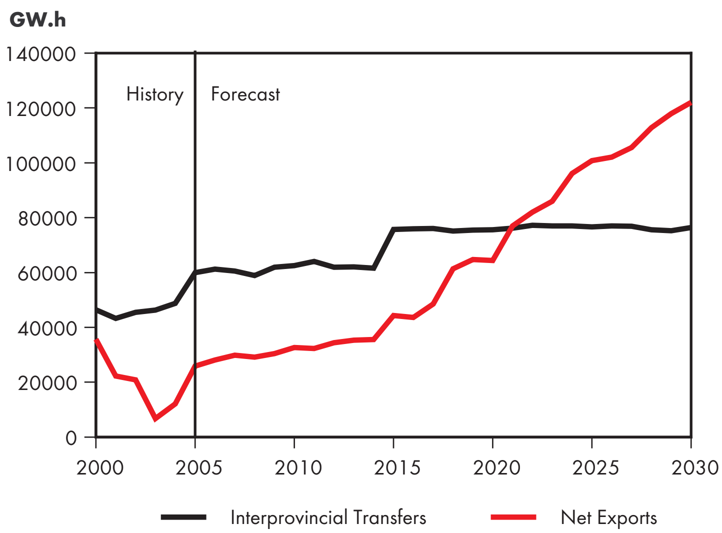
Emerging Technologies

Wind, small hydro and biomass will continue to be the most popular alternatives to traditional generation technologies, while emerging technologies such as solar, geothermal and wave power are forecast to experience large gains. For example, substantial growth in wave power is evidenced by the addition of 60 MW on the east and west coasts between 2015 and 2030. While these technologies show promise, the impact of emerging technologies is, and will likely remain, small relative to traditional generation types over the outlook period considered.

Wind generation makes up the highest percentage of installed capacity in the Triple E Scenario, reaching 17 percent by 2030. This will require investment in transmission and control systems to compensate for the intermittent nature of wind generation; however, environmental concerns make the investment worthwhile.

FIGURE 5.23

Interprovincial Transfers and Net Exports – Triple E



Exports, Imports and Interprovincial Transfers

Canadian net exports triple from 2006 to 122 000 GW.h in 2030 (Figure 5.23). This dramatic increase is due in large part to moderation of demand due to energy conservation measures, combined with availability of hydro and other alternative sources of generation that are favoured because of their contribution to reducing GHG emissions. The increase in interprovincial electricity transfers (by 23 percent to 76 400 GW.h in 2030) is much less marked, but still substantial.

Coal

Supply and Demand

In Triple E, there is a shift away from thermal coal used for power generation to gas-fired generation due to environmental concerns. Downward pressure on coal demand is exerted by the retirement of existing coal units, conservation and demand management, more efficient plants and the choice to construct cleaner alternatives to coal plants. It is assumed that CCS technology becomes available around 2020 and is only employed in the Triple E Scenario.

Coal demand and production growth are lowest in Triple E. Canadian coal production decreases to 39 Mt in 2030 from 49 Mt in 2015 because of the decrease in domestic demand of thermal coal. Thermal coal demand decreases to 7 Mt in 2030 from 22 Mt in 2015, with the preference for gas-fired generation choices to replace ageing coal-fired plants. There is a policy shift away from coal used in generation in Triple E, due to environmental concerns. Metallurgical and end-use coal demand decreases to 5 Mt from 7 Mt in 2015 due to declining output in the domestic iron and steel

Clean Coal and Carbon Dioxide Capture and Storage

In addition to oil sands plants and chemical facilities, coal-fired generating stations are another potential source of CO_2 for CSS. Alberta and Saskatchewan are good candidates for this technology, as they have access to cheap coal and to sites in the WCSB where CO_2 could be sequestered as part of IOR projects. Saskatchewan is currently in the final stages of developing a proposal for a 300 MW clean coal power plant equipped to capture 90 percent of the plant's CO_2 emissions. If this project proceeds, it could be in service as early as 2012.

There are a number of potential technologies for power plant CCS, which involve either scrubbing CO_2 from the exhaust stream after combustion or removing it from the fuel before power is generated.

Post combustion scrubbing is less efficient, but it allows the plant to operate as a conventional facility if there are technical difficulties with the CO_2 scrubbers. For this reason, and because of familiarity with the technology, Saskatchewan has selected the OxyFuel process. The OxyFuel process facilitates post-combustion CO_2 scrubbing by enriching the oxygen content of the combustion air.

Pre-combustion scrubbing typically involves combining CO_2 capture with an IGCC. Integrated Gasification Combined Cycle plants turn coal into synthesis gas, a mixture of carbon monoxide (CO) and hydrogen (H_2), which is then burned in a conventional combined-cycle power plant. Carbon dioxide capture uses the reaction ($H_2O + CO \rightarrow H_2 + CO_2$) to produce hydrogen gas for combustion and CO_2 for sequestration. Combining the CO_2 capture with the gasification process allows for higher efficiency, but makes the functioning of the plant dependent on the reliability of CO_2 capture equipment.

For more information on clean coal technology, see the coal chapter in our Energy Market Assessment: *Emerging Technologies in Electricity Generation, Energy Market Assessment March 2006* at www.neb-one.gc.ca.

industry. Metallurgical coal production increases somewhat with growth in the world iron and steel industry while thermal coal production decreases significantly to 6 Mt in 2030 from 18 Mt in 2015. Imports of coal are expected to decrease to 5 Mt in 2030 from the initial 10 Mt imported in 2015 while exports are expected to increase to 32 Mt in 2030 from 30 Mt in 2015. Net exports grow moderately by 24 percent between 2015 and 2030 due to the higher level of international trade and significant decrease of imported thermal and metallurgical coal.

Imports of thermal coal decline to 54 percent from 2005 to 2015 due to the phase out of Ontario coal-fired generation and the replacing of coal-fired plants with gas-fired plants. By 2030, imports of metallurgical coal are down 40 percent from 2015 due to declining iron and steel output. Exports of thermal coal remain low in Triple E.

Greenhouse Gas Emissions

Canadian total GHG emissions in the Triple E Scenario are expected to decrease by 0.1 percent per year between 2004 and 2030 (Figure 5.24). These declines are a result of long-run government policies directed at balancing energy use, environmental impacts and economic growth. The policies focus on improving the energy efficiency of the Canadian economy, including improving vehicle fuel efficiency, buildings and industrial processes. The policies also focus on supporting the development

FIGURE 5.24

Canadian Total GHG Emissions by Sector – Triple E

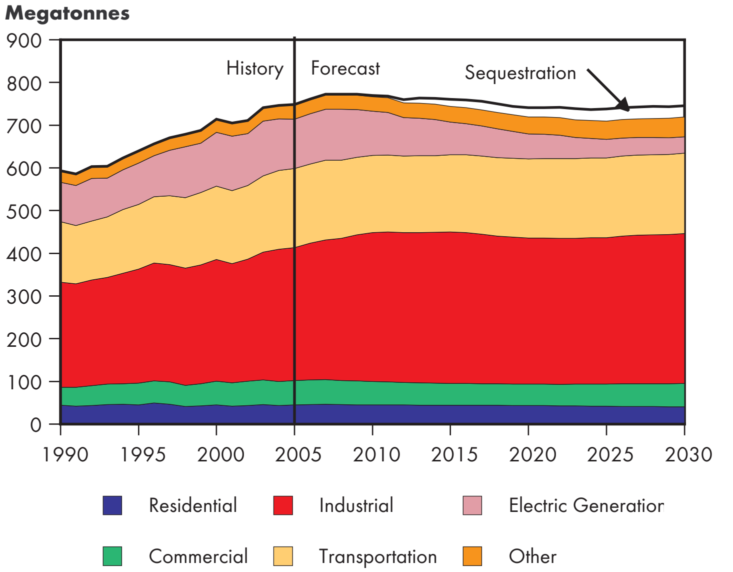
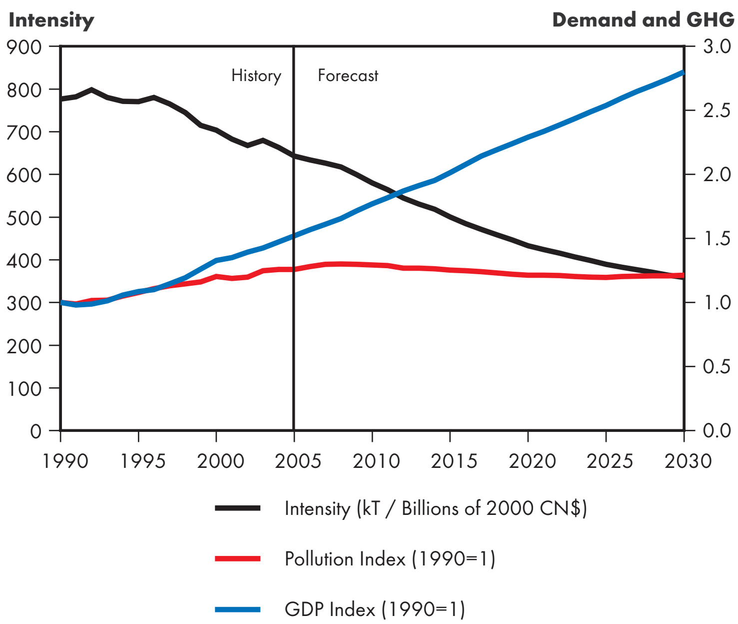


FIGURE 5.25

Canadian Total GHG Intensity – Triple E



of less GHG-intensive fuels, such as investments in wind generation, ethanol and biodiesel fuel use in the transportation sector and solar and geothermal fuel use in the residential and commercial sectors. Another important component is GHG emissions sequestration in the energy sector, which eliminates 3.6 percent of total emissions in Canada by 2030, bringing the level down from 746 Mt to 719 Mt.

The GHG intensity in Canada declines over the forecast at a rate of 2.3 percent per year in Triple E (Figure 5.25). This is much faster than the historical rate of 1.1 percent as a result of implemented energy policies, alternative energy use increases and sequestration.

In the Triple E Scenario, a number of programs are explored. In developing these assumptions, the NEB reviewed information on current and proposed energy and environmental policies both in Canada and internationally. Dozens of reports and hundreds of policies and programs were evaluated for inclusion. Ultimately, policies were modeled for *Canada's Energy Future* based on the following criteria:

- programs and policies enjoy broad acceptance – the programs and polices have a long history of use, are frequently employed, or have been repeatedly proposed as solutions;
- pragmatic policies and programs – the literature suggests that the policy or program will lead to a measurable impact on energy demand or emissions within the timeframe of the scenario analysis, or they are derived from best-in-class experiences from around the world;
- build on Canadian experiences – wherever possible, the methods employed to address energy and environmental issues are based on current Canadian programs;

- comprehensive coverage – numerous policies for each demand sector were adopted to ensure that the many factors contributing to decision-making processes were addressed; and
- ease of quantification and modeling – when competing policies satisfied the above filters, the policy that was more straightforward to model or quantify was employed. For example, Canada is developing an emissions trading system for the industrial sector. As a proxy for this program, we have modeled an emissions price. The industrial emissions trading system can be incorporated in future analysis once the details of the system are in place.

Recent federal government announcements have targeted a reduction in Canadian GHG emissions of 20 percent below 2006 levels by the year 2020. In this scenario, Canada only partially meets the target.

This report is an analysis of Canada's possible energy futures. As such, the report focuses strictly on GHG emission reductions from energy-related activities in Canada (e.g., energy efficiency measures, improved energy management systems or investment in CCS). The analysis does not directly focus on GHG emission reduction strategies. For example, the analysis does not incorporate two potential sources of GHG emissions reductions: (a) non-energy related emission reductions such as carbon sequestration in agricultural and forestry; and (b) GHG emission reductions from international mechanisms such as access to Kyoto's Clean Development Mechanism, or international CO_2 emissions trading regimes. Consideration of these and others as part of a full spectrum of GHG reduction strategies could go along way in contributing to Canada meeting its target of 20 percent by 2020.

It is also important to note that significant uncertainty exists over how consumers and technology will react to energy demand management and GHG emission policies. Every effort was made to include the most up-to-date information. However, climate policy and technological advancements rapidly evolve. More rapid progression of technology than assumed here or a higher willingness of consumers and industry to make significant lifestyle and production changes would result in a more aggressive GHG emission reduction profile. For example, it is assumed that by 2030 almost 30 Mt per year of GHG emissions are used in IOR or sequestered as a result of the CO_2 backbone pipeline. This number could prove to be higher depending on technological advancement and consumer acceptance.

Triple E Issues and Implications

- In Triple E, heightened awareness of energy issues has led to significant changes in the way Canadians use energy. These changes influence every part of life. People live in more densely populated communities, they use more efficient modes of transportation, and efficiency of goods and services is a key criterion shaping purchasing decisions. Progressive government policies encourage many of the changes in this scenario. As a result, despite moderate end-use energy prices and economic growth rates, the overall energy demand in this scenario is the lowest of all three scenarios.
- Access to resources on a worldwide scale and more moderate energy demand growth result in an abundance of energy supplies in the world in the Triple E Scenario. Canada relies on LNG imports for a significant portion of its supply in response to increased security of trade. This reduces the need to access high cost or remote resources within Canada and enable lower energy costs. In addition, availability of global oil supplies lowers oil prices resulting in slower Canadian oil production profiles with the exception of CO_2 flooding, aided by a backbone CO_2 pipeline.
- As a result of energy efficiency improvements and CCS technologies, GHG emissions decline in this scenario. This is a significant finding as it would be the first time in

Canadian history that GHG emissions decline over the long-term as a result of a concerted effort to manage emissions.

- It is also noteworthy that GHG emissions reductions occur despite growing economic activity. In the past, GHG emissions and economic growth have been linked. However, the programs and polices implemented in this scenario weaken this link and allow for economic growth while simultaneously lowering emissions.
- In some ways, Triple E might be regarded as a high-risk scenario. Aggressive energy demand management and GHG emissions reductions programs, technological advancements and cooperative international relations underpin the scenario outcomes. The absence of any of these factors put at risk scenario results.
- The implementation of the government programs and policies included in this scenario is not a simple matter. Significant debate would be required to ensure a balance of various objectives is achieved, including GHG emission reductions, program cost-effectiveness, distributional impacts and minimizing competitiveness implications.
- Many of the technologies require continued advancement to be economic, such as Integrated Gasification Combined Cycle (IGCC) with CCS and cellulosic ethanol technology. In addition, increased penetration of intermittent technologies, such as wind, creates potential reliability issues.
- Similarly, the expectation of more cooperative international relations and a shift in consumers' values to adopt lifestyle changes included in this scenario are highly uncertain.

FORTIFIED ISLANDS

Fortified Islands is the scenario wherein security concerns are top of mind. This scenario is characterized by geopolitical unrest, a lack of international cooperation and trust, and protectionist government policies.

