National Energy Board

Office national de l'énergie

Outlook for **Electricity** Markets

2005 – 2006

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An **ENERGY MARKET ASSESSMENT** • June 2005

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FIGURES

ACRONYMS

AC	Alternating Current
AECO-C or AECO	Alberta Energy Company storage facility (natural gas)
AESO	Alberta Electric System Operator
BCTC	British Columbia Transmission Corporation
BCUC	British Columbia Utilities Commission
CASA	Clean Air Strategic Alliance (Alberta)
CCPC	Canadian Clean Power Coalition
CETI	Clean Energy Transfer Initiative
DC	Direct Current
DR	Demand Response
DSM	Demand-side Management
EMA	Energy Market Assessment
EPP	Environmentally Preferred Power (Saskatchewan)
ERO	Electric Reliability Organization
EUB	Energy and Utilities Board (Alberta)
FERC	Federal Energy Regulatory Commission (U.S.)
GHG	Greenhouse Gas or Greenhouse Gases
HQ	Hydro-Québec
HVDC	High Voltage Direct Current
HYDRO	Newfoundland and Labrador Hydro
IEP	*2004 Integrated Electricity Plan* (British Columbia)
IESO	Independent Electricity System Operator (Ontario)
IGCC	Integrated Gasification Combined Cycle
IPL	International Power Line
IPP	Independent Power Producer
ISO	Independent System Operator
ISO-NE	Independent System Operator – New England
LDC	Local Distribution Company
LNG	Liquefied Natural Gas
MAPP	Mid-Continent Area Power Pool
MISO	Midwest Independent Transmission System Operator, Inc. (U.S.)
MRO	Midwest Reliability Organization (U.S.)
MSA	Market Surveillance Administrator (Alberta)
NBPUB	New Brunswick Board of Commissioners of Public Utilities
NBSO	New Brunswick System Operator

NEB	National Energy Board
NERC	North American Electric Reliability Council
NIMBY	Not In My Back Yard
NPC	Nunavut Power Corporation
NSPI	Nova Scotia Power Inc.
NTPC	Northwest Territories Power Corporation
NYISO	New York Independent System Operator
NYMEX	New York Mercantile Exchange
OATT	Open Access Transmission Tariff
OEB	Ontario Energy Board
OPA	Ontario Power Authority
OPG	Ontario Power Generation
PJM	Pennsylvania/New Jersey/Maryland Interconnection (U.S.)
PNW	Pacific Northwest (U.S.)
PPA	Power Purchase Agreement/Arrangements
PUB	Public Utilities Board
QEC	Qulliq Energy Corporation
RPP	Regulated Price Plan
RFP	Request for Proposals
RPS	Renewable Portfolio Standard
RTO	Regional Transmission Organization
SCR	Synthetic Catalytic Reduction
UARB	Nova Scotia Public Utility and Review Board
VICFT	Vancouver Island Call For Tenders
WPPI	Wind Power Production Incentive
YEC	Yukon Energy Corporation
YECL	Yukon Electric Company Limited

Abbreviations

BC Energy Plan	*Energy for Our Future: A Plan for B.C.*
Bill 100	*Electricity Restructuring Act, 2004* (Ontario)
Board	National Energy Board
CO_2	carbon dioxide
EP Act	*Electric Power Act*
NO_X	nitrogen oxides
SO_X	sulphur oxides
Transmission System Plan	*10-Year Transmission System Plan (2005-2014)* (Alberta)

Energy Units

k	kilo	10^3
M	mega	10^6
G	giga	10^9

Voltage Measures

kV	kilovolt	= 10^3 volts

Power Measures

kW	kilowatt[1]	= 10^3 watts
MW	megawatt	= 10^6 watts or 1 000 kW
GW	gigawatt	= 10^9 watts or 1 000 000 kW

Energy Measures

kW.h	kilowatt hour	one kW for the period of one hour
MW.h	megawatt hour	one MW for the period of one hour or 1 000 kW.h
GW.h	gigawatt hour	one GW for the period of one hour or 1 000 000 kW.h

1 A kilowatt hour is the amount of energy required to operate ten 100-watt light bulbs for an hour.

FOREWORD

This Energy Market Assessment (EMA) was undertaken by the National Energy Board (NEB or the Board) as part of its regulatory mandate. The NEB monitors the Canadian supply of all energy commodities, including electricity, and the demand for Canadian energy commodities in both domestic and export markets. The Board also has a mandate to keep the Canadian public informed about energy developments in Canada. This EMA, titled *Outlook for Electricity Markets 2005-2006*, follows three previous reports on electricity. These are *Canadian Electricity Trends and Issues*, *Canadian Electricity Exports and Imports* and A *Compendium of Electric Reliability Frameworks Across Canada*.

This EMA was produced in response to a Board survey and discussion with stakeholders that revealed a need for more short- and medium-term energy market assessments to supplement the NEB's longer term energy analysis. *Outlook for Electricity Markets 2005-2006* provides a discussion and analysis of Canadian electricity markets, with an emphasis on the main drivers influencing current trends in generation, demand, prices, infrastructure additions, and inter-regional and international trade. It also includes an update of electricity industry restructuring activities in Canada. While the focus of the report is on the short-term (2005-2006), current issues that may have a long-term effect on the Canadian electricity sector are identified and discussed. This EMA also acknowledges the close links between the American and Canadian electricity sectors due to the integrated nature of the North American power grid.

During the preparation of this report, consultations were held with stakeholders. These included generation, transmission and distribution companies, marketers, end-users, environmental groups, consumer groups and government agencies. The Board appreciates the information and comments it received during the course of these meetings.

Executive Summary

This Energy Market Assessment was undertaken by the NEB as part of its regulatory mandate to monitor the supply of energy commodities in Canada, including electricity, and the demand for Canadian energy commodities in both domestic and export markets. *Outlook for Electricity Markets 2005-2006* provides an analysis and discussion of Canadian electricity markets, with an emphasis on the main drivers influencing near-term trends in generation, demand, infrastructure additions, inter-regional and international trade, and pricing. The report includes an update of electric industry restructuring activities in Canada, focusing on the short-term (2005-2006), and identifies and discusses current issues that may have longer term effects. The report also acknowledges the linkages between American and Canadian electricity markets resulting from transmission interconnections.

Canada's electricity markets have developed along provincial or regional boundaries and the extent of restructuring varies by province across the country. Alberta and Ontario have moved furthest along the restructuring path, with other regions either choosing to partially restructure or to maintain the status quo. Since opening their markets to wholesale and retail competition, Alberta and Ontario have continued to make adjustments to meet the needs of market participants. With recent legislative changes, Ontario has transformed its electricity market into a hybrid competitive-regulated market.

Generally, electricity is considered an essential service that should be provided to domestic consumers at acceptable prices. Some provinces, usually those that rely on hydroelectric generation, have tended to use these resources to earn export revenues. As the utilities in hydro-based provinces tend to be Crown corporations, export revenues are returned to taxpayers, either in the form of lower prices or by contributions to government revenues.

Pricing of electricity varies by province according to the type of generation available and whether prices are regulated or market based. In Alberta and Ontario, prices more closely reflect market conditions. Most other provinces maintain regulated cost-of-service rate structures for domestic consumers.

Supply adequacy provides economic and reliability benefits to each region. Consequently, each region strives to ensure that mechanisms are in place to mitigate the potential for tightness in supply, or even a shortfall. While most regions are self-sufficient in generation capacity, many realize benefits from engaging in interprovincial and international trade, by taking advantage of the differences in generation fuel types and asymmetric peak demand periods between trading regions. In recent years, however, growth in generation in exporting regions has lagged growth in domestic demand so that the surplus available for export has been declining. At the same time, some regions have relied on imports to meet domestic load requirements.

Although the organization of the market and the degree of restructuring varies, governments and electric utilities across the country are endeavouring to balance three common long-term objectives:

adequate and reliable supply; environmental sustainability; and acceptable electricity prices. Recognizing the diverse strategies and specific initiatives toward achieving these objectives, this report has identified a number of issues and challenges facing the Canadian electricity sector. The analysis developed in this report leads to the following conclusions:

Supply is adequate in all regions during the 2005-2006 period; however, tight supply conditions could emerge as early as 2007

There will be adequate supply to meet domestic demand in all Canadian regions in the time frame of this EMA. However, actions must be taken soon to ensure supply adequacy in the future. Several regions have opted for natural gas-fired generation over traditional generation sources such as large hydro projects, nuclear power and coal. In response to high natural gas prices and price volatility, strategies toward developing gas-fired generation are being reconsidered. Longer term solutions are likely to include a diversity of generation options, including renewable energy, as well as increased inter-regional trade, and demand-side initiatives. Along with natural gas-fired generation, generation options include nuclear refurbishments, new nuclear plants and clean coal developments. Government-industry partnerships may be necessary to complement technological advances in making these options commercially feasible and socially acceptable.

Alternative and renewable resources and demand management are becoming more important in addressing air quality issues and supply adequacy

Growth in alternative and renewable resources, particularly wind, is accelerating. The drivers include the establishment of regional renewable portfolio standards, incentives such as the federal Wind Power Production Incentive (WPPI), the coming into force of the *Kyoto Protocol* and the general desire for clean air. Apart from the direct environmental benefits of green power, the potential also exists for the development of equipment manufacturing and service industries.

Currently, most alternative and renewable energy sources are more costly than thermal-based generation; however, this comparison does not take into account environmental externalities (e.g., the environmental costs associated with thermal-based generation), which are not fully reflected in energy prices. In addition, the cost for many alternative and renewable resources continues to decline as the result of technological innovations. There is also increasing recognition by the public and the electric industry that managing energy demand is part of addressing supply adequacy issues. Barriers to successful demand management programs include the lack of clear price signals to foster energy conservation and more efficient use of energy.

Uncertainty could delay timely investment and development of new infrastructure

Several provinces face uncertainty that could affect longer term supply adequacy. Uncertainty is related to evolving market structures, the lack of clear pricing rules, fuel costs and the impact of environmental initiatives. As well, the general resistance from parties that might be impacted, the so-called “not in my back yard” (NIMBY) effect, is often cited as a reason for delay in obtaining approvals to construct new facilities. From the standpoint of facilitating infrastructure development, these uncertainties add risk, cause delays and increase the cost of making investments in new technologies and infrastructures.

In all regions, there are forces that will exert upward pressure on electricity prices

Canadian consumers will face continuing upward pressure on electricity rates. Factors influencing rate increases include fuel prices, development of higher-cost generation resources, and the cost of enhancing transmission and distribution systems.

Since electricity is often perceived by consumers to be an essential service, there is a political motivation to ensure entitlement to electricity at acceptable prices through regulation. Such prices may or may not be sufficient to induce the appropriate responses by investors and consumers. Decisions as to what may constitute acceptable or reasonable prices are influenced by the need to ensure supply adequacy and environmental sustainability. Informing consumers about these objectives, and the choices that are implied, may assist consumers in understanding why prices will be rising.

Exports and imports continue to benefit Canadians; interprovincial energy transfers should be further explored

Under normal operating conditions, transmission interconnections between regions provide opportunities to engage in trade and contribute to reliability of the interconnected systems. For geographic and economic reasons, the strongest ties have been north-south between the provinces and adjacent American states. These have enabled the exporting provinces to earn revenue during periods of surplus supply and have enabled power purchases during off-peak times, or when required, to supplement domestic generation. The Board's analysis suggests that the benefits of north-south trade are expected to continue.

While there are important interprovincial power transfers in some regions, the historical tendency for provinces to supply their own markets has limited the extent of interprovincial transfers. The concept of expanded east-west interconnections, or an "East-West Grid" in Canada, was raised a number of times in the past, but typically was not considered economically attractive. Recent regional developments, such as the Clean Energy Transfer Initiative (CETI), between Manitoba and Ontario, and other potential interprovincial projects, suggest that specific opportunities may now exist.

In developing the conclusions for this report, the Board found an opportunity to formulate recommendations in five areas. These recommendations pertain to: policy clarity and predictability; electricity pricing; the need for diversity of generation sources; incentives for alternative and renewable energy; and expansion of east-west interconnections. With a view to informing policy makers, the Board is prepared to cooperate in providing further advice if there is interest in pursuing these recommendations.

Introduction

The NEB, as part of its regulatory mandate, continually monitors the supply of, and the demand for, Canadian energy commodities in both domestic and export markets. The Board also has a mandate to keep the Canadian public informed about energy developments. A recent Board survey and discussion with stakeholders revealed a need for more short- and medium-term energy market assessments to supplement the NEB's longer term energy analysis.

The federal government has jurisdiction over electricity exports, international power lines and nuclear safety. Parliament may designate a particular interprovincial power line for regulation in the same manner as international power lines. The provinces and territories have jurisdictional authority over generation, transmission and distribution of electricity within their boundaries.

This report, titled *Outlook for Electricity Markets 2005-2006*, is the latest in a series of EMAs of the Canadian electricity sector. The objectives of the report are to inform Canadians of recent electricity market developments, provide a short-term outlook for supply, trade and prices, and discuss current industry challenges and emerging issues.

Chapter Two of this report provides a national perspective on Canadian electricity markets, with an emphasis on the main drivers influencing current and near-term trends in generation, demand and demand management, infrastructure additions, and interprovincial and international trade. It also includes an update of electric industry restructuring activities in Canada. Although the focus of the report is on the short-term, i.e., 2005-2006, it identifies and discusses current issues that may have a long-term impact on the Canadian electricity sector. In addition, while the report focuses on Canadian electricity developments, it acknowledges the interconnected nature of the North American market.

Chapter Three provides a description of the industry structure, and discusses near-term market developments, outlooks and issues for each province and territory. Chapter Four concludes with a number of observations and recommendations.

This EMA is the product of the Board's detailed analyses, supported by information obtained through consultations with interested parties including government agencies, electricity generators, environmental groups, power consumers and public interest groups. These consultations provided stakeholders' perspectives on the electricity industry in the various regions, and allowed staff to develop a national perspective on the Canadian electricity markets. The Board appreciates the information and comments it received.

Overview of Canadian Electricity Markets

Electricity demand in Canada, fuelled by economic growth and increasing use of electricity in homes and offices, continues to grow, with all-time peak demand recorded in several jurisdictions during the past two years. Historically, electricity was mainly provided by vertically-integrated utilities, either investor-owned or provincial Crown corporations, which met growing demand by building large power projects. These projects were typically hydro in British Columbia, Manitoba and Québec; hydro, coal and nuclear in Ontario; and coal in Alberta, Saskatchewan, Nova Scotia and New Brunswick.

The supply situation varies across the country depending on regional circumstances and market conditions. Over the past two to three years some regions, such as Alberta, have benefited from high reserve margins, while others, such as Québec and Manitoba, have faced tight supply situations. In addition, the need for a reliable interconnected power system was clearly demonstrated by the 14 August 2003 blackout.

The investment climate for new supply to meet growing demand has become more challenging. Developing generation and transmission is capital intensive, and investors require stability with regard to market structures and rules. Additionally, public awareness and concerns about large projects has grown and investors must ensure that these projects make sense in terms of power supply needs and environmental quality. Many regions face difficult choices related to, for example, investing in new generation and transmission capacity, developing options to ensure that new facilities do not compromise the integrity of the environment, and designing appropriate pricing policies.

2.1 Outlook 2005-2006

Supply Adequacy

In the 2005-2006 time frame of this EMA, generation is expected to remain adequate in all regions to meet load requirements in each provincial or territorial market. Uncertainties in the outlook pertain to the rates of economic growth and extreme weather conditions, which could affect the demand side, and abnormal precipitation levels and forced plant outages, which could affect generation. Some provinces are deliberating on how to meet increasing demand beyond 2006. In many jurisdictions, key decisions are expected to be made over the next two years with regard to both supply and demand-side options to meet future needs. These include: the role of nuclear power in New Brunswick, the phase-out of coal in Ontario, development of the Lower Churchill River Project in Labrador, and renewable portfolio standards in several provinces. These near-term decisions will have an impact on Canada's evolving generation mix.

Canadian utility infrastructure is aging with many existing facilities approaching the end of their useful economic lives and in need of replacement or refurbishment. As significant lead time is required to bring new generation and transmission into operation, strategies for developing these assets must be developed in the time period of this EMA.[2] In most regions, siting new generation or transmission corridors is increasingly difficult due to potential public opposition on safety or environmental grounds.

International Trade

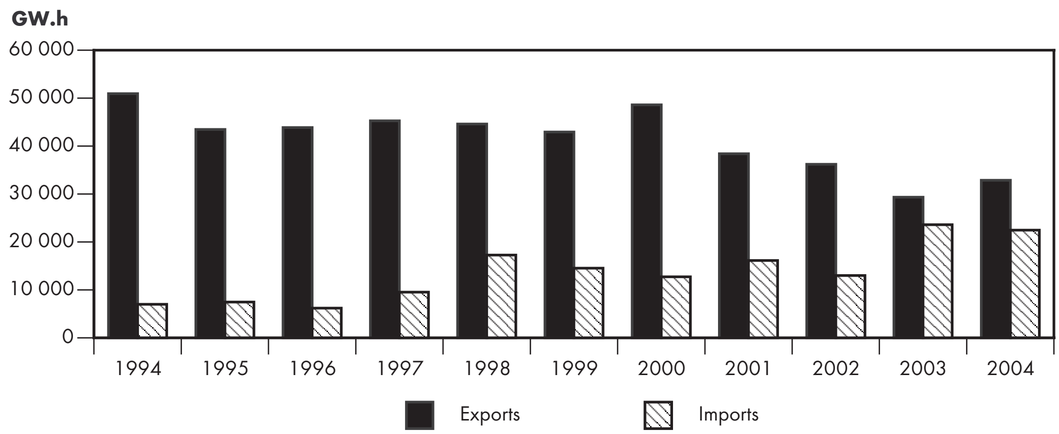
Canada is a net electricity exporter to the U.S. Mainly due to the availability of low cost hydroelectric resources, both countries realize commercial benefits and improved electric reliability through trade. The major U.S. initiative to augment inter-regional trade has been to allow wholesale market access by mandating open access to transmission systems.

Since the issuance of Order 2000 in 1999, the U.S. Federal Energy Regulatory Commission (FERC) has promoted the formation of Regional Transmission Organizations (RTOs) as the mechanism to achieve wholesale access, thus enabling U.S. consumers to obtain lower cost power from other regions. While FERC has no jurisdiction in Canada, its policies have an impact on Canadian entities that trade with the U.S.

Over the period 1994-2003, electricity exports were typically in the range of 35 000 to 45 000 GW.h per year. In recent years, exports have trended downward (Figure 2.1), mainly as a result of growing domestic demand and below average precipitation levels in hydro-based provinces, while imports have trended upward to meet temporary supply deficiencies in some areas. For example, although usually accounting for most of Canada's electricity exports, some hydro-based provinces were net importers in 2003-2004, due to low water levels. In 2004, exports comprised less than five percent of national generation compared with the historical average of seven to nine percent. Net exports, led by Québec and Manitoba, increased from 5 700 GW.h in 2003 to 10 400 GW.h in 2004. Assuming a return to normal precipitation levels, net exports should continue to recover in 2005 and 2006. Absent investment in generation and transmission, exports after 2006 could be constrained by lack of surplus generation and some regions might need to rely on imports to meet future domestic demand.

FIGURE 2.1

Canada International Electricity Trade

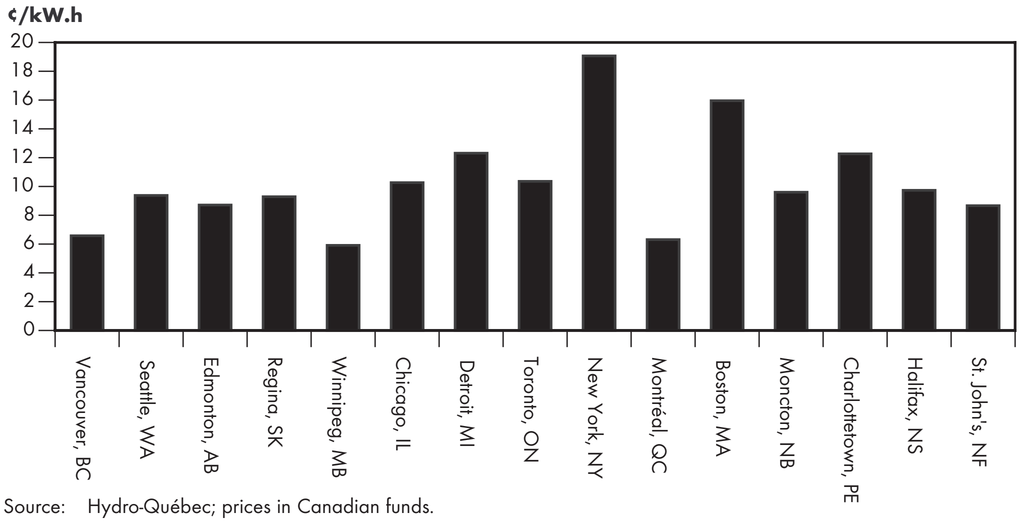


Source: NEB, Statistics Canada

2 Depending on the type of generation being developed, a construction lead time of between two and ten years is required.

F I G U R E 2 . 2

North America 2004 Residential Electricity Prices (excluding taxes)



Source: Hydro-Québec; prices in Canadian funds.

Electricity Prices

Energy prices have been high and volatile in recent years, especially for oil, natural gas and, to a lesser extent, imported coal. Rising fuel costs have contributed to near double digit electricity rate increases in some thermal-based jurisdictions (e.g., Nova Scotia, New Brunswick, Newfoundland and Labrador). Hydro-based jurisdictions (Québec, Manitoba, British Columbia) are experiencing moderate rate increases due to rising operating costs. Electricity prices vary considerably by region, and tend to be lower in Canada than in adjacent U.S. markets (Figure 2.2).

Ratepayers in many regions have derived benefits from existing heritage generation and transmission assets. In most cases, these assets have already been largely depreciated. As output from heritage assets becomes fully utilized, development of new facilities will be required. These incremental investments will exert upward pressure on electricity rates.

With the increased use of natural gas for electric generation, some convergence has occurred between natural gas and electricity prices (Figure 2.3). Short-term upward pressure on electricity prices will result from a tight supply and demand balance in the natural gas market. This pressure could be alleviated by an increase in natural gas supply, potentially by liquefied natural gas (LNG) imports and, in the longer term, from northern gas fields. In Atlantic Canada, recent sharp increases in oil and coal prices contributed to rising generation costs and, consequently, rising electricity rates.

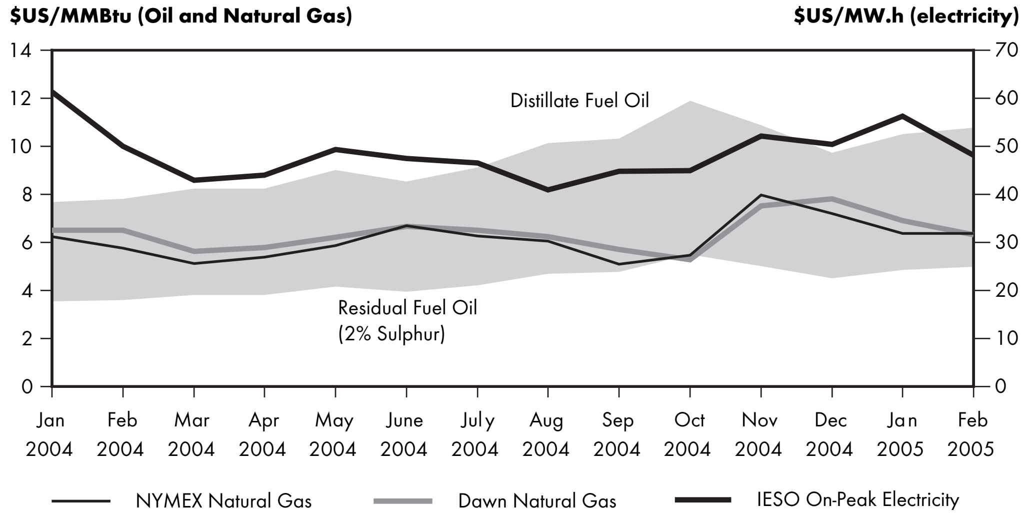
Although costs have decreased considerably over the last two decades as a result of technological advances, the inclusion of alternative and renewable resources in regional supply mixes could also exert upward pressure on prices. Such pressure could result from a combination of displacing new thermal resources and the cost of new transmission development and higher operating reserve requirements. Overall, increased costs could be offset by environmental benefits and increased diversification of regional supply portfolios.

2.2 Policy Development

With respect to the development of electricity policy and regulatory oversight, the federal government has jurisdiction over electricity exports, and international and designated interprovincial power lines.

FIGURE 2.3

Energy Price Comparison



Source: NEB

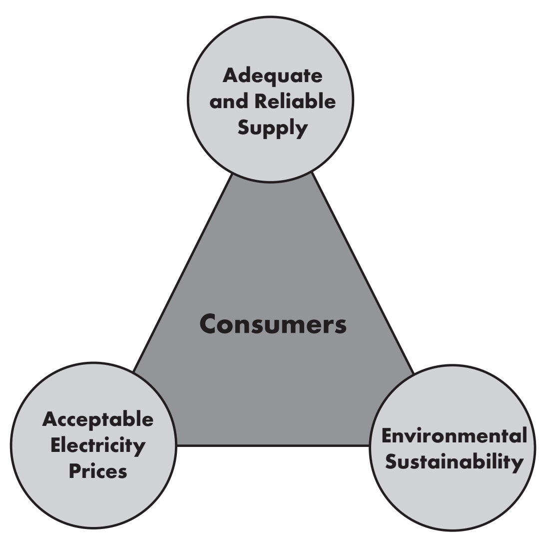
The provinces and territories have jurisdiction over generation, transmission and distribution of electricity within their boundaries including restructuring initiatives and electricity prices.

In most provinces, electric utilities were Crown corporations that served as instruments for regional and economic development. The ways that each province developed its generation mix varied and were largely dependent on the resources available and the objectives of its respective provincial government. Generally, regions with ample hydro resources and water storage capability have been able to keep domestic rates low and generate revenue from exports.

With growing electricity demand, increasing fossil fuel prices and the aging of the power system infrastructure, supply adequacy and reliability have become key issues. Moreover, the desire for a cleaner environment has resulted in more stringent environmental standards and consumers are concerned about rising energy prices. In response to evolving market conditions, and to meet consumers' needs, most provinces are in the process of developing energy strategies and, in some cases, related legislation. Although there are regional differences, most energy strategies are being designed to pursue, by varying degrees, a combination of the following key objectives: adequate and reliable supply; environmental sustainability; and acceptable electricity prices (Figure 2.4). Considering the potential trade-offs in pursuing these objectives, policy development requires a balanced approach.

FIGURE 2.4

Key Policy Objectives



2.3 Restructuring

Over the past decade, many North American jurisdictions have restructured their electricity markets to varying degrees. In the traditional market structure, a vertically-integrated utility provides transmission, generation and distribution service to a given franchise area, and often has limited access to other markets. Consumers pay regulator-approved prices based on the cost of service. The intention of restructuring is to separate, or unbundle the three functions and promote competition in the generation, wholesale and retail sectors. The general expectation has been that competition will encourage efficiencies and lead to lower costs. Wholesale access to transmission grids enables local distribution companies, or other large buyers, to use the grid to purchase electricity from the most competitive generation sources. Finally, retail access could economically benefit consumers as a result of having choice among suppliers.

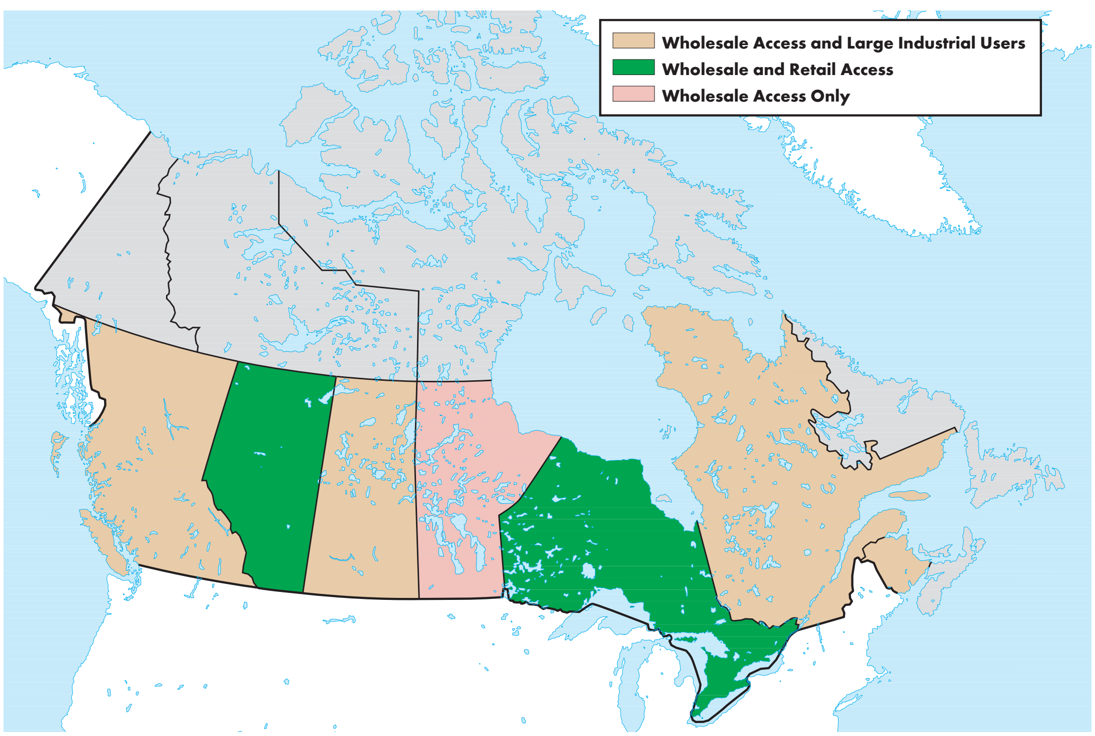
The extent of restructuring in Canada varies across the country (Figure 2.5). Alberta and Ontario have moved the furthest in restructuring their markets. British Columbia, Saskatchewan, Québec and New Brunswick have wholesale access and retail access to large industrial users, while Manitoba allows wholesale access only. Restructuring is an evolving process, and policy changes continue to be made to foster competition, enhance customer choice and improve market rules. Although changes are meant to improve the market, a concern exists that frequent policy changes may deter investment. There has been a debate in many jurisdictions as to whether or not restructuring is likely to achieve its intended objectives.

Several provinces have introduced competition in the generation sector and provided open access transmission tariffs (OATT). This allows independent power producers (IPPs) to bid on new generation development, and use the transmission system to gain access to wholesale markets. In many regions, IPPs and OATT development have been incorporated into the market structure while retaining many attributes of a vertically-integrated utility.

2.4 Key Industry Challenges

FIGURE 2.5

Status of Restructuring as of 1 April 2005



Source: NEB

Supply Adequacy

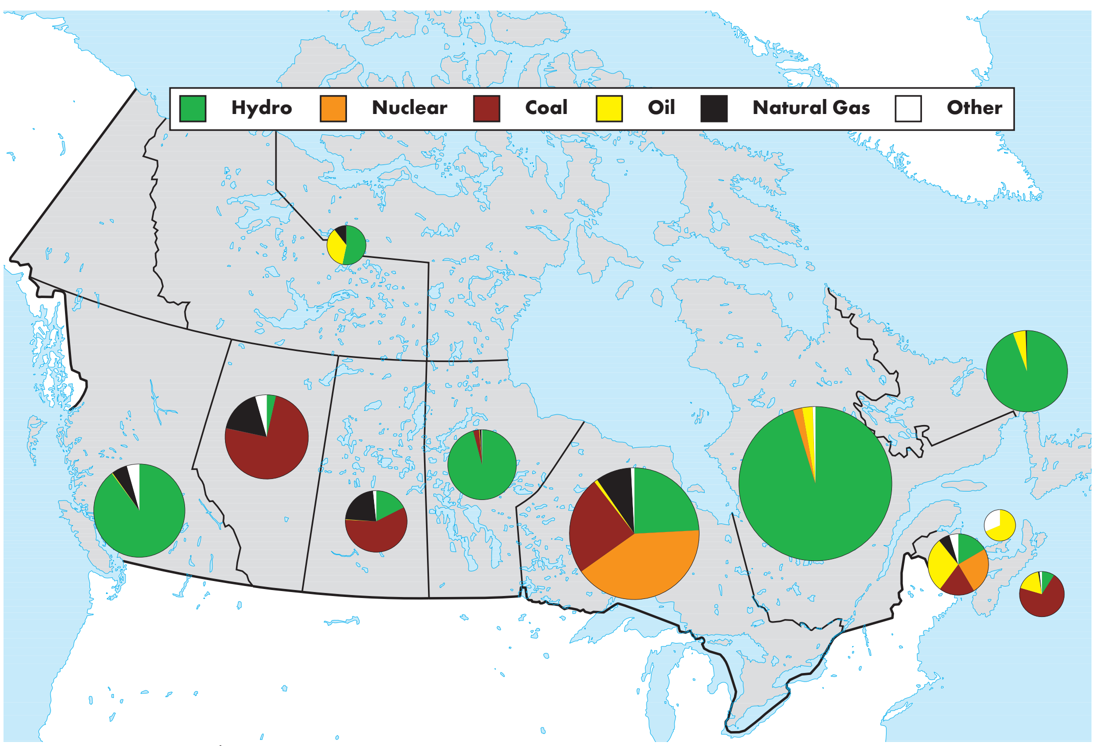
Canadian electric utilities are challenged to ensure generation and transmission infrastructures are adequate to serve increasing customer loads. Regional development of electrical assets is largely dependent on available resource endowments. In Canada, hydroelectric production is concentrated in British Columbia, Manitoba, Québec and Newfoundland and Labrador. Generation in Alberta, Saskatchewan, Ontario, the Maritime Provinces, and the Territories is largely thermal-based (Figure 2.6). There is a significant component of nuclear generation in Ontario and New Brunswick, while natural gas-fired generation, as stand-alone facilities or part of a cogeneration process, is becoming more common in most regions.