Scenario Overview (2005-2030)

Global Forces

At the beginning of the Fortified Islands Scenario, geopolitical tensions around the world threaten energy supply. This raises concerns about energy security in major energy-consuming regions that see energy resources increasingly becoming concentrated outside of their borders and their sphere of control. Increased security risks add a premium to fuel costs and by 2010, energy prices are at near record highs.

Despite these higher energy prices, adequate investment in global energy supplies and infrastructure do not take place, as political relations around the world continue to become more tenuous and access to energy resources and the capital to develop them becomes increasingly more difficult. Unlike in the Triple E Scenario, international cooperation is not seen as a viable option to deal with supply shortages and countries turn inwards or toward ‘friendly’ trading partners to find solutions. Large energy-consuming nations focus on energy self-sufficiency, and the development of domestic energy resources are a top priority. Pockets of technological development occur to reduce energy demand and increase supplies of alternative resources. However, the lack of global cooperation hinders deployment across countries.

A lack of trust between nations leads to increased trade barriers and other roadblocks that restrict supply chains and reduce the benefits of trade. These factors take their toll: global energy markets remain tight, oil prices remain high and unpredictable, and global economic growth is restrained.

The social and environmental principles espoused under ‘sustainable development’ at the turn of the century are less prevalent by the end of the Fortified Islands Scenario. Instead, national defence and job creation are topical issues. Further, international agreements on major environmental issues such as climate change remain tenuous and non-binding. Instead, environmental issues are addressed locally and are more likely a co-benefit of energy demand management, rather than a result of dedicated programs to improve emissions.

By 2030, energy security trumps environmental concerns in this scenario and, therefore, significant investments in local energy options including coal take place. Countries are also more willing to develop higher cost unconventional resources even if this may mean environmental trade-offs. Energy demand is lower in Fortified Islands than in the other scenarios because of the slower economic growth rates and high world energy prices.

Canadian Outcomes

Despite Canada's abundant energy resources, Canadians are not immune to security concerns shaping the globe, although they are affected differently. The Fortified Islands Scenario has the slowest economic growth for Canada. The more protectionist policies of Canada's trading partners and the reduction in demand worldwide have resulted in relatively slow overall growth in Canada. The energy industry is the exception. Limited access to global resources ensures Canadian supplies are in high demand.

In this scenario, large energy importers are conscious of their uncertain situation and self-reliance is the central theme in their domestic energy policies. A different dynamic occurs in countries like Canada, where there is a dual policy focus of providing safe, secure and affordable access to domestic supply, while also meeting international demand, in particular U.S. demand, in an integrated North American market. Canada develops an 'energy complex' in this scenario including returning the Sarnia-Montreal pipeline to eastbound service, by which Quebec gains access to western Canadian crude oil supplies. These projects are undertaken to ensure value added from resource supplies are derived domestically.

Canada's energy demand in this scenario is low due to slow economic growth. Canada's technology focus is on increasing energy supply and distribution. There is no national consensus on demand management issues or programs; however, Canada's energy intensity maintains a gradual improving trend. This is mostly due to high energy prices and North America-wide efficiency standards for appliances and transportation equipment. Although Canada is not subject to the same energy security issues as many countries, energy standards on imported goods is indicative of the efficiency legislation in place elsewhere.

Macroeconomic Outlook

Slow global economic growth and tight, unpredictable global energy markets shape the Canadian macroeconomic outlook in Fortified Islands. Population growth slows to 0.7 percent per year and labour force growth to 0.6 percent per year (Table 6.1). Productivity measured as output per employee is 1.2 percent per year. Slower export demand means less need to increase participation rates, keeping labour force growth low. It also means fewer resources for investment in capital, resulting in productivity levels lower than the other scenarios.

These combined factors lead to the slowest gross domestic product (GDP) growth of the three scenarios, averaging 1.8 percent per year.

In Fortified Islands there is a shift in the structure of the economy. The goods and services sector share drops as resources take a larger share of the economic base. The regional distribution of

Canadian economic growth in Fortified Islands also evolves. Western Canada expands at the expense of eastern Canada. Alberta, British Columbia and the Territories experience economic growth above the national average (Figure 6.1). Ontario's economic growth slips below the national average in this scenario. It is interesting to note that the higher oil and gas industry growth in Saskatchewan, Newfoundland and Labrador and Nova Scotia means the relative contribution of these economies to overall Canadian GDP increases, but it is not strong enough to offset the loss of manufacturing growth, and as a result, these areas experience slower economic growth than in the other scenarios.

TABLE 6.1

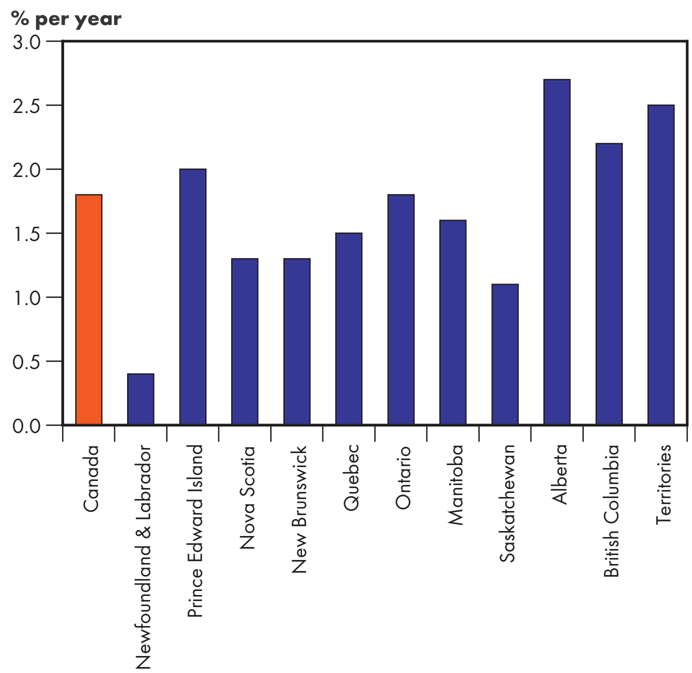
Key Macroeconomic Variables – Fortified Islands, 2004-2030

	1990-2004	2004-2030
Population	1.0	0.7
Labour force	1.3	0.6
Productivity	1.4	1.2
Gross domestic product	2.8	1.8
Goods	2.5	1.7
Service	3.0	1.9
Real disposable income	3.6	3.9
Exchange rate (average cents US/Cdn dollar)	74	103
Inflation rate (average %)	2.3	1.8

(Annual Average Growth Rate (% per year) unless otherwise specified).

FIGURE 6.1

Real GDP Growth Rates – Fortified Islands 2004-2030



Energy Prices

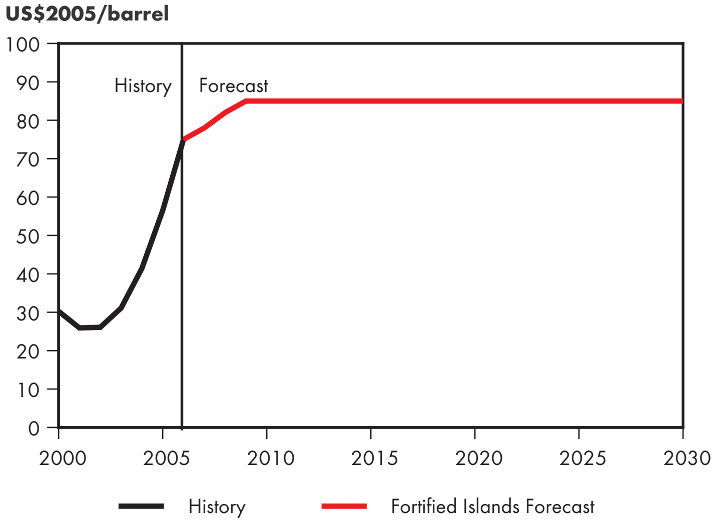
Crude Oil Prices

Significant uncertainty in the global oil and gas industries leads to high and volatile crude oil prices[72]. The Fortified Islands Scenario reflects restricted access to global oil supplies due to high security concerns and unacceptably high risks in making major international investments. Countries place more emphasis on developing domestic energy sources, including unconventional sources, and seek additional supply from regional trading partners.

72 The tools employed by the NEB for energy demand and supply modeling are based on annual historic data and forecasts annual series. In these types of models, the day-to-day volatility of oil and gas price markets can be masked. However, the NEB has taken a number of steps to ensure price volatility is considered within our analysis. Past decisions that consumers have made in the face of price volatility are captured in the estimated historic relationships and forecasted into the future. In addition, the NEB has modeled price variation within each of the scenarios and across scenarios. For example, within the Fortified Islands Scenario, oil prices increase from US$75 to US$85/barrel and gas prices range from US$7.50 to US$12/MMBtu. Across scenarios, oil prices range from US$35 to US$85/barrel and gas prices range from US$5.50 to US$12/MMBtu. The price trajectories that are modeled are consistent with market pressures inherent in each scenario, such as the availability of supply and the level of demand.

F I G U R E   6 . 2

West Texas Intermediate Crude Oil Price at Cushing, Oklahoma – Fortified Islands



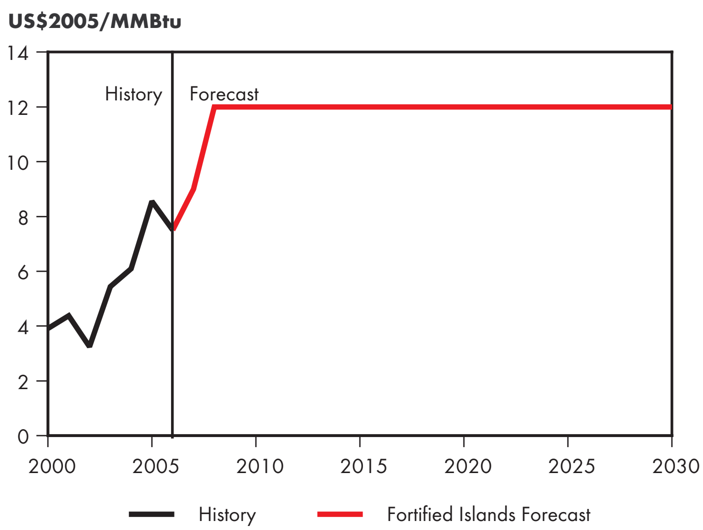
Crude oil prices in Fortified Islands increase to US$85/barrel rather than decline as in the other scenarios (Figure 6.2). They reach near record levels by 2010 and remain at this high level until the end of the period.

Natural Gas Prices

North American natural gas prices are assumed to generally track oil prices as they have historically. Security concerns and lack of international investment in the Fortified Islands Scenario severely limit liquified natural gas (LNG) imports and put increased emphasis on higher-cost domestic gas supplies. Under these conditions, the Henry Hub natural gas price is US$11.40/GJ (US$12.00/MMBtu) (Figure 6.3). This represents a continuation of the typical price relationship with natural gas at 85 percent of the crude oil price.

F I G U R E   6 . 3

Natural Gas Price at Henry Hub, Louisiana – Fortified Islands



Electricity Prices

In Fortified Islands, pressure on electricity prices increases as oil and natural gas prices escalate from the levels of the early 2000s (to $85 oil, $12 gas) putting upward pressure on the costs for fossil-fired generation. To some extent, price pressure is mitigated by declining demand for new power generation and the security of heritage hydro assets, but the overall trend is upward[73].

Coal Prices

Coal prices rise significantly from recent levels reflecting the sustained higher oil and gas prices in Fortified Islands ($85 oil and $12 gas), as well as the higher costs of exploiting new coal resources. Coal has a clear price advantage relative to its competitors in this scenario.

73 Regional electricity prices are provided in Appendix 5.

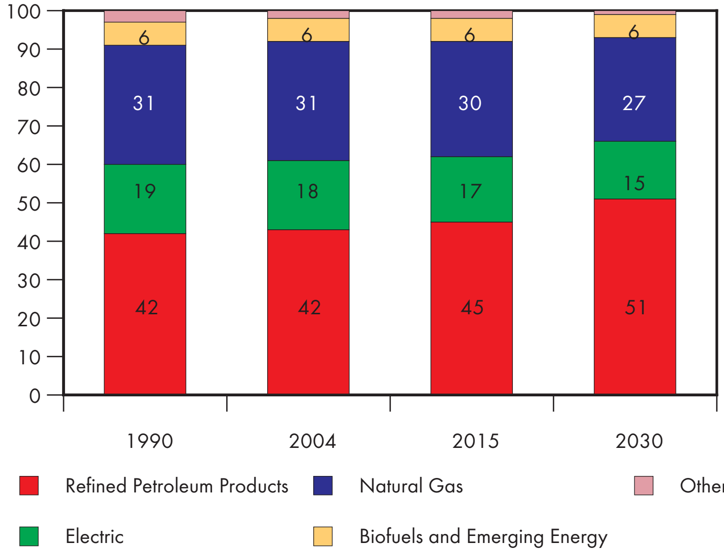
Energy Demand

Total Secondary Energy Demand Trends

Canadian total secondary energy demand in the Fortified Islands Scenario grows at a rate of 0.7 percent over the 2004 to 2030 period, significantly lower than the historical rate of 1.8 percent. The sectoral shares of demand do not change drastically over the forecast period. Oil and gas industries show strong growth, but total industrial sector energy demand growth is mitigated by the slowdown in non-energy industries as a result of higher energy prices and slower export demand for manufactured goods.

FIGURE 6.4

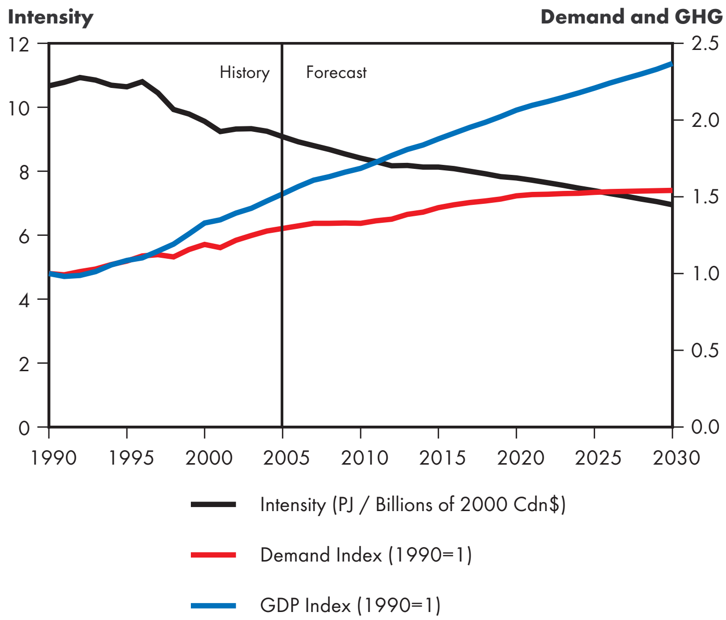
Canadian Total Secondary Energy Demand by Fuel – Fortified Islands



('Other' includes coal, coke, coke oven gas, and steam)

FIGURE 6.5

Canadian Total Secondary Energy Demand Intensity – Fortified Islands



Demand sector shares and growth rates vary significantly by province. The three largest energy consumers are Alberta, Ontario and Quebec. In 2030, Alberta accounts for 35 percent of total secondary energy demand in Canada, Ontario accounts for 27 percent and Quebec 16 percent. Provincial population, personal disposable income and economic activity assumptions all affect provincial energy demand. Alberta and the northern territories show total secondary energy demand growth rates higher than the Canadian average. While most of the national economy suffers from high energy prices, an all-out expansion of western oil and gas plays drives economies of resource-rich provinces.

Overall Canadian demand intensity declines at 1.1 percent per year in the Fortified Islands, close to the historical rate of 1.0 percent from 1990 to 2004 (Figure 6.5). Higher energy prices induce a large uptake in energy efficiency measures, in particular, the low-cost measures that make the most of existing equipment and each unit of energy.

FIGURE 6.6

Canadian Residential Secondary Energy Demand by Fuel – Fortified Islands

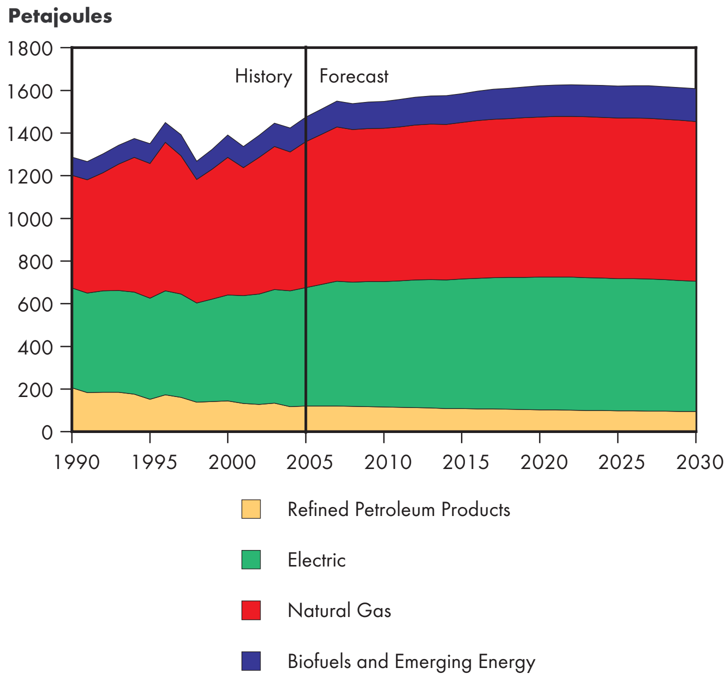
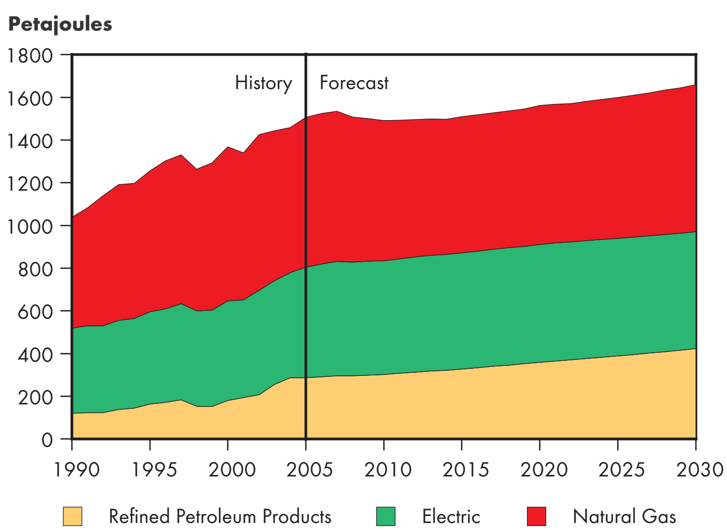


FIGURE 6.7

Canadian Commercial Secondary Energy Demand by Fuel – Fortified Islands



Residential Secondary Energy Demand

Canadian residential secondary energy demand grows at a rate of 0.5 percent over the 2004 to 2030 period (Figure 6.6). This is due to energy prices, economic constraints and efficiency improvements. Efficiency measures include low-cost retrofits such as compact fluorescent light bulbs (CFLs) and draft-proofing homes. There is some fuel-switching from oil, corresponding to an increase in biomass (wood) fuel. Fuel shares by province vary significantly.

Commercial Secondary Energy Demand

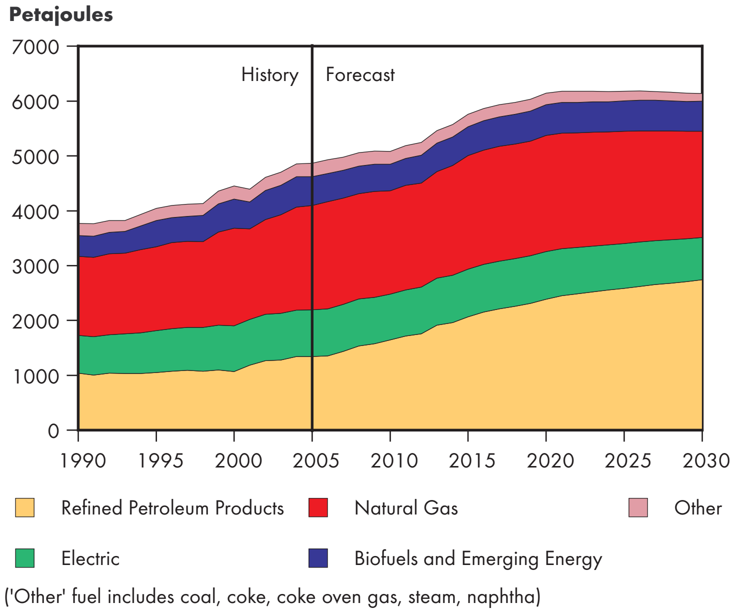
Canadian commercial secondary energy demand grows at a rate of 0.5 percent per year over the 2004 to 2030 period, a significant decrease from the historical growth rate (Figure 6.7). Many low-cost efficiency upgrades (i.e., the use of blinds in commercial windows) are implemented; however, the Fortified Islands Scenario lacks the long-term financial and social will-power needed for investment in state-of-the-art building technology. The demand shares by fuel for Canada from 2004 to 2030 indicate some fuel-switching in the commercial sector from natural gas to oil. Fuel shares by province follow the same overall levels as the residential sector, with more oil use and almost zero alternative or emerging energy use.

Industrial Secondary Energy Demand

Canadian industrial secondary energy demand grows at 0.9 percent per year over the 2004 to 2030 period, half the historical rate (Figure 6.8). Almost all industries demonstrate a slowdown in output and a corresponding decrease in energy demand. The exception is seen in the oil and gas industries, which expand as fast as possible to reap the benefits of high energy prices. The demand shares by fuel for Canada from 2004 to 2030 indicate fuel-switching into oil from all other fuels, including a share decrease in renewables as a result of slower pulp and paper industry economic growth.

FIGURE 6.8

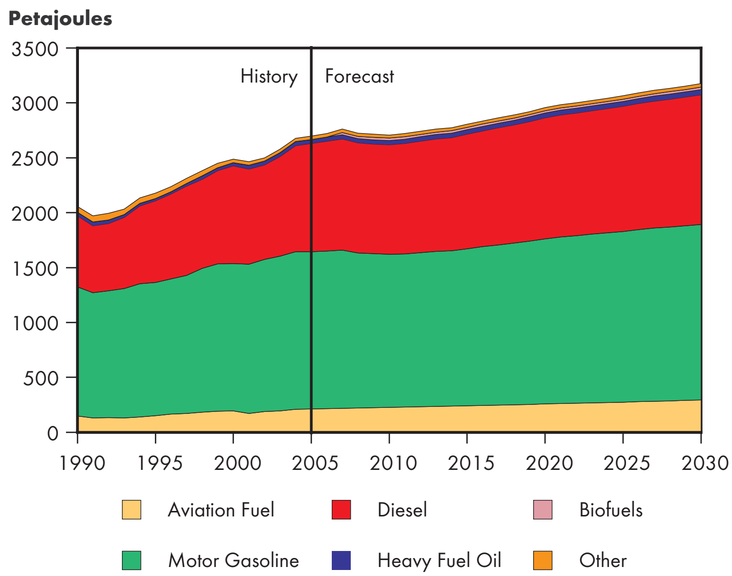
Canadian Industrial Secondary Energy Demand by Fuel – Fortified Islands



In 2030, the largest provincial energy consumers are Alberta, accounting for 50 percent of industrial energy demand in Canada, Ontario with 20 percent and Quebec following at 13 percent.

FIGURE 6.9

Canadian Transportation Energy Demand by Fuel – Fortified Islands



Transportation Energy Demand

Canadian transportation energy demand grows at 0.7 percent over the 2004 to 2030 period (Figure 6.9). Costs are sufficiently high to induce a price response, particularly in passenger transportation where options such as mass transit and trading to a smaller, fuel-efficient vehicle becomes widespread. The demand shares by fuel for Canada over the forecast illustrate a drop in gasoline demand shares as price response and efficiency measures take place. The renewables share rises from zero to one percent by 2030, due to the assumed ethanol policies in Ontario and Saskatchewan[74], while the off-road share remains strong over the forecast given strong growth in the oil sands industry (Figure 6.10).

74 The Ontario assumption is 5 percent ethanol volume (3.4 percent energy) of total gasoline use in the province by 2007. The Saskatchewan assumption is 7.5 percent ethanol volume (5.1 percent energy) of total gasoline use in the province by 2007.

FIGURE 6.10

Canadian Transportation Energy Demand by Mode – Fortified Islands

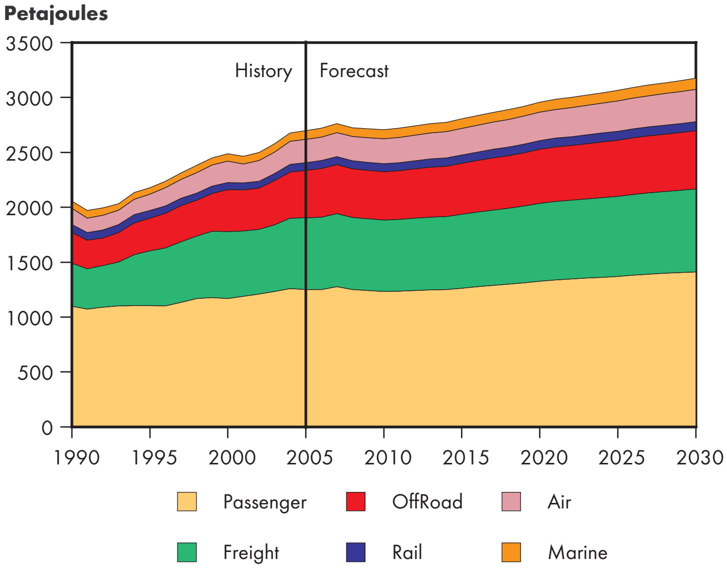
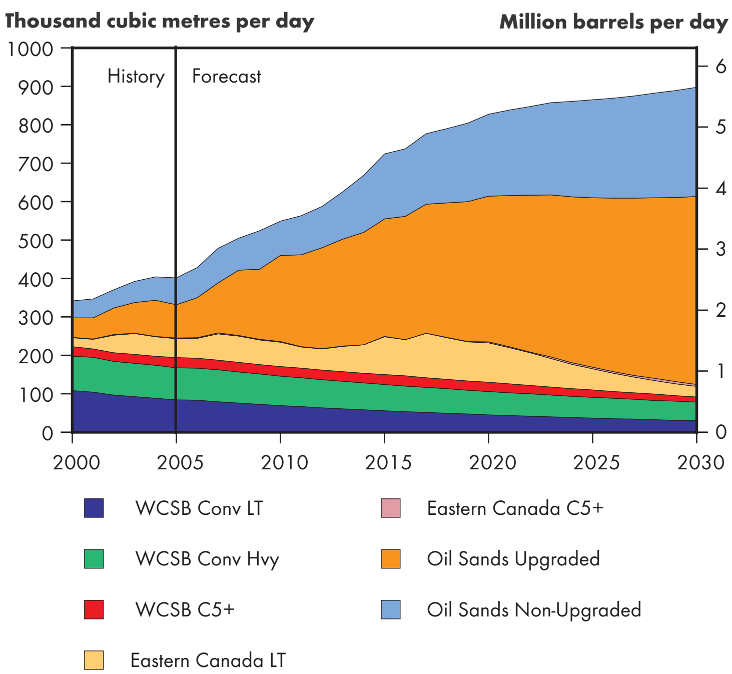


FIGURE 6.11

Total Canada Oil Production – Fortified Islands



Oil Supply

Crude Oil and Equivalent

The Fortified Islands Scenario, with its focus on higher oil prices and support for domestic energy supply, is the most conducive to expanding oil supply. Compared to the other scenarios, decline trends in conventional supply in the Western Canada Sedimentary Basin (WCSB) are moderated from historical levels, while declines in eastern Canadian production levels are softened as well. The higher oil prices of the Fortified Islands Scenario are also the most supportive of oil sands expansion.

Crude Oil and Bitumen Resources

Canadian crude oil and bitumen resources are the same in the Reference Case and all three scenarios[75].

Total Canada Oil Production

The Fortified Islands Scenario features the most aggressive production track, with an average increment of 27 000m^3/d (170 thousand b/d) of capacity per year between 2010 and 2020, supported by rapid growth in oil sands production and new discoveries on the east coast offshore (Figure 6.11). Growth slows after 2020, under the effect of declining production in the east coast offshore and in the WCSB, with production reaching 879 000 m^3/d (5.54 million b/d) by 2030.

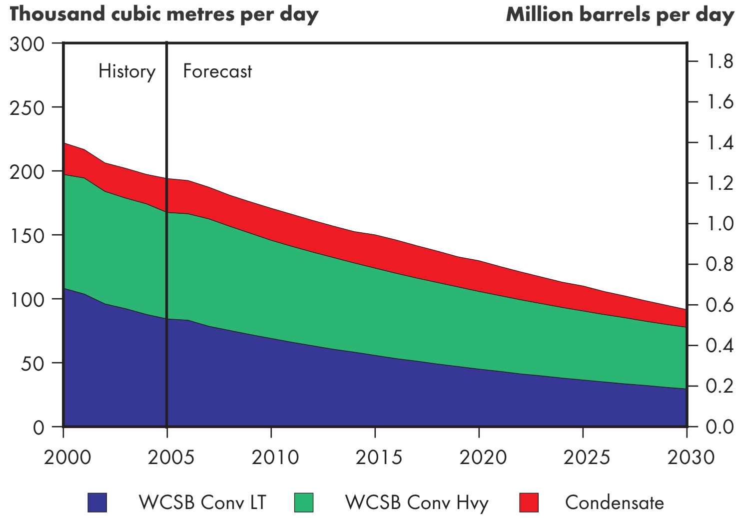
75 Canadian crude oil and bitumen resources are set out in Chapter 3, and in further detail in Appendix 3.