Traditional hydro, coal-fired and nuclear generation require large capital investments and long construction lead times but generally have low operating costs. Natural gas-fired generation tends to have lower initial investments and short lead times; however, fuel costs are higher and can be more volatile. Most regions must now consider more expensive generation options or imports to ensure short and long-term supply adequacy. These new incremental generation sources will contribute to increased costs to the end-user.

In addition to generation, an adequate transmission infrastructure is vital to ensure system reliability and realize economic benefits from optimal operation. In some areas (e.g., Alberta and Ontario), new transmission requirements have been identified. In many regions, industry, governments and transmission providers are moving toward a framework to resolve transmission concerns. Other factors that must be taken into consideration are that generation and transmission projects often require large investments, and that if generation is built close to load centers, transmission requirements are reduced.

FIGURE 2.6

Canada 2003 Generation by Fuel



Source: Statistics Canada

Demand-Side Management (DSM) and Demand Response (DR) Programs

DSM programs have been developed to encourage consumers to conserve power and to shift consumption to off-peak times. These programs include consumer education, promotion of energy efficient appliances and other energy saving devices, and energy audits. Some DSM programs provide incentives to participate, such as offering rebates to consumers to switch to high-efficiency lights.

DR programs target consumers that have the flexibility to switch energy use from on-peak to off-peak times, or to curtail consumption in response to price signals. In the past, DR programs were aimed at relatively larger consumers and usually included tariff provisions enabling consumers to economically benefit by changing consumption patterns. While these programs continue for large consumers, DR programs are now being considered for smaller consumers. Time-of-use metering and pay-as-you-go metering have been tried or are being considered in some jurisdictions.

Time-of-use metering, some times referred to as smart metering, requires installation of meters that read the quantity of energy consumed during various times of the day and implementing time-of–use tariffs that are structured to reflect cost variations throughout the day, and which would more closely reflect the real cost of providing power. For example, customers could be charged according to the amount of power used during each of three daily periods: on-peak; off-peak; and shoulder.

Pay-as-you-go metering is a system where consumers can track their consumption of electricity. Consumers pay in advance for electricity and a pay-as-you-go meter installed in the residence can be read to determine how much energy is consumed and how much it costs based on the regulated cost-of-service rate. Most pay-as-you-go meters support time-of-use rate registers, so eventually pay-as-you-go programs may become time-of-use programs.

Managing Demand

Another strategy to ensure consumers' needs are met is through demand-side management (DSM) and demand response (DR) initiatives. It is generally accepted that, within limits, the cost to reduce a kW.h through these methods is lower than the cost of producing an incremental kW.h. However, utilities are not necessarily motivated to promote energy conservation programs because these will have a negative impact on sales and revenues. In some jurisdictions, there is a growing belief that an effective way to encourage more efficient energy use is to rely on market-based mechanisms such as allowing rates to move towards market values established by supply and demand forces. Some jurisdictions have started to use time-of-day pricing and most regions are pursuing DSM and DR initiatives. Such initiatives initially focus on large consumers while residential consumers are now being targeted through programs that include energy conservation, education and time-of-day prices.

While electricity costs can be significant for commercial and industrial customers, they are not a major item in an average household budget. As a result, some have suggested that costs are often not high enough to induce residential consumers to conserve energy. Residential consumers are generally not exposed to market price signals, making it difficult to implement residential DR programs.

Green Generation

The Canadian electricity sector accounts for about 20 percent of greenhouse gas (GHG) emissions. Generation technologies vary in terms of GHG emissions. Nuclear and hydro-based generation have no and low GHG emissions respectively, while thermal-based generation is a major source of GHG emissions, with coal and oil being higher emitters than natural gas. Since the generation mix varies by region, thermal-based regions could face additional challenges from new GHG emission standards as they become an economic cost, while hydro-based regions could benefit.

Due in part to their oil and gas industries and their reliance on coal-fired generation, Alberta and Saskatchewan have greater levels of GHG emissions when compared with their proportions of the national population (Figure 2.7). This implies that, on a per capita basis, significant GHG reductions or alternative strategies for reduction may be required. Conversely, provinces that are hydro-based, such as British Columbia, Manitoba and Québec, emit less GHGs per capita and might benefit from emission standards by selling “clean” power or carbon credits to higher emitting regions.

The *Kyoto Protocol* came into effect on 16 February 2005. However, governments and industry had already started to take actions on climate change and improving environmental performance. Electricity generators have made gains in areas such as low-emission technologies, energy efficiency, emerging renewable power and emission offsets. Through the Canadian Clean Power Coalition (CCPC), industry is partnering with governments in research, development and demonstration of commercially viable clean coal technologies. In addition, most regions have developed either mandatory or voluntary renewable portfolio standards that encourage development of green generation such as wind, biomass and small hydro. Spurred by the quadrupling of the federal Wind Power Production Incentive (WPPI) target to 4 000 MW, and initiatives at the provincial level such as Hydro-Québec’s call for proposals, the development of wind generation is increasing substantially.

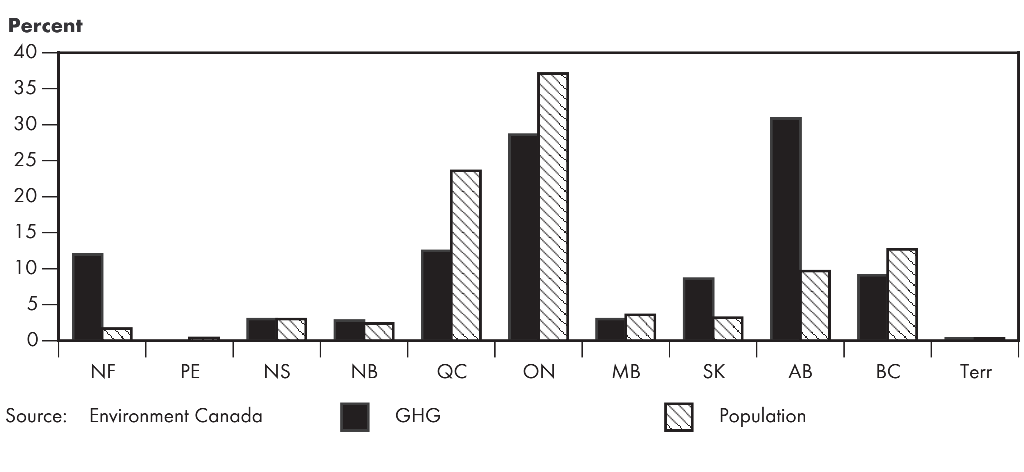
The 23 February 2005 federal budget outlined policy direction and introduced measures to reduce GHG emissions, including: a Clean Fund to support green projects; an emerging emissions trading system; and further incentives to support wind energy production, and other forms of renewable energy such as biomass and landfill gas. The 13 April 2005 release of *Project Green*, the Federal Government’s plan to honour Canada’s *Kyoto Protocol* commitment, has provided further details on how *Kyoto Protocol* targets can be met.

An emerging trend is that an increasingly informed public is participating more actively in the decision making process, particularly as it relates to siting new generation and transmission facilities. Proposals for generation to be sited near population centres may be opposed by the general public. This resistance could be based on environmental concerns, relating to emissions and other potential environmental problems associated with large facilities, or it could be related to the negative visual aesthetics such a facility would present.

Strong public reaction can be expected when transmission lines are proposed, particularly if siting is to be in close proximity to urban areas. In addition, transmission lines require continuous corridors, which have their own set of environmental issues with potential impact on wildlife, vegetation, water

FIGURE 2.7

Greenhouse Gas Emissions and Population as Percent of Canadian Total (2000)



Source: Environment Canada

crossings and soil. These problems increase the complexity of defining routes and obtaining the necessary permits.

Natural Gas-Fired Generation

Until recently, natural gas was the fuel of choice for new generation. Many regions opted for natural gas-fired generation over conventional generation sources that included coal, nuclear and large hydro. The significant growth in natural gas-fired generation capacity in North America can largely be attributed to: a relatively short construction lead time for gas-fired plants; low natural gas prices throughout the 1990s; and natural gas being preferred over other fossil fuels for its clean burning properties. Moreover, there has generally been less public opposition to natural gas-fired plants than to coal-fired or nuclear facilities. However, with natural gas prices reaching unprecedented levels and experiencing greater price volatility, the "dash-for-gas" has lost some of its allure. As a result, many regions are reassessing the economic feasibility and extent of the natural gas-fired generation option.

An outcome of the growing use of natural gas for electric generation in many regions is the development of convergence between electricity and natural gas prices. Additionally, there are emerging infrastructure issues that may occur from having to move substantial quantities of natural gas; for example, if a substantial amount of coal-fired generation in Ontario is replaced with natural gas.

Electric Reliability[3]

As demand increased and subsequent investment occurred in new generation development, investment in new transmission did not keep pace. Consequently, transmission constraints are becoming more prevalent. Furthermore, in the wake of the 14 August 2003 blackout, reliability of the interconnected North American bulk power system has become a priority concern. *The Final Report of the Canada-U.S. Task Force* outlined 46 recommendations to improve overall reliability and called for the establishment of mandatory reliability standards. A number of recommendations have been implemented. The proposed creation of an Electric Reliability Organization (ERO) to administer mandatory reliability standards is still awaiting legislation in the U.S. to be passed and implemented. The ERO will replace the current North American Electric Reliability Council (NERC) which administers the current system of voluntary standards.

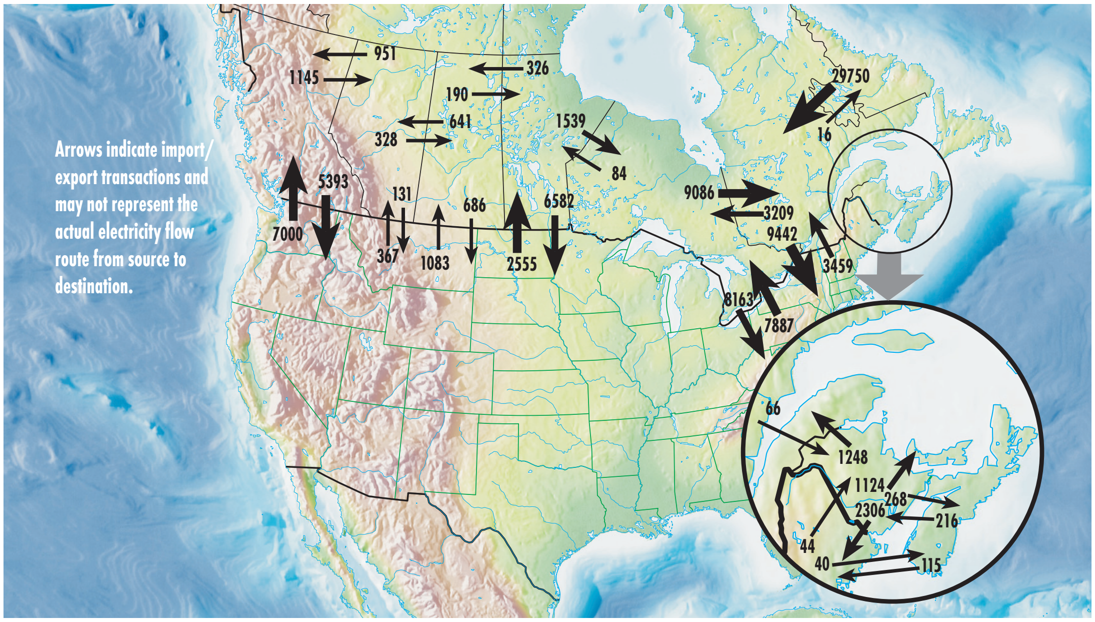
Canadians derive benefits from exports and imports that flow across international power lines (IPLs). The main exporting provinces, mostly hydro-based, are able to capture trade opportunities by storing water and then generating hydroelectricity when it is most economically advantageous. Recently, regions that experienced low hydro conditions benefited, both in reliability and economic terms, from the ability to import power. Even under normal hydro conditions, IPLs will continue to provide incremental benefits to these regions. In conjunction with development of RTOs, potential system reliability and potential economic opportunities should increase.

Connections between provinces are typically not as strong as north-south connections (Figure 2.8). In some cases, these interconnections are not developed sufficiently to optimize interprovincial synergies. Although the development of a comprehensive coast-to-coast grid would be very expensive, further regional developments could combine the attributes of hydro-based and thermal-based regions, along with improved reliability through increased energy supply options. CETI, a project aimed at bringing hydro power from Manitoba to Ontario, is an example of a proposal to expand east-west connections.

3 For more information on this topic, see A *Compendium of Electric Reliability Frameworks Across Canada*, June 2004, National Energy Board.

FIGURE 2.8

Canada Electricity Trade 2004 (GW.h)



Source: NEB, Statistics Canada

Clear Pricing and Investment Rules

Although supply resources are adequate today, the Canadian electricity sector needs significant investment over the next two decades to build new generation and transmission facilities, and upgrade or replace existing infrastructure. There is a need to foster an investment climate to ensure future reliable supply. An area of concern from an investor's perspective is related to electricity pricing. Since electricity prices remain largely regulated in many jurisdictions, industry is not getting clear pricing signals, which are needed to enable suppliers and consumers to make appropriate decisions in investing and using energy. Mixed or unclear price signals may lead to inappropriate or deferred investment decisions. Industry also faces uncertainties associated with, for example, changing market rules, political intervention in the market, and the impact of clean air initiatives such as the *Kyoto Protocol.*

2.5 Summary

Under normal operating conditions, the Canadian electricity sector will have adequate resources in 2005-2006 to meet growing electrical loads. However, some regions will experience supply tightness as early as 2007. Several jurisdictions are in the process of developing new energy strategies to balance the objectives of adequate and reliable supply, environmental sustainability and acceptable prices. Considering market uncertainties, policy makers and industry face difficult choices in balancing these three objectives in the near term. There will be upward pressure on consumer prices due in part to fuel costs and the development of new supply and transmission. Canadian and U.S. entities will continue to benefit from trade as exports will likely recover from depressed levels in recent years. The provincial sections of this report will discuss the above issues in more detail in the context of the near-term outlook.

Regional Market Assessments

3.1 British Columbia

British Columbia (B.C.) is a hydro-dominated region with interconnections to the U.S. Pacific Northwest (PNW) and Alberta. Although BC Hydro, the largest electricity utility in British Columbia, has the goal of being a self-sufficient supplier of capacity and energy, it takes advantage of trade opportunities with connected regions to optimize the economic benefits of the province's hydro resources.

In response to demand growth, and with the goal of ensuring future prosperity derived through relatively inexpensive electricity, the B.C. Ministry of Energy and Mines developed a long-term energy strategy titled *Energy for Our Future: A Plan for BC* (BC Energy Plan) in November 2002. The cornerstones of the BC Energy Plan are to maintain low electricity rates and maintain public ownership of BC Hydro's core assets, to have secure energy supply to meet current and future requirements, to stimulate private investment, and to have environmentally responsible energy development excluding nuclear generation.

3.1.1 Market Structure

The majority of British Columbia has been served by BC Hydro, a traditional vertically-integrated utility. The BC Energy Plan has furthered a partial market restructuring (i.e., wholesale access) begun in the mid 1990's. Under this plan, independent power producers will develop new generation while BC Hydro will generally be restricted to improvements at existing plants.[4] The plan also creates a framework where large electricity consumers will be able to choose their generation supplier, rather than be restricted to supply through their traditional local distributor, which in most cases is BC Hydro. At this time, residential and commercial customers continue to be served by their incumbent utility under a cost-based rate structure.

The British Columbia Transmission Corporation (BCTC) was created under provincial legislation. The role of BCTC is to manage BC Hydro's core transmission assets as an independent transmission entity to ensure non-discriminatory access to the transmission system for all market participants and to create a single focus on transmission issues. Through this partial restructuring, the British Columbia Utilities Commission (BCUC) maintains regulatory oversight of supply, transmission and distribution of electricity.

BC Hydro operates approximately 11 000 MW of the existing generation while the remaining 3 200 MW is provided by FortisBC (formerly Aquila), independent power producers and self-generation. Transmission needs are mostly met by BCTC while FortisBC is the next largest

4 The Energy Plan includes the development of the Peace Site C project as a special case where BC Hydro could be allowed to develop a new hydro generating facility.

service provider. British Columbia's distribution needs are predominantly met by BC Hydro, with FortisBC providing distribution in part of the south central portion of the province. Smaller municipal utilities and industrial facilities with on-site generation meet most of the remaining load.

BC Hydro released the *2004 Integrated Electricity Plan* (IEP) in March 2004. The IEP outlines BC Hydro's objectives to accommodate the BC Energy Plan's cornerstones through an action plan devised to procure supply-side and demand-side resources to meet forecast demand. The IEP focuses on BC Hydro's principal goal of achieving self-sufficiency with respect to domestic energy requirements.

3.1.2 Current Market Developments

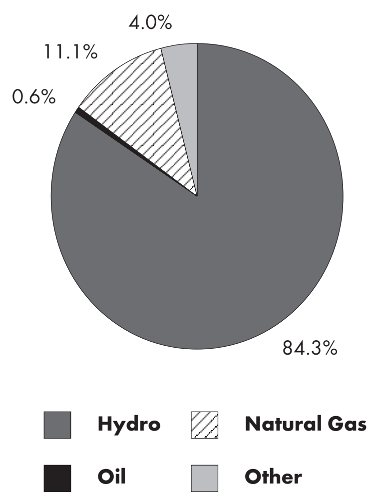
Generation

British Columbia continues to meet the majority of its electrical energy commitments through hydroelectric resources (Figures 3.1.1 and 3.1.2). Recent additions to the supply mix include clean technologies, such as small hydro, which added 700 MW of supply to the system from 2000 to 2003. Hydro availability is a key risk for provincial generators and utilities. Water levels were low in a number of years, particularly 1995 and 2001 (Figure 3.1.2). In these years, British Columbia utilities altered their export strategies so that, when compared with normal water years, exports decreased and imports increased allowing B.C.'s domestic demand to be met.

The BC Energy Plan states that electricity distributors should pursue a voluntary goal of acquiring 50 percent of new supply from clean generation. According to the IEP, BC Hydro responded to this goal through encouraging customer-based generation, the release of green energy request for proposals, and the optimization of existing hydro assets (Resource Smart).

FIGURE 3.1.1

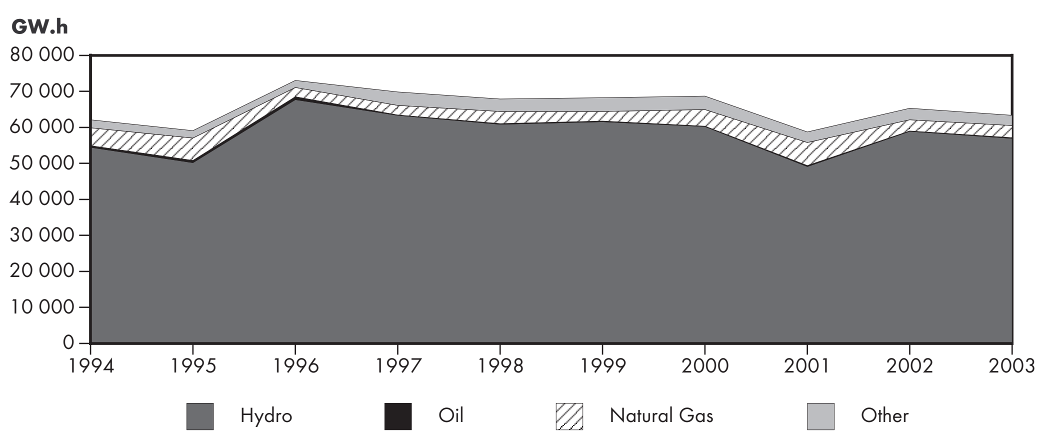
British Columbia 2003 Generating Capacity by Fuel (14 233 MW)



Source: Statistics Canada

FIGURE 3.1.2

British Columbia Generation by Fuel



Source: Statistics Canada

To meet the growing demand on Vancouver Island, the Vancouver Island Call for Tenders (VICFT) for new generation was held. The successful tender was Duke Point Power Limited Partnership (Duke Point Project), which committed to building a 252 MW gas-fired generator. The project received BCUC approval in February 2005 but the decision is currently before the British Columbia Court of Appeal. At the time of writing, the facility is scheduled to be available for the winter of 2007-2008.

Transmission

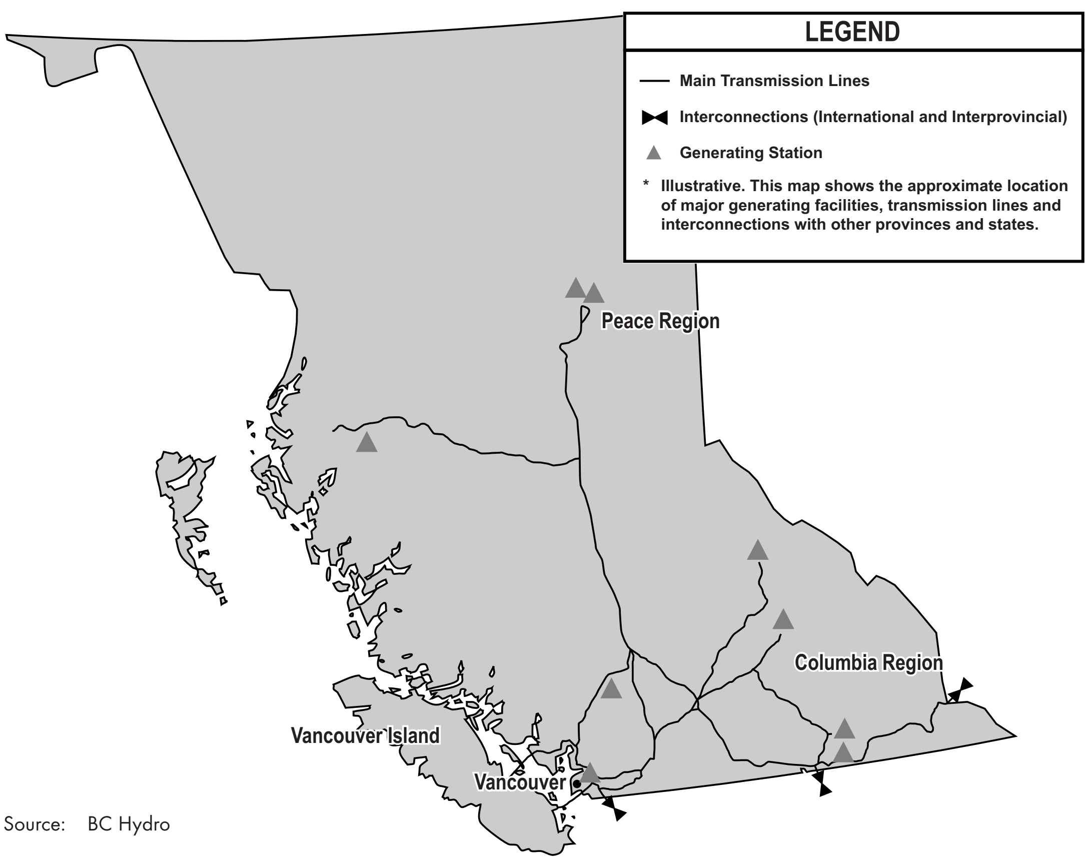
As indicated, BCTC is responsible for most of British Columbia's transmission infrastructure while FortisBC operates part of the infrastructure in the south central part of the province (Figure 3.1.3). In order to sustain and develop transmission infrastructure, both entities recently filed development plans with the BCUC. The BCTC plan received BCUC approval while FortisBC's plan is presently under review. To further promote wholesale access, BCTC is developing an OATT to replace the existing Wholesale Transmission Tariff.

Studies are being undertaken by the Northwest Power Pool Transmission Assessment Committee to assess transmission development spanning Western Canada to California. In addition, Sea Breeze Power Corporation, a merchant transmission developer, is undertaking feasibility studies for projects that would provide additional interconnections between B.C. and the PNW.

British Columbia and the interconnected American regions are in the process of developing an RTO. Due to the significant trade that occurs between British Columbia and the western U.S.,

FIGURE 3.1.3

British Columbia Electric Transmission System



Source: BC Hydro

Regional Transmission Organizations (RTOs)

Historically, the electric systems in North America began in municipalities and expanded to adjacent regions. Whether companies were private or public, they tended to focus on serving the customers in their service territories, with external trade and energy transfers a secondary concern. One of the main factors that promoted restructuring in the U.S. was that customers in higher cost service areas were unable to access power in lower cost service areas. To address the barriers to inter-regional trade, the U.S. Federal Energy Regulatory Commission (FERC) released Order 888 in April 1996 and Order 2000 in December 1999.

The purpose of FERC Order 888 is to promote wholesale competition through the provision of open access to transmission services on a non-discriminatory basis. While FERC has no jurisdiction in Canada, there are implications for Canadian entities that trade with the U.S. Specifically, in order to gain access to U.S. wholesale markets, Canadian jurisdictions must provide reciprocal transmission access.

FERC Order 2000 established a framework for the creation of Regional Transmission Organizations (RTOs), composed of one or more transmission companies that would function as an integrated transmission entity. This structure is intended to promote competition in wholesale markets by providing non-discriminatory access to transmission and to reduce the cost of transmission within the RTO area by eliminating rate pancaking.

Participation by transmission providers in an RTO is voluntary. FERC promotes RTOs in the U.S. and encourages Canadian entities to participate. Canadian entities generally recognize the benefits of RTOs if they are properly implemented. However, there are concerns by some stakeholders about the possibility of loss of control over the regional electricity system and that the cost involved could outweigh the benefits. To date, no Canadian entities have joined a cross-border RTO; however, there are many instances of cooperation. For example: Manitoba has a coordination agreement with the Midwest ISO; British Columbia has been participating in the development of the GridWest RTO; and Ontario cooperates with adjacent RTOs in the U.S. Northeast and Midwest.

the development of an RTO would provide economic and reliability benefits. British Columbia would be affiliated with Grid West (formerly RTO West). Although the creation of Grid West has not been as timely as the development of RTOs such as the Pennsylvania/New Jersey/Maryland Interconnection (PJM) in the Northeastern U.S., an important milestone was achieved in December 2004 when the majority of owners of the regional high voltage grid adopted by-laws that would govern Grid West. Consequently, achieving the goal of creating an independent regional transmission operator by 2007 has become more likely.

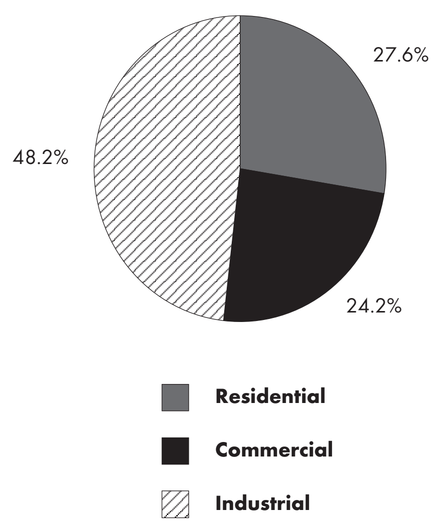
Consumption

During 2003, industrial, commercial and residential consumption were at 28 800 GW.h, 14 400 GW.h and 16 400 GW.h, respectively (Figure 3.1.4). Peak demand continues to rise with the growing economy.

With respect to demand-side management, the BC Energy Plan commits to developing new rate structures that will provide better price signals through stepped rates for large electricity consumers. Such rates would allow for 10 percent of a customer's historic

FIGURE 3.1.4

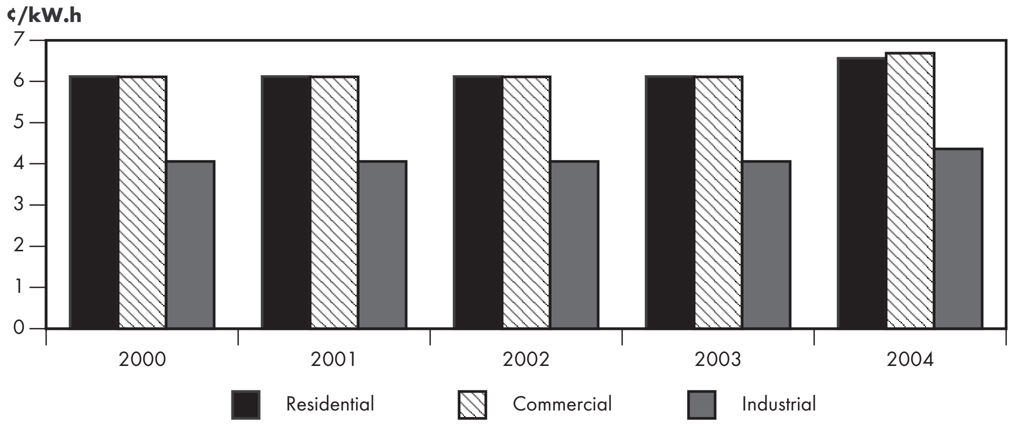
British Columbia 2003 Electricity Demand by Sector (59 651 GW.h)



Source: NEB, Statistics Canada

FIGURE 3.1.5

British Columbia Electricity Prices in Vancouver (excluding taxes)



Source: Hydro-Québec

electricity consumption to be sold at market prices. BC Hydro is presently developing rates to meet the BC Energy Plan commitment. In addition, utilities such as BC Hydro and FortisBC have developed demand-side management initiatives (PowerSmart and PowerSense, respectively) that are open to all classes of consumers.

BC Hydro consumer rates were frozen from 1993 to 2004. To recover the additional costs required to meet growing demand, BC Hydro received BCUC approval in October 2004 to increase rates by 4.85 percent, effective 1 April 2004 (Figure 3.1.5). FortisBC applied for a 4.4 percent rate increase. Rate increases will likely continue to occur as a result of new supply development and infrastructure upgrades, which are required to meet current and future demand.

Even with the approved rate increase for BC Hydro and the proposed rate increase for FortisBC, B.C.'s electricity rates will continue to be below the national average as a result of the hydro-based resources and ratepayer entitlement to these resources.[5]

Trade

From the standpoint of interprovincial transfers, electricity normally flows from British Columbia to Alberta during peak hours and from Alberta to British Columbia during off-peak hours (Figure 3.1.6). This is a result of the synergies that exist between the resource mix of the two provinces and because hydro storage allows energy banking.

The ability to incorporate energy banking into its portfolio has been economically beneficial for the BC Hydro trading subsidiary Powerex. Consequently, the ratepayers of BC Hydro benefit due to a reduction in BC Hydro's overall revenue requirement.[6] Energy banking entails the purchase of electricity from other markets during low price periods, which allows for hydro generation to be stored within British Columbia's reservoirs until it can be sold to other markets at higher prices. For example, a recent study by the Alberta Market Surveillance Administrator titled A *Review of Imports, Exports, and Economic Use of the BC Interconnection* estimates that Powerex, during a seven-month

5 The intent of the *BC Hydro Public Power Legacy and Heritage Contract Act* (Heritage Contract) is that customers of BC Hydro will continue to receive the low-cost electricity from BC Hydro's existing hydroelectric and thermal resources.

6 The Heritage Contract regulatory framework provides that the first $200 million in Powerex's audited net income is credited against the overall BC Hydro revenue requirement.

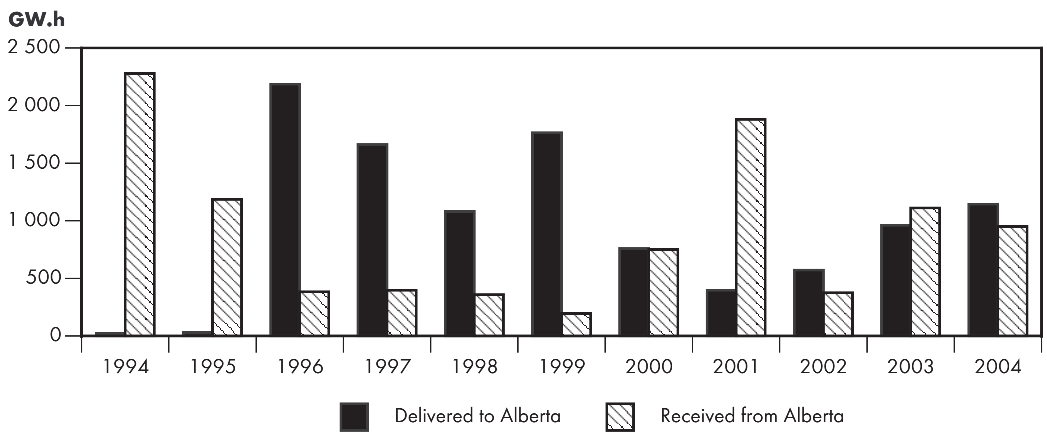
review period, realized a benefit of $13/MW.h on approximately 830 000 MW.h through energy banking.[7]

British Columbia benefits from interconnections with the PNW that also indirectly provide access to California. Historically, the benefits derived via the interties were primarily a result of exports and energy banking.

As a result of regional supply and demand rebalancing, wholesale market prices in the western U.S. have decreased from the peak experienced in 2001. Consequently, potential export margins and opportunities have also decreased. In addition, British Columbia recently increased imports due to below normal hydroelectric conditions, increased domestic demand, and transmission restrictions to the California market.[8] These factors resulted in a net import position for B.C. in 2004 (Figure 3.1.7).

FIGURE 3.1.6

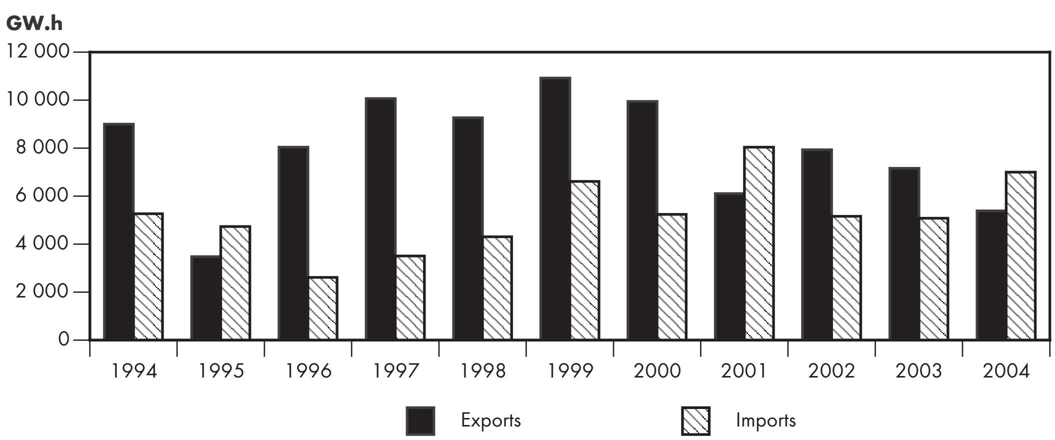
British Columbia Interprovincial Electricity Transfers



Source: NEB, Statistics Canada

FIGURE 3.1.7

British Columbia International Electricity Trade



Source: NEB, Statistics Canada

7 These numbers do not represent actual results from Powerex.

8 The Pacific Direct Current Intertie which connects California to the PNW was derated through the summer of 2004 and removed from service during the fall and early winter of 2004 to allow equipment upgrades.

At times, the decision to import power on the spot market is economic rather than physical. Instead of running the natural gas-fired Burrard Generating Station (Burrard), which is relatively inefficient, to meet the energy deficit that was developed during below normal hydro conditions, Powerex has opted to import energy from the PNW for less than the cost of operating Burrard.[9] Consequently, BC Hydro and its ratepayers have benefited from a reduction in overall energy costs through its interconnections with the PNW. Powerex is the largest volume exporter and importer of electricity in the PNW.

3.1.3 Outlook and Issues

Under normal hydro conditions, British Columbia will have an adequate supply base to meet domestic energy and capacity requirements through 2006. Although BC Hydro has a goal of being self-sufficient, it is expected that spot market imports from both Alberta and the U.S. will continue for energy banking and the economic displacement of Burrard.

The greatest risk to British Columbia's supply adequacy is below-normal hydroelectric conditions. Under this scenario, British Columbia will be able to meet domestic requirements, at a potentially higher overall cost, through a combination of running Burrard and importing power from both Alberta and the PNW. In addition, generation can be procured from the Canadian Entitlement capacity derived from the Downstream Benefits of the Columbia River Treaty.[10]

BC Hydro announced that it will proceed with energy calls for the development of new generation in the fall of 2005 for 1 000 GW.h instead of the originally planned 400 GW.h.[11] The increase is primarily a result of the desire to achieve self-sufficiency, increased domestic demand, the uncertainty surrounding the development of the Duke Point Project and the possible attrition of power developers who successfully bid on earlier energy calls. To further support the development of green resources, which tend to be intermittent in nature, BCTC is proposing the development of a new transmission rate.

British Columbia's potential opportunities for short-term spot market power exports to California during the summer of 2005 have increased for three reasons. First, the California supply and demand balance continues to tighten due to increased demand and the potential retirement of up to 9 000 MW of California generation. Second, the transmission constraint on the Pacific Direct Current Intertie that connects the PNW to California has been eliminated. Third, the PNW is currently experiencing a below normal hydro year that will minimize the ability to export energy to California from this region during the summer of 2005. These opportunities are offset by uncertainties including litigation surrounding electricity sales during the California energy crisis of 2000-2001.

British Columbia is likely to continue to have opportunities to import power from the PNW during the off-peak and periodically during peak periods. Under normal hydro conditions, the PNW would be well supplied through the near-term and efficient combined-cycle gas-fired generation would set the spot market price frequently through 2006. This would allow Powerex to import energy as an alternative to running the Burrard Plant. However, these import opportunities could diminish if either the PNW economy strengthens, leading to increased demand for electricity in the PNW, or the PNW experiences a below normal hydro year. For the summer of 2005, indications are that the PNW

9 Burrard is a 950 MW conventional natural gas-fired facility that provides back-up to B.C.'s hydroelectric system. It runs less efficiently and is more expensive to operate than newer gas-fired generation facilities.

10 Entitlement power currently amounts to 1 170 MW of capacity of which BC Hydro incorporates up to 500 MW into its Service Plan.

11 There will be a further energy call for 1 000 GW.h in 2006.

will experience a below normal hydro year, which will reduce potential opportunities for economic imports.[12]

Interprovincial electricity trade volumes could increase in the near-term as a result of transmission components returning to service in the Calgary region and the recent addition of base load generation in Alberta.

Potential increases in overall prices will result from the costs of natural gas, new supply development, and transmission infrastructure maintenance and development. The cost of natural gas is particularly noticed when domestic demand is met by running Burrard or importing power from the PNW. Until northern gas or significant quantities of liquefied natural gas appear within North America, the possibility of the price of natural gas prices being high and volatile is much greater.

By 2009, upgrades to the transmission system between Calgary and Edmonton will increase the potential for interprovincial power transfers. The Alberta Electric System Operator's (AESO) *10-Year Transmission System Plan (2005-2014)* states that these upgrades would assist in increasing exports from Alberta to British Columbia to over 700 MW during the peak and off-peak periods. For market participants to derive the greatest possible benefits of the diversity between British Columbia's hydro capacity and Alberta's dependable base load thermal generation, continuous analysis with follow-up actions is required.

As noted, BC Hydro is currently in the process of ensuring generation for Vancouver Island through the VICFT process. BC Hydro has also requested that BCTC obtain approval to preserve an in-service date of 2008 for 230 kV alternating current (AC) submarine transmission cables to connect the Lower Mainland to Vancouver Island. Both BCTC and BC Hydro believe that the submarine transmission cables are necessary for long-term reliability purposes whether or not on-Island generation is built. The current set of high voltage direct current cables are old and cannot be counted on beyond 2006 and the existing 138 kV submarine cables are aging as well and will also need to be replaced.

Under a scenario where on-Island generation is not built, and new submarine cables are constructed, a concern exists since the energy would be provided to the Island from the existing supply base on the Mainland. This would have the effect of accelerating BC Hydro's dependable energy requirements and of decreasing the certainty of having adequate supply. To compound this issue, some entities believe that it would be difficult to build any new large-scale base load generation in British Columbia due to the potential of significant resistance by some stakeholders. Consequently, uncertainty surrounding the timeliness of developing new generation could increase.

If the Duke Point Project is constructed, overall rates will increase due to the cost of building and operating a natural gas-fired generator. Specifically, the Duke Point Project power purchase arrangement subjects BC Hydro and its ratepayers to a capacity payment and the provision of natural gas for the facility. However, it can be argued that the alternatives to the Duke Point Project would be even more expensive and require a larger rate increase. The BC Energy Plan includes elements such as the least cost addition of new resources requirement and BCUC scrutiny to ensure that rates are kept as low as possible.

In either case, new base load generation (i.e., Island or Mainland generation) will exert upward pressure on overall rates as the cost for new facilities will be significantly higher than the existing

12 As of 1 April 2005, the Northwest River Forecast Centre, a division of the National Oceanic and Atmospheric Administration, has predicted in its final January forecast that Columbia River flows from April through September will be 68 percent of normal at The Dalles Dam on the Washington and Oregon border.

heritage assets. The exception is two proposed hydro capacity additions at Mica and Revelstoke, which will not have a significant impact on price due to favourable economics surrounding these expansions.

3.1.4 *Summary*

In recent years, British Columbia has benefited from its ability to export and import via interconnections with the U.S. and Alberta. This fact and the public ownership aspect of the province's Heritage Assets are two drivers behind the province's ability to maintain a low cost structure for end-users. B.C.'s growing demand for electricity can only be met with higher cost supply. These costs will be passed through to consumers.

3.2 Yukon, Northwest Territories and Nunavut

The Yukon, Northwest Territories and Nunavut (the Territories – Figure 3.2.3) cover 40 percent of the Canadian land mass. However, with a population of about 102 000 - of which 31 000 reside in the Yukon, 42 000 in the Northwest Territories (N.W.T.) and 29 000 in Nunavut - there is a very low population density. Therefore, apart from the transmission systems that serve more concentrated loads in the Yukon and N.W.T., there are many isolated communities and industrial sites that rely on diesel-fired generation plants and local distribution networks.

While the Territories all share certain characteristics, they have unique patterns of generation.

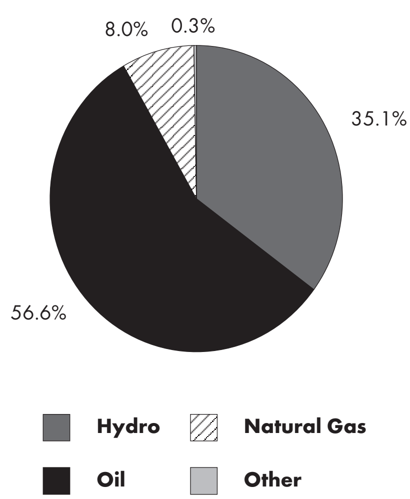
3.2.1 *Market Structure*

Yukon

In 2003, generation in the Yukon was 320 GW.h, of which 88.9 percent originated from hydro sources, 0.3 percent from wind and the remainder from diesel-fired generation units. Generating capacity was approximately 125 MW, of which hydro accounted for 76 MW and diesel 48 MW. Wind capacity was just less than one MW (Figures 3.2.1 and 3.2.2).

FIGURE 3.2.1

Yukon, Northwest Territories and Nunavut 2003 Generating Capacity by Fuel (304 MW)



Source: Statistics Canada

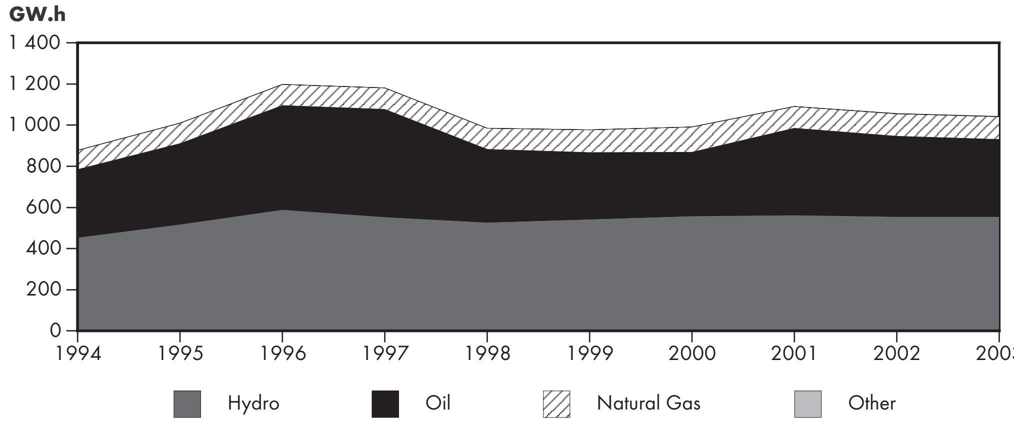
Yukon Energy Corporation (YEC), a subsidiary of the crown-owned Yukon Development Corporation, is the dominant power generator with almost 90 percent of capacity, including all the major hydro facilities. It also owns and operates two separate transmission systems that serve loads in the vicinity of Whitehorse-Aishinik-Faro and Dawson City-Mayo. The remaining generation capacity in most of the Yukon's other rural communities is owned and operated by Yukon Electric Company Limited (YECL), a subsidiary of ATCO Electric. Outside the Dawson City area, YECL handles most of the distribution in the Yukon and in some places, including the capital city Whitehorse, distributes power as a wholesale customer of YEC.

Northwest Territories

In 2003, electricity generation in the N.W.T. was 588 GW.h, of which about 46 percent originated from hydro sources,

FIGURE 3.2.2

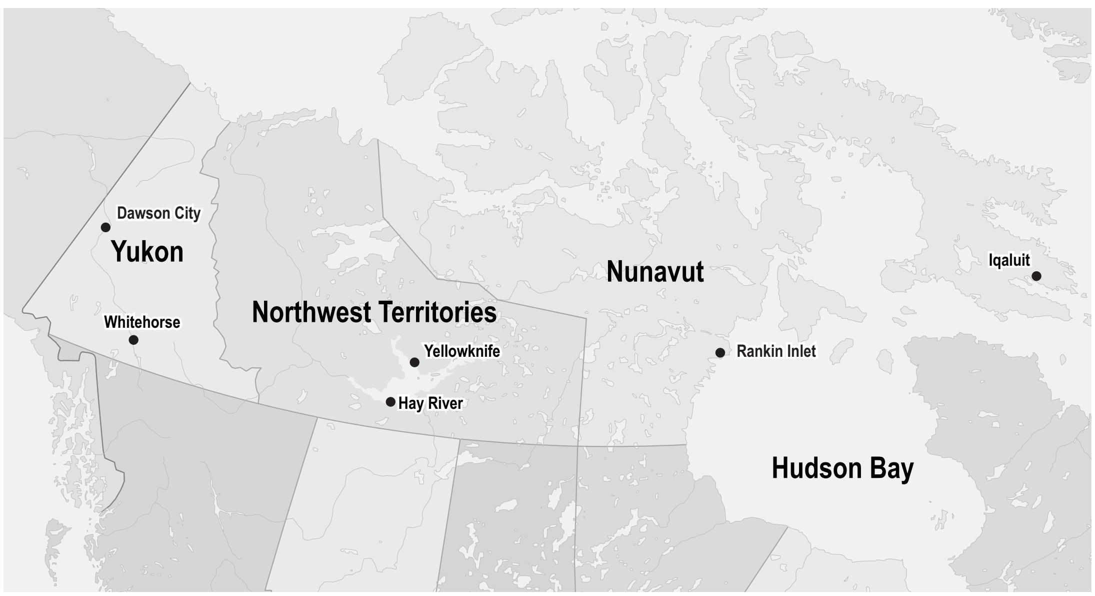
Yukon, Northwest Territories and Nunavut Generation by Fuel



Source: Statistics Canada

FIGURE 3.2.3

Yukon, Northwest Territories and Nunavut



Source: NEB

50 percent from diesel-fired units and four percent from natural gas-fired units (Figure 3.2.2). The Northwest Territories Power Corporation (NTPC), a Crown corporation of the Government of the Northwest Territories, is the main producer of electric power in the N.W.T. Power is produced from 27 systems including six hydro facilities and two separate transmission systems located near Fort Smith and Yellowknife. The hydro facilities are the main generators of power for Hay River, Fort Smith, Fort Resolution, Yellowknife, Dettah and Rae-Edzo. Power is produced from natural gas-fired facilities in Inuvik and Norman Wells, and diesel-fired facilities in other communities. Power distribution is handled by Northlands Utilities Ltd. (a subsidiary of ATCO Electric) in Hay River, Yellowknife, and four other isolated communities. NTPC looks after distribution in the remainder of the N.W.T.

Nunavut

In 1999, the Northwest Territories was divided into two parts. The western part retained the name Northwest Territories, while the eastern part became Nunavut. In April 2001, Nunavut Power Corporation (NPC) assumed the eastern operations of NTPC, after the two territorial governments agreed to divide the assets and liabilities of NTPC and establish two new corporate entities. Since then, NPC has become a subsidiary of Qulliq Energy Corporation (QEC), a territorial Crown corporation with headquarters in Iqaluit. In 2003 generation in Nunavut was 133 GW.h (Figures 3.2.1 and 3.2.2).

NPC provides electricity for 25 communities, either on the coast or with near access to the coast. Power is produced by diesel-fired facilities, which require that fuel be supplied by coastal shipping. The operations of the NPC come under the *Qulliq Energy Corporation Act* and applications for capital expenditures greater than five million dollars and rate increases are subject to the advice of the Utility Rates Review Council.

3.2.2 Current Market Developments

There are no plans for restructuring in the Yukon, Northwest Territories or Nunavut. Given their low population density, it is difficult to foresee a reasonable way to develop a retail or a wholesale energy market in the near future.

A major issue is that high oil prices have led to increased costs for diesel generation, which is an important source of energy. Fuel price stabilization funds can reduce the effect of fuel price swings on electricity rates, but the recent period of high fuel prices depleted these funds, which has led to rate increases. Any further responses designed to mitigate the effect of high fuel prices will be dependent on the resources in the individual jurisdictions.

Yukon

The YEC built the Mayo-Dawson Power Line, a 232 kilometre transmission facility that extends from the Mayo hydro facility to Dawson City, replacing diesel generation. This was the largest capital project undertaken in the history of the YEC and some problems with project management were encountered. In spite of the problems, the benefits of the project are significant, allowing the YEC to replace almost all of its diesel generation with hydro power. This is expected to save Yukoners about $20 million over 40 years.

Northwest Territories

The Northwest Territories has access to hydro generation and locally available natural gas for power generation at Norman Wells and Inuvik. This more diversified supply portfolio helps to moderate prices. Work continues on evaluating potential hydro sites.

Nunavut

Nunavut is the only jurisdiction to depend entirely on diesel fuel for electric generation, reducing its options for electricity price mitigation. The high price of diesel fuel led to a recent rate increase of 15 percent for residential customers and a 16.5 percent increase for commercial customers.

This is the first rate increase realized in this region since 1997. In addition to bringing electricity prices more in line with generating costs, the new rates initiated a move away from community based prices, where the cost of power depends on local infrastructure and generation costs towards a single price for electricity across Nunavut. The Government of Nunavut is also providing assistance to help the utility deal with accumulated debt.

3.2.3 *Outlook and Issues*

Although residential and commercial demand changes slowly and is fairly predictable, industrial demand associated with mining and other forms of resource exploitation can vary from year to year and have a significant impact on overall consumption of electricity in the Territories. Given the cyclical nature of commodity markets, industrial demand can increase or decrease from year to year. However, the effect of these variations on consumers is somewhat mitigated because many industrial sites provide their own generation, as distance makes it difficult to connect to existing generation.

As long as northern Canada is dependent on imported diesel fuel for electric generation, the associated high costs of electricity will be an issue. Use of hydro, where available, helps moderate costs, but there are load centres far from potential hydro sites. One option that is attracting attention is the use of wind turbines to supplement diesel generation in isolated communities. While still more expensive than power from conventional generation in the south, wind power has the potential to be competitive with diesel, particularly when the cost of transportation is included.

Isolated communities still require diesel generators to provide a back-up for wind, but even so there is a considerable potential to reduce overall costs if wind technology can be proven in the north. This has led to a number of pilot projects and studies, which indicate that the major challenge to introducing wind power appears to be technical. Wind turbine designs that work well in the south have encountered problems in the northern climate. There are other technical issues that must be addressed. While diesel generators are well understood, with trained personnel and spare parts available, the same is not true for wind turbines. It will take time to build up a similar support infrastructure for them. There are also additional costs to install and maintain wind turbines in remote areas without easy access to industrial equipment for erecting the towers.

Progress on northern wind will depend on the solution to these technical issues, but wind has overcome similar although less severe obstacles in the past in southern Canada. There does not appear to be any fundamental reason why wind cannot contribute to generation in northern Canada.

3.2.4 *Summary*

The Yukon, Northwest Territories and Nunavut face challenges not seen in the rest of the country. While areas with alternative sources of generation see rates comparable to rural regions of southern Canada, jurisdictions dependent on diesel generation face both a high cost of electricity and vulnerability to swings in the price of fossil fuels. Utilities in these regions are working to address these issues and have the potential to achieve more stable rates.

3.3 Alberta

Alberta has moved the furthest with respect to restructuring and the development of competitive markets. Since the *Electric Utilities Act* and subsequent market opening in 2001, Alberta's electricity market has continued to evolve. To ensure that the market is functioning optimally, policies such as the new *Electric Utilities Act, 2003* and the T*ransmission Regulation* (Alberta Regulation 174/2004) have been implemented. In addition, a review of the wholesale and retail markets is in progress to assess the existing challenges and to develop appropriate solutions.

3.3.1 Market Structure

Under the existing structure derived from the *Electric Utilities Act*, the generation component is competitive while the transmission and distribution functions are regulated monopolies. Retail for industrial and large commercial consumers is competitive. Although the retail market for residential, farm, and small and medium commercial consumers is open to competition, these consumers have the option to remain on a regulated rate tariff until 1 July 2006. At the time of writing, a large percentage of these classes of customers have made the choice to remain on the regulated rate tariff.

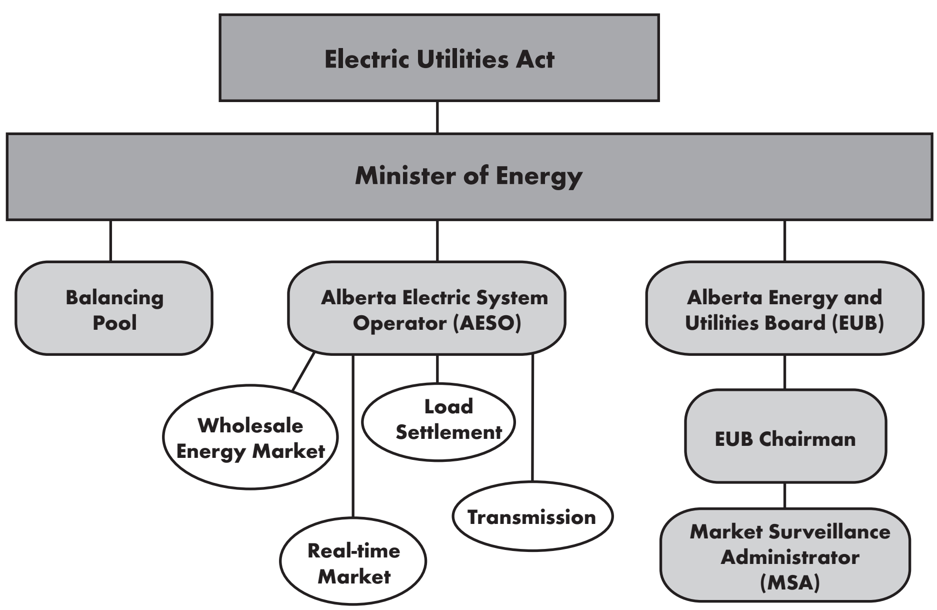
A competitive wholesale market exists in Alberta, which is facilitated by the AESO and monitored by the Market Surveillance Administrator (MSA). The Balancing Pool manages the financial accounts arising from the transition to a competitive generation market on behalf of electricity consumers including any obligations and responsibilities associated with Power Purchase Arrangements (PPAs). The role of the Alberta Energy and Utilities Board (EUB) is three-fold: to ensure the safe, responsible and efficient development of generation and transmission facilities; to ensure that distribution utilities and the AESO provide safe and reliable service at just and reasonable rates; and to approve the Regulated Rate Tariff applicable for smaller consumers.

There are numerous market participants. Some of the original entities such as EPCOR, ENMAX, TransAlta and ATCO continue to operate in many, but not all, of the restructured segments (e.g., neither TransAlta nor ATCO participate in the residential retail market). Entities such as TransCanada Energy, Direct Energy, Alta Link and FortisAB have entered the restructured market.

Long-term supply adequacy and the future termination of the regulated rate option for residential customers are two challenges. Alberta Energy is examining ways to manage these and other challenges that arise in the current market structure. For example, the department recently implemented the Transmission Regulation and is also conducting a wholesale and retail market review, which will lead to a final policy due to be released by the summer of 2005.

FIGURE 3.3.1

Alberta Electricity Industry Structure



Source: AESO

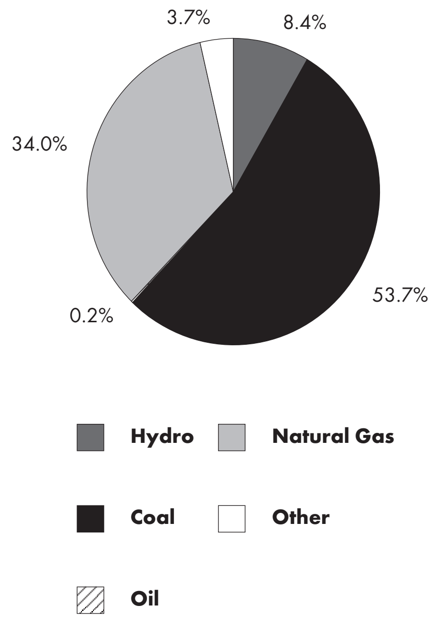
3.3.2 *Current Market Developments*

Generation

Through market restructuring, Alberta developed a healthy reserve margin when over 3 000 MW of new generation was brought onto the system between 1998 and 2004. Three-quarters of Alberta's energy requirements are met through coal-fired generation (Figures 3.3.2 and 3.3.3). This portion will grow as a result of the recently commissioned coal-fired 450 MW Genesee 3 generating unit located west of Edmonton.

FIGURE 3.3.2

Alberta 2003 Generating Capacity by Fuel (10 797 MW)



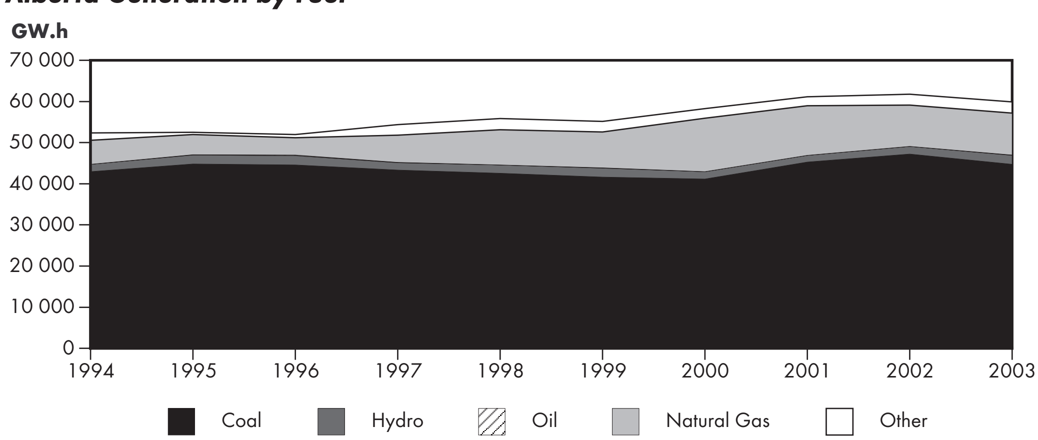
Source: Statistics Canada

However, the largest increase in Alberta's generation capacity in recent years has been natural gas-fired, due to the increased use of cogeneration technology and factors favouring the development of natural gas-fired generation.[13] For example, natural gas facilities have a lower capital cost, can be sited near load centres, have lower environmental impacts, and shorter construction lead-times.

The provincial government's voluntary renewable supply requirement is to have an additional 3.5 percent of energy being generated by renewable and alternative energy by 2008. Helping to achieve this goal, Alberta has developed additional supply that includes wind, biomass and small hydro. A number of factors encourage the development of wind generation in the southern part of the province. These include alleviating transmission constraints in southern Alberta, the quadrupling of the federally-funded WPPI, retail products that provide green energy at a premium, and the potential offset value of renewables in response to climate change initiatives.

FIGURE 3.3.3

Alberta Generation by Fuel



Source: Statistics Canada

13 Over 2 300 MW of the capacity additions since 1998 have been cogeneration.

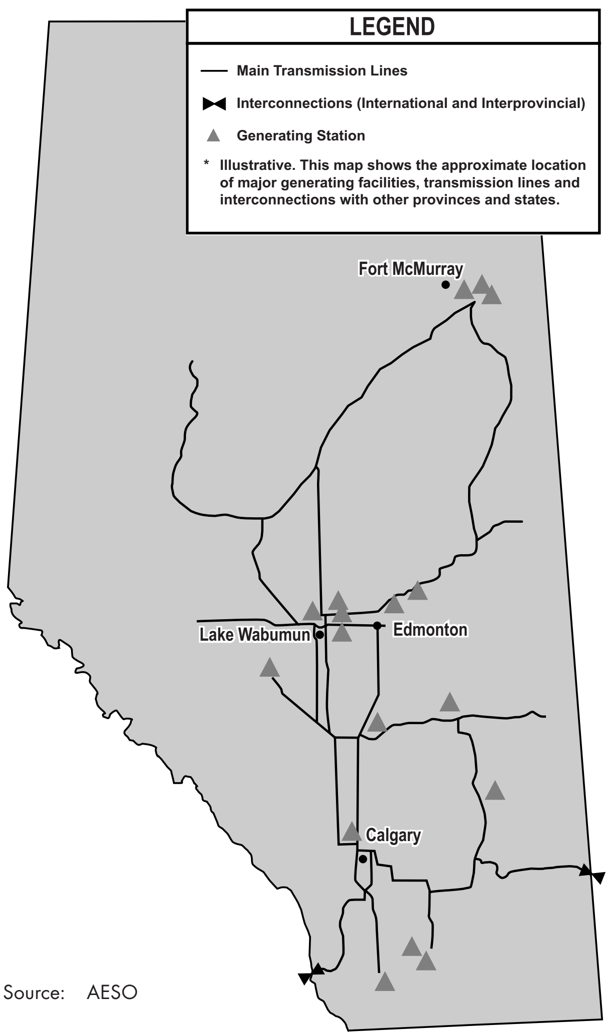
Transmission

In August 2004, the Alberta government enacted the *Transmission Regulation*, which is intended to provide direction for transmission planning and development in Alberta. Two objectives of the *Transmission Regulation* are to enhance system reliability and to facilitate the development of new supply and load. As part of the *Transmission Regulation*, the AESO was required to develop the *10-Year Transmission System Plan (2005-2014)* (Transmission System Plan). The latter outlines proposed system upgrades to the Calgary-Edmonton corridor, the Southwest and the Northeast Alberta regions (Figure 3.3.4).

In 2004, the AESO filed two key applications with the EUB. The first is the recently approved Edmonton-Calgary 500 kV Transmission Development with an estimated project completion date of 2009. The intended benefits include: enhanced reliability in the Calgary and southern Alberta region; increased opportunities to develop new generation in the Edmonton region such as a new coal-fired generation in the Lake Wabamun area or new cogeneration in the Fort Saskatchewan region; partial restoration of the export capability to the British Columbia and Saskatchewan interties; and a reduction in transmission line losses.

FIGURE 3.3.4

Alberta Electric Transmission System



Source: AESO

The second application, still before the EUB, is the Southwest Alberta Transmission System Development Need Application. The intent of this project is to resolve the growing need for transmission resulting from the development of wind energy potential, and to help ensure transmission reliability in the province.

Two merchant transmission projects that would connect Alberta directly with U.S. markets are currently in the developmental phase. These are the Montana Alberta Transmission Line, a 300 MW AC line from Lethbridge to Great Falls, Montana, and the NorthernLights project, a 2 000 MW high voltage direct current (HVDC) line that would connect the oil sands to the PNW or Montana.

Stakeholders in the Alberta system are currently working with their counterparts from British Columbia and the western U.S. to determine the feasibility of enhancing the interconnected transmission grid. A subgroup of the Northwest Power Pool Transmission Assessment Committee is presently evaluating numerous options and overall feasibility for increasing the transmission capacity from Northeast Alberta to California.

Alberta has taken the role of an observer in the Grid West RTO, because benefits of membership are limited due to Alberta's relative isolation from other markets.

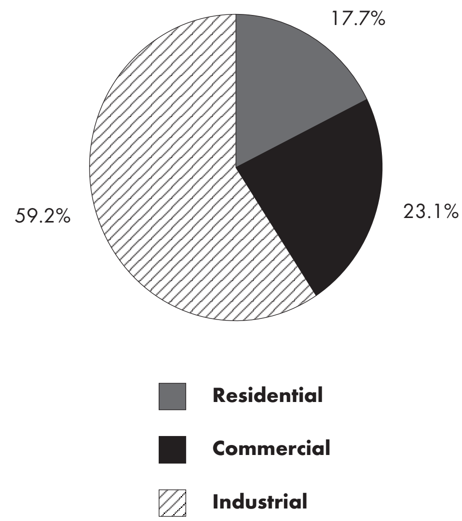
Consumption

In 2003, Alberta end-use consumption was dominated by industrial consumption (Figure 3.3.5), which continues to grow as a result of activities in the oil and gas sectors. Alberta's growing economy led to another peak demand record of 9 236 MW on 22 December 2004.

Demand-side management initiatives, such as conservation activities developed by Climate Change Central, a public-private partnership that promotes energy conservation through a combination of funded programs and education, occur within the province. In addition, ATCO Electric, Natural Resources Canada and InfoEnergy Incorporated are undertaking a pilot project to determine whether smart metering technology will allow utility customers to better manage their electricity use. Demand response, where industrial customers respond to high spot power prices by curtailing demand, also exists in Alberta.

FIGURE 3.3.5

Alberta 2003 Electricity Demand by Sector (53 628 GW.h)



Source: Statistics Canada

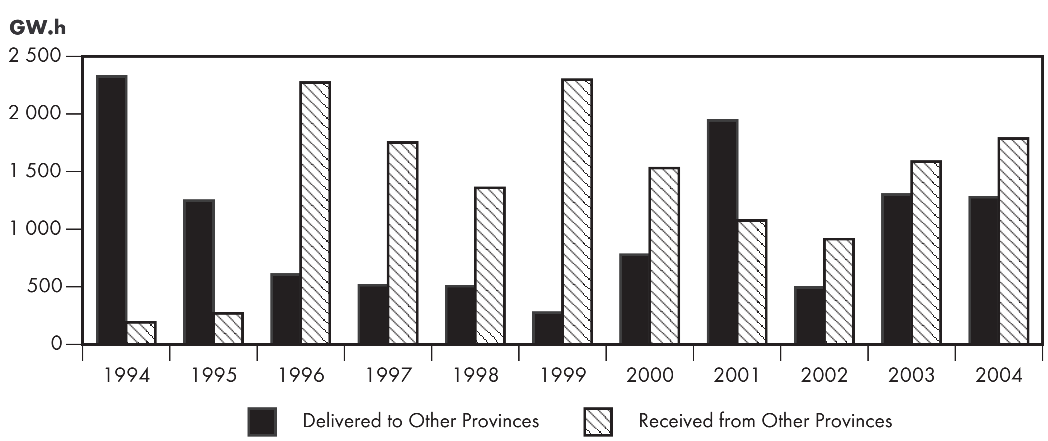
Trade

Alberta is a thermal-based generation region that has interconnections with British Columbia and Saskatchewan (Figure 3.3.6). Trade opportunities between Alberta and B.C. are enhanced by B.C.'s ability to bank energy (store water) and Alberta's base load coal-fired generation. Less energy flows between Alberta and Saskatchewan due to the limited transmission transfer capability.