Oil sands production plays an increasingly important role, accounting for 88 percent of total Canadian oil production by 2030.

Conventional Crude Oil – WCSB

FIGURE 6.12

WCSB Conventional Oil Production – Fortified Islands



This scenario is the most favourable for an expansion in oil supply, with aggressive exploration drilling, more infill drilling and greater emphasis on improved recovery methods.

For conventional light crude oil, the long-term declining trend of five percent is reduced to 4.2 percent, with an additional 35 million cubic metres of production added above levels assumed for the Continuing Trends Scenario.

Alberta and Saskatchewan are the primary sources of conventional heavy crude oil, with British Columbia contributing minor amounts. Similar to light oil, the long-term declining trend of three percent is softened to 2.1 percent, with 51 million cubic metres of production added above levels described in the Continuing Trends Scenario (Figure 6.12).

Conventional light oil production declines to 29 500 m^3/d (186 thousand b/d) and conventional heavy oil production declines to 48 100 m^3/d (303 thousand b/d), by 2030. Condensate production levels decline to 14 000 m^3/d (88 thousand b/d) in Fortified Islands.

Eastern Canada Light Crude Production

Projections for eastern Canada oil production are dominated by the east coast offshore, with only minor amounts of production expected from Ontario.

Higher prices in the Fortified Islands Scenario allow for a more aggressive expansion of east coast production, compared with the other scenarios. Similar to the Continuing Trends Scenario, Fortified Islands includes Hebron production commencing in 2013 along with contributions from smaller satellite pools in the Jeanne d'Arc Basin. It is assumed that a new 80 million m^3 (500 million b) field is found in the relatively unexplored regions of the East Coast, potentially in the Flemish Pass region or in the Deepwater Scotian Shelf. The pool comes on-stream in 2015, bumping production levels to 75 000 m^3/d (473 thousand b/d). In the Fortified Islands Scenario, a second similar sized pool comes on production in 2018 and allows for peak production of 118 000 m^3/d (743 thousand b/d) in 2018, after which a relatively rapid decline begins. By 2030, production has declined to 26 700 m^3/d (168 thousand b/d) (Figure 6.13).

Oil Sands Supply

In the Fortified Islands Scenario, aggressive expansion is driven by high oil prices and supported by a lower cost of environmental compliance compared with the other scenarios. While cost pressures are assumed to moderate over time, the higher activity levels in this scenario will maintain these cost pressures at somewhat higher levels, relative to the other scenarios.

Fortified Islands also features rapid increases in production from thermal projects, primarily steam assisted gravity drainage (SAGD) and cyclic steam stimulation (CSS), with greater application of vapourized extraction (VAPEX) and toe-to-heel air injection (THAI™) than in the other scenarios.

Production reaches 774 000 m^3/d (4.74 million b/d) in Fortified Islands. Upgraded bitumen volumes total 489 000 m^3/d (3.08 million b/d) while non-upgraded volumes total 285 000 m^3/d (1.80 million b/d) (Figure 6.14).

The Fortified Islands Scenario also includes 18 000 m^3/d (113 thousand b/d) of oil sands production from Saskatchewan by 2030.

FIGURE 6.13

Eastern Canada Light Crude Production – Fortified Islands

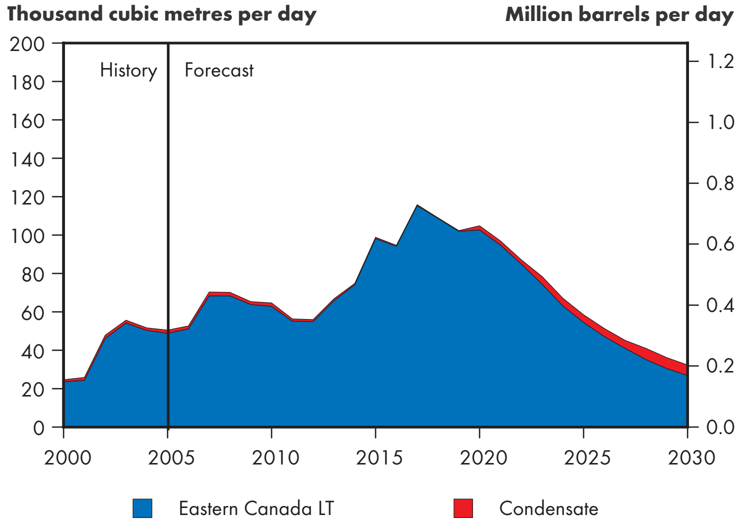
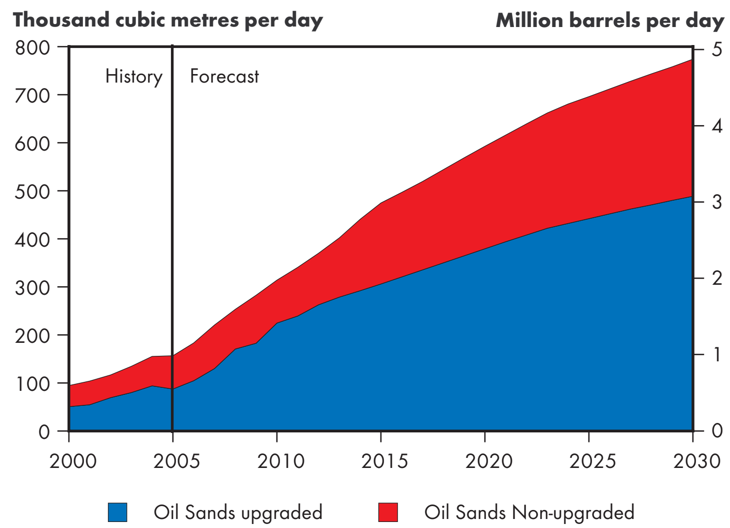


FIGURE 6.14

Canadian Oil Sands Production – Fortified Islands



High natural gas prices in this scenario provide a significant economic incentive for oil sands operators to reduce their dependence on natural gas. An ongoing improvement in energy efficiency of one percent per year is assumed, while the pace of fuel-switching to alternative fuels is accelerated with respect to the other scenarios. In general, there is earlier and more prolific application of bitumen gasification, as well as increased application of multiphase superfine atomized residue (MSAR), THAI™, and VAPEX technologies, with potential for projects using geothermal energy as well.

In this scenario, the purchased natural gas intensity is reduced from 0.67 Mcf/b in 2005 to 0.49 Mcf/b in 2030, with total purchased natural gas requirements, excluding on-site electricity requirements, increasing from 18.4 million m^3/d (0.65 Bcf/d) in 2005 to 62.3 million m^3/d (2.2 Bcf/d) by 2030, in line with substantial oil sands production growth.

Supply and Demand Balances

This scenario is characterized by increasing supply and decreasing domestic demand. Although a new refinery added in the Atlantic region is also incorporated in Fortified Islands, there is little net effect on the supply and demand balance as the refined product produced at this refinery would be targeted to export markets such as the U.S. Northeast. The option of returning Enbridge Line 9 to eastbound service enabling Quebec refineries to obtain access to western Canadian crude oil is explored in this scenario[76]. The domestic demand for petroleum products in 2005 is 290 000 m³/d (1.8 million b/d) and increases to 352 000 m³/d (2.22 million b/d) in 2015. By 2030, demand is 415 000 m³/d (2.62 million b/d).

FIGURE 6.15

Supply and Demand Balance, Light Crude Oil – Fortified Islands

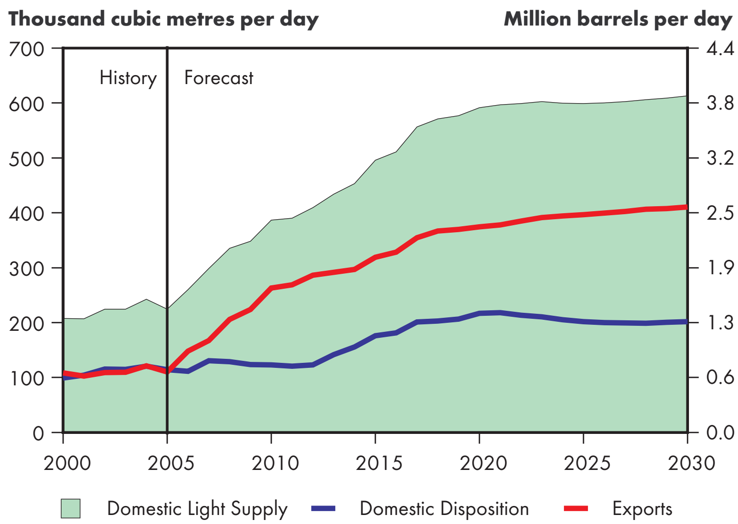
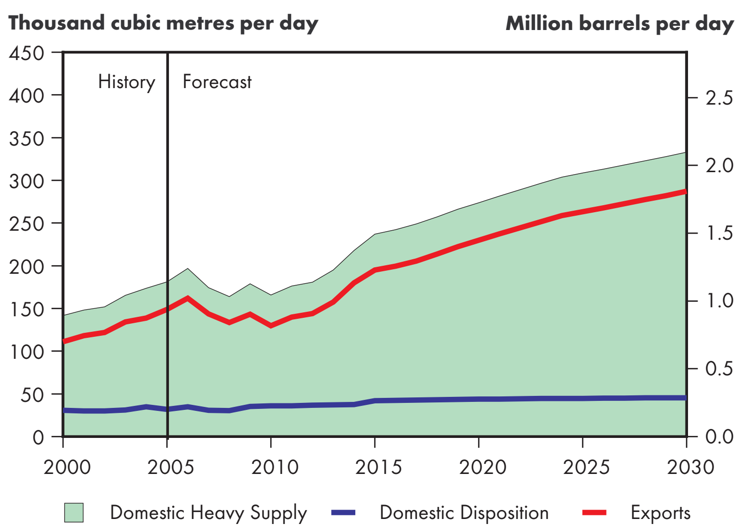


FIGURE 6.16

Supply and Demand Balance, Heavy Crude Oil – Fortified Islands



Light Crude Oil – Supply and Demand Balance

Exports of light crude oil increase sharply from 110 200 m³/d (694 thousand b/d) in 2005 to 319 700 m³/d (2.01 million b/d) in 2015 (Figure 6.15). This trend continues to 2030 with exports reaching 411 300 m³/d (2.59 million b/d).

Heavy Crude Oil – Supply and Demand Balance

Exports of heavy crude oil increase from 149 200 m³/d (940 thousand b/d) in 2005 to 195 000 m³/d (1.23 million b/d) in 2015. By 2030, exports increase to 287 500 m³/d (1.81 million b/d) (Figure 6.16).

Natural Gas Supply

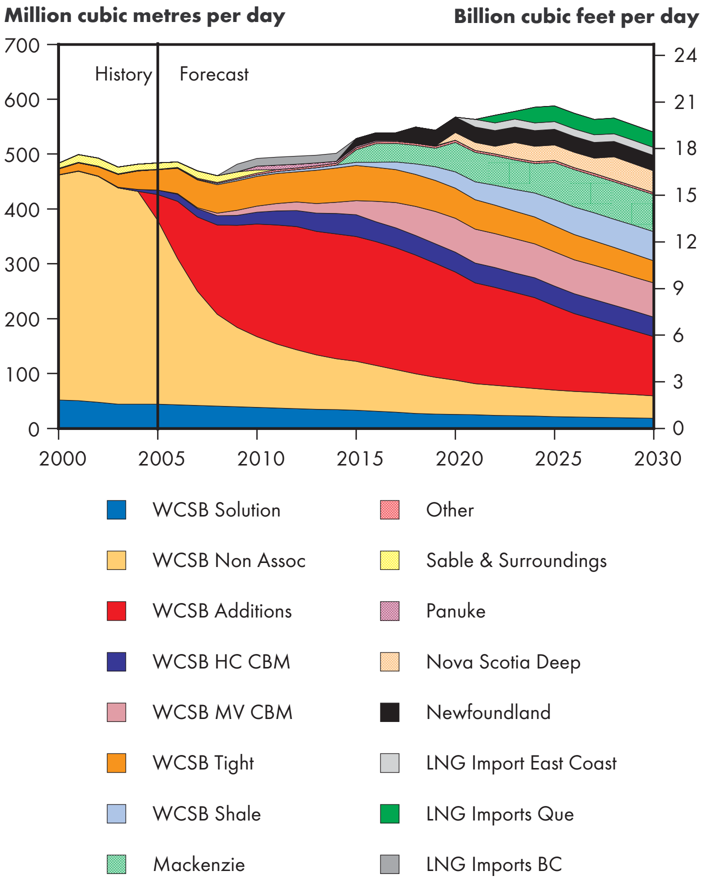
Canadian Natural Gas Resource Base

The higher prices of the Fortified Islands Scenario allow previously uneconomic volumes of unconventional

76 Line 9 is a section on the Enbridge pipeline system that extends from Sarnia, Ontario to Montreal, Quebec. Originally, the crude oil flowed in the pipeline in a west-to-east direction. In 1999, the pipeline was reversed and began operations in an east-to-west direction, which enabled imports to reach the refining centres in Ontario.

FIGURE 6.17

Natural Gas Production Outlook – Fortified Islands



resources to be included in the recoverable category. Western Canadian coalbed methane (CBM) remaining resources increase to 1 416 billion m^3 (50 Tcf)[77]. Similarly, remaining tight gas and shale gas resources are raised to 737 and 365 billion m^3 (26 and 12.9 Tcf), respectively. These increases reflect the estimated economic viability of additional unconventional deposits in settings with lower permeability and at greater depths. To access these additional resources, the higher gas price in Fortified Islands could accommodate the increased cost of wells with longer horizontal legs and more extensive hydraulic fracture stimulation.

As with the Triple E Scenario, the estimate of the remaining conventional resource base is unchanged. The estimate of the remaining conventional resource base is defined by the minimum reservoir size for each play type that is considered technically feasible for the industry to develop. Within the price range considered, the minimum reservoir sizes adopted in the resource estimate for the Reference Case and Continuing Trends Scenario are also applicable to the Triple E and Fortified Islands Scenarios. However, the higher price environment in the Fortified Islands is better able to accommodate higher annual levels of gas drilling and the corresponding escalation of costs.