Although it has no direct interconnection with the U.S., Alberta generally is a net importer of power from the PNW through British Columbia. However, in 2001, Alberta exported significant power to the PNW and California to capture price differentials resulting from the California

FIGURE 3.3.6

Alberta Interprovincial Electricity Transfers



Source: NEB, Statistics Canada

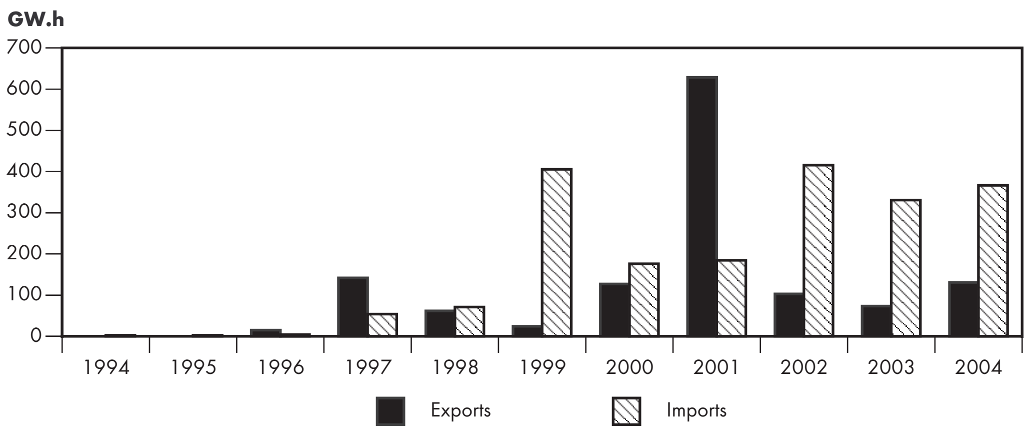
crisis (Figure 3.3.7). Since 2001, peak hour export opportunities have been greatly reduced due to transmission constraints in the Calgary region, limited access through British Columbia, and reduced arbitrage opportunities.[14]

During many off-peak hours, export opportunities have increased due to price differentials between Alberta and the PNW. This is due in part to increased base load generation (i.e., coal-fired generation) in Alberta frequently setting the spot power price at levels lower than the PNW. TransCanada, EPCOR, ENMAX and TransAlta were the main exporters and importers in 2004.

Prices in Alberta reflect the furthest movement toward market-based rates in Canada (Figure 3.3.8). Since natural gas-fired units typically set the spot market price during peak hours, natural gas prices set Alberta's peak wholesale market prices. Wholesale market prices in the PNW also influence Alberta prices, albeit to a much lesser extent, because of: limited intertie connections; differences in generating resource options; and strategies taken by some Alberta market participants who import or export depending on their existing shortage or surplus of energy in the domestic market.

FIGURE 3.3.7

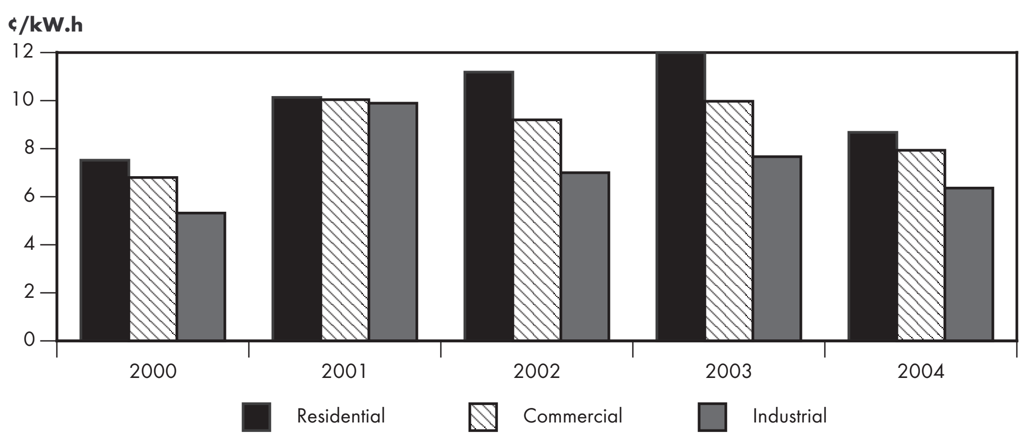
Alberta International Electricity Trade



Source: NEB, Statistics Canada

FIGURE 3.3.8

Alberta Electricity Prices in Edmonton (excluding taxes)



Source: Hydro-Québec

14 During some peak hours, export capacity to British Columbia is reduced to zero as a result of voltage constraints in the Calgary region.

Retail prices in Alberta can be separated into two components. The first component is the energy (commodity) charge. Since 2003, wholesale market prices gradually shifted downward due to the significant increase of efficient gas-fired generation (Figure 3.3.9). However, resulting benefits have not been as great as they would have been due to the rising cost of natural gas, which affects the variable cost of operating these units. Wholesale prices and subsequent retail prices will continue to reflect the cost of natural gas as natural gas-fired units set the price of generation in the province.

The second component is the transmission and distribution charge. The *Transmission Regulation* requires that the full cost for transmission development will be recovered from end-use customers. Due in part to the existing and proposed transmission development applications, this component will lead to an overall rate increase for Albertans.

3.3.3 Outlook and Issues

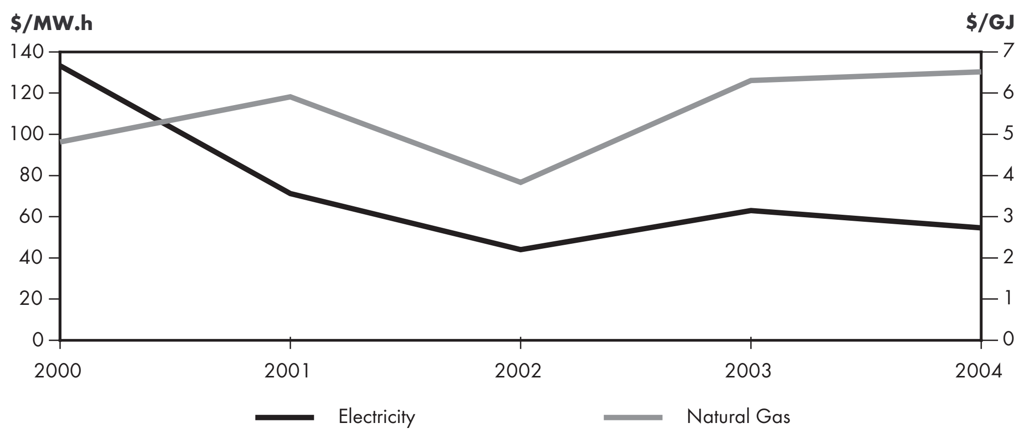
Alberta should have adequate generation through the 2005-2006 period barring any anomalies in the availability of the base load generating units. Alberta's supply adequacy was further enhanced earlier this year with the commissioning of the coal-fired Genesee 3 generating station. However, as noted in AESO's Transmission System Plan, Alberta's generation reserve margin will begin to erode as there is no near-term guarantee of significant generation entering the system after Genesee 3 to meet expected strong domestic demand growth. As a result of the uncertainty surrounding load growth, the potential retirement of older generation and the development of new wind generation, many believe that new generation could be required around the 2007-2009 time period.

Some are concerned that the existing market structure will not encourage the development of new generation on a timely basis. The Alberta Government recognizes this as a potential challenge and is seeking the development of solutions through the *Alberta Wholesale Market Review*. At the same time, other Alberta participants suggest that political market intervention will create greater uncertainty and negatively impact future supply investment.

Access to large U.S. west coast markets is another concern of some entities. With better access, development of new cogeneration in the oil sands may be more likely to proceed, as improved market access decreases the risk that power would be trapped in Alberta.

FIGURE 3.3.9

Alberta Annual Wholesale Electricity and Spot Natural Gas Prices



Source: AESO, Canadian Natural Gas Focus

The *Alberta Wholesale Market Review* addresses short-term issues and will provide recommendations that could enhance system reliability and recognize the differences in the market operating characteristics with adjacent Canadian and U.S. markets. Such recognition could eventually lead to an increase of energy transfers within the interconnected regions.

Alberta ratepayers should benefit from the existing generation oversupply that increased with the addition of Genesee 3. However, as demand continues to grow, the oversupply will diminish. Combined with the effect of natural gas prices and increased costs associated with transmission development, upward pressure will be exerted on overall electricity rates.

In the near term, the potential to export energy could increase. Upward pressure on exports from Alberta to either British Columbia or the PNW may result from a number of factors. These could include lower Alberta spot market prices during the off-peak due to the addition of Genesee 3, upward pressure on PNW prices from a low water year and the partial relief of a transmission export constraint around the Calgary region.

There is downward pressure on imports to Alberta as a result of the issues identified in a recent MSA report on the economics of energy flows on the B.C. tie line. As a result, some importers are unsure of actions they can take regarding importing electricity to meet a deficit in their portfolios.

The retail market review is examining the regulated rate option that expires 1 July 2006. Consumers who have not signed a competitive contract will move to a default supply contract with the incumbent provider. The existing regulation states that individuals moving to default contracts are subject to an average monthly flow-though commodity price. Alberta Energy is currently reviewing the default supply option to determine whether it is an appropriate way to meet residential consumer needs.

Another issue that affects Alberta's future electricity supply and overall end-use cost is the federal government's plan to meet Canada's *Kyoto Protocol* commitment. Depending on the final requirements for large emitters, two potential issues arise. First, the variable cost of coal-fired generation and to a lesser degree the variable cost of natural gas-fired generation could increase and subsequently could cause wholesale and retail prices to rise. Second, the technology and subsequent economic decision to build new coal-fired generation becomes increasingly more complex.

An effort has already been made to reduce emissions associated with electricity generation prior to Canada's commitment to the *Kyoto Protocol*. The Clean Air Strategic Alliance (CASA) developed an Air Emissions Management Framework that was approved by the provincial Cabinet in early 2004. The framework will lead to a reduction of emissions of mercury, oxides of nitrogen (NO_X), oxides of sulphur (SO_X) and particulate matter. With regard to sensitivity surrounding clean air, power developers have started to respond to the potential emissions impact as evidenced by the choice of more efficient technology that has been incorporated into Genesee 3, the proposed TransAlta 450 MW Centennial project and the proposed Luscar 1 000 MW Bow City project. In addition, the Canadian Clean Power Coalition, an entity that includes ATCO Power, EPCOR, TransAlta, Luscar and other players across the country, is in the process of developing clean coal technology.

As indicated in the British Columbia section, there are potential opportunities that may be assessed with respect to energy transfers between Alberta and British Columbia. Alberta has significant potential to develop base load thermal generation through either cogeneration in areas such as the oil sands region or coal-fired generation near Edmonton. British Columbia could benefit from the transfer of surplus base load generation while at the same time returning peak energy via its hydroelectric resources. By 2009, Alberta is expected to alleviate transmission constraints such that the ability to export power will increase to 700 MW for all times of the day. Two potential economic benefits include improving overall base load generation economics and a reduction in cost of peaking energy.

Clean Coal Technologies

Clean Coal technologies provide noticeable reductions in the emissions from coal-fired power plants; in particular, oxides of nitrogen (NO_X), oxides of sulphur (SO_X), carbon dioxide (CO_2), particulates and heavy metals such as mercury. NO_X and SO_X are components of acid rain; CO_2 is the primary greenhouse gas; and there are health concerns about particulates and heavy metals.

The following provides an overview of clean coal technologies:

Supercritical Pulverized Coal

Supercritical pulverized coal plants are advanced conventional coal plants that are run at higher temperatures and pressures than older plants, so they burn less coal and produce less CO_2 per MW.h generated. They are equipped with special burners, scrubbers and precipitators that reduce the NO_X, SO_X and particulate matter emissions. The Genesee 3 plant that went into service in March 2005 in Alberta is an example of a supercritical pulverized coal plant.

Fluidized Bed Combustion

A fluidized bed combustion generator such as Point Aconi in Nova Scotia features crushed coal and limestone being suspended at the bottom of a boiler by an upward moving stream of hot air. While coal is burned in this liquid-like mixture, sulphur from the combustion gases combines with the limestone to form a solid compound that can be removed with the ash. Although no more efficient than conventional coal-fired generation plants, this design reduces SO_X and NO_X emissions.

Integrated Gasification Combined Cycle (IGCC)

A strict definition of clean coal technology limits it to technologies such as IGCC, which are inherently cleaner and more efficient than a conventional coal plant. IGCC plants process coal to convert it into a gas, removing sulphur, heavy metals and particulate matter before combustion. This gas is then burned in a high efficiency combined cycle power plant for lower CO_2 emissions. The absence of particulate matter also makes it easier to remove NO_X from the exhaust gases, and makes IGCC a good candidate for future CO_2 sequestration projects, which capture and store CO_2 in geologic formations such as oil reservoirs. There are currently no IGCC plants in operation in Canada, although there are plants in operation in the U.S., Europe and Japan.

The Canadian Clean Power Coalition, an entity that includes companies with interests in coal-fired generation, plans to use the latest available technologies to enable future coal-burning plants to meet environmental requirements. A demonstration plant, expected to be in operation by 2012, will be designed to remove greenhouse gases and all other emissions.

To derive the greatest possible benefits of the diversity of British Columbia's hydro capacity and Alberta's dependable base load thermal generation for the provinces' ratepayers, continuous analysis, and action on the analysis, is required.

3.3.4 Summary

Although Alberta currently has a healthy reserve margin, activities are underway today to ensure that there is adequate supply to meet anticipated robust demand growth in the near future. Through their Wholesale and Retail Market Reviews, Alberta Energy is in the process of developing a strategy to ensure adequate generation to meet consumer needs.

3.4 Saskatchewan

Saskatchewan Power Corporation (SaskPower), a vertically-integrated utility and Crown corporation, serves most of the province. SaskPower's goal is to be an environmentally conscious, self-sufficient provider of low cost electricity. It has developed an approach to address climate change, a Green Power Portfolio and implemented an ISO 14001 environmental management system.

3.4.1 *Market Structure*

SaskPower operates under the mandate and authority of the *Power Corporation Act*. The Board of Directors is accountable to the Minister Responsible for SaskPower. The Minister functions as a link between the corporation and cabinet, as well as the provincial legislature. SaskPower's proposed rate increases are reviewed by the Saskatchewan Rate Review Panel at the request of the Minister of Crown Management Board and decisions regarding rates are approved by Cabinet.

The posting of an OATT in 2001 opened Saskatchewan's electricity system to wholesale access. The OATT allows third parties with generation to export, and competitors can schedule access to SaskPower's transmission system to wheel power through Saskatchewan, or to sell power to Swift Current's or Saskatoon's municipal utilities, SaskPower's only wholesale customers. Saskatchewan does not anticipate further restructuring unless a clear benefit can be demonstrated to the province.

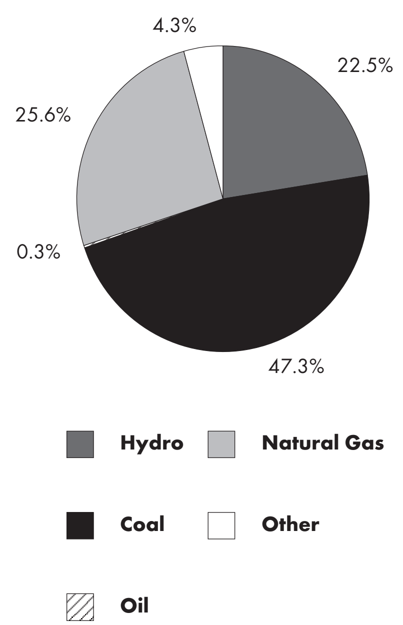
SaskPower is the primary electric utility in the province. NorthPoint Energy Solutions, Inc. (NorthPoint), formed in 2001 to meet the OATT requirement to separate transmission and marketing, is a wholly-owned subsidiary of SaskPower. NorthPoint performs generation and load management services in addition to energy trading functions related to SaskPower's generation assets. Trading functions include marketing surplus generation to other jurisdictions and purchasing electricity for domestic load during shortfall periods or when lower cost opportunities arise.

A recent commitment by Saskatchewan's Premier is that Saskatchewan consumers would be provided with the lowest cost package of basic utilities in Canada. To assist in reaching this goal, SaskPower strives to provide fairness in its rate structures. Development of the electrical infrastructure is also used as an economic development tool in Saskatchewan.

As provincial generation is primarily coal-fired, potential climate change standards present a challenge for the province. SaskPower has introduced a Green Power Portfolio, which focuses on wind, small scale Environmentally Preferred Power (EPP) projects and DSM initiatives.

FIGURE 3.4.1

Saskatchewan 2003 Generating Capacity by Fuel (3 786 MW)



Source: Statistics Canada

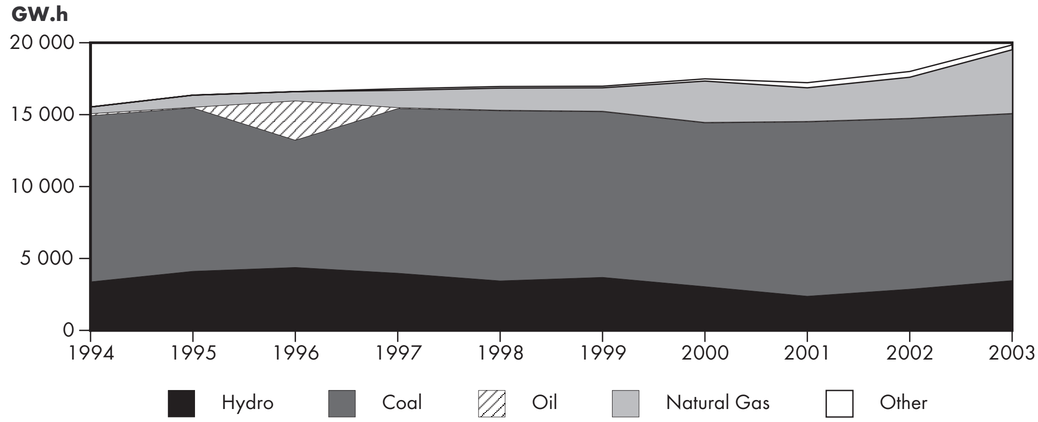
3.4.2 *Current Market Developments*

Generation

About one half of the province's generating capacity is coal-fired (Figure 3.4.1). Hydro, natural gas and a small amount of wind generation capacity comprise the remaining half. SaskPower owns 3 056 MW of generation capacity, and holds

F I G U R E 3 . 4 . 2

Saskatchewan Generation by Fuel



Source: Statistics Canada

power purchase agreements with the Cory and Meridian cogeneration facilities and the SunBridge Wind Power Project, for a total of 3 505 MW. The recent growth in natural gas-fired generation results from the development of the Cory and Meridian cogeneration facilities (Figure 3.4.2).[15]

The climate change issue, and its implications, pose a significant challenge for Saskatchewan, a mainly thermal based region. A significant portion of SaskPower's coal-fired generation will reach the end of its life within the next 15 years, which will necessitate decisions regarding replacement within six years. In the intervening time, SaskPower is meeting incremental demand by investing in generation technologies that result in no net carbon emission increases. Consequently, coal-fired generation decreased by about four percent, between 2002 and 2003, while SaskPower's power purchases increased by approximately five percent over the same time period (Figure 3.4.2).

The EPP program is part of the strategy to meet load growth over the next few years with low environmental impact power. Qualifying projects would generally be between 0.025 MW and 5.0 MW in size, for a total of 45 MW of new generation over three years. Eligible technologies include: wind, low-impact hydro, biomass, solar, flare gas, and heat recovery from existing waste heat sources. EPP project operators would be required to sell all power produced to SaskPower. Two wind turbine projects, and a heat recovery project, were selected for the first year of the program.

In addition to the Green Power Portfolio (the 11 MW Cypress Wind Power Facility), SaskPower International is developing an additional 150 MW of wind power, in the Rushlake Creek area of southwest Saskatchewan.

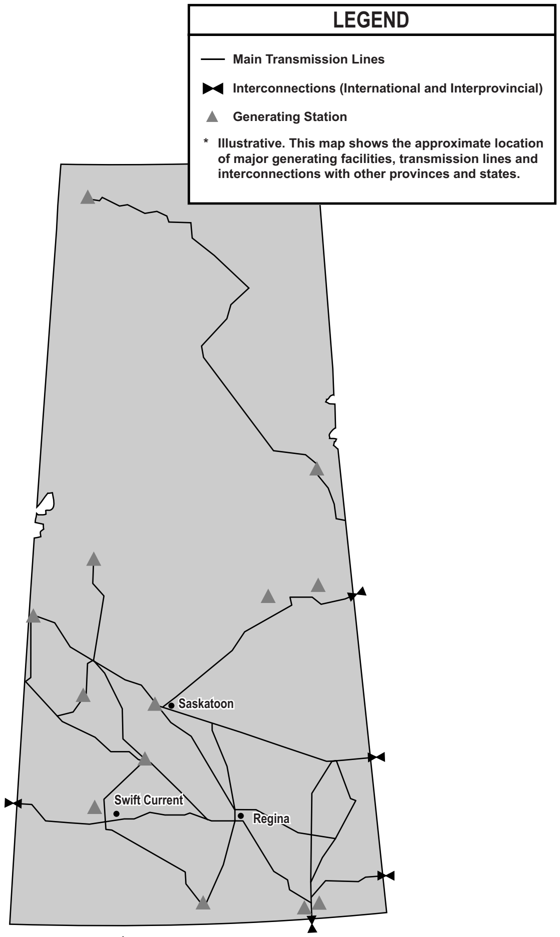
Transmission

SaskPower's transmission network (Figure 3.4.3) serves approximately three customers per circuit kilometre compared to the North American average of 12 customers per circuit kilometre. This low customer density is due to the large geographic area of the province and its widely distributed population, which poses a challenge to establish and maintain an adequate power distribution infrastructure.

15 The Cory Cogeneration Station, located near Saskatoon, is a joint venture between SaskPower International, SaskPower's development arm and ATCO Power. The Meridian Cogeneration station, located near Lloydminster, is a joint venture between Husky Oil Ltd. and TransAlta Cogeneration L.P. The SunBridge Wind Power Project, located west of Swift Current, was developed through a 50/50 partnership between Enbridge Inc. and Suncor Energy Inc.

FIGURE 3.4.3

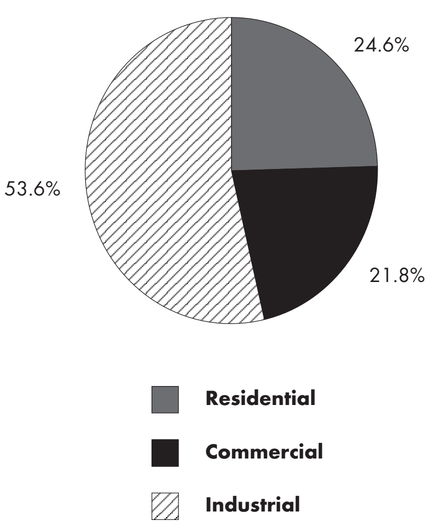
Saskatchewan Electric Transmission System



Source: SaskPower

FIGURE 3.4.4

Saskatchewan 2003 Electricity Demand by Sector (17 678 GW.h)



Source: NEB, Statistics Canada

Approximately 70 percent of SaskPower's transmission and sub-transmission facilities are over 30 years old. Because of its maintenance program, SaskPower does not anticipate that significant replacement will be required.

SaskPower has participated in the Mid-Continent Area Power Pool (MAPP), now the Midwest Reliability Organization (MRO). SaskPower recently became a NERC certified control area, and is presently seeking recognition by MRO and NERC as a reliability coordinator.

Consumption

The oil and natural gas industry is the province's largest consumer of electricity and one large load, either into or out of the system, could affect overall provincial requirements by as much as 10 percent. Large pipeline operators, such as TransCanada PipeLines Limited and Enbridge Pipelines Inc., are among SaskPower's largest consumers of power. The growth of the oil and natural gas industry, and its increasing use of electric drives, also contribute significantly to increased demand. Figure 3.4.4 shows electricity demand by sector.

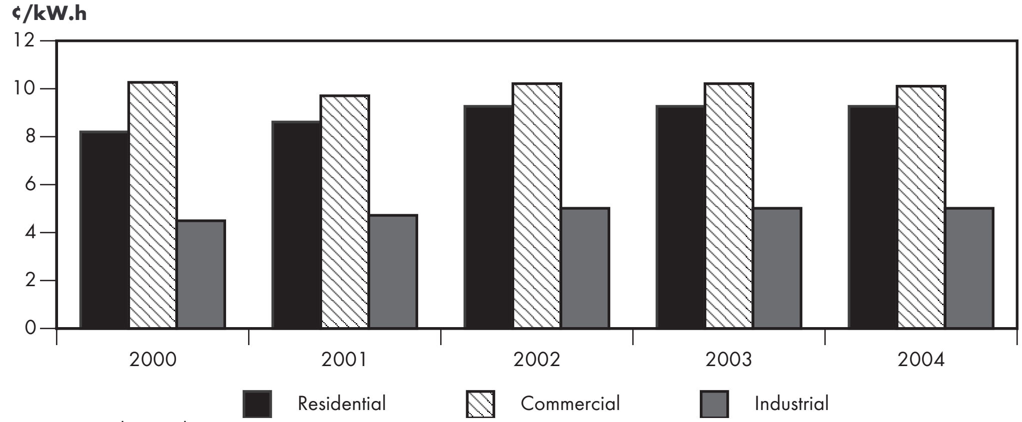
Although Saskatchewan's peak demand occurs in winter, in part due to electric heating that is common in the north, its summer peak is increasing from year to year, particularly in the load centres in the southern part of the province where the use of residential air conditioning is growing. In the past, the summer peak was about 70 percent of the winter peak, while in recent years the summer peak has grown to approximately 90 percent of the winter peak. The most recent peak record of 2 954 MW was set on 20 December 2004.

SaskPower's DSM program, Energy Solutions, which previously targeted only commercial and industrial buildings for efficiency retrofits, is being expanded to include community facilities.

Cross-subsidization among SaskPower's customer rate classes has meant that certain

FIGURE 3.4.5

Saskatchewan Electricity Prices in Regina (excluding taxes)



Source: Hydro-Québec

customers benefited at the expense of others, but this has largely been reduced by a rate change implemented in December 2004. Figure 3.4.5 shows Regina electricity prices by customer class over a five year period prior to this change.

In August 2004, SaskPower requested a system weighted average increase of nine percent, effective 1 September 2004, which it justified by outlining various cost pressures. In December 2004, the Saskatchewan Rate Review Panel recommended to the Minister of Crown Management Board a system weighted average increase of six percent, suggesting that a higher increase could cause rate shock.

Trade

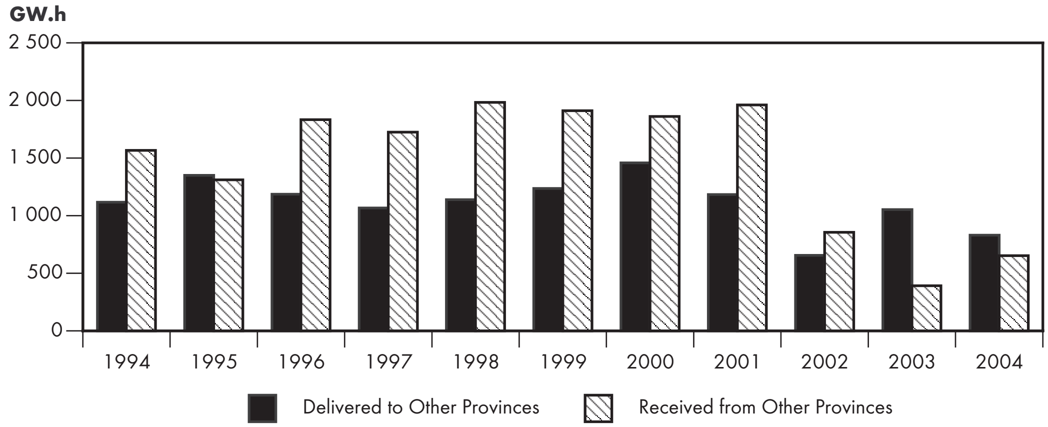
Saskatchewan has not built generation with the intention of serving long-term export transactions; however, the incentive for SaskPower to post the OATT was to establish reciprocity and thus allow a continuance of electricity trade and wheeling opportunities as other entities transport power, from source to destination, through the province's transmission system. In addition, NorthPoint engages in energy trade when it is necessary to mitigate and manage SaskPower's position, or when opportunities arise to take advantage of price differentials between regions.

Saskatchewan is surrounded by relatively low cost producing regions and was a net importer of power between 1996 and 2001. The province was a net exporter from 2002 to 2004, although the latest movement is toward a net import position. The high transfers in 2003 correspond to the drought period in Manitoba, when that province became a net importer to meet its demand requirements. In 2003, SaskPower export sales contributed nine percent of total revenue to the utility. Saskatchewan also sells power to Alberta and Ontario, though to a lesser extent. The constraints on the intertie between Saskatchewan and Alberta limit trade opportunities. In addition, the real-time market in Alberta tends to be more volatile than other markets available to Saskatchewan. Transfers to Ontario tend to be for short periods (usually hourly), in small blocks (e.g., 25 MW) and through neighbouring transmission systems (Figure 3.4.6).

NorthPoint engages in north-south trade (Figure 3.4.7), as this offers more arbitrage opportunities and access to a number of potential trading partners within the Midwest Independent Transmission System Operator, Inc. (MISO) region. The opening of the Midwest Energy Market, in April 2005, is an opportunity to expand trade in the U.S.

FIGURE 3.4.6

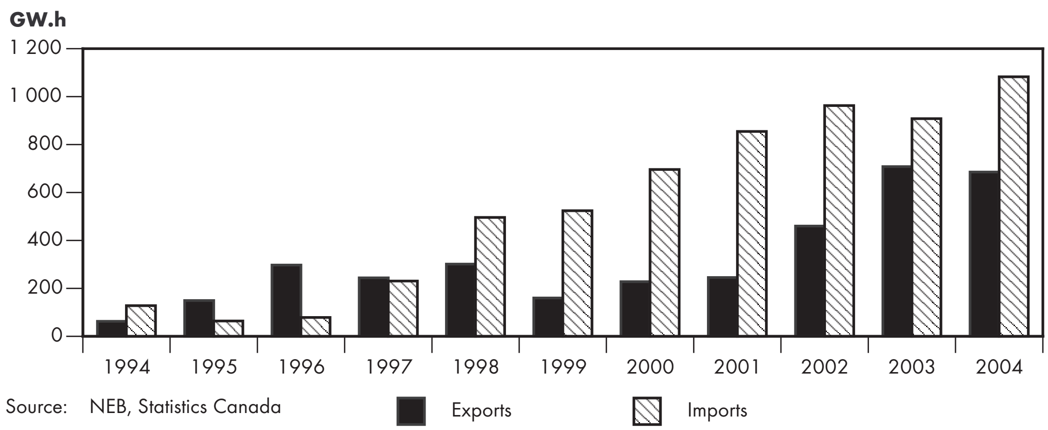
Saskatchewan Interprovincial Electricity Transfers



Source: NEB, Statistics Canada

FIGURE 3.4.7

Saskatchewan International Electricity Trade



Source: NEB, Statistics Canada

3.4.3 Outlook and Issues

Although SaskPower has adequate generation capacity for the period covered by this report, Saskatchewan faces the challenges of an aging infrastructure, increased operating costs, and uncertainties surrounding climate change and evolving environmental issues.

As noted, a significant component of SaskPower's coal-fired generation facilities is due to retire within the next 15 years. As the Province has abundant coal resources, coal will continue to play an important role in providing energy in Saskatchewan. SaskPower, as a member of the Canadian Clean Power Coalition, the Zero Emissions Coal Alliance and the Lignite Energy Council, is investigating new technologies to enable the continued use of coal-fired generation on a more sustainable basis.

To meet some of its load requirements, SaskPower has either partnered with or arranged Power Purchase Agreements with cogeneration facilities, which are natural gas-fired. Higher gas prices and natural gas price volatility, along with other significant cost increases, have acted to increase SaskPower's costs and possibly added risk to its cost structure.

SaskPower is assessing alternative and renewable technologies to meet incremental generation requirements using EPP technologies. This strategy allows SaskPower to evaluate new technologies in a low risk situation while meeting its additional load requirements. In addition, SaskPower is evaluating other available generation technologies, such as hydro, natural gas, and nuclear, although each of these options has drawbacks for the utility.

The evaluation of new technologies and the push toward "clean coal" is driven in part by the anticipation that new standards will be required to meet climate change mitigation goals.[16] Timing of the need for new generation in the province coincides with the period that these new standards are likely to be implemented. By taking time to evaluate its options over the next few years, SaskPower has the opportunity to choose a mix of generation technologies that will enable it to optimize the balance required between being a reliable provider of relatively low cost energy and ensuring that its generation meets environmental requirements.

3.4.4 *Summary*

The need for new generation facilities, higher fuel costs and other cost increases, and tightening emissions and environmental standards, will all put upward pressure on costs for SaskPower, which in turn will lead to higher electricity rates for Saskatchewan consumers.

3.5 Manitoba

Manitoba Hydro owns and operates virtually all segments of the electricity industry in Manitoba, which is dominated by hydro generation. It is focused on providing low cost electricity to consumers and on maximizing the export value of its hydro resource assets. Hydro power is a relatively low emitter of greenhouse gases and other air pollutants, a characteristic promoted by Manitoba Hydro to market its hydro power. DSM measures and other environmental programs allow the company to maximize the available volume of electricity for export.

3.5.1 *Market Structure*

Manitoba Hydro is a Crown corporation, owned by the Province of Manitoba and governed by the Manitoba Hydro-Electric Board. This Board, appointed by provincial cabinet, reports to the Minister responsible for the *Manitoba Hydro Act*. Retail electricity rates are regulated by the Manitoba Public Utilities Board. In September 2002, the Manitoba Government established the Department of Energy, Science and Technology, which has a mandate to further develop the province's energy resources, in particular emerging alternatives such as wind power.

In 1997, Manitoba Hydro published its non-discriminatory OATT generally in keeping with the pro-forma U.S. FERC tariff. This OATT allows third party use of the Manitoba transmission system, providing capacity is available, and facilitates reciprocity for those third party users. Its open access reciprocal tariff enables Manitoba Hydro to maximize export opportunities.

Manitoba Hydro purchased Winnipeg Hydro in 2002 with the result that Manitoba Hydro is now the only electric utility in the province. There are also a few small generation facilities owned by local industry. In addition, the first wind farm in Manitoba is being built by private developers, with the output being sold to Manitoba Hydro.

16 SaskPower has voluntarily committed to reducing its greenhouse gas emissions to six percent below 1990 levels by 2012.

Key components of Manitoba's electricity strategic plan are to provide Manitoba consumers with the lowest electricity rates in North America and to maximize net power export revenues. The province promotes its power reliability and stable, low cost electricity rates to attract industry. This strategy has resulted in some industry relocation to the province from jurisdictions that have seen prices increase in recent years. In addition, efforts are made to ensure that new infrastructure projects maximize the potential benefits to local people in terms of employment and purchase of goods and services.

3.5.2 *Current Market Developments*

Generation

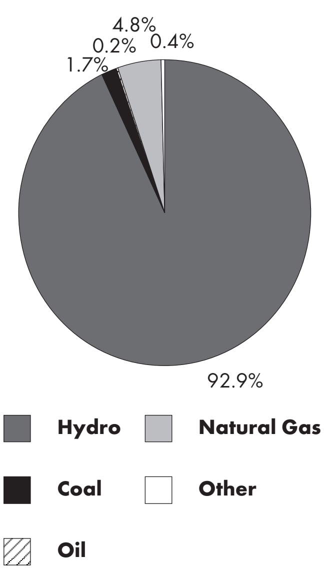
About 98 percent of the provincial generation is hydro based (Figures 3.5.1 and 3.5.2). Manitoba Hydro also owns one coal-fired and four natural gas-fired thermal units. Some diesel generation is located in remote areas, which are not connected to the transmission grid. Although its infrastructure is aging, Manitoba Hydro does not contemplate retiring any of its facilities in the near future.

The company estimates that only about one half of its potential hydro resources have been developed and has identified 16 potential hydro generation developments for future consideration. These include the 200 MW Wuskwatim Generating Station, the power from which would be surplus to domestic requirements from the proposed in-service date of 2011 until 2020.[17] By bringing Wuskwatim into service before it is required for domestic use, the utility anticipates an opportunity to export additional surplus power to Canadian and U.S. markets.

The Clean Energy Transfer Initiative is a joint initiative between Manitoba and Ontario. It would involve development of new hydro generation facilities for the purpose of exporting up to 1 500 MW of additional hydro power to Ontario.

FIGURE 3.5.1

Manitoba 2003 Generating Capacity by Fuel (5 407 MW)



Source: Statistics Canada

The storage capability and operating characteristics of Manitoba's hydro system could facilitate wind power development, as hydro generation could be run during periods when wind power is not available. Consequently, wind and hydro power together could be offered as firm energy. Manitoba Hydro has stated that it would produce or purchase 250 MW of wind power should it be viable from an economic and technical perspective. The Province of Manitoba's promotion of wind power resulted in plans to develop its first independently-owned wind farm southwest of Winnipeg. This 99 MW project is scheduled for completion by the end of 2005.

Transmission

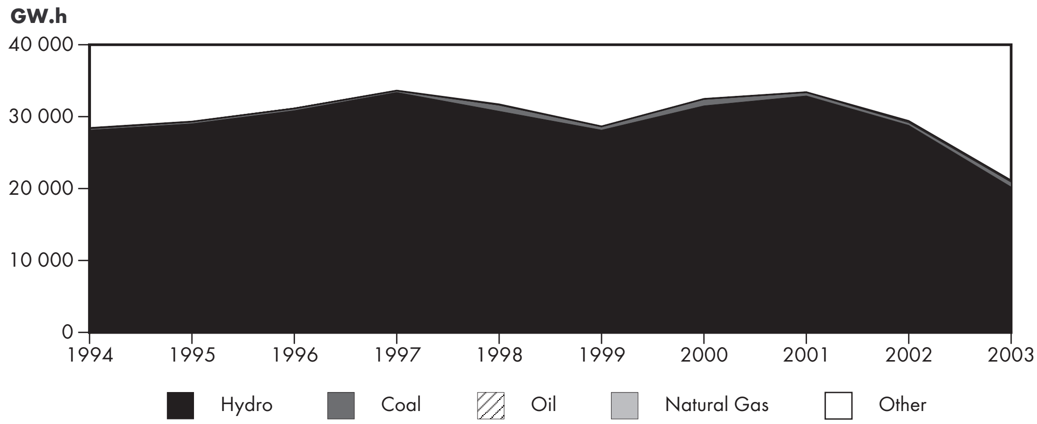
The transmission system in Manitoba is substantial as the bulk of its hydro-power is produced along the Nelson River System in the north of the province (Figure 3.5.3). The long-distance HVDC transmission capability is desirable to economically transport electricity to southern load centres.

There are 12 interconnections between Manitoba and adjacent provinces and states. Although Manitoba is typically a net

17 The Nisichawayasihk Cree Nation, a potential partner with Manitoba Hydro for this project, would hold up to a 33 percent share, with Manitoba Hydro holding at least a 67 percent share in the project.

FIGURE 3.5.2

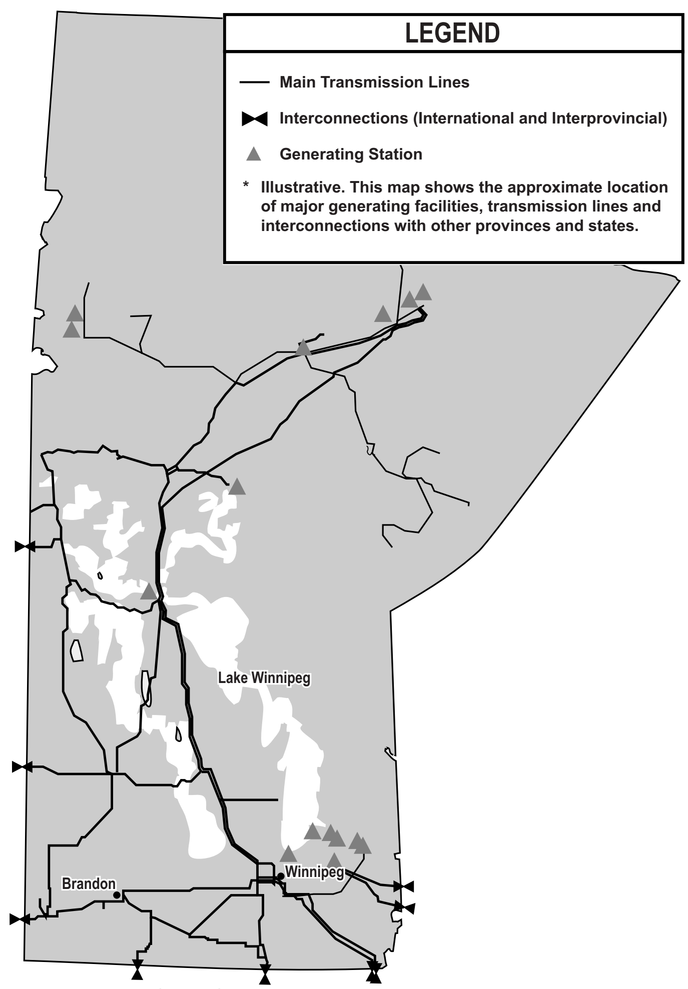
Manitoba Generation by Fuel



Source: Statistics Canada

FIGURE 3.5.3

Manitoba Electric Transmission System



Source: Manitoba Hydro

exporter, the ability to import was important in providing secure electricity supply for Manitoba during the recent drought period. In November 2002, the Glenboro-North Dakota transmission line came into service. This line was built primarily to increase import capability into Manitoba, but also increases export capability to the U.S., by 175 MW.

Manitoba Hydro proposes to construct a new 500 kV HVDC transmission line, east of Lake Winnipeg, for an in-service date of 2012. This line would reduce transmission losses and would provide a greater degree of overall security and reliability. If the CETI project proceeds (in the 2014-2018 time frame), significant transmission additions would be required to deliver power to the Ontario grid. Three alternative transmission paths have been identified.[18]

18 General route possibilities have been identified; however, detailed routing has not been studied.

Consumption

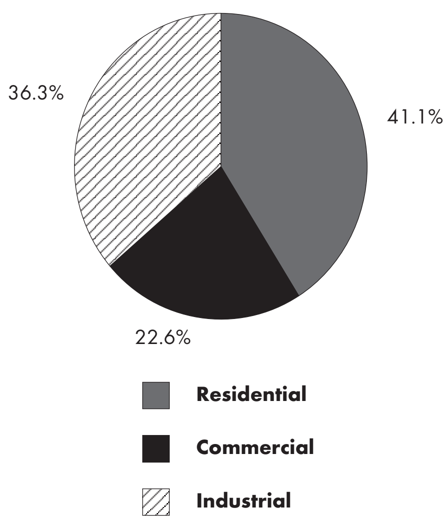
The residential sector has the fastest growing demand in Manitoba as population continues to grow and there are more housing starts (Figure 3.5.4). While this alone would increase demand, demand growth is compounded as new residences tend to be built with electric water heaters.

The low operating cost of the province's hydro generation facilities, in combination with export revenues, enables the utility to maintain low rates for Manitoba consumers. However, the additional costs of importing power to meet demand during the drought conditions of 2003-2004, and the increasing costs of operating the utility, prompted Manitoba Hydro to apply to the Manitoba Public Utilities Board for rate increases in 2004. This marked the first time in seven years that rates increased for residential and small commercial customers and the first time in 12 years that industrial consumer rates increased (Figure 3.5.5). After the extent of the losses following the drought were fully assessed, the Manitoba Public Utilities Board approved a five percent increase, effective 1 August 2004, for all rate classes. A further increase of 2.5 percent for all rate classes was approved effective 1 April 2005. Even with the rate increases, Manitoba electricity continues to be the lowest priced in Canada.

In December 2004, Manitoba Hydro announced a doubling of its DSM PowerSmart program target to reduce peak demand by 640 MW by 2018. This conserved power is conceptually added to generation capacity and considered surplus for export. Revenues earned by exporting surplus power contribute to low prices for Manitobans. In the fiscal year ended 31 March 2003, about 34 percent of Manitoba Hydro's electricity revenue came from power sales outside the province.

FIGURE 3.5.4

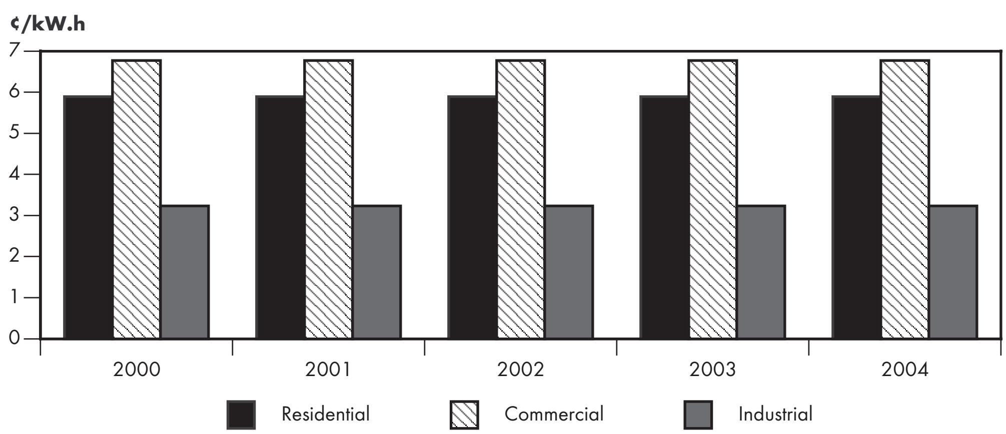
Manitoba 2003 Electricity Demand by Sector (18 406 GW.h)



Source: NEB, Statistics Canada

FIGURE 3.5.5

Manitoba Electricity Prices in Winnipeg (excluding taxes)



Source: Hydro-Québec

Trade

Manitoba sells hydroelectricity to neighbouring states and provinces (Figures 3.5.6 and 3.5.7). In most years, Manitoba is a net exporter. Typically about 30 percent of Manitoba's generation is sold to Canadian and U.S. markets.

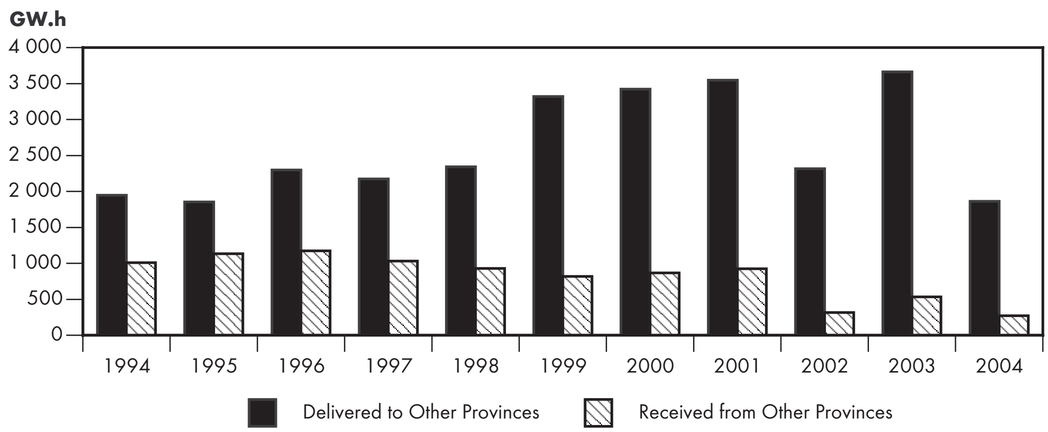
In 2003-2004, Manitoba experienced its second worst drought year since the 1940s, with the result that the province was a net importer of electricity for the first time since 1989. It is thought that normal water conditions have returned and Manitoba Hydro will return to normal export levels.

Manitoba's transfer capacity to other provinces is constrained, with Ontario and Saskatchewan typically limited to 200 MW and 375 MW respectively. Interconnections between Saskatchewan and Alberta are also limited, restricting exports from Manitoba to Alberta through Saskatchewan.

Export capacity to U.S. markets is considerably larger, at approximately 1 850 MW. The large interconnections with the U.S. provides access to Minneapolis, Minnesota, the closest major population (or load) centre to Manitoba. The marginal generators in adjacent Canadian and U.S. markets are

FIGURE 3.5.6

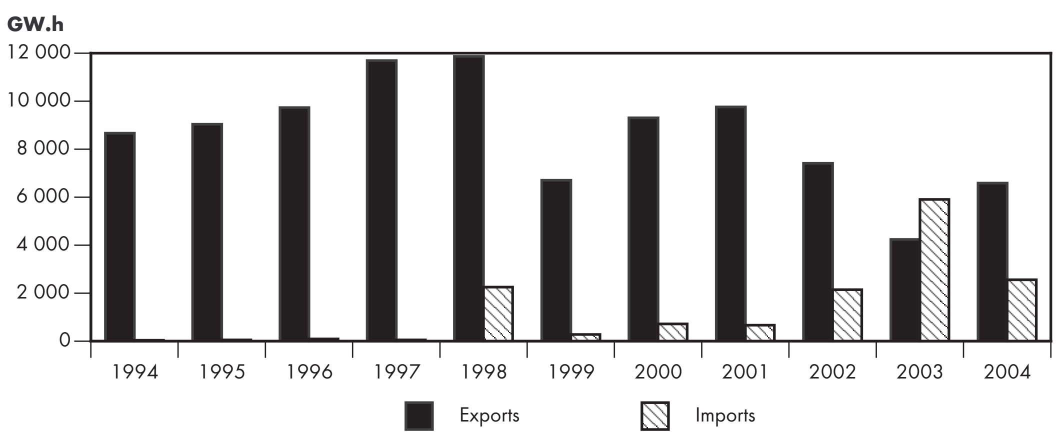
Manitoba Interprovincial Electricity Transfers



Source: NEB, Statistics Canada

FIGURE 3.5.7

Manitoba International Electricity Trade



Source: NEB, Statistics Canada

coal units, or natural gas during the higher load periods. Hydro exports tend to displace this thermal generation, and export prices are generally based on the cost of the displaced thermal resources.

Although Manitoba Hydro has not relinquished control of its system to MISO, as U.S. entities are required to do, it signed a coordination agreement with MISO in 2001 and is participating in the day-ahead and real-time markets introduced by MISO in April 2005.

3.5.3 Outlook and Issues

Manitoba's electricity industry faces opportunities and challenges. The *Kyoto Protocol* offers an opportunity for the province to promote its hydro power as renewable. In addition a wind generation industry is beginning to develop. The risk of drought and resistance by consumers and other groups to increased rates and proposed projects present challenges to the province's electric industry.

The MISO and Pennsylvania/New Jersey/Maryland Interconnection (PJM) joint and common market, implemented in April 2005, allows Manitoba Hydro to market its power into the Midwest region. It improves efficiency by reducing rate pancaking, providing a uniform set of rules throughout the market, and reducing transaction costs. However, many barriers to new transmission development exist, including the difficulty in establishing new transmission corridors and the competition between transmission and generation projects for investment.

In *Project Green*, the Federal Government's plan to honour Canada's *Kyoto Protocol* commitment, the Federal Government indicates its support of closely assessing east-west transmission links to enhance the environmental benefits of supplying hydro power to load centres that are becoming more reliant on thermal generation. Federal support through the Partnership Fund, could facilitate proposed projects such as the CETI, which would require significant investment in transmission infrastructure.

The 2003-2004 drought highlighted the sensitivity of Manitoba Hydro's system to precipitation levels. As Manitoba Hydro became a net importer for that year, significant changes in the patterns of regional flows occurred. Flow directions reversed, so that energy flowed from east to west and south to north. This raised awareness of drought impacts, including the $112 million decline in export sales and a $418 million increase in fuel and power purchased by Manitoba Hydro in 2003-2004 during the drought.

Green Energy – The Case for Large-Scale Hydro Generation

Hydro power does not emit SO_X, NO_X or particulate matter, and removing vegetation from the reservoir area will minimize production of GHG from decaying vegetation. Based on these characteristics, many believe power produced by large-scale hydro should command a premium as green power. However, others point out the impact of hydro dam construction and operation. Dams can change the flow regimes of rivers, affect fish and other wildlife and their habitats, and if large enough can change local climate. Decomposing flooded vegetation releases low levels of greenhouse gases and by flooding forest soils, reservoirs may create conditions that allow mercury to accumulate in fish and other biota. In addition, the loss of land from flooding could diminish the livelihood of the local population.

Proponents of emerging generation technologies suggest that continued development of large hydro projects discourages research, development and investment in new alternative and renewable technology that is smaller scale, less capital intensive, potentially cost competitive and located closer to load centres. In spite of the controversy surrounding the definition of large-scale hydro as "green," it is generally agreed that it has lower environmental impacts than fossil-fuelled generation and has the potential to reduce GHG and other emissions in Canada.

Although electricity rates in Manitoba continue to be the lowest in North America for all customer classes, certain groups have concerns relating to some Manitoba Hydro strategies and were represented at recent proceedings related to rates and facilities. Intervenors believe they should not have to pay for losses resulting from the drought, suggesting the utility should expect one year in ten to be a low water year and that any resulting losses would be recovered in good years. There is resistance to the recent five percent across the board rate increase, which has been subject to appeal by consumer groups.

There is also a view that the DSM program should be maximized before new facility developments proceed. The announcement that DSM targets would be doubled over the next 13 years mitigates some of this concern. However, as industry believes it accounts for the majority of DSM gains to date and that DSM has a high and effective penetration rate in the industrial sector, there is the suggestion that future DSM efforts be targeted toward other sectors.[19] In addition, projects such as Wuskwatim and the 500 kV HVDC line proposed to run east of Lake Winnipeg have met with some resistance from concerned groups.

One goal of the provincial government is to establish the province as a hub of development for renewable and alternative energy technology. Among the various technologies, wind has produced the most interest and is furthest along in development. While there is enthusiasm about developing wind resources, and wind projects are welcomed in rural areas, Manitoba Hydro is concerned about the technical and economic challenges involved in integrating wind into its hydro-based system.

3.5.4 Summary

The ability to export power, assuming a return to normal water conditions, will continue to benefit the province. For Manitoba, addressing climate change issues provides an opportunity to strengthen its market position as a supplier of clean power.

3.6 Ontario

Ontario was the second province to restructure its electric industry and, with the December 2004 adoption of the *Electricity Restructuring Act, 2004* (Bill 100), Ontario is implementing a hybrid regulated-competitive model that is unique in Canada.[20] Ontario's electricity industry is evolving and faces many challenges. The province has a diversity of generation resources, including hydro, nuclear, coal and natural gas. Wind power is currently a small portion of generation but is expected to grow.

3.6.1 Market Structure

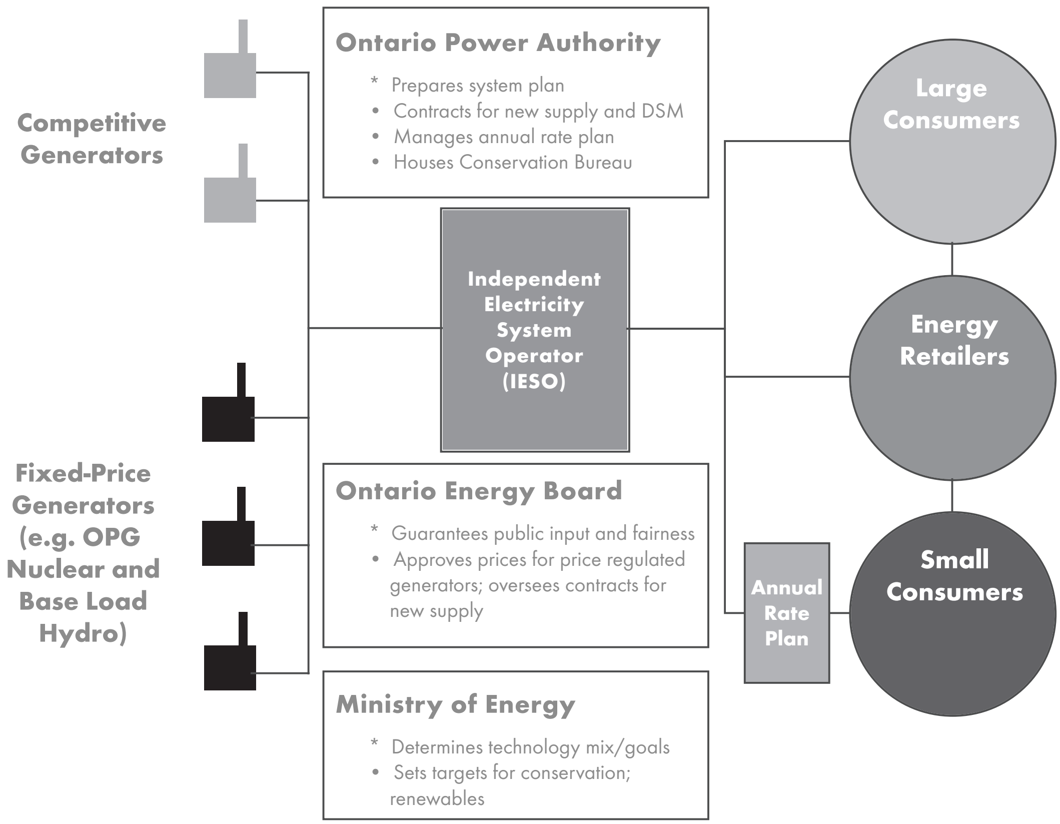
Ontario's electricity market was opened for wholesale and retail access on 1 May 2002. Electric generation outages, along with above-normal temperatures during the summer, resulted in high and volatile prices. Legislation was implemented in December 2002, and later in December 2003, to introduce and continue price caps to soften the effects of potential price spikes on Ontario consumers. Bill 100 is designed to address issues arising from the initial restructuring initiatives and chart the future course of the electricity industry in Ontario (Figure 3.6.1).

19 Manitoba Hydro estimates that, between 1991 and March 2004, a reduction of 292 MW of demand, and annual energy savings of about 631 GW.h, were achieved.

20 Alberta was the first province to restructure.

FIGURE 3.6.1

Ontario Electricity Sector: Institutional Structure



Source: IESO

To increase the competitive aspect of Ontario's electricity market following the initial restructuring, Ontario Hydro was unbundled into a number of separate entities:

- Ontario Power Generation (OPG) owns and operates all fossil-fuelled and most of the hydro generating stations that were formerly owned by Ontario Hydro, as well as the Pickering A, Pickering B and Darlington nuclear plants, for a total of 75 percent of the installed generating capacity in the province. Bruce Power Limited Partnership is the licensed operator of the Bruce A and Bruce B nuclear generating stations.
- Hydro One owns and operates 97 percent of the provincial transmission lines, and most rural distribution lines. Since restructuring, Hydro One has acquired 88 of the 180 smaller municipal utilities in Ontario, making it the largest electric distribution company in the province. Toronto Hydro, which serves about 20 percent of the province, is the next largest distributor.
- The Independent Electricity System Operator (IESO), formerly the Independent Market Operator, directs the operation of Ontario's bulk power system, ensuring that the system is operated reliably, runs the wholesale electricity market and is responsible for shorter term electricity supply forecasting. The recently formed Ontario Power Authority (OPA) is responsible for ensuring adequate long-term electricity supply.

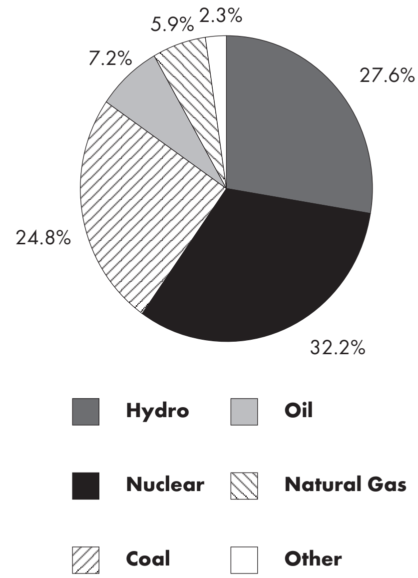
The Ontario Energy Board (OEB) has regulatory oversight of the IESO and other market participants, including generators, distributors, retailers, transmission companies and wholesale power consumers. It has a mandate to protect consumer interests and promote the economic efficiency and cost effectiveness of the electricity industry in Ontario.

The implementation of legislation to mitigate high prices for consumers resulted in uncertainty for investors in generation, and deterred investment. With the changes introduced in Bill 100, electricity policy in Ontario now combines the features of an evolving competitive wholesale market with regulation that mitigates undesirable effects, such as extreme price volatility.

The Ontario government has also become involved in generation by establishing the OPA to address generation adequacy concerns and to handle long-term planning. The OPA is mandated to contract for new generation when required through an RFP process. The intent is to obtain reliable generation at the lowest cost, to ensure generation is built in a timely manner, and to encourage a generation mix that meets social and environmental goals, such as increasing the use of renewable resources. Bill 100 also established, within the OPA, a Conservation Bureau charged with implementing conservation measures, including a specific mandate to reduce electricity consumption by five percent by 2007.

FIGURE 3.6.2

Ontario 2003 Generating Capacity by Fuel (30 457 MW)



Source: Statistics Canada

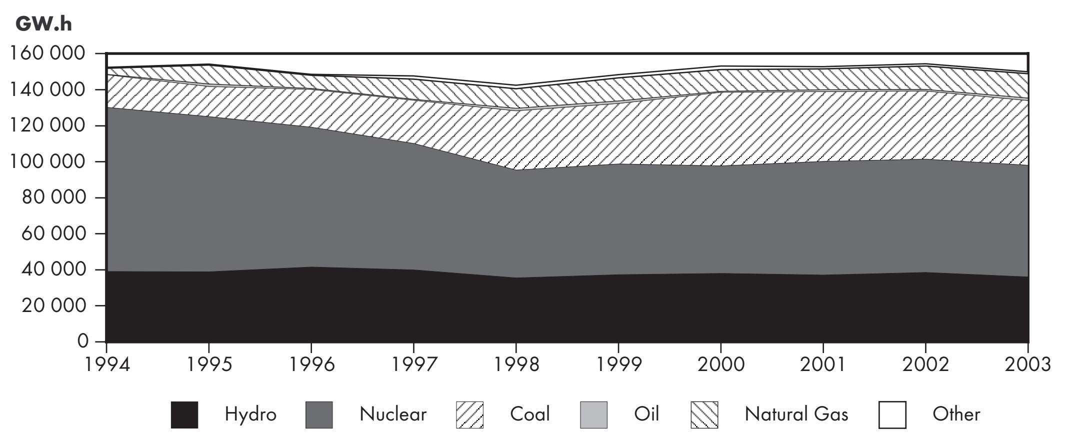
3.6.2 Current Market Developments

Generation

Nuclear generation provides 41 percent of electricity in Ontario, with hydro generation and coal each providing about 24 percent. The remainder is provided by oil, natural gas and other generation (Figure 3.6.3).

FIGURE 3.6.3

Ontario Generation by Fuel



Source: Statistics Canada

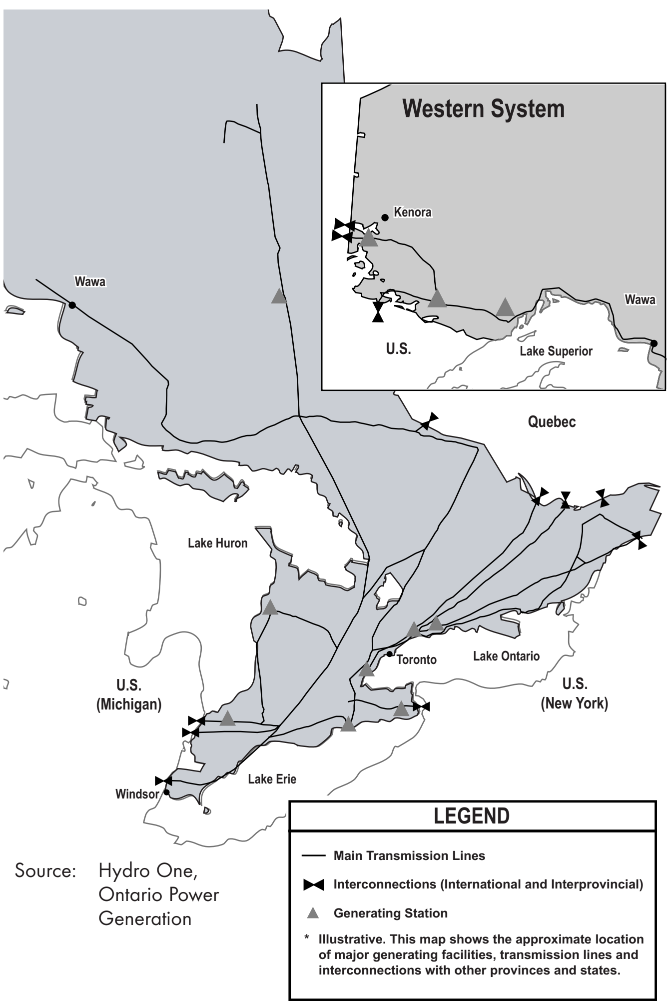
For environmental and health reasons, the Ontario government's announced policy is to phase out the province's coal-fired generation by the end of 2007, without jeopardizing reliability of supply. Installed coal-fired capacity at the end of 2004 was 7 500 MW, from five generating stations. The Lakeview generating station in Mississauga (1 150 MW) was taken out of service on 30 April 2005. While it is expected that this can be accommodated within Ontario's current near-term generation outlook, the closure of the remaining coal-fired facilities presents challenges.

In June 2004, an RFP for 300 MW of renewable energy was issued as a first step to ensuring adequate generation will be available by 2007. Ten projects totalling 395 MW of generation capacity were accepted. In September 2004, RFPs for 2 500 MW of clean generation (mainly gas-fired) and demand-side management were issued and 33 proposals for projects totalling 8 268 MW are being evaluated. As of mid-April 2005, proposals for 1 665 MW of natural gas-fired generation and 10 MW of Demand Response have been accepted.

In addition to the existing and proposed large hydro facilities, the Province intends that five percent (about 1 350 MW) of generation capacity be provided by renewable sources by 2007 and 10 percent by 2010. The ten projects accepted to date represent about 30 percent of the 2007 target. They include small hydro and landfill gas projects but most of the new capacity will come from wind. Wind generation is intermittent; however, by combining it with hydro and thermal generation, a 10 percent wind generation share is considered attainable. The ability to locate wind sites near existing transmission and the construction of new transmission, to link wind sites to customers, are significant challenges.

FIGURE 3.6.4

Ontario Electric Transmission System



Source: Hydro One, Ontario Power Generation

Transmission

Ontario is served by a 29 000 km transmission system. This includes a network of 500 kV, 230 kV and 115 kV power lines extending from southern Ontario to the Manitoba and Minnesota border, and from the Québec border in the east to Michigan and New York in the west (Figure 3.6.4).

Interconnections with neighbouring provinces and states allow Ontario entities to engage in trade, optimize the utilization of generation, and enhance the reliability of the Ontario power system. The largest transfer capabilities are with Michigan, New York and Québec, followed by Manitoba and Minnesota. Due to internal constraints on the Ontario transmission system, the expected maximum coincident import capability is in the range of 4 000 MW. Theoretical maximum imports of 5 300 MW in the summer and 5 500 MW in the winter are achievable only through substantial generation reductions in the vicinities of the Sarnia/Windsor and Niagara Falls interconnections.