For similar reasons, the remaining resource base for frontier projects is also unchanged for this scenario. The frontier resource estimate from the Reference Case and Continuing Trends Scenario incorporates the NEB's best current estimate of technically recoverable marketable gas and is applicable to the range of prices considered. The high cost and risk to establish basin-opening infrastructure makes it likely that facilities will be sized at a conservative level initially and then gradually expanded as the productivity of the resource is confirmed. Until such confirmation is available through more extensive drilling and some production history, an upward adjustment to the resource base can not be made with any confidence.

Production and LNG Imports

In this scenario, LNG supply to North America is dramatically curtailed and natural gas markets are reliant on continental supplies. Liquefied natural gas imports might be curtailed by a shortage of new

77 As indicated in Appendix 4.

liquefaction facilities due to an unstable foreign investment climate, or by extreme LNG demand growth outside North America, or some combination of the two. Except for a brief period from 2009 to 2014 when LNG imports into Canada average 14 million m^3/d (0.5 Bcf/d), LNG serves markets with little to no indigenous natural gas supply including Japan, Korea, India and western and southern Europe, instead of North America. Liquefied natural gas has no influence on North American natural gas prices, which are able to move upward and support the costs of high drilling activity, major frontier projects and higher-cost conventional and unconventional gas developments in Western Canada.

Natural gas drilling in Western Canada is projected to gradually increase after 2007 to average roughly 24 000 wells per year. This level of activity could be in the range of about 1 075 drilling rigs operating at an average annual utilization of 55 percent[78].

At this high rate of drilling, Western Canada natural gas production could be maintained at between 467 and 484 million m^3/d (16.5 and 17.1 Bcf/d) from 2011 to 2020, as shown in Figure 6.17. After 2020, conventional gas production begins to decline gradually as drilling fails to keep up with ongoing reductions in new well productivity.

The increase in the unconventional gas resource base and higher activity allows unconventional gas production to rise steadily, outpacing conventional gas output by 2028. Coalbed methane production reaches 57 million m^3/d (2.0 Bcf/d) in 2014 and stabilizes at 99 million m^3/d (3.5 Bcf/d) from 2020 to 2030. From 2016 onward, Mannville Formation CBM overtakes output from the Horseshoe Canyon Formation and CBM represents slightly more than half of the unconventional production. Tight gas production peaks in 2015 and then enters a shallow decline, while shale gas production grows steadily to reach almost 54 million m^3/d (1.9 Bcf/d) by the end of the period.

While Western Canada is able to hold production fairly flat to 2020, it is the contribution from frontier projects from 2015 onward that accounts for significant growth in Canadian natural gas production. Subject to regulatory reviews and subsequent commercial decisions, Mackenzie Delta production is assumed to begin in late 2014 and expand to 68 million m^3/d (2.4 Bcf/d) by 2025. Production of the gas associated with oil projects on Newfoundland's Grand Banks is assumed to begin two years earlier in 2015 and subsequently double its scale to 28 million m^3/d (1 Bcf/d). Other conceptual frontier projects could potentially be economically viable sources of supply in Fortified Islands, including development of the 1970s-era gas discovery on Melville Island in the western Arctic, the possibility of a Nova Scotia deepwater discovery and development of discoveries offshore Labrador.

Supply and Demand Balance

Until 2015, Canadian natural gas supply remains relatively flat while gas demand increases moderately. Relative to 2005, this results in a tightening of the differential between Canadian natural gas supply and demand by an average of 20 million m^3/d (0.7 Bcf/d) through 2014, as shown in Figure 6.18. From 2015 onward, strong growth in Canadian gas supply far exceeds demand growth that is being slowed by higher prices. As a result, from 2015 to 2030 the differential widens by an average of 45 million m^3/d (1.6 Bcf/d) above 2005 levels.

In Fortified Islands, Canadian gas demand growth is slowed by higher energy prices and lower economic growth. An exception is seen in increased gas demand for oil sands due to significantly higher oil output. Gas intensity for oil sands is lowest in Fortified Islands, as higher gas prices create

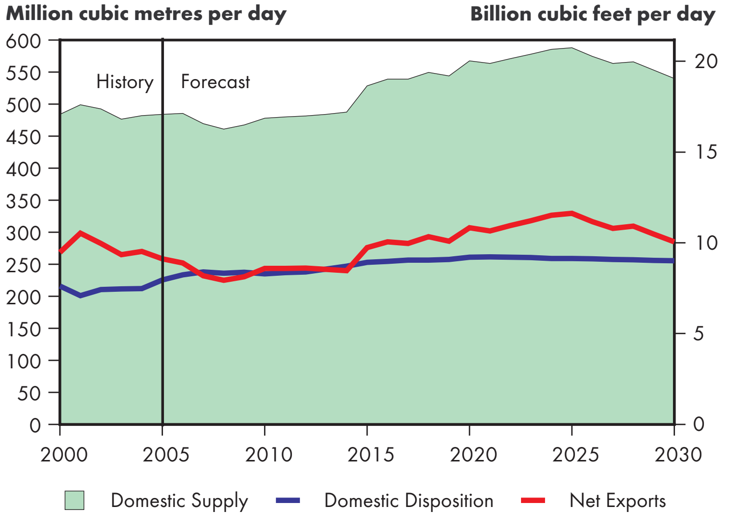
78 The recent gas drilling peak in 2005 was 18,300 wells from 700 drilling rigs, averaging 59 percent utilization. The size of the 2007 Western Canada rig fleet is roughly 880 rigs (NEB, Canadian Association of Oilwell Drilling Contractors [CAODC]).

a greater incentive to employ alternative technologies. Relative to 2005, overall Canadian natural gas demand rises by roughly 16 percent over the period.

With the initial shrinkage in the differential, the net amount of natural gas available for export slips below the 2005 level until 2015. From 2015 onward, the average level of potential annual net exports is 303 million m^3/d (10.7 Bcf/d), exceeding the previous peak of 297 million m^3/d (10.5 Bcf/d) achieved in 2001.

FIGURE 6.18

Supply and Demand Balance, Natural Gas – Fortified Islands



Natural Gas Liquids

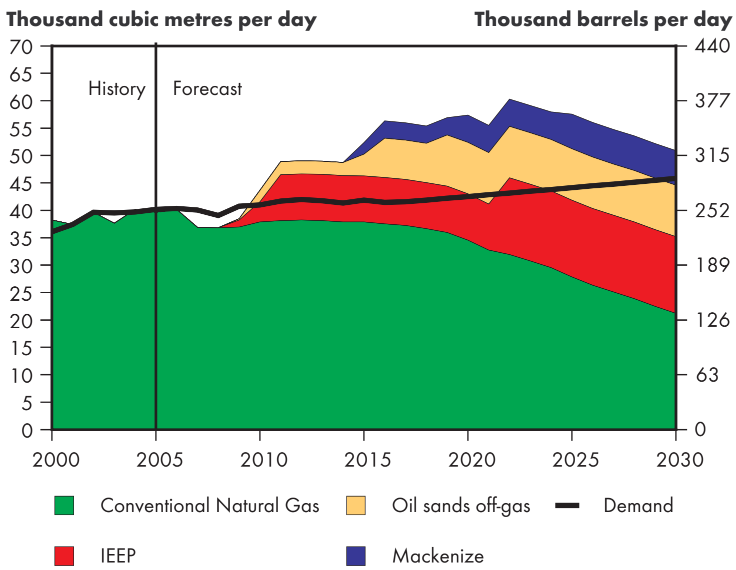
Supply and Disposition

In the Fortified Islands Scenario, large excess volumes of propane and butanes are available for export throughout the projection period, as this scenario has the highest conventional natural gas and oil sands off-gas production[79].

Ethane Supply and Demand Balances

FIGURE 6.19

Canadian Ethane Supply and Demand Balance – Fortified Islands



In Fortified Islands, supply exceeds demand through the entire projection period, with excess ethane of about 2 700 m^3/d (17 thousand b/d) commencing in 2010, reaching a peak of about 17 000 m^3/d (107 thousand b/d) in 2022 (Figure 6.19). The excess supply is caused mainly by higher supply of conventional ethane, as natural gas production is the highest under this scenario due to the rising price environment. In addition, increments of supply from oil sands off-gas, enhanced deep-cut straddle plant expansions and Mackenzie Delta gas are also the highest under this scenario.

79 Further detail on the propane and butane supply and demand balances can be found in Appendix 3.

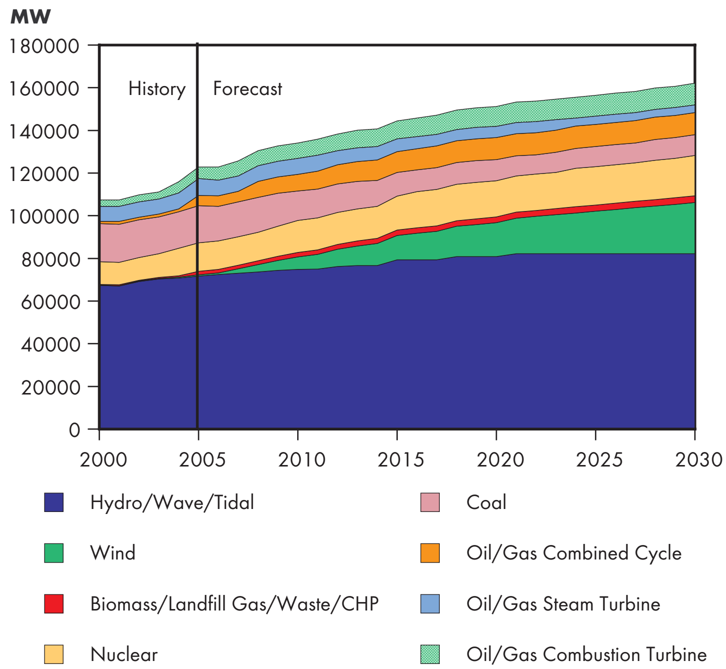
Electricity Supply

Capacity and Generation

In the Fortified Islands Scenario, the combination of higher energy prices and slower income growth causes a decline in demand for electricity after 2020. The impact of high energy prices is especially strong during the early years of the forecast period, when the greatest reduction in the growth of electricity demand occurs. Demand stabilizes once Canadians become accustomed to higher energy prices.

FIGURE 6.20

Canadian Generating Capacity – Fortified Islands



Generation capacity will increase by 32 percent between 2005 and 2030 in Fortified Islands (Figure 6.20). Capacity additions are intended to meet projected load requirements in a reliable, self-sustained manner. Electricity supply will primarily come from traditional generation sources, yet wind and other emerging technologies still experience strong growth.

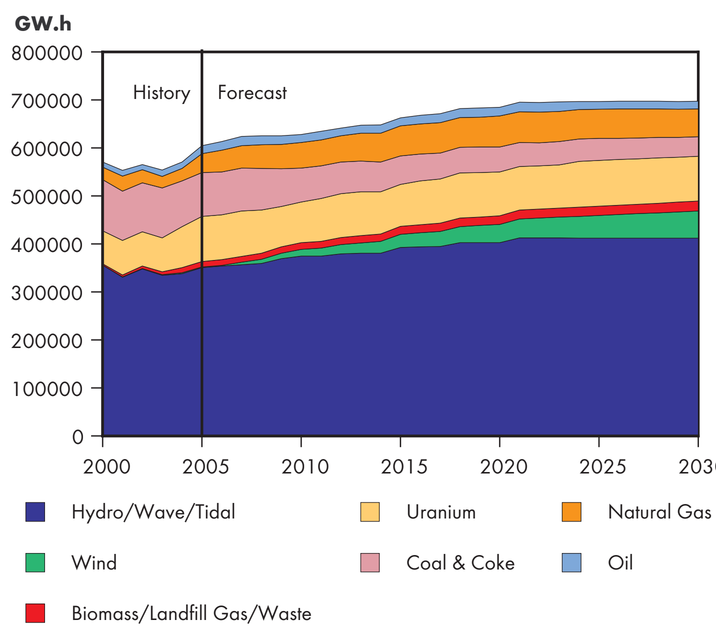
Hydro

In addition to the units listed in the Reference Case, after 2015 the following hydro facilities will be constructed: Peace River Site C (900 MW) in British Columbia and both Conawapa (1 380 MW) and Gull/Keeyask (600 MW) in Manitoba.

Hydroelectric generation will continue to provide about 60 percent of electricity needs throughout the forecast period (Figure 6.21). Hydro-based capacity will expand to 82 200 MW by 2030, an increase of 10 450 MW from 2006.

FIGURE 6.21

Canadian Generation – Fortified Islands



Nuclear Generation

While nuclear power has never lost favour in parts of Europe, in the last few years volatile fossil fuel prices, energy security concerns and increased focus on emissions have increased interest in nuclear power in North America. The last Canadian Deuterium (CANDU) reactor built in Canada was commissioned in 1993, but international sales have led to continual improvement in construction techniques and encouraged Atomic Energy Canada Limited to proceed with the design of the new Advanced CANDU Reactor (ACR). This design promises increased safety, quicker construction time and lower costs.

There are several applications for site licenses for new CANDU reactors before the Canadian Nuclear Safety Commission, which if approved, could lead to construction of new nuclear power plants inside a decade. All three scenarios include new nuclear facilities in Ontario and New Brunswick – provinces, which, like Quebec, have existing nuclear power plants.

While they have not been included in the scenarios of this study, there have also been proposals to use nuclear power instead of natural gas in the Alberta oil sands. Nuclear reactors are well suited to the 24/7 operation of oil sands facilities, promise independence from the price of natural gas and can be used to produce hydrogen for use in the upgrading of bitumen. Potential obstacles to the use of nuclear energy include the large size of a typical nuclear generator compared with a typical oil sands plant, the oil sands producers' lack of experience with the technology, and public concerns about safety and the disposal of nuclear waste.

While use of nuclear energy in the oil sands poses certain challenges (as discussed in *Alternative Fuels for Oil Sands* text box earlier in this report), certain conditions may make this option less of a challenge. As ACR or other reactor technology matures, and if oil sands producers see a long-term, upward trend in natural gas prices, nuclear energy could look increasingly attractive. Concerns about minimizing greenhouse gas (GHG) emissions would also favour the use of nuclear energy. If an entity with nuclear experience were willing to build and operate such a plant, selling steam to oil sands producers and electricity to the Alberta market, nuclear energy could prove to be a viable option.

For further information on the use of nuclear energy in the oil sands, please refer to the Board's Energy Market Assessments: *Canada's Oil Sands: Opportunities and Challenges to 2015 - May 2004* and *Canada's Oil Sands - Opportunities and Challenges to 2015: An Update - June 2006*, found on the Board's website at www.neb-one.gc.ca.