The geographic position of Ontario, between Michigan and New York, provides arbitrage opportunities, since Michigan's coal-fired electricity is less expensive than New York's natural gas-fired generation (Figure 3.6.5).

Consumption

Demand in Ontario is almost evenly split between residential, commercial and industrial demand (Figure 3.6.6). In recent years the province has seen a rapid increase in summer demand due to air conditioning load, which led to a summer peak in August 2002 of 25 414 MW. Residential demand growth is expected to moderate as the air conditioning market is saturated. The winter peak attained in December 2004 was 24 979 MW.

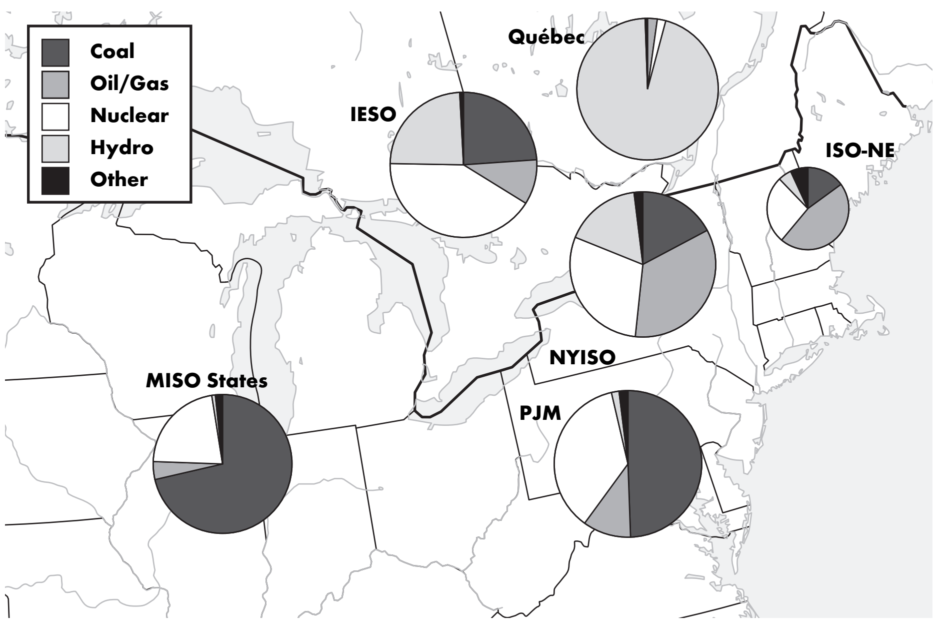
An important goal of Bill 100 is the creation of a conservation culture. DSM initiatives of the Conservation Bureau include a mandate for the installation of smart meters for 800 000 customers by 2007 and for all consumers by 2010.[21]

Examples of initiatives implemented before Bill 100 include:

- Toronto has a central district cooling system that uses cool water, from deep in Lake Ontario, for conventional air conditioning and other cooling needs. It is estimated that this has reduced summer peak electricity demand by 59 MW; and

FIGURE 3.6.5

Ontario and Region Market Size and Generation Diversity (2003)



Source: Statistics Canada, U.S. Energy Information Agency

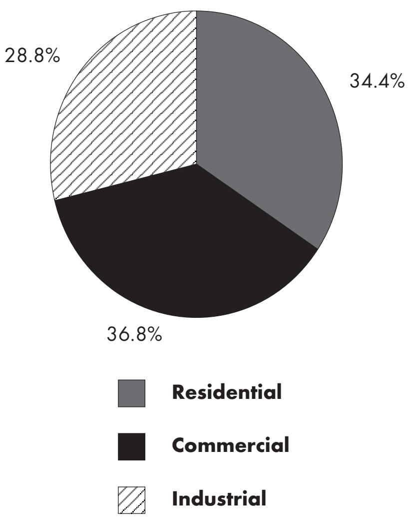
21 A smart meter records how much energy is used and when it is used. This allows for the introduction of different electricity rates that vary by time of day, encouraging customers to reduce their usage during peak hours.

- The Town of Woodstock has implemented a pay-as-you-go program for residential consumers, also resulting in a notable reduction in consumption.[22]

Since market opening in May 2002, wholesale prices have been determined by the wholesale market administered by the IESO (Figure 3.6.7). However, due to price volatility, resulting from abnormally warm weather and generator outages later in the summer of 2002, the province implemented a price cap (4.3 cents per kW.h) for small consumers. The difference between the wholesale price and the price caps was funded by the province and surplus revenue from OPG which arose from the difference between the wholesale price of electricity and the fixed price, set by the Government, for OPG production.

FIGURE 3.6.6

Ontario 2003 Electricity Demand by Sector (144 967 GW.h)



Source: NEB, Statistics Canada

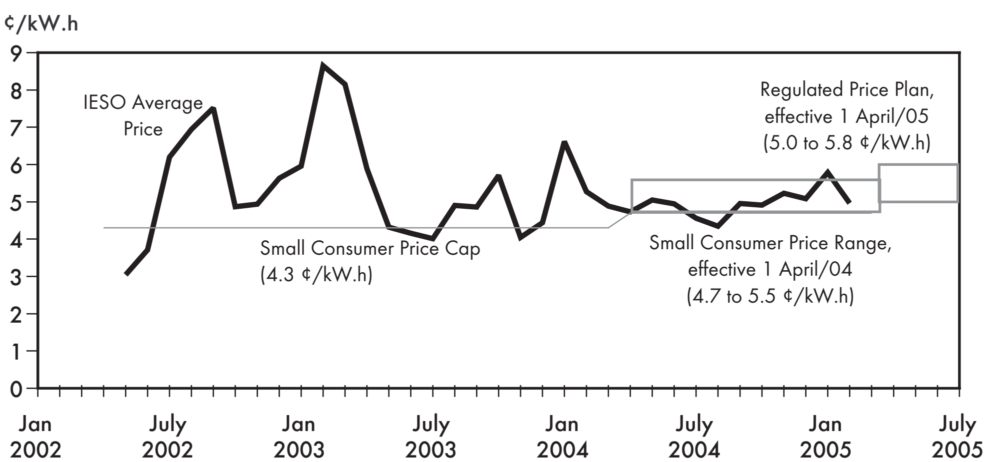
On 1 April 2004, the price cap for residential consumers rose from 4.3 cents per kW.h to 4.7 cents for the first 750 kW.h consumed each month, with amounts above 750 kW.h priced at 5.5 cents per kW.h. Fixed prices applied to electricity consumers using 250 000 kW.h or less per year. Designated consumers, such as farms, certain public-sector institutions and charitable organizations using more than 250 000 kW.h per year, also paid the set rate of 5.5 cents per kW.h.

Prices paid by consumers reflect the capped commodity price plus transmission and distribution charges (Figure 3.6.8).

The two-block price plan, for customers whose annual usage is 250 000 kW.h or less (as described previously), was replaced by a Regulated Price Plan (RPP). Effective 1 April 2005, residential and small business customers pay 5.0 cents for the first 750 kW.h consumed each month, and 5.8 cents per kW.h for any additional energy. These prices

FIGURE 3.6.7

Ontario Market and Residential/Small Consumer Prices (cents/kW.h)

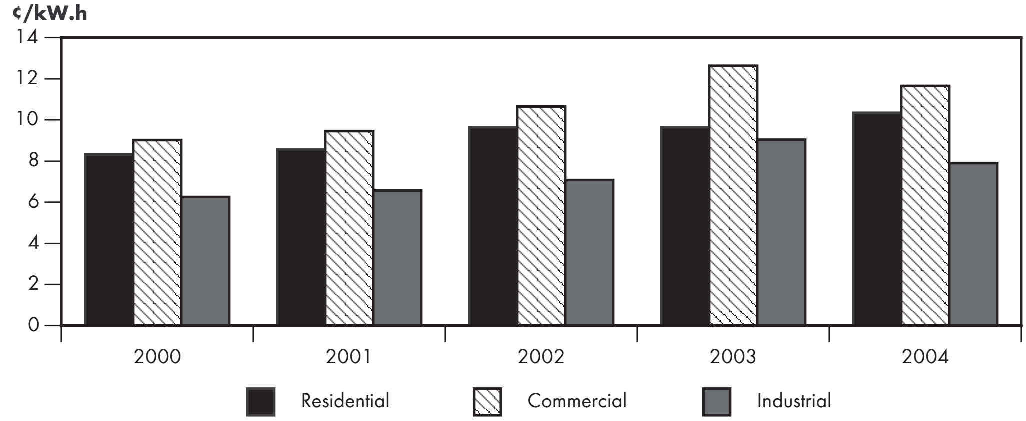


Source: IESO, OEB

22 Pay-as-you-go billing programs are explained in the Demand-Side Management (DSM) and Demand Response (DR) Programs text box in section 2.4.

FIGURE 3.6.8

Ontario Electricity Prices in Toronto (excluding taxes)



Source: Hydro-Québec

will remain in effect until 1 April 2006. At that time, and every six months thereafter, the rates will be adjusted to reflect the expected price of wholesale energy and any adjustment to "true up" the price paid to match the actual cost of wholesale energy.

Also, beginning November 2005, the threshold for the lower price available to residential customers will change from a flat 750 kW.h per month to 1 000 kW.h per month in the winter (November–April) and 600 kW.h per month in summer (May–October). The price threshold for commercial customers will stay at 750 kW.h per month all year. Effective April 2008, the RPP will be limited to residential customers and general service customers with a peak demand under 50 kW. Commencing April 2006, residential consumers with smart meters will pay a three-part variable rate base on peak, off-peak and shoulder prices.

As of May 2003, rebates to large customers were fixed at 50 percent of the amount by which the average spot market price exceeds 3.8 cents per kW.h. Large business and industrial customers who use more than 250 000 kW.h per year will continue to pay default rates that fluctuate with wholesale electricity prices. They also have the option of entering into electricity-supply contracts with competitive retailers, several of which offer fixed-price and other types of deals.

Bill 100 implemented a hybrid, three-tier wholesale market. Effective April 2005, power from large hydro and nuclear generators owned by OPG is sold at a fixed price (3.3 cents per kW.h for hydro and 4.95 cents per kW.h for nuclear). Power from new generation built under the RFPs will have a contract support price, but is expected to earn revenue by selling into the wholesale market. Finally, the balance of generation in the province (including all non-OPG and non-RFP generation) will be sold at the market rate. The intent of this pricing structure is to introduce more price certainty for consumers, by reducing volatility, and to attract investment in new generation facilities.

To mitigate OPG's market power, there is a temporary cap on the price of other OPG generation. Until the end of April 2006, the price of energy from OPG's small hydro, coal, oil and natural gas plants will be capped at 4.7 cents per kW.h. After that date this generation will receive the wholesale market rate.

East-West Transmission Grid

Canada has a large land area with a relatively small population, with most Canadians concentrated in population centres near the Canada–U.S. border. For reasons of economics and population distribution, transmission development has emphasized north-south rather than east-west flows. As a result, regional electricity markets in Canada are often more closely linked with markets in adjacent U.S. states than with other regional Canadian markets.

Recently, there has been some discussion of developing the east-west grid system in Canada to allow for more interprovincial electricity transfers, thereby improving overall system reliability and enhancing Canada's energy self-sufficiency. Two proposed projects, the Clean Energy Transfer Initiative (CETI) and the Lower Churchill River hydro development, would require development of east-west transmission facilities. The Manitoba-Ontario CETI project is intended to provide Manitoba hydro power to load centres in Ontario. The Lower Churchill River hydro development could provide power to Ontario via Labrador and Québec. Both projects are being evaluated by the relevant provincial governments and industry.

Both projects would involve new interprovincial transmission, but not a coast-to-coast grid. It is generally accepted that a coast-to-coast grid would face unfavourably high development costs and its operation would imply large transmission line losses due to long distances involved. Other projects are assessed in a 2003 report undertaken for the Federal-Provincial-Territorial Electricity Transmission Working Group titled Regional Electricity Transmission Grid Study.

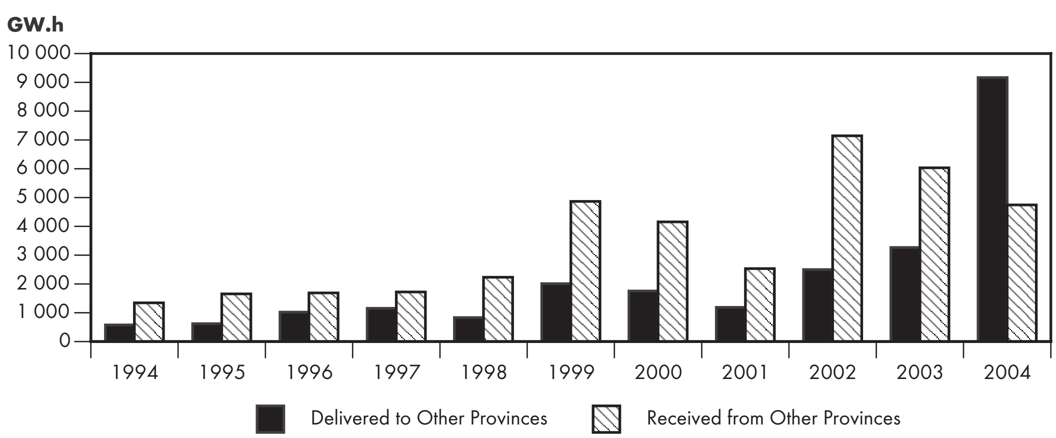
Trade

Prior to 1997, the province was typically a net exporter (exporting as much as nine percent of the power it generated in 1994). However, since the 1997 lay-up of several nuclear units, exports and imports have each averaged just three percent of generation with the result that net trade is approximately zero (Figures 3.6.9 and 3.6.10). Ontario presently exports available surplus power when demand and prices are high in the U.S. and imports as required during peak periods.

Most of Ontario's electricity trade is with Michigan (mainly imports) and New York (mainly exports). Sales to Québec have risen in recent years despite the fact that Hydro-Québec energy is less expensive than Ontario's. The increased sales reflect purchases of off-peak energy from Ontario, allowing Québec, and to a lesser extent Manitoba, to save water behind their dams and sell in U.S. markets when prices are high.

FIGURE 3.6.9

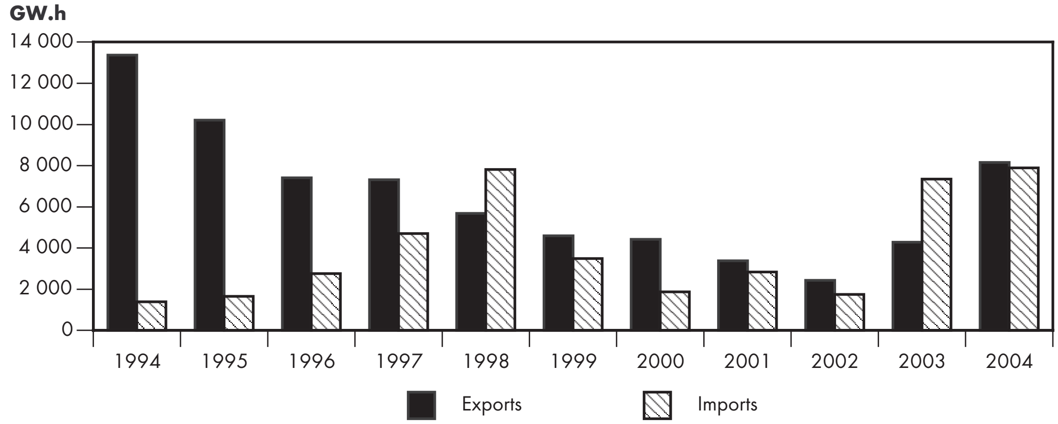
Ontario Interprovincial Electricity Transfers



Source: NEB, Statistics Canada

FIGURE 3.6.10

Ontario International Electricity Trade



Source: NEB, Statistics Canada

3.6.3 Outlook and Issues

In the near-term, installed generation capacity for Ontario, currently 31 500 MW, is expected to be adequate since expected peaks for 2005-2006 are in the range of 25 600 to 26 600 MW. However, the goal of eliminating 7 500 MW of coal-fired generation from Ontario, and the uncertainties regarding the return to service of additional nuclear units, present clear challenges beyond 2007. Implementation of the government policy initiatives contained in Bill 100 will assist in mitigating, but seems unlikely to eliminate, the impact of the retirement of coal units. The resolution of generation issues will likely include upward pressure on electricity prices.

With respect to nuclear generation in the province, there are currently four units at Darlington (3 524 MW), six units at Bruce (4 978 MW) and five units at Pickering (2 575 MW) in service, with a sixth unit at Pickering (515 MW) being refurbished. At the time of writing it is uncertain if or when the remaining two units at Pickering (1 030 MW) and two units at Bruce (1 538 MW) will return to service.

If replacement generation is not available, the utilization of coal units will need to be extended. Converting some of the Lambton units, near Sarnia, to burn natural gas has been considered, but this would be expensive as they would be less efficient than newer combined cycle plants. There is also a concern that the gas distribution infrastructure would need to be expanded to allow such a conversion. Gas infrastructure is likely to be an important issue, whether in converting existing coal units to gas or accommodating new gas-fired generation facilities.[23]

Post 2007, the province will face the long-term challenge of refurbishing, rebuilding, replacing or conserving 24 000 MW of generation (about 80 percent of current capacity) by 2020, at a cost of up to $25 to $40 billion.[24] To achieve this outcome will require resolution of many uncertainties in the investment climate, including stability of government policy.

23 *Natural Gas Regulation in Ontario: A Renewed Policy Framework*, Ontario Energy Board, 30 March 2005, pp. 50-52. The OEB estimates that the growth in gas-fired generation could increase annual gas demand by 25 percent in the next few years.

24 Presentations by the Ontario Ministry of Energy to conferences sponsored by the Canadian Institute, 20 October 2004 and 29 March 2005.

Part of the make-up capacity is expected to come via interprovincial transfers. One longer term proposal (in the 2014 to 2018 time frame) is the CETI, in which hydroelectric generation would be built in Manitoba, and new transmission capacity added, to bring up to 1 500 MW of power to Ontario. Another longer term option is obtaining access to hydro power from new projects on Labrador's Lower Churchill River via an expanded interconnection with Québec. A recent joint proposal by the Ontario Government, Hydro-Québec and SNC-Lavalin, in response to a call for "Expressions of Interest" from the Province of Newfoundland and Labrador, suggests that up to 900 MW could be available to Ontario, with initial power transfers starting in 2009.

The retirement of coal-fired generation is motivated by the goal of improving air quality but would also assist in meeting commitments under the *Kyoto Protocol* to reduce carbon dioxide (CO_2) emissions. Similarly, increasing the proportion of non-emitting nuclear generation, relatively low emitting renewable energy and clean natural gas-fired generation will also assist in meeting these goals.

Even under the RPP, in the long run, electricity prices will be determined by the cost of generation. While it improves air quality, introducing more natural gas-fired generation will result in higher generation costs, as natural gas is more expensive than coal and subject to price spikes during periods of supply shortage. Price volatility, introduced by increased use of natural gas, would be moderated by increasing the proportion of generation that does not use fossil fuels.

Imports from the United States may also help moderate gas price spikes but electricity prices in many U.S. regions are also dependent on gas prices. Ontario has the option of buying less expensive electricity, generated by coal-fired plants in the U.S. mid-west, but this has an environmental cost. Many of these plants are located upwind of Ontario and the added pollution, produced by U.S. coal plants generating power to meet Ontario demand, would negate some of the environmental benefits of retiring Ontario's coal units.

Concerns about the effect of increased imports from the U.S. on air quality, and the effects of the retirement of coal units on electricity prices and the provincial economy, have led to suggestions that refitting some of the existing coal plants in Ontario might be the preferred option. This would help control electricity prices and reduce pollution in the province, without increasing power plant emissions upwind of Ontario.

While Ontario has moved from a single market clearing price for wholesale electricity to a three-tier pricing scheme there are still competitive elements to encourage investment in generation and transmission facilities.

3.6.4 Summary

With its strategy to retire all its coal-fired generation plants, Ontario has increased its need for new generation by 2007, which will be a significant challenge. Renewable energy is being encouraged, the use of natural gas-fired generation is expected to increase, and the possible return to service of additional refurbished nuclear units may also contribute to replacing coal-fired generation.

While the three-tier wholesale market and RPP for end-use consumers will tend to moderate price volatility, upward price pressure will continue as the result of the need to replace existing generation with new facilities. On the demand side, implementing DSM and DR programs, and establishing prices that reflect the cost of generation, can also contribute to addressing the supply adequacy issue.

3.7 Québec

Québec is the largest electricity market in Canada and the country's largest exporter. Hydro-Québec (HQ), a Crown corporation wholly-owned by the Government of Québec, owns and operates through its unbundled divisions (generation, transmission and distribution) most of the provincial electricity sector, which is dominated by hydro generation. By virtue of the *Hydro-Québec Act*, HQ is mandated to supply power and to pursue endeavours in energy-related research and promotion, energy conservation and any field connected with, or related to, power or energy. Due to abundant hydro resources and relatively low historic production costs, electricity plays a predominant role in satisfying Québec's overall energy needs.

3.7.1 *Market Structure*

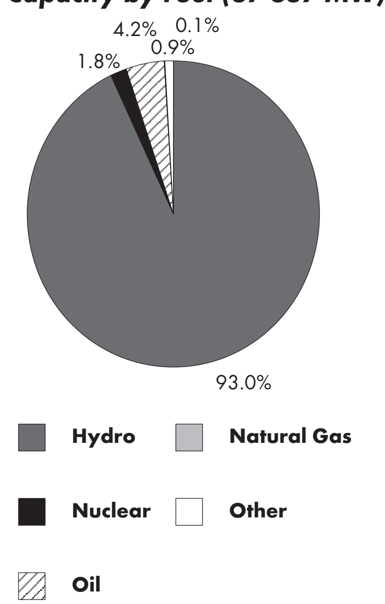
Hydro-Québec has evolved from a vertically-integrated utility to a functionally unbundled entity. The three main divisions of HQ are HQ Production, HQ TransÉnergie and HQ Distribution. HQ Production generates electricity and sells it on wholesale markets. HQ TransÉnergie operates and administers HQ's transmission grid. HQ Distribution has the exclusive obligation to provide electricity to Québec customers with the exception of one cooperative and nine municipal networks that together serve about 125 000 customers, or four percent of the market. HQ Distribution's operations and those of HQ TransÉnergie, are regulated by the Régie de l'énergie on a cost-of-service basis.

In order to gain access to the U.S. market, Québec provides open access to its transmission network pursuant to the U.S. FERC Order 888. In addition, Québec legislation introduced in 2001 established the heritage electricity pool whereby HQ Production must supply to HQ Distribution up to 165 000 GW.h per year at a fixed price of 2.79 cents per kW.h. To meet demand in excess of this amount, HQ Distribution must enter into supply contracts by issuing calls for tenders to interested power suppliers. Demand is expected to exceed 165 000 GW.h. in 2005. In anticipation of this, HQ Distribution has issued seven calls for tenders since 2003.

In the fall of 2004, Québec embarked on a multi-stakeholder consultative process to develop a new energy strategy. The final result will be the release of a White Paper by the end of 2005.

FIGURE 3.7.1

Québec 2003 Generating Capacity by Fuel (37 637 MW)



Source: NEB, Statistics Canada

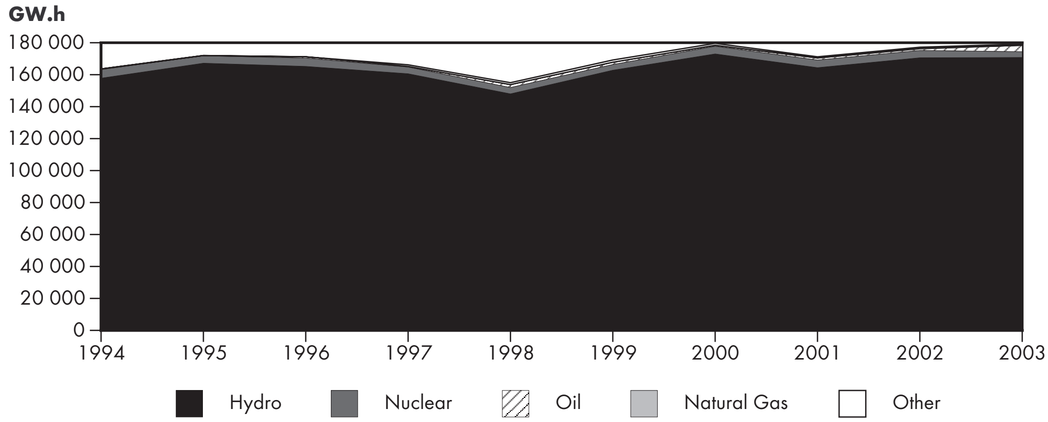
3.7.2 *Current Market Developments*

Generation

Québec's generation is predominantly hydro-based (Figure 3.7.1). Hydro resources and significant storage reservoirs are concentrated in remote areas far from major load centres. In addition to its own generating stations and to contracts with independent power producers in Québec, HQ Production has access to most of the output from Churchill Falls (Labrador), which has a rated capacity of 5 428 MW. In 2003, provincial generation amounted to 177 850 GW.h of which 95.3 percent was hydro. Nuclear generation accounted for 2.0 percent of the total, while oil, gas, wind and biomass generation accounted for the remainder (Figure 3.7.2).

FIGURE 3.7.2

Québec Generation by Fuel



Source: NEB, Statistics Canada

Electric Heating

Although gas heating is clean, reliable and comfortable, in a number of provinces electricity remains the preferred choice for heating in existing and new homes. Historically, provinces such as Québec and New Brunswick lacked access to natural gas and have had low electricity rates. Electric heating is clean, safe, requires a low initial investment and, where low cost power is available, is cost-competitive with other fuels.

As natural gas availability increases and the use of natural gas for power generation becomes more widespread, one would expect there would be a shift to using natural gas for heating instead of electricity. A new natural gas furnace can have a combustion efficiency of 80-90 percent, while a new natural gas-fired power plant will not exceed 50 percent efficiency. Therefore, more energy is needed to heat a home with electricity produced from natural gas than by using gas directly.

The limited penetration of natural gas in some residential heating markets reflects a number of factors:

- The infrastructure for electric heating is already in place in existing houses, reducing the incentive to switch.
- Home builders in these regions are familiar with electric heating, and lack experience with natural gas.
- While natural gas may be available to power plants, a natural gas distribution system to deliver gas to homes may not be in place.
- Consumers typically pay an average cost for electricity, which rolls together power from low-cost hydro and coal facilities with more expensive natural gas generation. As a result they would not realize the full benefits of switching to gas heating.

Of these issues, pricing is probably the most important. While a switch to natural gas heating would reduce overall demand for electricity and the need for natural gas-fired generation, it would have only a small impact on the consumer's power bill so there is little incentive for them to make the change. Only if consumers can see significant benefits from the change will there be a major switch to natural gas heating in these regions.

HQ Production, the principal power producer in the province, generates electricity and sells it on the wholesale markets both inside and outside of Québec. For the Québec market, as indicated previously, HQ Production must supply HQ Distribution with heritage electricity up to 165 000 GW.h per year. For the incremental markets, HQ Production competes freely with other power producers.

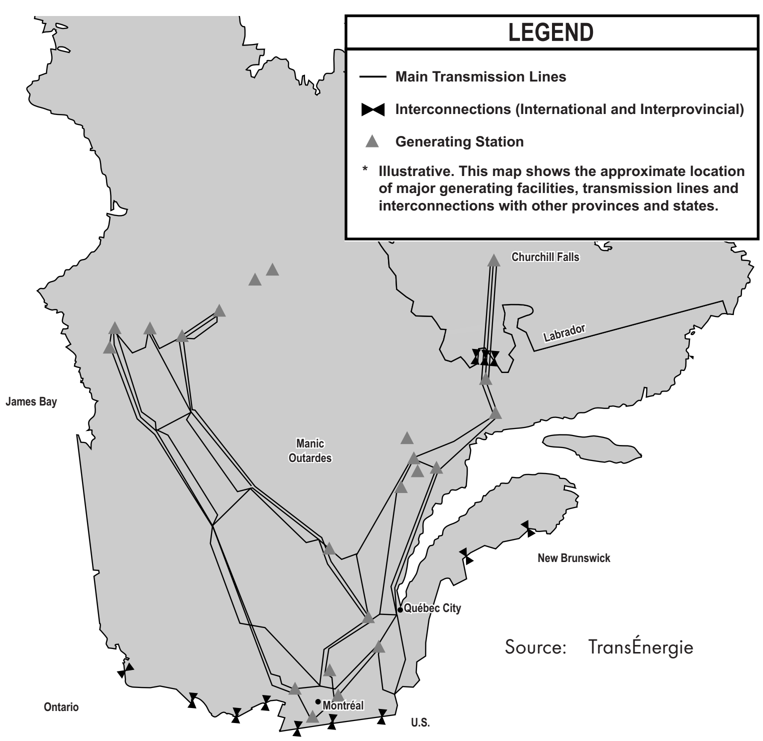
In 2003, HQ Distribution signed a contract with TransCanada Energy Limited for the supply of electricity, starting in 2006, from a 507 MW natural gas cogeneration plant which is under construction in Bécancour. Under the same call for tenders, HQ Distribution also signed a contract with HQ Production for the supply of 600 MW from the La Grande-1 and Robert-Bourassa generating stations that will be available starting in March 2007.

To promote the development of renewables, and to optimize synergies with the existing hydroelectric system while increasing supply, HQ Distribution issued a call for tenders in 2003. This resulted in IPPs being awarded contracts to develop 990 MW of wind power capacity subject to the Régie de l'énergie's approval.[25] These wind energy facilities are expected to be commissioned during the 2006 to 2012 time period. As these units come on line, Québec could surpass Alberta as the province with the largest total installed capacity of wind power in Canada. Currently, Québec has 113 MW of installed wind power capacity and is second only to Alberta (275 MW).

Significant water storage capability facilitates the integration of wind power into the bulk power system, since it allows HQ to backstop wind generation. HQ, in partnership with the Québec government, is currently assessing how much wind power can economically be incorporated into HQ's system. Additionally, HQ Distribution contracted for 39 MW of biomass-based capacity to be added to its supply portfolio by 2008. Another call for tenders was issued in 2004 for 350 MW of power to be produced from cogeneration.

FIGURE 3.7.3

Québec Electric Transmission System



Source: TransÉnergie

HQ Production continues to develop its hydro generation base with a number of new project initiatives. The recently built Sainte-Marguerite 3 and Grand-Mère generating stations added 820 MW to the system. The Eastmain-1, Toulnustouc, Mercier and Péribonka generation facilities are currently under construction. These projects will add a total capacity of 1 441 MW to HQ's system.

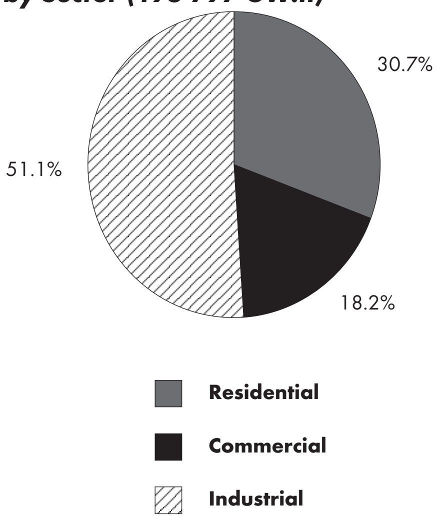
Transmission

HQ TransÉnergie operates and administers HQ's transmission grid (Figure 3.7.3), which

25 There were 4 000 MW of proposed capacity resulting from the 1 000 MW call for tenders.

FIGURE 3.7.4

Québec 2003 Electricity Demand by Sector (193 797 GW.h)



Source: NEB, Statistics Canada

includes 18 interconnections allowing power interchange between Québec and electrical systems in Labrador, New Brunswick, Ontario and the U.S. Northeast.

The most recent development in transmission was the reconstruction of the Cedars Rapids Transmission international power line which was approved by the NEB in June 2002 (EH-1-2002). The 72 km line was energized in January 2004 and extends from Les Cèdres, Québec to Cornwall, Ontario. The line is operated at 120 kV.

Consumption

Over the period 1994-2004, electricity consumption increased by 1.7 percent per year. HQ Distribution projects consumption will grow by 1.2 percent per year over the next ten years.

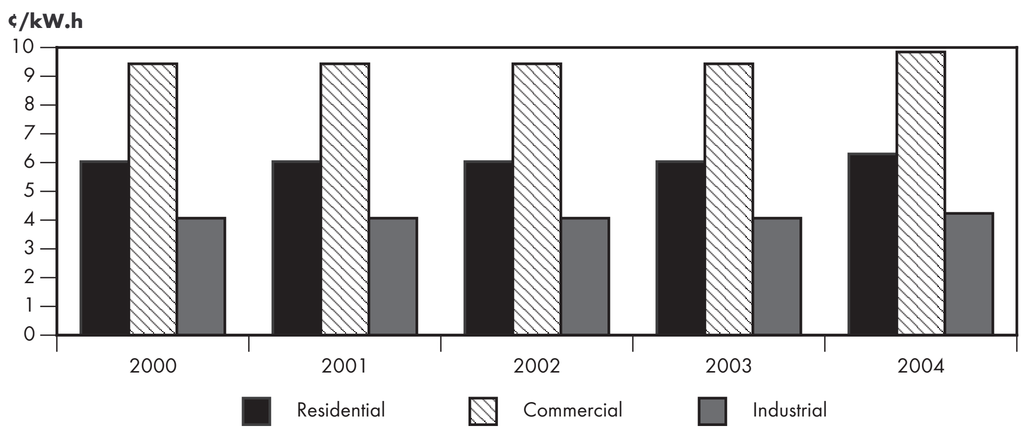
In 2003, Québec's end-use electricity demand amounted to 193 797 GW.h of which 31 percent was consumed by the residential sector, 18 percent by the commercial sector and 51 percent by the industrial sector (Figure 3.7.4). Two industries, smelting and metal fabricating, and pulp and paper, accounted for about 70 percent of industrial demand. Electricity is the dominant energy choice for residential heating, mainly because of its lower energy and installation costs relative to other forms of energy.

In 2004, HQ Distribution launched a revised comprehensive energy efficiency plan designed to contain domestic demand growth and promote efficient use of electricity. This one-billion-dollar plan, intended for all HQ's customers, targets 3 000 GW.h of energy savings by 2010, which have been deducted from HQ's projected demand.

Due to its historic low hydroelectricity cost, Québecers have enjoyed low electric rates (Figure 3.7.5). Furthermore, rates were stable during 1999-2003 as a result of a government decision to freeze rates. Prices registered two increases in 2004: a three percent increase in January and a further 1.4 percent in April. In February 2005, the Régie de l'énergie approved a further 1.2 percent increase effective

FIGURE 3.7.5

Québec Electricity Prices in Montréal (excluding taxes)



Source: Hydro-Québec

1 April 2005, compared with a 2.7 percent hike requested by HQ Distribution. The latest increase allows HQ Distribution to recover increases in operating costs.

According to HQ's recent price survey, Montréal has the second lowest residential rates (after Winnipeg) among the 12 North American cities surveyed, and the third lowest rates for large industrial customers (out of 21 cities surveyed). Québec's electricity rates are often 50 percent lower than in other parts of North America. To encourage energy conservation for residential customers, HQ Distribution has higher rates commencing after a minimum amount of energy consumption. Time-of-use pricing remains at an experimental stage in Québec.

Trade

Inside Canada, Québec has interconnections with Ontario, New Brunswick and Labrador. By virtue of a long-term supply contract, Québec receives significant transfers from Labrador, averaging 30 000 GW.h annually. In 2003, transfers from New Brunswick have been less than 2 000 GW.h annually compared with 3 400 GW.h from Ontario. Net inter-provincial transfers to Québec have increased significantly over the 2002-2004 period, reflecting in part a relatively tight supply situation in the province (Figure 3.7.6).

Considering trade with the U.S., total exports from Québec have declined in recent years (Figure 3.7.7). This reflects a combination of factors including rapid growth in domestic demand and low precipitation levels in recent years, which have resulted in lower surpluses available for export. Most exports are for short-term spot transactions. HQ Production has only two remaining long-term export contracts.

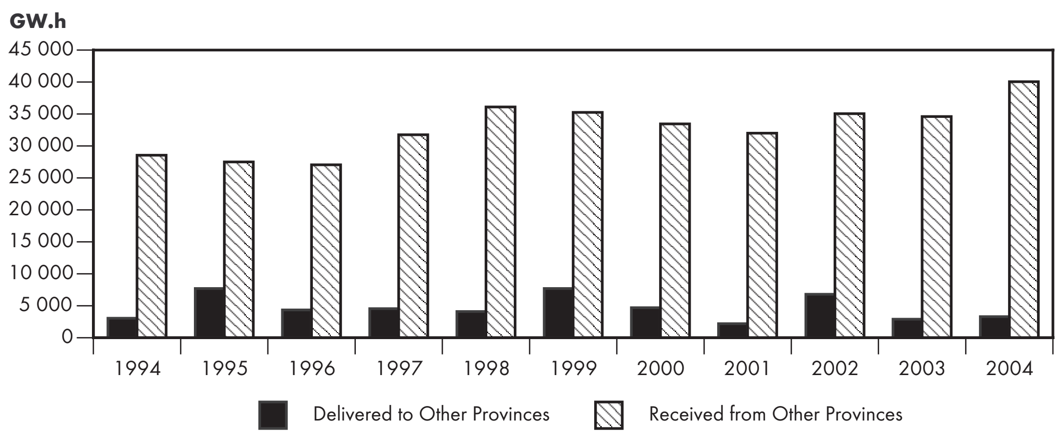
Reflecting the large increase in deliveries to the Québec market and most probably the hydro situation, the volume of net out-of-province exchanges declined 70 percent in 2003 from 2002.

3.7.3 Outlook and Issues

The short-term outlook calls for an improvement in Québec's electricity supply situation, coupled with a recovery in export and some upward pressure on prices. Although precipitation levels remain a key uncertainty in the supply outlook, reserve margins have improved over the last twelve months with above average precipitation over the summer and fall 2004. Growing domestic demand

FIGURE 3.7.6

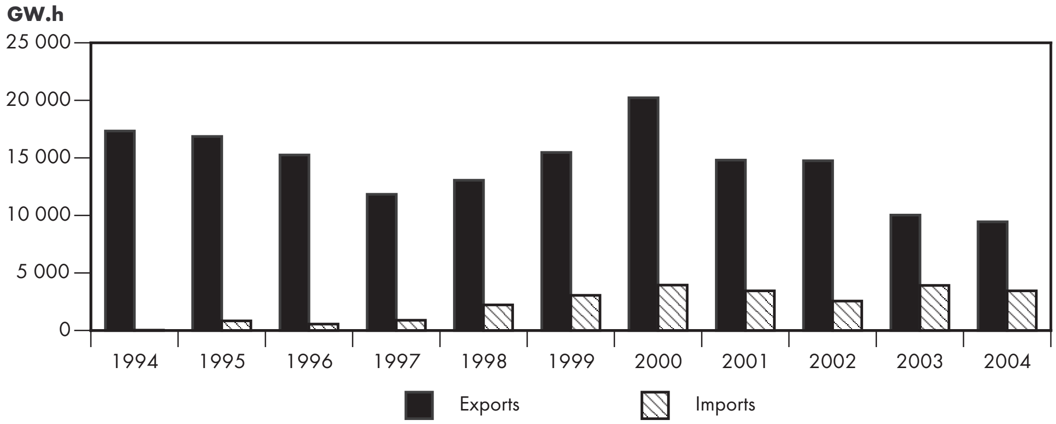
Québec Interprovincial Electricity Transfers



Source: NEB, Statistics Canada

F I G U R E 3 . 7 . 7

Québec International Electricity trade



Source: NEB, Statistics Canada

combined with low precipitation levels motivated HQ's efforts to secure additional power and energy. In addition to new hydro capacity brought on stream, short-term calls for tenders were issued by HQ Distribution for 3 500 GW.h of power in 2005.

Furthermore, HQ Distribution plans to issue two RFPs in 2005: the first one for 6 000 GW.h of energy, which it expects to need in 2006, and the second for an additional 1 000 MW of wind power capacity, which would come on line as soon as 2008. A third RFP in 2005 is possible if HQ Distribution decides to secure its 2006 energy needs in two separate calls for tenders, or if the amount of energy the utility expects to require in 2006 rises significantly. HQ Distribution will likely issue a solicitation in 2007 for a significant, though unspecified, amount of energy for subsequent years.

Hydro-Québec's exports depend on the amount of available surplus power and energy, which in turn depend on provincial economic growth, precipitation levels and timely start up of new generating facilities. Under normal operating conditions, exports will likely recover from the depressed levels registered in 2002-2003. Considering the competitiveness of hydroelectricity in the export markets, the new Energy Strategy may outline an approach to boost electricity exports and export revenue. The Québec government has recently reiterated a desire to use hydroelectricity for economic development. Québec's energy policy in the 1990s relied on low electricity rates to attract energy-intensive industries. However, some believe that the argument for the use of hydro as an economic development tool is not as strong as it once was. Hydro cannot create as many jobs as it used to because industries are less labour-intensive and higher electricity prices south of the border make electricity a valuable export commodity.

Furthermore, the Energy Strategy is expected to establish the framework for the development of long-term generation options. While there are strong indications that HQ will concentrate on bringing new hydro dams and wind-power generation on-line, uncertainties remain regarding the natural gas and nuclear generation options. The Québec government approved a gas-fired cogeneration project and, in the midst of public opposition, decided against a combined-cycle gas-fired power plant project (the Suroît project). Although potential liquefied natural gas imports could contribute to natural gas price stability, public opposition on the siting of the project could be a major obstacle to its development. Generation from the Gentilly-2 nuclear plant is expected to continue to the end of this decade. A major study is being undertaken concerning the refurbishment of this plant, with a decision expected by year end 2006.

As in many other provinces, Québec's consumers will likely see rising electricity bills, mainly as a result of increasing generation, transmission and distribution costs. The increase, in the average generation costs, reflects the more expensive development of hydro sites and relatively higher costs of wind power. HQ Distribution recently indicated that it will require a two-to-three percent rate hike each year, for the next several years, to cover increases in costs and ensure Québec remains self-sufficient in energy.

As HQ increases the integration of wind energy into its system, its average generation cost will gradually increase. Based on HQ's estimates, the acquisition cost of wind energy is 6.5 cents per kW.h, compared to 2.79 cents per kW.h for the 165 000 GW.h associated with the heritage electricity pool. Connecting wind farms to the provincial grid also requires significant transmission investments. The total cost of wind energy, including transmission, is estimated at 8.7 cents per kW.h, which is significantly higher than current residential rates. To some extent, integration of wind power into the provincial grid is more an economic than an operational issue. As wind power has about a 30 to 35 percent capacity factor, HQ must balance the costs of investing in a new transmission line, that could be used less than 35 percent of the time, versus the benefits associated with this "clean" energy source.

Electricity prices, including a potential move towards market-based electricity rates, are being publicly debated in Québec. Proponents of market-based pricing believe that higher prices, which would reflect the true cost, would provide incentive for energy conservation and the associated energy savings could be exported to higher-priced markets.

Hydro-Québec, in conjunction with the Ontario government and the engineering firm SNC-Lavalin, announced recently that they have partnered on two development options. One would see the creation of a joint-venture company to fund the development of the Lower Churchill. Ontario would own one-third of the company, Hydro-Québec the other two-thirds. The new firm would lease the sites from Newfoundland and Labrador for 50 years. The second option would see Newfoundland and Labrador Hydro finance and build the Lower Churchill facilities. Ontario and Québec would then negotiate an agreement to buy the power.

3.7.4 Summary

Québec has generally experienced a relatively stable electricity market structure; however, the province recently registered periods of tight supply and reduced exports. Decision makers currently face the challenge of selecting appropriate long-term generation options to assure adequate and reliable supply at acceptable costs while protecting the environment and promoting economic development. Consumers will likely experience moderate price increases over the 2005-2006 horizon. Assuming average precipitation levels, exports from Québec should return to historical levels.

3.8 New Brunswick

New Brunswick (N.B.) is the largest provincial electricity market in Atlantic Canada, accounting for about 40 percent of this region's electricity demand. It has a diverse generation portfolio, which includes nuclear, fossil-fuelled and hydro generation, although the future status of the 635 MW Point Lepreau nuclear generating station is uncertain.

Currently, sufficient generating capacity exists to meet both domestic demand and export opportunities. To ensure continued generation adequacy beyond 2006, the province will rely on expanding transmission interconnections with neighbouring regions, supporting the development of in-province generating capacity and improving energy efficiency.

3.8.1 Market Structure

On 1 January 1998, New Brunswick Power Corporation (NB Power), a provincially-owned integrated utility, opened its transmission system to allow parties to wheel energy through the province and to transfer energy from N.B. to external destinations.

In 2001, New Brunswick released the *White Paper on New Brunswick Energy Policy* to provide a framework for the period 2000-2010 allowing the province to fully participate in a competitive energy market and prepare for the future, while protecting the economic, environmental and societal concerns of its citizens. This energy policy is intended to strike a balance between many competing goals, including, among others: ensuring a secure, reliable and cost-effective energy supply; promoting economic efficiency and development; and ensuring an effective and transparent regulatory regime.

As a result of this energy policy, the *Electricity Act* was passed by the legislature in April 2002 and proclaimed on 1 October 2004. Through this legislation, New Brunswick restructured the provincially-owned utility, opened the wholesale market, and opened the retail market for large industrial customers connected to the transmission system.

Regulated standard service rates are still available to all customers including large industrials. However, should any wholesale or large industrial customers choose to leave standard service, the *Electricity Act* allows for the PUB to assess exit fees to cover the utility's historical costs of developing the generation and transmission infrastructure.

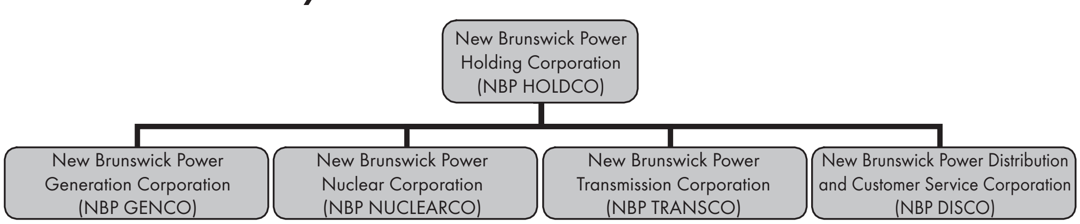
By virtue of the *Electricity Act*, the former NB Power continues to exist as a holding company, under the new name of New Brunswick Power Holding Corporation (NBP HOLDCO). The province remains the sole shareholder of NBP HOLDCO, which in turn controls the ownership of its four operating companies (Figure 3.8.1).

A separate not-for-profit statutory corporation, the N.B. System Operator (NBSO), was established to operate the provincial grid and the electricity market, ensure system reliability, co-ordinate power system planning, and administer the Open Access Transmission Tariff (OATT). The *New Brunswick Electricity Market Rules* govern relationships between the system operator and market participants.

The provincial electricity market continues to be regulated by the N.B. Board of Commissioners of Public Utilities (NBPUB) whose mandate includes market monitoring and oversight, rate approvals and dispute resolution. One key feature of this new market structure is that any new resources required by New Brunswick Power Distribution and Customer Service Corporation (NBP DISCO)

FIGURE 3.8.1

New Brunswick Electricity Sector: Institutional Structure



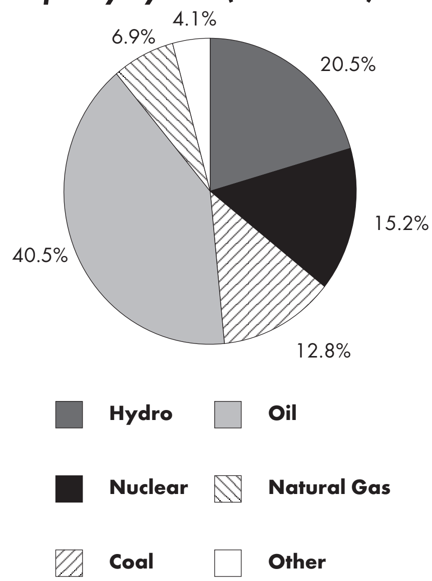
must be acquired through RFPs open to both IPPs and New Brunswick Power Generation Corporation (NBP GENCO).

In September 2004, to address growing energy demand and environmental concerns, the New Brunswick Department of Energy published a *White Paper on an Energy Efficiency System for New Brunswick*. This document outlines the objectives and main components of DSM program and reveals the establishment of an energy efficiency agency based on the model of Efficiency Vermont.[26] In addition to its DSM efforts, the province is also planning on fostering the development of renewable energy though the introduction of Renewable Portfolio Standards.

The province also participates in the proceedings of the Atlantic Energy Ministers' Forum. This Forum, which reports to the Council of Atlantic Premiers, focuses its initial efforts on promoting a cooperative approach to energy development for the whole Atlantic region.

FIGURE 3.8.2

New Brunswick 2003 Generating Capacity by Fuel (4 470 MW)



Source: Statistics Canada

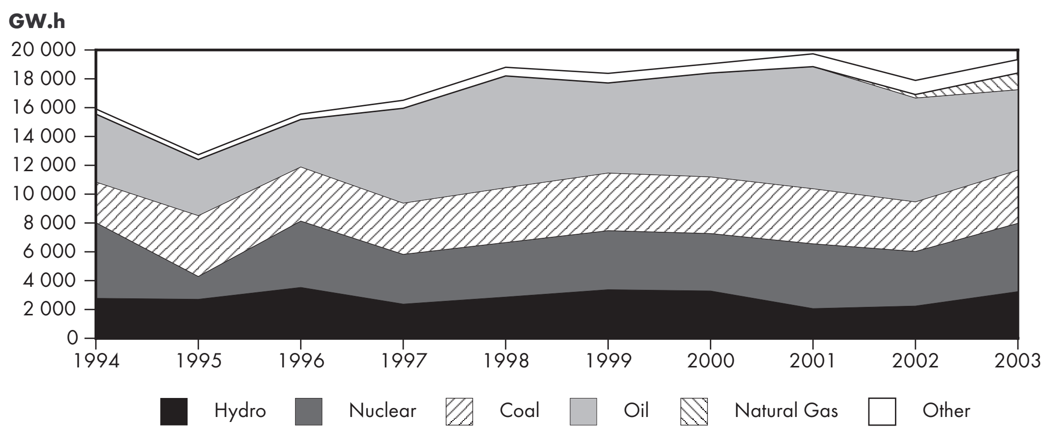
3.8.2 Current Market Developments

Generation

New Brunswick's generation is relatively diverse (Figure 3.8.2). Oil comprises the largest component of the provinces generation at about 29 percent. Hydro, nuclear and coal, which range from about 15 to 25 percent, all contribute a significant proportion of generation. Natural gas and other fuel sources round out the province's portfolio (Figure 3.8.3).

FIGURE 3.8.3

New Brunswick Generation by Fuel



Source: Statistics Canada

26 Efficiency Vermont is a state agency that has been achieving savings equal to one percent of annual electricity sales which is close to the projected demand growth in New Brunswick.

New Brunswick's large proportion of oil fired generation could significantly affect the average cost of producing electricity in the province. Oil is a relatively expensive fuel source and is tied to pricing in the world commodity market so when oil prices increase, the cost of oil fired generation in the province also increases.

Nuclear generation provides base load and in New Brunswick's case, although the nuclear component is only 15 percent of installed capacity, it provides about 25 percent of the province's total generation as the facility operates continuously. This is important to understand, as taking the plant off line would require substitution of power from other sources.

As of 2005, NBP GENCO and New Brunswick Power Nuclear Corporation (NBP NUCLEARCO) have a combined production capacity of 3 894 MW and are the principal N.B. generators, while IPPs connected to the NBSO controlled grid have a combined capacity of 402 MW. There are also 170 MW of industrial self-generation.

Total provincial generation reached 19 300 GW.h in 2003 (Figure 3.8.3). Overall, generation has increased over the last 10 years but, in the last three years, there have been substantial fluctuations. Hydro generation has been lower than historical averages, reflecting low precipitation levels. In recent years, oil-fired generation has also declined, in part because of the Bayside project which became operational in 2001. The Bayside project involved the conversion of a 100 MW oil-fired steam turbine at the Courtney Bay plant to a 263 MW gas-fired combined-cycle unit. Electricity produced at the Bayside plant is sold to NBP DISCO during the winter and the ISO-New England market during the rest of the year.

In addition to the Bayside project, the Grandview 90 MW gas-fired cogeneration plant, a joint venture between TransCanada Corporation and Grandview Cogeneration Corporation (an affiliate of Irving Oil), was completed in late 2004. The Grandview plant is located on the site of the Irving oil refinery in Saint John, New Brunswick.

With regard to future gas-fired generation development, Irving Oil has announced it is developing a gas-fired power plant project to be built near Saint John in conjunction with a proposed LNG facility. That power plant, which needs provincial regulatory approvals, will have a capacity between 500 and 750 MW and could supply as much as one third of the province's electrical load requirements.

As of 30 November 2004, the Coleson Cove Generating Station, which provides about 33 percent of New Brunswick load during the peak winter months, has been refurbished to allow it to burn Orimulsion® as well as heavy fuel oil.[27] This work included addition of scrubbers to significantly reduce emission rates and meet current and emerging environmental standards. Plans for using Orimulsion® are currently on hold due to problems associated with securing long-term supply. In the absence of a guaranteed supply of Orimulsion®, NBP GENCO is continuing to burn heavy fuel oil while evaluating its alternatives.

The Point Lepreau generating station, the only nuclear facility in Atlantic Canada, is nearing the end of its life cycle. The Point Lepreau Refurbishment Review, released in April 2004, concluded that refitting is a viable option. The plant supplies 25 percent of all electricity used in New Brunswick. The decision regarding refurbishment of Point Lepreau will significantly influence future generation in the province. NBP NUCLEARCO is assessing the feasibility of the Point Lepreau refurbishment with Atomic Energy of Canada Limited and other potential investors. If Point Lepreau is not refurbished, a proposal to build a 450-600 MW coal-fired unit at NBP GENCO's Belledune facility is an option being considered as a source of replacement energy.

27 Orimulsion® is a bitumen and water mixture imported from Venezuela.

As far as renewable energy is concerned, the Eastern Wind Power Inc. 20 MW wind generation plant, scheduled for Dark Harbour, on the western side of Grand Manan Island, is expected to be complete by the end of 2005 or early 2006.

Transmission

New Brunswick shares interconnections with each of its neighbouring provinces and states (Figure 3.8.4). Two HVDC interconnections link the province with Québec, while the province is connected to Prince Edward Island, Nova Scotia and Maine through AC lines. Its main 345 kV interconnection with Maine has an export capacity of 700 MW. Several smaller interconnections that serve isolated loads in Maine account for an additional transfer capability of 120 MW.

In order to improve system reliability and increase import and export capability, a second 345 kV IPL to Maine has been proposed. Regulatory approvals on the U.S. side have not been completed. The NEB approved the Canadian portion of the line in May 2003, contingent on all U.S. regulatory approvals being granted. A detailed route process for the Canadian portion of the line was initiated and, as a result of landowner concerns, the NEB held hearings on 9 May 2005 in St-Stephen. Assuming all regulatory approvals are received, the new line is expected to be in-service by the winter of 2006-2007.

In March of 2003, the NBPUB approved an OATT designed to be consistent with U.S. FERC Order 888 and to be managed by the NBSO. Hearings have just been completed regarding modifications to the OATT with expected implementation for 1 May 2005.

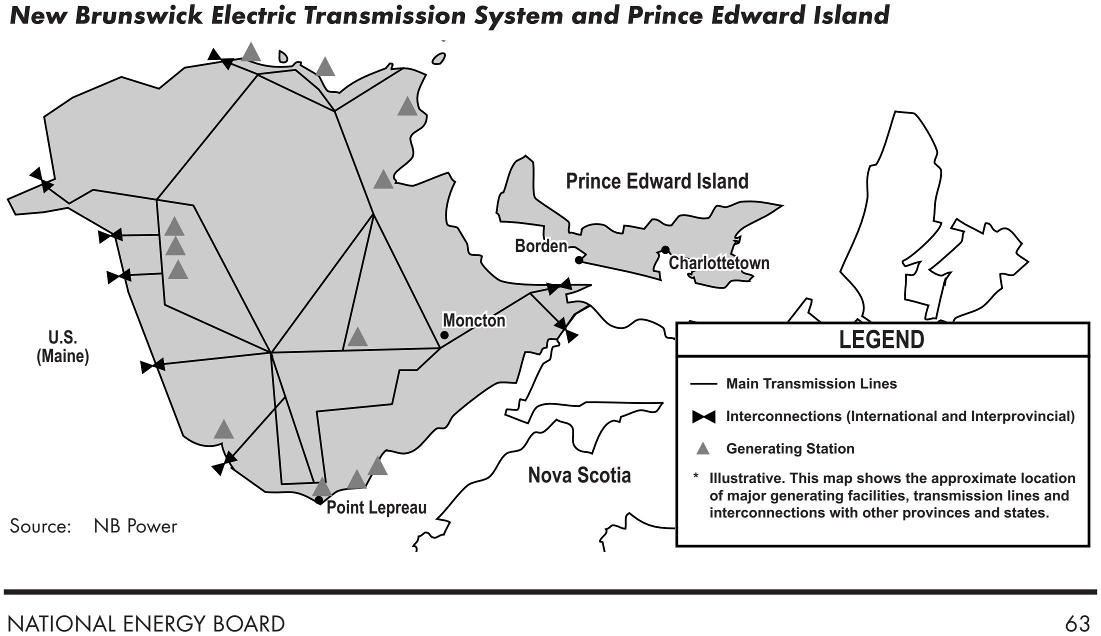
The Maritime provinces have considered, but have not pursued, the formation of an RTO. The creation of the NBSO could lead to the development of a Maritime market, although there are jurisdictional and tariff issues to be addressed.

Consumption

Electricity consumption in New Brunswick is split approximately 46 percent industrial, 35 percent residential and 19 percent commercial (Figure 3.8.5). Over half of all residences in New Brunswick use electricity for heating. In an effort to stimulate diversification, the province encourages home builders

FIGURE 3.8.4

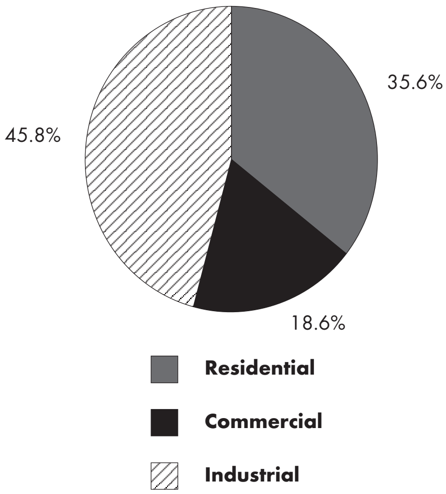
New Brunswick Electric Transmission System and Prince Edward Island



Source: NB Power

FIGURE 3.8.5

New Brunswick 2003 Electricity Demand by Sector (15 303 GW.h)



Source: NEB, Statistics Canada

to use alternative heat sources such as oil or natural gas, for new housing starts. However, in spite of these efforts, electricity is still the dominant choice for heating for about 80 percent of new housing. Industrial load softened due to the recent closures of two pulp and paper plants.

New Brunswick benefits from trade with the New England states and other Maritime provinces, which have higher prices. For this reason, New Brunswick consumers benefit as revenues earned by selling New Brunswick power into higher cost regions contributes to keeping domestic rates lower than Prince Edward Island and Nova Scotia. Although the former NB Power has been functionally unbundled, New Brunswick customers continue to benefit from export sales for the time-being because there are long-term contractual arrangements between NBP GENCO and NBP DISCO that allow for the transfers of export benefits to end-use customers.

Residential and commercial electricity rates in New Brunswick increased in recent years while industrial rates remained relatively stable (Figure 3.8.6). In April 2002, a 2.1 percent average rate increase was implemented, followed by further average increases of 2.6 percent in April 2003 and 2.5 percent in April 2004. Uneven price increases for different customer classes reflect varying operating and maintenance costs.

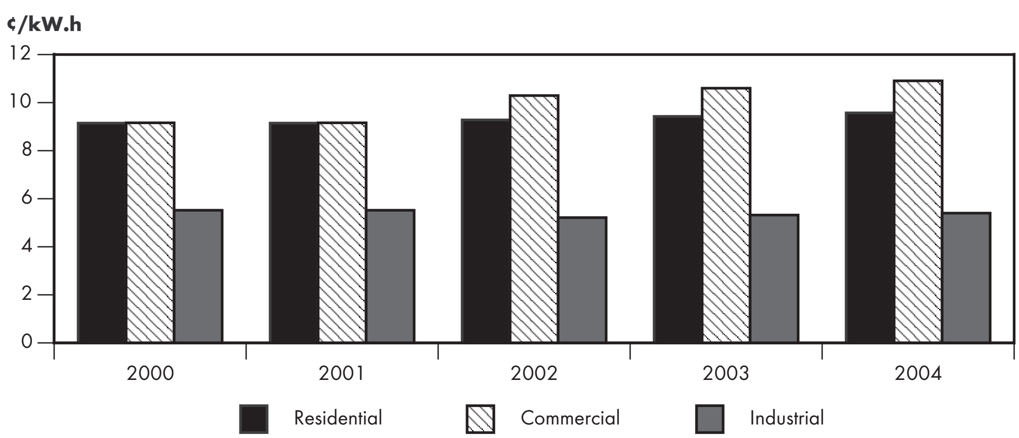
NBP DISCO implemented an average 3.0 percent rate increase on 31 March 2005 and in April 2005 applied for a further 4.5 percent average rate increase. Although the total average increase requested for 2005 will be 7.5 percent, residential customers face a combined increase of 9.7 percent. This reflects increasing fuel prices and a move towards reducing cross-subsidization.

Trade

Transfers into New Brunswick from neighbouring provinces have decreased over time while transfers from New Brunswick to other provinces have remained fairly stable (Figure 3.8.7). This was

FIGURE 3.8.6

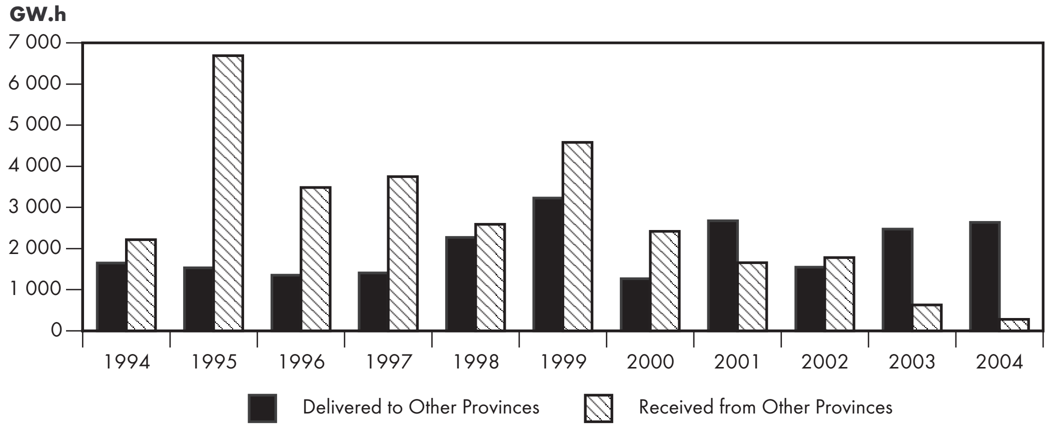
New Brunswick Electricity Prices in Moncton (excluding taxes)



Source: Hydro-Québec

FIGURE 3.8.7

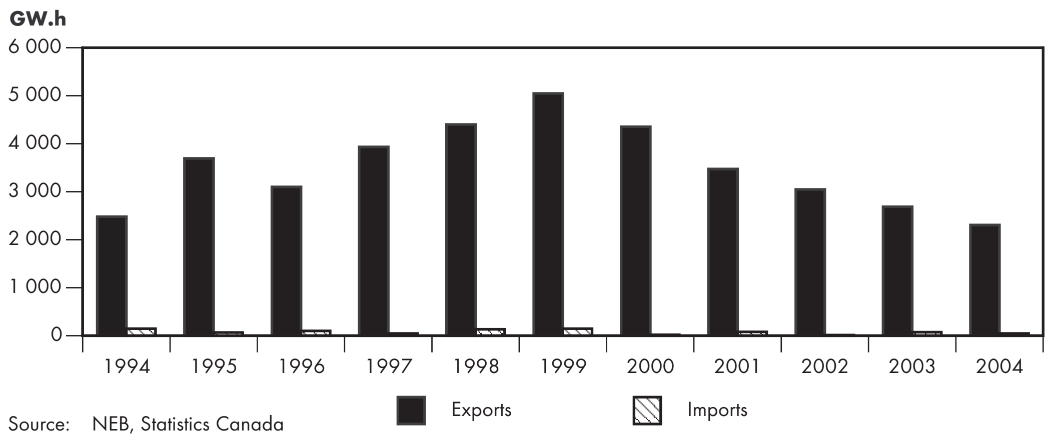
New Brunswick Interprovincial Electricity Transfers



Source: NEB, Statistics Canada

FIGURE 3.8.8

New Brunswick International Electricity Trade



Source: NEB, Statistics Canada

demonstrated in recent tight supply situations where Québec received higher transfers from New Brunswick than previously. As a result, Québec is now New Brunswick's largest single customer for out-of-province sales although sales into New England continue to exceed those into Québec. In the near term New Brunswick will continue to supply 95 percent of Prince Edward Island's electricity needs. Overall, the net result is that inter-provincial trade is increasing.

Exports to the U.S. have been declining steadily since 1999 while imports remained negligible (Figure 3.8.8). Higher in-province sales and higher transfers to adjacent provinces constrain the amount of surplus available for exports, and cause exports to decline.

3.8.3 Outlook and Issues

New Brunswick should have adequate supply for the 2005-2006 period. A key decision to be made soon is with respect to the future of Point Lepreau. Demand is expected to continue to increase and there are potential supply concerns that need to be addressed to ensure adequate supply during the possible refurbishment period. If Point Lepreau is to be refurbished, the plant will be out of service between April 2008 and December 2009. As Point Lepreau is a base-load generating plant, the associated energy must be replaced by domestic sources and imports. Since import capability is currently limited, if the second IPL connecting N.B. to Maine is not in service in time, the N.B. market may experience a shortage of power.

In recent years, declining exports were offset by increasing interprovincial transfers and this trend is expected to continue in the foreseeable future. Levels of transfers to Québec will undoubtedly depend on precipitation conditions in the near-term. With surplus natural gas-fired generation capacity in New England, it appears unlikely that exports could rebound significantly in the 2005-2006 period. Furthermore, depending on the future of the Point Lepreau refurbishment project, in addition to curtailed exports, significant imports may be required over the 2008-2009 period.

Export revenues have helped to keep domestic rates among the lowest in Atlantic Canada. However, with rising fuel costs and declining export revenues, electricity rates may increase sharply in the near term. In addition, electricity rates in the future will experience upward pressures due to the substantial investments already made to convert the Coleson Cove Generating Station to Orimulsion® and the potential expenditure to refurbish the Point Lepreau plant.

New Brunswick plans to expand its transmission capability to allow for increased imports and exports with the Northeastern U.S. markets. The challenge will be to get the second IPL in service in time so that imports can help ensure supply adequacy during the Point Lepreau refurbishment period.

Allowable emission levels for SO_X will decrease this year and again in 2010, and caps on emissions of NO_X and mercury will go into effect in 2009. New Brunswick expects to be able to meet its 2009 and 2010 targets with the retrofit of Coleson Cove Generating Station and by retiring the Grand Lake coal plant, a 57 MW coal plant built in 1964 that burns high sulphur coal.