Nuclear

Total nuclear capacity increases 42 percent between 2005 and 2030, an increase of 5 500 MW from 2005. Assumptions regarding nuclear capacity are the same as in the Continuing Trends and Triple E Scenarios.

Natural gas-fired

The volume of gas-fired generation is similar to that of the Continuing Trends Scenario, with slightly less combined-cycle technology employed, but more combustion turbine/cogeneration units are constructed. As a result of higher gas prices and lower electricity demand, natural gas-fired generation is not called upon as often. Though natural gas-fired generation output accounted for 12 percent of 2030 electricity generation in the Continuing Trends Scenario, it accounts for eight percent in Fortified Islands.

Coal-fired

An assured supply of fuel and lower fuel cost provides the impetus for the construction of new coal-fired generation facilities in the Fortified Islands Scenario, but there is serious competition from oil sands associated cogeneration. Also, lower demand leads to a decline in installed capacity compared to the Continuing Trends Scenario, as not all existing coal-fired generation is replaced when it reaches the end of its operational life.

Oil-fired

Despite lower electricity demand and reduced generation from conventional oil-fired generation, in 2030 oil generation is about

15 percent higher in the Fortified Islands Scenario compared to Continuing Trends. This is due to bitumen-fuelled cogeneration associated with oil sands electricity and heat requirements. In 2020, retiring oil-fired generation in Newfoundland is replaced with a 180 MW natural gas-fired combined-cycle generation.

Emerging Technologies

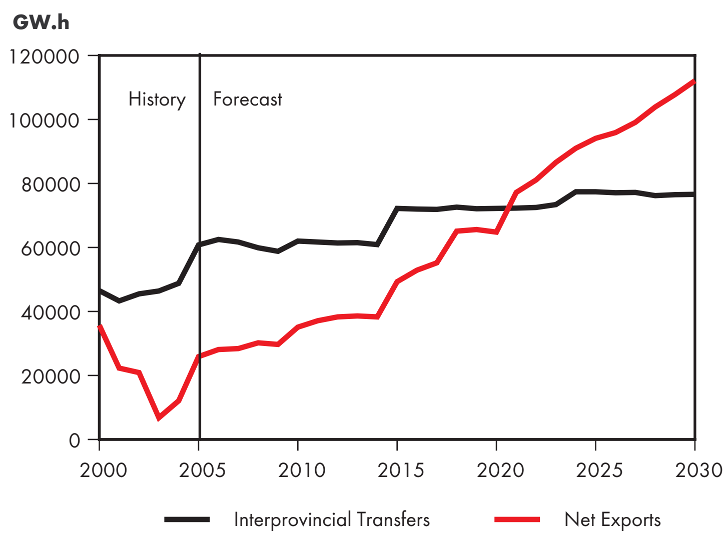
High energy prices drive an increase in installed wind generation comparable to the Continuing Trends Scenario, despite lower demand for electricity. Wind power capacity is projected to reach 23 900 MW by 2030, representing 15 percent of total Canadian generation. Other alternative generation sources grow by 1 500 MW, or 89 percent. This illustrates that even in Fortified Islands, emerging technologies have a presence.

Exports, Imports and Interprovincial Transfers

Canadian net exports increase by 300 percent from 2006 to 112 100 GW.h in 2030 (Figure 6.22). This dramatic increase is due in large part to high electricity prices curtailing demand, combined with availability of hydro and other alternative sources of generation that are not subject to the higher price of fossil fuels in Fortified Islands. The increase in interprovincial electricity transfers (by 26 percent to 76 600 GW.h in 2030) is much less marked, but still substantial.

FIGURE 6.22

Interprovincial Transfers and Net Exports – Fortified Islands



Coal

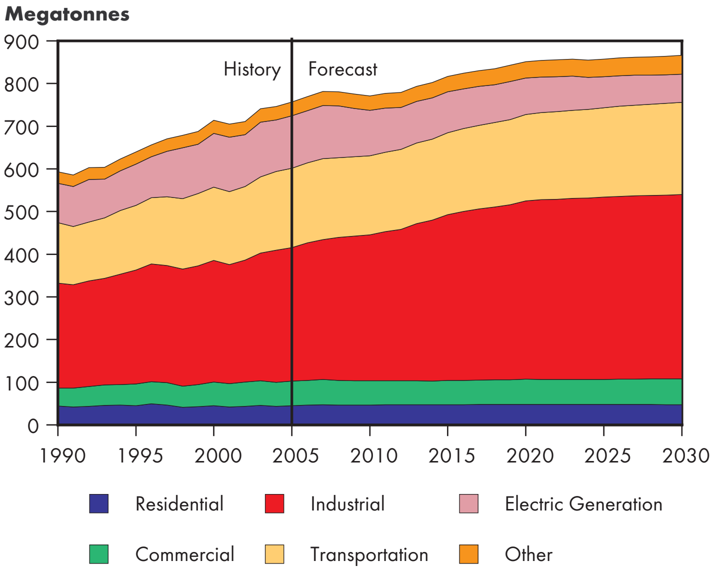
Supply and Demand

In Fortified Islands, isolationist policies slow economic growth and moderate demand for coal. As a result, production is lower than in Continuing Trends, but more than in Triple E. Energy security concerns encourage new coal-fired generation, most likely to be sited in Western Canada and the Maritimes. Demand for metallurgical coal decreases significantly in the Fortified Islands Scenario. Canadian coal production decreases to 47 Mt in 2030 from 55 Mt in 2015 because of the decrease in domestic demand of both thermal and metallurgical coal. Canada continues to be a net exporter in Fortified Islands. Canada's coal demand between 2015 and 2030 is estimated to decrease from 34 Mt to 22 Mt. Electricity generation will consume about 27 Mt in 2015, decreasing to 18 Mt by 2030. Canada's iron, steel and cement industries decrease by about 3 Mt of coal over this period with a substantial metallurgical coal decrease from 4 Mt to about 1 Mt. This could also result in a decrease in exports out of the iron, steel and cement manufacturing hubs in Ontario under Fortified Islands.

Exports of thermal coal remain low in Fortified Islands. Net exports remain consistent, at the same level as Triple E and Continuing Trends. Both thermal and metallurgical coal exports grow moderately by six percent between 2015 and 2030, due to slow economic growth in the U.S. and

FIGURE 6.23

Canadian Total GHG Emissions by Sector – Fortified Islands



the lack of international cooperation. Between 2015 and 2030, there is a moderate increase of about four percent in thermal imports due to the addition of coal-fired units in the Maritimes, with metallurgical imports down roughly 78 percent due largely to the lack of competitiveness of the Canadian iron and steel industry.

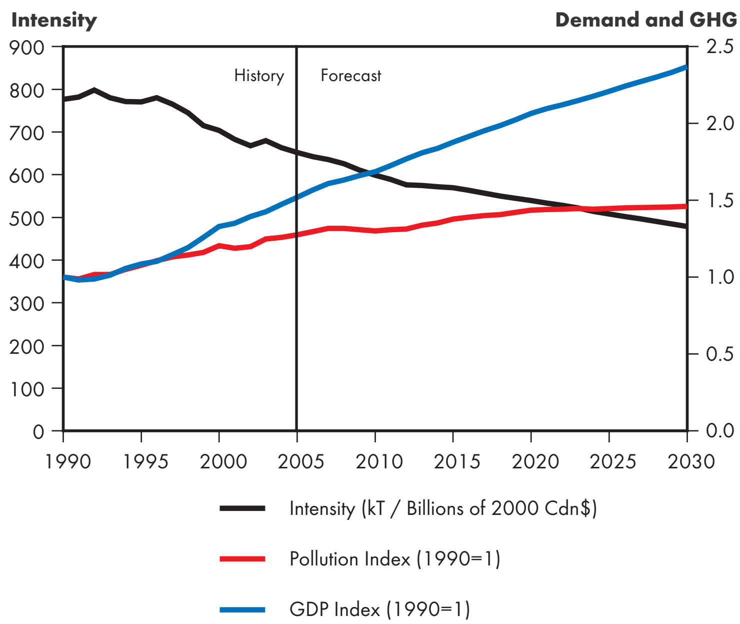
Greenhouse Gas Emissions

Canadian total GHG emissions in Fortified Islands grow at a rate of 0.6 percent per year over the 2004 to 2030 period (Figure 6.23). This is lower than the historical growth rate of 1.7 percent from 1990 to 2004, largely due to the lower GDP growth rates and higher commodity prices leading to lower energy demand. The sectoral shares of GHG change over the forecast. The industrial sector share increases from 41 percent to 50 percent due to oil and gas growth assumptions in this scenario.

Greenhouse gas shares and growth rates vary by province. The three largest GHG emitters in 2030 are Alberta, Ontario and Quebec. Alberta accounted for 31 percent of total Canadian GHG emissions in 2004, and for 39 percent in 2030. Ontario's share drops from 27 to 22 percent over the outlook period, while Quebec's share hovers around 13 percent over the forecast.

FIGURE 6.24

Canadian Total GHG Intensity – Fortified Islands



Greenhouse gas levels do increase in Canada, but the GHG emissions intensity in Canada declines over the forecast. In Fortified Islands, the GHG emissions intensity declines at 1.3 percent per year, slightly faster than the historical rate of 1.1 percent per year as energy efficiency improvements take place and the share of alternative and emerging fuels increase (Figure 6.24).

Fortified Islands Issues and Implications

- Overall, total Canadian economic growth is the lowest in this scenario and regional economic differences deepen. Stronger economic activity occurs in energy producing regions, whereas there is a slowdown in manufacturing regions.
- Energy demand in this scenario is dually impacted by higher energy prices and low income and economic growth. As a result, energy demand over the outlook period slows considerably from historic levels.
- Energy supply is exceptionally price dependent. This scenario represents a maximum plausible energy supply outlook for Canadian oil and gas.
- Fortified Islands features rapid expansion of oil sands development. It is assumed that oil sands operators will continue to make efficiency gains and employ alternative energy sources and recovery methods, with gasification of bitumen and petroleum coke playing a dominant role. As the scenario with the greatest available supply, exports of both light and heavy crude oil increase the most in this case.
- It is particularly interesting to note that maintaining current natural gas production levels requires very high prices. In this scenario, these high prices allow for Canada to continue to be a net exporter of natural gas, whereas in the other scenarios considered, Canada becomes a net importer of natural gas before the end of the outlook period. This is a result of the high prices bringing on additional supplies, such as mega-projects in remote locations in the north and off the East Coast. In addition, natural gas prices curb domestic natural gas demand growth.
- Finally, the slowdown in the energy demand growth rate translates into slowing GHG emissions growth rates compared to historic trends.
- The results are based on certain scenario assumptions. If these inputs do not materialize, then it puts at risk the outcomes described here. Specifically:
    - For this scenario to occur, global relationships need to be under ongoing stress. Access to oil and gas supplies are constrained keeping energy prices high. These prices govern economic conditions as well as energy demand and supply trends.
    - As well, to allow these types of energy supply expansions to take place technological advancements must occur; sufficient inputs into the production processes, such as labour, must be in place; and, infrastructure must be developed.

Conclusions: Key Implications for the Canadian Energy System

Canada's Energy Future highlights challenges and opportunities facing the energy sector and individual Canadians, both today and in the future. The cross-country consultations and subsequent analysis strongly suggests that although energy supplies are adequate and energy markets are currently functioning well, a return to sustained low commodity price levels is not foreseeable. Despite this, Canadians are adjusting to this new energy price paradigm. Canadians continue to witness a changing supply mix as conventional resources mature and new technologies emerge, although fossil fuels will continue to dominate the energy system for the next few decades. The last several years have shown Canadians to be especially interested in the impact of greenhouse gas (GHG) emissions. New policies and programs designed to reduce GHG emissions are in their infancy, and although public concern is high, measurable impact of such initiatives is difficult to predict. Each of these aforementioned issues will impact evolving Canadian energy policy, as governments work to balance market considerations with the ability to be flexible and responsive to the Canadian energy environment.

Following is a summary of these issues, highlighted under five key themes.

1. Energy Markets and Resources

Canadian energy markets are expected to function well with energy prices acting to ensure there is sufficient energy supply to meet energy demand. The analysis in *Canada's Energy Future* presents a broad range of energy prices resulting from variant demand and supply outcomes. The price of oil and natural gas are determined by continental and global markets. Electricity price is shaped by regional demand and supply and government policies, but are also influenced by inter-provincial and international trade.

Long-term historical prices in North America of approximately $20/barrel for crude oil and US$1.90 to $2.85/GJ (US$2 to $3/MMBtu) for natural gas have been eclipsed in recent years, and there is little expectation of returning to these lower price levels for any sustained period to 2030. Higher oil and gas prices have also resulted in higher coal and electricity prices, to the extent these fuels are used in power generation. In all three scenarios, energy prices remain at higher levels than those experienced in the last decades. In the Triple E Scenario, the existence of a carbon dioxide (CO_2) price results in dual pricing: first, at the wellhead level (commodity price), determined by the global/continental demand and supply forces; and second, at the end-use level (delivered price), established by a combination of the CO_2 price and the wellhead price. Overall, it appears that North American and global economies are adjusting to higher prices.

Availability of energy resources in the future is not expected to be an issue. As an element of efficient energy markets, energy prices will provide appropriate market signals for the development of adequate energy resources. The type and mix of energy resources will be determined by the level of energy prices. Overall, Canadian energy supply and the fuel mix is price-sensitive, creating a broad range of outcomes in response to alternative price trajectories modeled in the three scenarios.

2. Energy Supply, Demand and Exports

Fossil fuel energy continues to be the dominant source of supply, although non-conventional and non-fossil fuel supplies begin to play a larger role. Conventional resources that have been the backbone of energy supply throughout the twentieth century are growing increasingly mature, requiring ever greater physical and financial inputs to produce diminishing increments of supply. Future opportunities for significant incremental supply growth are likely to originate from unconventional energy sources such as oil sands, coalbed methane (CBM), oil and gas shales, improved recovery techniques, off-gases from bitumen upgraders, and coal gasification. This is the case in all three scenarios, with the most notable effect on the oil sector, where oil sands contribute in excess of 80 percent to Canadian oil supply.

While some unconventional resources such as oil sands are well established and have a large in-place resource, others such as gas shales are at early stages of experimentation and assessment and may require significant increments in production and involve long lead times and high upfront capital expenditures to make them commercially viable. In addition, alternative and emerging energy sources such as wind generation are increasingly becoming important as technological advancements make them more economic. This is an area of growing importance and continued fuel diversity is expected to be part of the energy balance in Canada. All scenarios depict a fuel mix that is mostly conventional at the base, but varies in terms of additions from emerging and alternative technologies and fuels.

While energy supply is quite price-responsive, energy demand is not. The pattern of energy consumption is largely predetermined by the make-up of the existing stock of energy-using devices such as buildings, appliances, cars, industrial motors and others. Since this stock has long life, the possibilities for demand reductions are limited. Also as long as energy expenditures continue to be a minor proportion of operating budgets, demand reductions in response to higher price will be small.

Despite the inflexibility of established energy consumption patterns, there are some indications that price may be a potentially bigger factor in future scenarios than the historical data and current analysis would suggest. Historical trends and modeling results indicate the influence of personal income (spending power) overrides energy price changes. However, recent qualitative evidence suggests Canadians are responding to increased energy costs by adjusting lifestyles and spending habits. Due to a lack of sufficient quantitative data, this may not be fully reflected in the results of the current analysis. Thus the sustained high energy prices as observed in the Fortified Islands Scenario or the consumer response to dedicated government programs in Triple E could see some further downward pressure on demand.

Total Canadian net energy exports are expected to increase in the future. However, the growth varies by commodity and scenario. While the oil and electricity exports are higher than the historical levels in all scenarios, the net natural gas exports see growth only in Fortified Islands. Growing oil exports are the result of production increases from oil sands and frontier oil off the East Coast. Frontier gas is also a contributing factor in the growth of natural gas exports. Electricity exports increase due to a combination of demand and supply factors.

Expansion of export markets will be directed by market forces and could take the form of growth in existing export markets, displacement of competing volumes from existing export markets, and/or accessing new offshore markets. Each of these has important implications for supporting infrastructure. Ongoing development of oil supply will require significant additions of export pipeline capacity and expansion of export markets to absorb the throughput. Similarly, there will be a need for additional transmission capacity to materialize growing exports of electricity. Depending on the scenario, there may be costs associated with underutilized natural gas infrastructure and new infrastructure to accommodate liquified natural gas (LNG) imports.

3. Energy Interactions with the Economy and Environment

The state of the economy continues to be an important driver for the energy system, and alternative macroeconomic projections in the three scenarios lead to different energy outcomes, especially in energy demand. Macroeconomic growth in all scenarios is lower than observed in recent history. The common constraint to economic growth is the decelerating population growth, with serious implications for labour force and availability of adequate labour and skill sets to meet the growing demand across all economic sectors. Labour shortages are currently having a dramatic impact on energy sector developments and the situation may worsen in some scenarios.

Labour productivity improvements are assumed in most scenarios to compensate for lower growth in labour force. Alternatively, stabilization in population growth could be assumed with higher immigration levels. Regardless, this is an important area for consideration by decision makers if continued robust growth in the economy is desired.

Canadians are concerned about climate change. Numerous policies and programs are being developed at the federal and provincial levels to reduce GHG emissions. It is challenging to predict the response to these policies and programs, as uncertainty exists over how consumers and technology will react. It is possible that without the implementation of these more stringent policy changes and a further shift in Canadians' behaviours, GHG emissions would increase, as is demonstrated by the Reference Case and Continuing Trends Scenario.

Reducing Canadian GHG emissions will require utilization of all the strategies at our disposal. These options, as explored in Triple E, include the adoption of progressive energy efficiency polices and a market mechanism for the inclusion of emissions from fossil fuel use in consumers decision-making process. Greenhouse gas emission reduction targets announced in recent policies will require strategies beyond those presently considered in the Triple E Scenario.

4. Building Blocks for Canada's Energy Future

Technology can offer solutions to many challenges in the energy system. While technology makes incremental inroads into Canada's energy future, the direction, pace and extent of these changes vary across scenarios. The technology push in Fortified Islands is most evident on the supply side. The drive to expand the boundaries of conventional resource supply as quickly as possible supports very specific high-tech industries, whereas demand technology retreats into more basic, conservation-type measures such as vehicle fuel economy and light bulbs. In Triple E, technology is inextricably tied to efficiency improvements. This scenario suggests fundamental technology goals of the future are not linked to any singular, breakthrough 'clean' technology; rather the holistic evaluation of the energy supply chain from bottom to top. Analysis of energy production, conversion and utilization reveals a wealth of optimization opportunities. These near-term efficiency opportunities provide the platform for advancing long-term, clean energy solutions.

An examination of the current state of technology in Canada confirms that change happens slowly. Promising end-states, such as the 'hydrogen economy' imply a multitude of progressive, integrated steps that affect almost every aspect of energy production and use. Seizing technology opportunities requires a combination of market mechanisms and incentives. It also requires consistent, reliable signals from policy-makers that will direct much-needed, long-term, strategic investments from the private sector.

A 'smart' energy policy is essential to the continued development of the energy sector. Canadian energy policy went through extensive reforms in the last two decades and is currently driven by a market-oriented system. According to the International Energy Agency (IEA), "competition in the Canadian energy markets is well advanced benefiting the consumers of Canadian oil, gas and electricity in Canada, the U.S. and outside North America"[80]. Earlier sections of *Canada's Energy Future* reflect the significant contribution made by the energy sector to the Canadian economy and support IEA views.

Energy development in Canada is reaching new heights. With its enormous reserves of oil sands, Canada is being touted as an energy 'superpower'. Meanwhile, Canada is at an important juncture, where sustained development of the energy sector may conflict with other objectives gaining importance in the minds of Canadians. ***'Smart' policy is required to help optimize multiple objectives of economic growth, environmental sustainability and development of the energy sector***. Flexible policy frameworks that extend beyond provincial borders will need to be constructed to consider wide regional differences with respect to energy and emissions, evolving energy supply systems and a changing global environment. In recent years, there have been calls for development of an integrated energy, environment and economic vision[81]. These frameworks will need to include the entire energy chain, all jurisdictions and the various layers of governments to maximize effectiveness.

These observations are driven by stakeholder input received during the consultation process and subsequent analysis for *Canada's Energy Future*. In undertaking the analysis for *Canada's Energy Future*, it was challenging to stipulate potential policies in areas where none existed, or where intent has been expressed, but programs are yet to be articulated. Clearly expressed policies and programs are a critical element of establishing plausible future energy paths and providing more definite analysis.

80 International Energy Agency (IEA). *Energy Policies of IEA Countries: Canada, 2004 Review.*

81 The Conference Board of Canada. *Canada's Energy Future: An Integrated Path*, May 2007.

Major investments are needed in the next decade to develop new sources of energy and meet the growth in energy demand as well as replace the ageing infrastructure. Many of these are already described with the Reference Case, although there are uncertainties surrounding the timing of larger projects, such as the Mackenzie gas pipeline and specific oil sands proposals.

Common themes in infrastructure development include the competition for skills and rising costs. While some of these issues might be regarded as bottlenecks that can be dealt with by phasing developments and aggressively addressing skills shortages through training, the matter of obtaining approvals for large new pipeline and electric transmission projects and production infrastructure from oil refineries to power plants remains a key source of uncertainty. New approaches are required to resolve differences between developers and local opposition in order to improve the predictability of project completion. In some cases, this may include improving clarity in the regulatory and public engagement processes, while in other cases it may require more use of 'single window' approaches when several jurisdictions are involved.

Over the longer term, 2015 to 2030, the infrastructure requirements and issues are more influenced by circumstances of the scenario, including implications arising from continued diversity of fuel mix. Continuing Trends would tend to have the broadest increases in production and transmission requirements, given that this scenario has the highest level of domestic demand. Project developers and consumers would need to deal with and accommodate the above risks associated with project completion. Triple E would suggest different and possibly higher risks associated with project completion, as this outcome relies on the success of new technologies that may or may not materialize. Additionally, if consumption efficiencies are not realized or demand management measures are not successful in the low-price environment, planned infrastructure may not be adequate and possibilities of diverting export resources to domestic use will need to be explored. Developments in Fortified Islands would face challenges of high and volatile energy prices, putting at risk the completion of high-cost conventional projects that are more prevalent in this scenario, along with those projects requiring technological advancements.

As the requirement to renew and expand our energy infrastructure increases to meet the growing and diverse needs for energy, greater public engagement and acceptance for these initiatives are important. Economic and environmental sustainability are high level precepts that could under-estimate individual concerns. As the 'footprint' of energy extraction, production, and distribution grows, projects face increasing public inquiry. New and emerging technologies, for all their promise, are equally as susceptible. Whether it is CBM gas wells, LNG terminals, or wind farms, future energy developments face an increasingly organized, informed, and committed public. An increased awareness of the major societal benefits and costs to all energy development, will be needed. A balance will need to be established between public acceptance and the need for timely decision making with all stakeholders working towards this objective.

Public buy-in is also required in altering consumer behaviour to achieve the energy and environment objectives. Recent evidence suggests the public is more willing to 'walk the talk'[82].

High-quality data forms a solid foundation for supply and demand analysis, such as the analysis for Canada's Energy Future. Canada is currently a world leader in the quantity and quality of energy data collected. The breadth and depth of data published by statistical agencies across the country is impressive, and has allowed for the development of advanced analytical tools.

82 61 percent of respondents in Ontario and Alberta are "very concerned" about climate change and 42 percent are willing to pay more to do something about it. Ipsos Reid survey for Direct Energy. May 2007.

As energy issues become increasingly complex, requiring timely decision- making, there emerges a need for enhancements and improvements to existing statistical databases. Statistics need to be responsive and relevant to emerging energy issues[83]. Ongoing collaboration is needed to address gaps, timeliness, and identify future priorities. One such successful initiative is the effort to standardize the reserve definition and its application at the global level[84].

Together with data, good information and analyses is also important in fostering good decision making on the part of all stakeholders.

5. Canada's Energy Future

The analysis suggests significant change in several elements of the energy system. Energy prices have moved to a higher platform, and are expected to remain at those levels in the foreseeable future. There is a growing focus on environment issues, notably on greenhouse gas and other emissions. At a global level, energy security and the ability to meet growing energy demand are becoming key. There is a fast approaching need to renew and expand the energy supply infrastructure. Technological breakthroughs in the way we consume and produce energy, and growth in technology development which is unprecedented in scale and speed of deployment may be required.

A long-term energy vision and strategy for Canada is needed to balance multiple objectives. This plan must be well integrated at the regional level, consider environmental issues and economic growth, and be developed with input from Canadians. Only then will we be able to overcome the challenges ahead and take advantage of the opportunities available.

The NEB plans to contribute to this debate by continuing to pursue our vision of being an active, effective and knowledgeable partner engaging Canadians in the discussion of Canada's energy future.

83 Additionally, data and definitions need to be consistent between the various collecting and communicating agencies at both the federal and provincial levels.

84 There has always been some inconsistency on a global basis with respect to oil and gas reserves, in both the actual definitions and the application of the definitions to oil and gas accumulations. In order to resolve some of these inconsistencies and challenges, there have been several international efforts to standardize the reserves definitions and applications of reserves.

GLOSSARY

The definition of terms in this glossary refers to their use in the context of the report on Canada's Energy Future.

Accelerated Capital Cost Allowance	A federal government allowance which provides an accelerated rate of write-off for certain capital expenditures on equipment designed to produce energy in a more efficient way, or from alternative renewable sources.
Alternative or Emerging Technologies	New and emerging environmentally-friendly technologies used as an alternative to existing resource-intensive methods to produce energy. Alternative technologies make limited use of resources, and include fuel cells and clean coal technologies, for example.
Anthracite coal	A hard coal with the highest rank, which has the highest carbon count, and can have significant ash content. Anthracitic coals burn with little flame and smoke and produces a high amount of heat.
Average Annual Growth Rate (AAGR)	For purposes of *Canada's Energy Future*, the growth rate refers to the growth rate from 2004 to 2030, with 2004 the base year, for scenarios. For the Reference Case, the growth rate refers to 2004 to 2015, with 2004 the base year.
Barrel	One barrel is approximately equal to 0.159 cubic metres or 158.99 litres or approximately 35 imperial gallons.
Biodiesel	A diesel fuel substitute produced from vegetable oils and animal fats.
Biofuel	See biomass.
Biomass	Organic material, such as wood, crop waste, municipal solid waste, hog fuel and pulping liquor, processed for energy production.
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.
Bituminous coal	A relatively hard form of coal, with a higher rank which burns readily with a smoky flame.
Capacity (Electricity)	The maximum amount of power that a device can generate, use or transfer, usually expressed in megawatts.

Carbon capture and storage (CCS)	A process of capturing and storing carbon dioxide (CO_2), such that it is not released into the atmosphere, hence reducing greenhouse gas (GHG) emissions. Carbon dioxide is compressed into a transportable form, moved by pipeline or tanker, and stored in some medium, such as geological formations.
Cellulosic ethanol	Also known as cellanol, cellulosic ethanol is produced from lignocellulose, and composed of cellulose, hemicellulose and lignin. It is found in a variety of biomass sources.
Clean coal technologies	Clean coal technologies refer to methods in which emissions resulting from coal-fired generation may be reduced. Development of clean coal technologies is currently focused on reducing emissions of carbon dioxide (CO_2). Clean coal technologies may generally be characterized as improved efficiency in combustion, stack gas cleanup and capture and sequestration of CO_2.
CO_2 flooding	CO_2 flooding is a process of improved oil recovery, wherein carbon dioxide (CO_2), in a liquid form, is deposited into oil-bearing formations in an effort to increase the amount of oil that can be extracted.
Coalbed methane (CBM)	A form of natural gas extracted from coalbeds. Coalbed methane (CBM) is distinct from typical sandstone or other conventional gas reservoir, as the methane is stored within the coal by a process called adsorption.
Cogeneration	A generating facility that produces electricity and another form of useful thermal energy, such as heat or steam as a by-product of generation.
Combined-cycle generation	The production of electricity using combustion turbine and steam turbine generation units simultaneously.
Condensate	A mixture comprised mainly of pentanes and heavier hydrocarbons recovered as a liquid from field separators, scrubbers or other gathering facilities or at the inlet of a natural gas processing plant before the gas is processed.
Conservation	For purposes of *Canada's Energy Future*, conservation refers to minimizing energy use.
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 natural gas	Conventional natural gas is gas contained in higher porosity geological formations that is produced by expansion of the gas molecules into the well bore.
Crude Oil	A mixture, consisting mainly of pentanes and heavier hydrocarbons that exists in the liquid phase in reservoirs and remains liquid at atmospheric pressure and temperature. Crude oil may contain small amounts of sulphur and other non-hydrocarbons, but does not include liquids obtained from the processing of natural gas.

Cyclic steam stimulation (CSS)	A repeateable, thermal in-situ recovery technique involving steam injection followed by oil production from wells injected with steam. Steam injection increases oil mobility and allows heated bitumen to flow into a well.
Demand-side management (DSM)	Actions undertaken by a utility that result in a change and/or sustained reduction in demand for electricity. This can eliminate or delay new capital investment for production or supply infrastructure and improve overall system efficiency.
Diluent	Any lighter hydrocarbon, usually pentanes plus, added to heavy crude oil or bitumen in order to facilitate its transport in crude oil pipelines.
Edmonton Par (price)	The price of Edmonton Par, a light crude oil, which serves as the benchmark for crude oil produced in the region.
End-use demand	Energy used by consumers in the residential, commercial, industrial and transportation sectors.
Energy efficiency	Technologies and measures that reduce the amount of energy and/or fuel required for the same work.
Energy intensity	The amount of energy used per unit of real GDP.
Improved oil recovery (IOR)	The extraction of additional crude oil from reservoirs through a production process other than natural depletion. Includes both secondary and tertiary recovery processes such as pressure maintenance, cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. (Also referred to as enhanced oil recovery [EOR]).
Ethane	The simplest straight-chain hydrocarbon structure with two carbon atoms.
Ethylene	A chemical building block made up of two carbon atoms and four hydrogen atoms used to manufacture plastics, solvents, pharmaceuticals, detergents and additives.
Extraction	A process unique to the oil sands industry, in which bitumen is separated from the oil sands.
Feedstock	Natural gas or other hydrocarbons used as an essential component of a process for the production of a product.
Fossil fuel	Hydrocarbon-based fuel sources such as coal, natural gas, natural gas liquids and crude oil.
Frontier areas	Generally, the northern and offshore areas of Canada.
Fuel cell	Batteries which convert fuel directly into electricity. Most fuel cells take in hydrogen and oxygen, and produce electricity, heat and water.
Fuel economy	The average amount of fuel consumed by a vehicle to travel a certain distance, measured in litres per 100 kilometres.
Fuel-switching	The ability to substitute one fuel for another, generally based on price and availability.
Generation (electricity)	The process of producing electric energy by transforming other forms of energy. Also, the amount of energy produced.

Geothermal energy	The use of geothermal heat to generate electricity. Also used within energy demand to describe ground-source heating and cooling (also known as geoexchange or ground-source heat pump).
Greenhouse effect	An atmospheric phenomenon through which incoming solar short-wave radiation passes through the atmosphere relatively unimpeded, but long-wave radiation emitted from the warm surface of earth is partially absorbed, adding net energy to the lower atmosphere and underlying surface, thereby increasing their temperatures.
Greenhouse gases (GHG)	Gases such as carbon dioxide, methane and nitrogen oxide, which actively contribute to the atmospheric greenhouse effect. Greenhouse gases also include gases generated through industrial processes such as hydroflurocarbons, perflurocarbons and sulphur hexafluoride.
Gross domestic product (GDP)	GDP is a measure of economic activity within a country. It is the market value of all goods and services in a year within Canada's borders.
Gross output	The value of net output or gross domestic product plus consumption.
Heating oil	Also known as No. 2 fuel oil. A distillate fuel oil commonly used for household space heating.
Heavy crude oil	Generally, a crude oil that has a density greater than 900 kg/m^3.
Heavy fuel oil	No. 6 fuel oil (residual fuel oil)
Henry Hub (price)	Henry Hub is the pricing point for natural gas futures traded on the New York Mercantile Exchange (NYMEX). The hub is a point on the natural gas pipeline owned by Sabine Pipe Line and located in Louisiana.
Heritage assets	An amount of energy and capacity determined by the existing generation assets that resulted from past decisions under a previous market regime. This energy is generally sold into the marketplace at a price reflecting historical costs.
Hub	A geographic location where large numbers of buyers and sellers trade a commodity and where physical receipts and deliveries occur.
Hydroelectric generation	A form of energy wherein electricity is produced from hydropower.
Hydraulic fracture	A technique in which fluids are injected underground to create or expand existing fractures in the rock, allowing oil or gas to flow out of the formation, or to flow at a faster rate.
Income effect	The change in demand that is related to the change in a consumer's income.
In-situ recovery	The process of recovering crude bitumen from oil sands other than by surface mining.

Integrated Gasification Combined Cycle (IGCC)	Coal (or biomass fuel), water and oxygen, are fed to a gasifier, which produces syngas. This gas is cleaned and is fed to a gas turbine. The hot exhaust of the gas turbine and heat recovered from the gasification process are routed through a heat-recovery generator to produce steam, which drives a steam turbine to produce electricity.
Interchange (interprovincial)	Electricity transfers between provinces.
Kyoto's Clean Development Mechanism	The Kyoto Clean Development Mechanism is a mechanism within the Kyoto Protocol to assist countries in meeting greenhouse gas reduction targets. It enables industrialized countries with emission reduction targets to invest in emission reduction projects in developing countries and earn credits. These credits can be used against domestic emission reduction targets and/or sold. Developing countries gain access to low-emission technologies providing an incentive to participate in the Protocol, by supporting such countries in sustainable development.
Gas well	A well bore with one or more geological horizons capable of producing natural gas.
Large final emitter	Large final emitters refer to heavy industries, including the oil and gas, electricity generation, mining and energy-intensive manufacturing industries, which produce close to half of Canada's GHG emissions.
Light crude oil	Generally, crude oil having a density less than 900 kg/m^3. Also a collective term used to refer to conventional light crude oil, upgraded heavy crude oil and pentanes plus.
Light fuel oil	No. 2 fuel oil (furnace fuel oil).
Lignite	A low rank of soft coal with a high moisture content which burns with a smoky flame. It is used primarily for steam-electric power generation.
Liquefied natural gas (LNG)	Liquefied natural gas is natural gas in its liquid form. Natural gas is liquefied by cooling, and the process reduces the volume of gas by more than 600 times, allowing for efficient transport via LNG tanker.
Marketable natural gas	Natural gas that has been processed to remove impurities and natural gas liquids. It is ready for market use.
Metallurgical coal	Coal used in the steelmaking industry.
Mine mouth	A method of integrated mining and power generation, wherein coal is transported directly out of the ground directly into a power plant
Mixed-use neighbourhood	In reference to 'smart growth', a mixed-use neighbourhood is designed to include various types of buildings including residential, commercial, industrial and other land uses.
Naphtha	A category of liquids from the middle distillate cut of crude oil. It includes end products such as benzene, toluene and xylene.

Natural gas liquids (NGL)	Those hydrocarbon components recovered from natural gas as liquids. These liquids include, but are not limited to, ethane, propane, butanes and pentanes plus.
Net metering	A system wherein electricity consumers may receive credit for a portion of electricity they generate via a renewable energy generator. Excess electricity will result in moving an electricity meter backwards, such that excess energy is banked by the consumer.
New York Mercantile Exchange (NYMEX)	The largest physical commodity futures exchange traded on the New York Mercantil Exchange for delivery of natural gas at the Henry Hub in Louisiana.
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.
Particulate matter (PM)	Atmospheric particles composed of both natural materials, such as pollen and dust, and manmade pollutants, such as smoke particles and metallic ash. Particulate matter can cause respiratory irritation in significant concentrations.
Peak demand	The maximum load consumed or produced in a stated period of time.
Pentanes Plus	A mixture mainly of pentanes and heavier hydrocarbons obtained from the processing of raw gas, condensate or crude oil.
Personal disposable income	The amount of income available to a household or person after the deduction of federal and provincial income taxes.
Photovoltaic (solar PV)	Solar power employing solar cells or solar photovoltaic arrays to convert sunlight into electricity.
Primary energy demand	The total requirement for all uses of energy, including energy used by the final consumer, intermediate uses of energy in transforming one energy form to another, and energy used by suppliers in providing energy to the market.
Real price	Price levels that are held constant, eliminating the effect of inflation.
Reliability	The degree of performance of any element of an electricity system, which results in electricity being delivered to customers within acceptable standards and in the amount desired. Reliability can be measured by frequency, duration or magnitude of adverse effects on electricity supply.
Reserves – Established	The sum of proven reserves and half probable reserves.
Reserves – Initial established	Established reserves prior to deduction of any production.
Reserves – Proven Reserves	Recoverable under current technology and present and anticipated economic conditions, specifically demonstrated by drilling, testing or production.
Reserves – Remaining	Initial reserves less cumulative production at a given time.
Reserves – Recoverable	That portion of the ultimate resources potential recoverable under expected economic and technical conditions.

Reserve to Production Ratio	Reserve to Production ratio is defined as the remaining reserves at the end of any year divided by the production in that year. The result is the length of time that those remaining reserves would last if production were to continue at that rate.
Residual fuel oil	The remaining refinery product after the removal of more valuable fuels such as gasoline and middle distillates. It is used primarily for power generation and fuel for various industrial processes.
Secondary energy demand	See End-use demand.
Security of supply	The availability of sufficient energy resources at reasonable prices.
Shale gas	A continuous, low-grade accumulation of natural gas contained in rocks such as shales or silty shales.
Solar energy	Includes active and passive solar heat collection systems and photovoltaics.
Steam assisted gravity drainage (SAGD)	Steam Assisted Gravity Drainage is a steam stimulation technique using pairs of horizontal wells in which the bitumen drains, by gravity, into the producing wellbore, after it has been heated by the steam. In contrast to cyclic steam stimulation, steam injection and oil production are continuous and simultaneous.
Straddle plant	A reprocessing plant located on a gas pipeline. It extracts natural gas liquids from previously processed gas before the gas leaves or is consumed within the province.
Sulphur oxides	A natural occurring element found in most crude oils and some natural gas.
Supply cost	Expresses all costs associated with resource exploitation as an average cost per unit of production over the project life. It includes capital costs associated with exploration, development, production, operating costs, taxes, royalties and producer rate of return.
Synthetic crude oil	Synthetic crude oil is a mixture of hydrocarbons generally similar to light sweet crude oil, derived by upgrading crude bitumen or heavy crude oil.
Terrestrial Sequestration	Refers to the removal of CO_2 emissions from the atmosphere or the prevention of CO_2 emissions entering the atmosphere from terrestrial sources. This can include forest and agricultural management practices, such as planting trees, preventing deforestation, or changing agricultural tilling practices
Thermal generation	Energy conversion in which fuel is consumed to generate heat energy which is converted to mechanical energy and then to electricity.
Time-of-use rate	Rates that are based on the time of day when the electricity is actually used. These rates allow consumers to pay less for the electricity used during off-peak or low-demand periods. Electricity used during on-peak hours is more costly.

Toe-to-heel air injection (THAI)	A version of in-situ combustion that uses specifically-placed vertical air injection wells and horizontal producing wells to promote a controllable combustion front in an oil reservoir.
Unconventional crude oil	Crude oil that is not classified as conventional crude oil (e.g., bitumen).
Unconventional natural gas	Natural gas which is not classified as conventional natural gas. It includes coalbed methane, tight gas, shale gas and gas hydrates.
Unconventional resources	Unconventional resources exist in petroleum accumulations that are pervasive throughout a large area and that are not significantly affected by hydrodynamic influences. They may also be associated with abnormal trap types, reservoir quality, chemical and physical form of the hydrocarbon in its native state, extraction methods (mines versus wells), or the amount of processing that must be applied to the raw production to yield a marketable commodity.
Upgraded bitumen	The process of converting bitumen or heavy crude oil into a higher quality crude oil either by the removal of carbon (coking) or the addition of hydrogen (hydroprocessing).
Upstream	Those activities related to the development, production, extraction and recovery of natural gas, natural gas liquids and crude oil.
Vapourized Extraction (VAPEX)	Vapourized Extraction is a process similar to SAGD but uses a vaporized hydrocarbon solvent, rather than steam, to reduce the viscosity of crude oil in the reservoir.
Waterflooding	A recovery method wherein water is injected into a reservoir to displace residual oil to adjacent production wells.
Wave / Tidal power	Also known as tidal energy, tidal or wave power makes use of the rise and fall in sea levels, or tidal flow, to create hydropower.
WCS at Hardisty (price)	Western Canadian Select (WCS) is an oil composed of Canadian heavy conventional and bitumen crude oils, blended with sweet synthetic and condensate diluents. The WCS price at Hardisty represents the price benchmark for Canadian crude oil, along with Edmonton Par.
West Texas Intermediate (WTI)	WTI is a light sweet crude oil, produced in the United States, which is the benchmark grade of crude oil for North American price quotations.

Conversion Tables

Imperial and Metric Conversions

Unit		Equivalent
m	metre	3.28 feet
m^3	cubic metres	6.3 barrels (oil); 35.3 cubic feet (gas)
t	metric tonne	2200 pounds

Energy Content Equivalents

Energy Measure		Energy Content
GJ	gigajoule	0.95 million btu
PJ	petajoule	1 000 000 GJ

Electricity

MW	megawatt	
GW.h	gigawatt hour	3600 GJ
TW.h	terawatt hour	3.6 PJ or 1 000 GW.h

Natural Gas

Mcf	thousand cubic feet	1.05 GJ
Bcf	billion cubic feet	1.05 PJ
Tcf	trillion cubic feet	1.05 EJ

Natural Gas Liquids

m^3	ethane	18.36 GJ
m^3	propane	25.53 GJ
m^3	butane	28.62 GJ

Crude Oil

m^3	Light	38.51 GJ
m^3	Heavy	40.90 GJ
m^3	Pentanes plus	35.17 GJ

Coal

t	Anthracite	27.70 GJ
t	Bituminous	27.6 GJ
t	Subbituminous	18.80 GJ
t	Lignite	14.40 GJ

Petroleum Products

m^3	Aviation Gasoline	33.52 GJ
m^3	Motor Gasoline	34.66 GJ
m^3	Petrochemical Feedstock	35.17 GJ
m^3	Naphtha Specialties	35.17 GJ
m^3	Aviation Turbo Fuel	35.93 GJ
m^3	Kerosene	37.68 GJ
m^3	Diesel	38.68 GJ
m^3	Light Fuel Oil	38.68 GJ
m^3	Lubricants	39.16 GJ
m^3	Heavy Fuel Oil	41.73 GJ
m^3	Still Gas	41.73 GJ
m^3	Asphalt	44.46 GJ
m^3	Petroleum Coke	42.38 GJ
m^3	Petrochemical Feedstock	35.17 GJ
m^3	Other Products	39.82 GJ

Guide to Appendices

Appendices are available on the Boards' Website at www.neb-one.gc.ca, and include the following detailed data.

Appendix 1 Key Drivers

Table A1.1	Economic Indicators: Canada
Tables A1.2 to A1.12	Economic Indicators: Provinces

Appendix 2 Energy Demand

Table A2.1	Demand, Reference Case and Continuing Trends, Canada
Tables A2.2 to A2.14	Demand, Reference Case and Continuing Trends, Provinces
Table A2.15	Demand, Triple E, Canada
Tables A2.16 to A2.28	Demand, Triple E, Provinces
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Appendix 3 Oil and Natural Gas Liquids

Table A3.1	Crude Oil and Bitumen Resources
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Table A3.14	Oil, Triple E, Production Outlook by Province
Table A3.15	Oil, Fortified Islands, Production Outlook by Province

Appendix 4 Natural Gas

Appendix 5 Electricity

Appendix 6 Coal

Appendix 7 Greenhouse Gas Emissions