Through the Atlantic Energy Ministers Forum, the region is developing an energy strategy to achieve a more integrated regional market. This may lead to enhanced interprovincial transfers in the Atlantic provinces. Since a significant portion of its generation is fossil-based, New Brunswick is assessing its generation options. The 13 April 2005 release of Project Green, the Federal Government's plan to honour Canada's *Kyoto Protocol* commitment will reduce some of the previous uncertainty regarding clear rules to achieve *Kyoto Protocol* emissions reduction targets. Energy efficiency, renewable portfolio standards and the development of wind energy are current government priorities to achieving greener generation sources.

3.8.4 *Summary*

New Brunswick has adequate supply to meet its electrical loads in the near-term; however, there is uncertainty with respect to supply adequacy in the future. Once the decision with respect to Point Lepreau is made (expected by mid-2005) some of this uncertainty should be alleviated. Completion of the second IPL to Maine will play an important role in meeting N.B.'s electrical loads while, at the same time, providing more trade opportunities for in-province generators.

3.9 Prince Edward Island

Prince Edward Island (P.E.I.) relies almost exclusively on electricity transfers from New Brunswick to meet its power requirements. A key focus of a comprehensive energy strategy expected to be released in the spring 2005, will be the development of renewable energy. To date, the Province continues to actively pursue the development of wind power to diversify its supply sources and reduce reliance on out-of-province generation.

3.9.1 Market Structure

Maritime Electric Company Limited (Maritime Electric), a wholly-owned subsidiary of investor-owned Fortis Inc., is the principal electric utility in the province. The City of Summerside has its own municipal distribution network. Maritime Electric operates under the provisions of the *Maritime Electric Company Limited Regulation Act* and is regulated by the Island Regulatory and Appeals Commission. In December 2003, Prince Edward Island passed the *Electric Power Act* (EP Act) to return Maritime Electric to the traditional cost-of-service rate regulation model. Before the EP Act, Maritime Electric's rates were directly linked to NB Power rates.

P.E.I. unveiled a Renewable Energy Strategy in June 2004. The main objective of this strategy is to reduce the province's reliance on fossil fuels. Under this strategy, the Province will commit to a renewable portfolio standard for electricity of at least 15 percent by 2010, and evaluate opportunities to have 100 percent of its electrical demand (at least 200 MW) supplied by renewable energy by 2015.

3.9.2 Current Market Developments

Generation

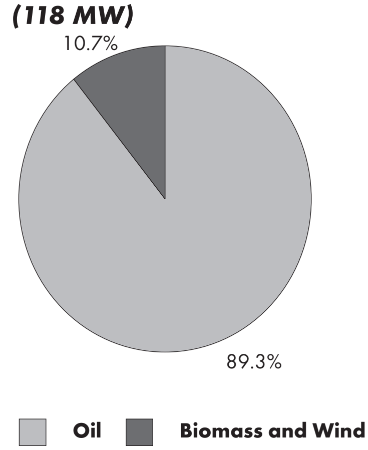
Maritime Electric operates two generating facilities with a combined total capacity of 104 MW. The 40 MW Borden Generating Station has two diesel-fired combustion turbines while the Charlottetown Generating Station has 64 MW of oil-fired generation capacity. The province has experienced the development of biomass and wind facilities (Figures 3.9.1 and 3.9.2). Wind energy currently supplies about two percent of P.E.I.'s annual electricity usage. As a result of new wind capacity, generation on the island has increased in recent years.

Transmission

Power is transmitted to P.E.I. via two 138 kV submarine transmission cables with a combined total capacity of 200 MW.

FIGURE 3.9.1

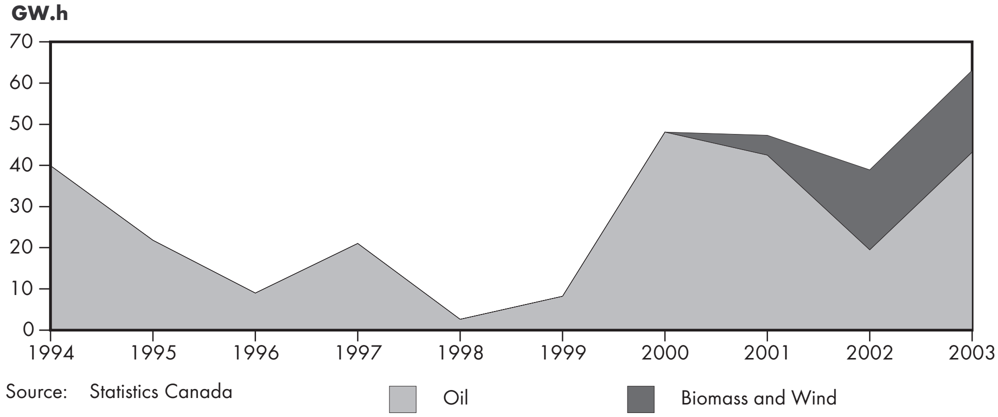
Prince Edward Island 2003 Generating Capacity by Fuel (118 MW)



Source: Statistics Canada

FIGURE 3.9.2

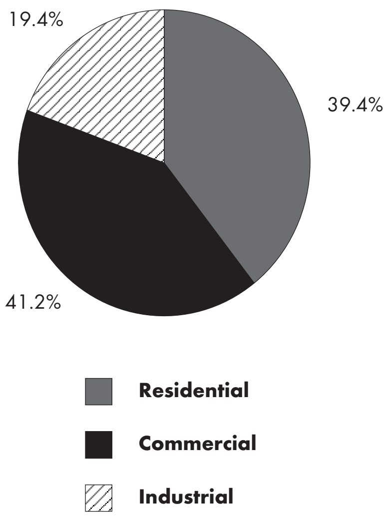
Prince Edward Island Generation by Fuel



Source: Statistics Canada

FIGURE 3.9.3

Prince Edward Island 2003 Electricity Demand by Sector (958 GW.h)



Source: NEB, Statistics Canada

Consumption

Electricity demand has increased as a result of economic growth. With limited industrial activity in the province, nearly 80 percent of electrical demand originates from the residential and commercial sectors (Figure 3.9.3). Total peak demand was 209 MW in 2004.

Electricity rates in P.E.I. are relatively high in comparison with those prevailing in the other Atlantic provinces. Although rates remained stable over the 2000-2002 period, consumers experienced a 13.3 percent increase in April 2003 (Figure 3.9.4). From 1994 to 2003, Maritime Electric's rates were pegged to 110 percent of NB Power's rates. Since 1 January 2004, rates have been based on the costs incurred to provide service in P.E.I. This regulatory change will further reduce Maritime Electric's exposure to energy costs since all energy-related costs are now fully recoverable.

Trade

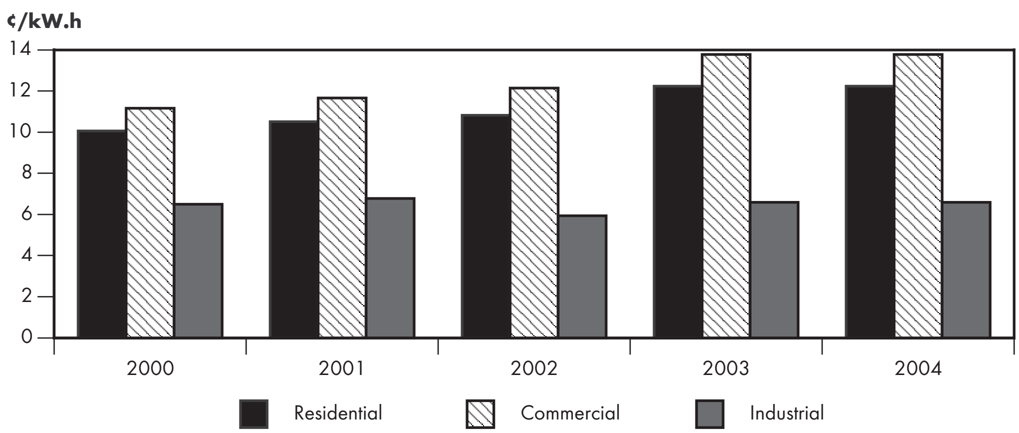
Transfers from New Brunswick to P.E.I. trended upward in recent years, reflecting continued growth in demand (Figure 3.9.5). In 2003, Maritime Electric concluded a new energy purchase agreement with NB Power, which provides for an increase in firm energy purchases.

3.9.3 Outlook and Issues

In the short-term, there should be adequate supply as the province continues to benefit from generation sources in New Brunswick. In the long-term, new generating capacity will be developed on the Island, reducing its reliance on out-of-province purchases. To ensure increased capacity to meet energy demand growth, Maritime Electric obtained regulatory approval to construct a 50 MW gas turbine at its existing Charlottetown generating station. The new facility, used primarily for peaking

FIGURE 3.9.4

Prince Edward Island Electricity Prices in Charlottetown (excluding taxes)



Source: Hydro-Québec

Wind Power

Within Canada, wind-powered generation has grown from a few pilot projects in the mid-1990s, to over 444 MW of installed capacity by the end of 2004, mostly in Québec and Alberta. This growth can be attributed to factors including: the declining capital cost of wind facilities; the rising cost of fossil fuels; the opening of competitive generation markets to Independent Power Producers (IPPs); the onset of voluntary and mandatory renewable portfolio standards; and incentive programs such as the Federal Wind Power Production Incentive (WPPI). The Canadian Wind Energy Association believes a goal of 10 000 MW of installed wind power capacity by 2010 is achievable.

As the proportion of wind power on the electric system increases, unique environmental and technical challenges must be met. Although wind is considered a green source of energy, there are aesthetic issues as well as perceived environmental concerns relating, for example, to noise pollution and the affect wind farms can have on birds. None of these are insurmountable obstacles given proper siting and the tower design and slow turning speed of modern wind turbines; however, there are other factors that wind farm developers must address. For example, wind turbines operate only within a specific range of wind velocities. A minimum amount of wind is required to produce energy, and when wind velocities exceed a maximum level, turbine blades are turned into the wind to cease operations. Although this prevents turbines from producing energy, it also prevents damage to the equipment. Similarly, while cold, dense air is preferred, as it contains more energy than hotter, less dense winds at the same velocity, cold weather can make materials brittle, and lead to frost formation, which reduces energy output and can damage equipment.

Additionally, some wind sites are located near population centres, although others are in more remote locations and require construction of new transmission or expansion of existing facilities to bring their power to market. The cost of integrating this new generation can be an important consideration. Another challenge is the intermittent nature of wind power. Typical wind turbines have a capacity factor of 25 to 35 percent. This requires that some other energy source must be available to cover periods when wind is unavailable.

However, there are measures that could mitigate this concern:

Diversity

If wind turbines span a large geographic region, it is less likely that all of them will 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.

Forecasting

Advanced (daily or hourly) forecasts for wind speed and wind turbine production are valuable, as this provides more time to respond to these changes.

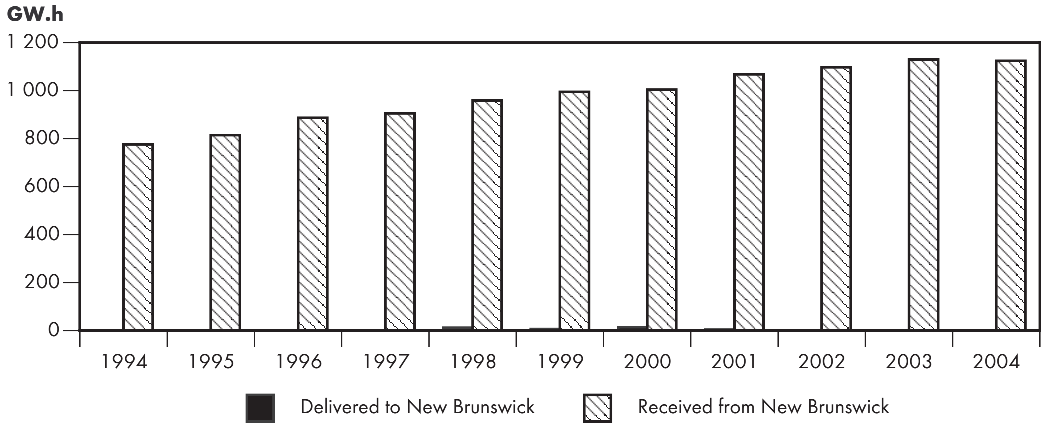
Hydro Synergy

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 when it is needed most.

The amount of wind power a system can absorb depends on its configuration. Based on technical studies and experience in Europe, 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, while a mainly hydro-based system could support more wind power.

FIGURE 3.9.5

Prince Edward Island Interprovincial Electricity Transfers



Source: NEB, Statistics Canada

purposes, will initially burn light oil and can eventually be converted to natural gas. It is expected to be in service for the fall of 2005.

The Renewable Energy Strategy will continue to influence new supply and demand-side resources in P.E.I. The short-term goal, of achieving a 15 percent renewable energy component by 2010, will be met through the establishment of an additional 40 MW of wind capacity. To further promote wind development, Islanders can pay a green premium to purchase wind energy under the Green Power Program. The Renewable Energy Strategy also calls for Maritime Electric to file a demand-side management strategy to promote efficient energy use and to develop an Open Access Transmission Tariff to define the price that others must pay to access Maritime Electric's transmission infrastructure. The move to cost-of-service rates, combined with the addition of cleaner but higher cost renewable energy, could put upward pressure on rates in P.E.I.

From a regional perspective, the Atlantic Energy Ministers' Forum will provide opportunities for the province to cooperatively assess key issues affecting its long-term energy future including resource adequacy, climate change, and the potential for integrating renewable energy such as wind, into the Atlantic electric system.

3.9.4 *Summary*

P.E.I. has developed policy initiatives to diversify its energy supply sources and reduce reliance on out-of province electricity purchases. The province sees a strong role for renewable energy in future energy development, especially wind power. However, due to the intermittent nature of wind, there could be a continued need to develop reliable sources of base load electricity supply.

3.10 Nova Scotia

The restructuring of Nova Scotia's electricity market continues to evolve, especially with the passage of a new *Electricity Act* by the provincial legislature in the fall of 2004. The new act will open Nova Scotia's wholesale electricity market, and will establish a mandatory renewable portfolio standard (RPS) to foster the development of renewable energy in the power generation sector.

3.10.1 Market Structure

Nova Scotia Power Inc. (NSPI), a subsidiary of the investor-owned Emera Inc., is the dominant electricity supplier in the province. It owns and operates 97 percent of generation, 99 percent of transmission, and 95 percent of the distribution systems. The vertically-integrated utility is regulated by the Nova Scotia Public Utility and Review Board (UARB) on a cost-of-service basis. The remaining distribution is owned and operated by six municipal utilities, the province's wholesale customers.

The new *Electricity Act* requires NSPI to file an OATT to provide non-discriminatory access to its transmission system. The OATT hearings will take place in May 2005. A primary driver behind the development of the OATT is to satisfy New Brunswick's requirement for reciprocal access.

Under announced government policy, NSPI will continue to produce demand forecasts while the UARB will determine if new generation is required. One method of implementation would be that, if new generation is necessary, the regulator will issue an RFP open to any interested party. To ensure the success of an RFP, NSPI would be required to bid.

An Independent System Operator (ISO) is not seen as cost effective given the size of Nova Scotia's system and the limited number of market participants. Considering efforts by the Atlantic provinces to develop regional market integration, the New Brunswick System Operator might evolve into a regional ISO that would include New Brunswick, Nova Scotia, Prince Edward Island and northern Maine. If this development occurs, it will be a unique Canadian example of a cross-border ISO.

3.10.2 Current Market Developments

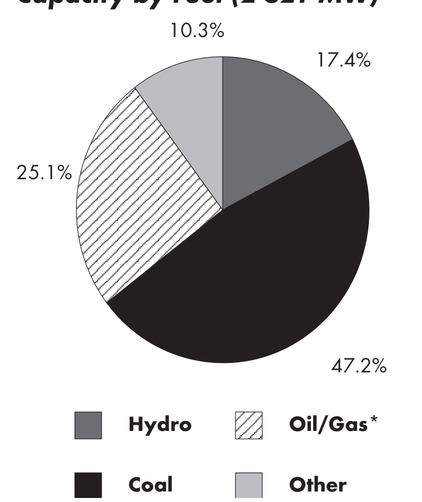
Generation

Nova Scotia has a mix of generation, with a total capacity of 2 321 MW (of which 332 MW is dual-fuelled oil/natural gas) as of December 2003 (Figure 3.10.1). Almost half the total capacity and 70 percent of generation are accounted for by coal-fired units. The coal-fired units burn about 20 percent petroleum coke and 10 percent domestic (strip mined) coal, with the rest being coal imported by ship, typically from South America. To increase availability of domestic coal, the Nova Scotia government issued an RFP to develop the Donkin Coal Resource Block within the Sydney Coalfield.

NSPI's current strategy for generation expansion includes retrofits at existing units and an increased emphasis on renewable sources of generation. Two 47 MW natural gas-fired combustion turbines have been added at the Tufts Cove generating plant (one for the winter of 2003-2004 and one for the winter of 2004-2005). While three of the earlier Tufts Cove units can use either natural gas or oil, with high natural gas prices, oil was more often used than gas in the last two years (Figure 3.10.2). Also in 2004, 100 GW.h per year of IPP wind energy (30 MW) was added. Further contracts were signed for an additional 200 GW.h per year of wind energy to come on line in a staged fashion by 2007.

FIGURE 3.10.1

Nova Scotia 2003 Generating Capacity by Fuel (2 321 MW)



* Includes 332 MW of dual oil or gas-fired units

Source: Statistics Canada

DSM and DR measures such as the Extra Large Industrial Interruptible Rate have been successful in reducing demand growth in recent years, and Nova Scotia has a goal of conserving a further 67 MW with DSM and DR by 2010. The combination of the projected DSM and DR savings, with increased generation through renewable energy and unit upgrades, will allow NSPI to avoid having to add any major new generation before 2011 or 2012.

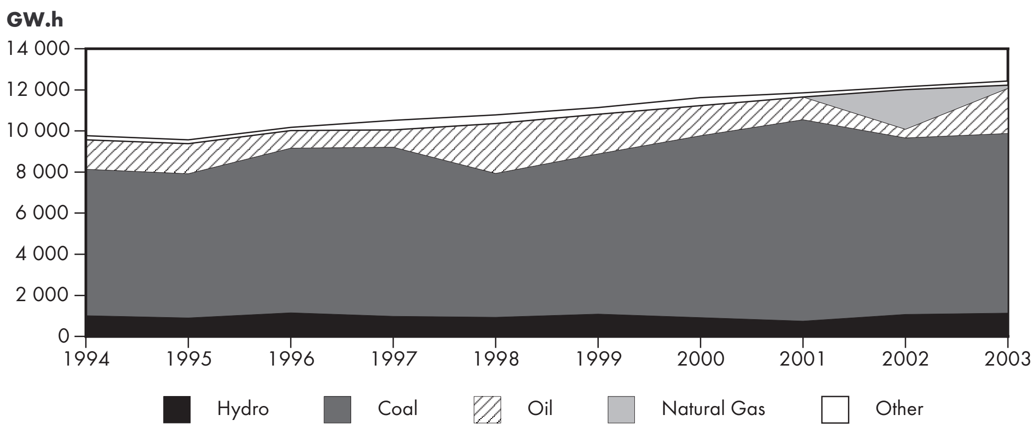
Transmission

In addition to permitting sales of up to 300 MW to New Brunswick and purchases of up to 350 MW, the links between the provinces (Figure 3.10.3) allow for the sharing of operating reserve. Reserve sharing benefits small jurisdictions such as New Brunswick and Nova Scotia by allowing their systems to support larger more efficient units than either system could separately.

The Nova Scotia government is part of the Atlantic Energy Ministers' Forum, which aims to maximize the benefits of cooperation and coordination within the region. In particular, they are looking at ways to maximize alternative and renewable energy while keeping costs as low as possible.

FIGURE 3.10.2

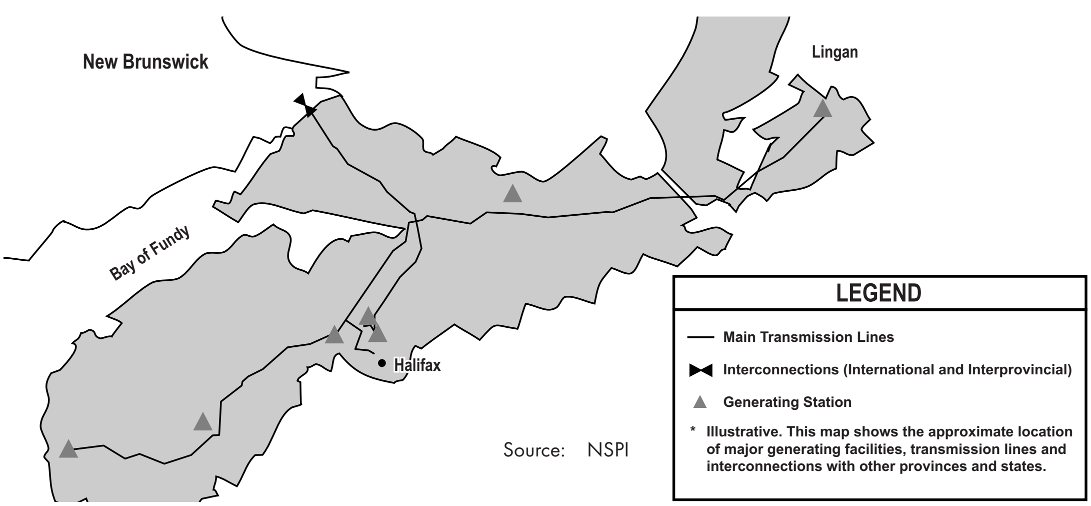
Nova Scotia Generation by Fuel



Source: Statistics Canada

FIGURE 3.10.3

Nova Scotia Electric Transmission System



Source: NSPI

Consumption

Electricity demand in Nova Scotia is about evenly distributed among the residential, commercial and industrial sectors (Figure 3.10.4). About 25 percent of residential heating in Nova Scotia is electric. Industrial demand has a large interruptible component (equivalent of 400 MW). To reduce peak demand, NSPI adopted time-of-use rates to encourage electro-thermal storage, a technology where electricity is used to heat a thermal storage mass such as ceramics during off-peak hours, with the heat released to the residence when electricity prices are high. It is estimated that this program reduced the peak in Nova Scotia by 9.0 MW this winter, with more savings expected in the future.

Electricity rates were stable over the last few years (Figure 3.10.5) but, in 2005, a rate increase, with annual adjustments, was approved. The rate rose by an average of 5.3 percent for most customers, but industrial customers face a 10.4 percent increase. The increase in part reflects NSPI's accumulated liabilities due to deferred taxes.

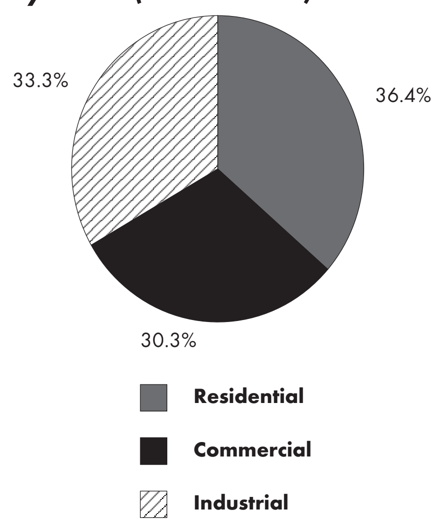
NSPI developed an interruptible rate structure, which includes a basic interruptible rate that allows interruption for system security in emergencies and an Extra Large Industrial Interruptible Rate that allows interruptions for both economic and security reasons.

Trade

Since 2002, electricity transfers from Nova Scotia to New Brunswick have declined while transfers from New Brunswick to Nova Scotia have increased (Figure 3.10.6). In 2004, Nova Scotia was a net purchaser of electricity from New Brunswick. Exports from Nova Scotia to New England (via New Brunswick) increased since they were initiated in 2002 (Figure 3.10.7). Like New Brunswick, Nova Scotia is a winter peaking system and therefore is likely to have capacity and energy surplus in the summer when demand in New England peaks.

FIGURE 3.10.4

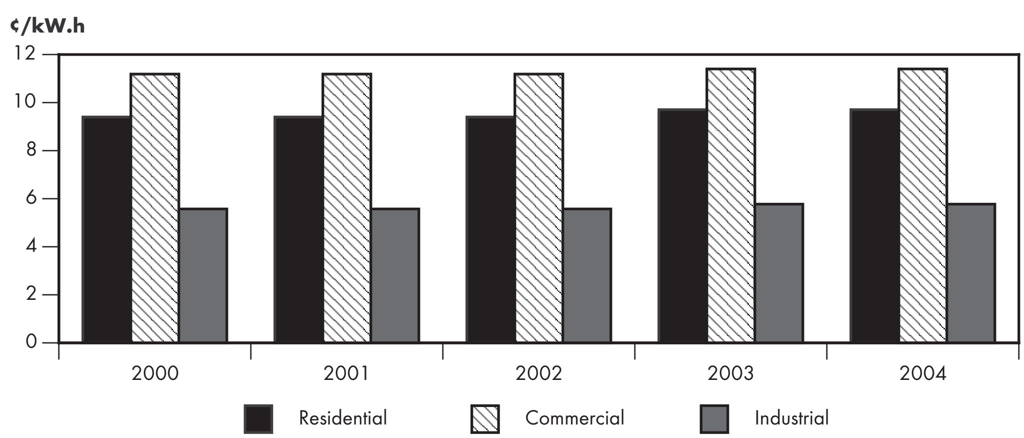
Nova Scotia 2003 Electricity Demand by Sector (11 197 GW.h)



Source: NEB, Statistics Canada

FIGURE 3.10.5

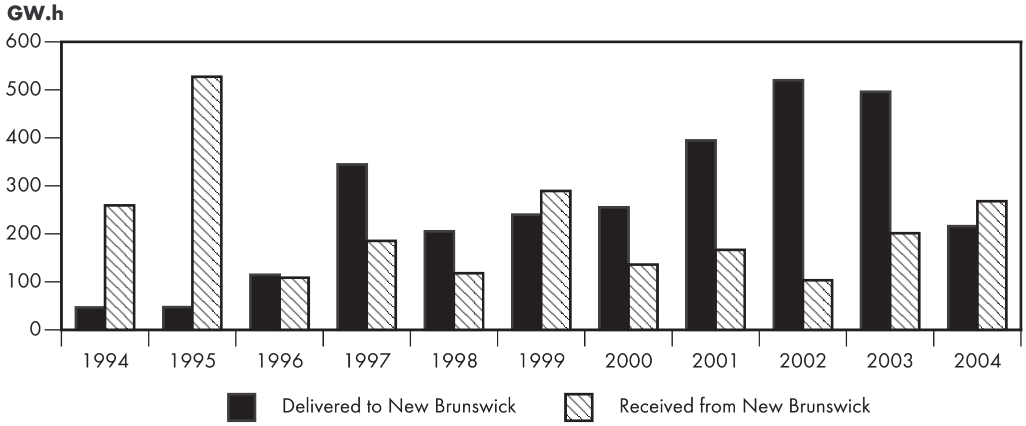
Nova Scotia Electricity Prices in Halifax (excluding taxes)



Source: Hydro-Québec

FIGURE 3.10.6

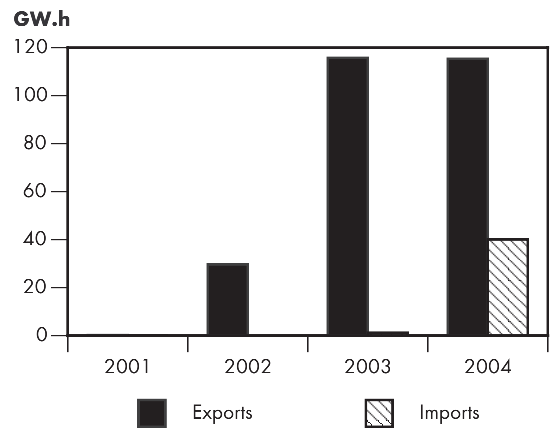
Nova Scotia Interprovincial Electricity Transfers



Source: NEB, Statistics Canada

FIGURE 3.10.7

Nova Scotia International Electricity Trade



Source: NEB, Statistics Canada

3.10.3 Outlook and Issues

With recent capacity additions, equipment updates at existing plants and demand management initiatives NSPI has adequate generation in the near and medium-term. The large interruptible load NSPI serves, coupled with the contractual reserve sharing with New Brunswick, contribute further to the system's ability to meet domestic firm load.

In the near-term (2005-2006), transfers between Nova Scotia and New Brunswick are not expected to change significantly. However, if Point Lepreau is taken off-line for refurbishment, there could be significant opportunities for electricity transfers from Nova Scotia to New Brunswick.

Opportunities for trade with the U.S. are expected to improve in the next few years. In its Reasons for Decision - New Brunswick Power Corporation (EH-2-2002), the National Energy Board approved a second transmission line between New Brunswick and Maine, which could lead to higher electricity exports in the summer and facilitate imports in the winter.

Near-term electricity rates continue to be subject to fluctuations in the price of oil and imported coal. In the long run, rates will be influenced by the cost of incremental generation, a large part of which will be renewable. While renewable energy is environmentally less intrusive, and its cost is declining, it generally remains more expensive than conventional generation. As in other jurisdictions, addition of renewable energy into the provincial system will exert upward pressure on end-use electricity rates.

Nova Scotia's planned renewable portfolio standards specify that five percent of its energy requirement be met with new renewable generation by 2010. While there is potential for landfill gas and more biomass, most new renewable energy will likely be wind. The system should accommodate 200 MW of wind capacity without the need for new transmission. Nova Scotia has a 20 MW pilot tidal project and there is potential for further tidal development. Like wind, tidal energy is intermittent and may not provide power when it is most needed; however, tidal power is more predictable so it is easier to integrate it into an electric system. Large tidal projects are possible but have potential negative environmental effects.

In addition to renewable power, it appears that cogeneration could be an attractive long-term generation option. One study, based on gas prices lower than current values, estimated there is potential for several hundred megawatts of cogeneration. There is interest in extending the natural gas distribution system to Halifax and natural gas-fired cogeneration could form the anchor load for such an extension.

There is potential for one or more LNG facilities in the province, each with a capacity of up to one billion cubic feet of natural gas per day. Such a facility has potential for associated gas-fired cogeneration but the deciding factor on whether any of these projects go ahead will probably be availability of long-term contracts to guarantee a supply of natural gas and long-term customers. The proposed Bear Head facility on Cape Breton Island along the Strait of Canso has received provincial approval but has yet to apply to the NEB for an Import License or for authorization to connect to the Maritimes and New England Pipeline.

Because of its predominantly coal-fired generation, Nova Scotia is taking major steps to address emissions issues. The province targeted a 25 percent SO_X reduction by March 2005, with a further 25 percent reduction by 2010. The first target can be met by switching to low sulphur coal but the latter target will require retrofits to some of the older units. The Point Aconi fluidized bed unit includes SO_X emission controls. Scrubbers do have an economic benefit as they allow units to use cheaper high sulphur coal, partially compensating for the capital cost of the scrubbers.

In 2009, provincial NO_X caps go into effect, which NSPI plans to meet by burner modification. Mercury emissions were reduced, by the switch to low sulphur coals, and further improvements are expected if scrubbers are retrofitted. Electricity generation currently produces about 50 percent of greenhouse gas emissions in the province, so NSPI is participating in development of plans to meet *Kyoto Protocol* targets. In the short-term it is planning on smaller, lower risk options for new generation.

3.10.4 Summary

Generation in Nova Scotia is predominantly coal-fired but the Province is planning to adopt a mandatory RPS to accelerate the development of renewable energies, especially wind. NSPI is relying on renewable generation, demand management measures to meet future load growth but, if it does not meet its targets, it may require new generation. Consumers face a significant increase in rates this year due mainly to tax related issues. In the future, electricity rates may be subject to high and volatile fuel costs if significant new oil or natural gas-fired generation is required.

3.11 Newfoundland and Labrador

The Province of Newfoundland and Labrador consists of two major geographic areas, each of which has a separate electrical system. Labrador, on the mainland, has a system that is almost entirely hydro-based, while the system on the Island of Newfoundland (Island) is based on a mix of hydro and oil-fired thermal generation. The provincial government is currently investigating the possibility of developing the Lower Churchill River hydro project in Labrador to increase revenue from electricity sales outside the province.

3.11.1 Market Structure

Electricity markets within Newfoundland and Labrador are served by two utilities, which are regulated by the Board of Commissioners of Public Utilities (Public Utilities Board or PUB). Newfoundland and Labrador Hydro (HYDRO), a Crown corporation, owns and operates the majority of the generation and high voltage transmission facilities in the province. HYDRO also distributes power to some rural communities on the Island, as well as to all residential, commercial and industrial customers in Labrador. Newfoundland Power, owned by Fortis Inc., serves about 90 percent of all retail customers on the Island. It purchases over 90 percent of its electricity requirements from HYDRO and generates the balance from its own facilities.

A comprehensive energy plan is under development by the Department of Energy and will be delivered to the government by the end of 2005. A public information package will be released, to be followed by public consultations. This review will address the electricity industry, as well as expanding HYDRO's role to include other energy sources such as oil and natural gas.

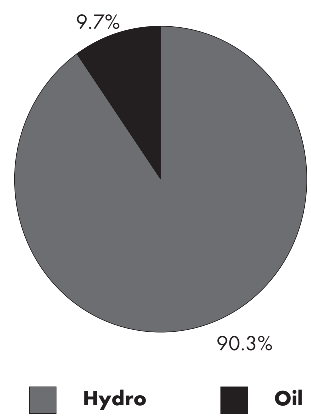
3.11.2 Current Market Developments

Generation

Ninety-four percent of generation in the province comes from hydro resources (Figures 3.11.1 and 3.11.2). Most of this comes from the 5 400 MW Churchill Falls hydro complex in Labrador, almost all of which is sold under long-term contract to Québec. On the Island, hydro makes up about two thirds of the generation. The remaining third is provided by thermal generation, which is almost entirely heavy fuel oil burned at HYDRO's Holyrood generating station.

FIGURE 3.11.1

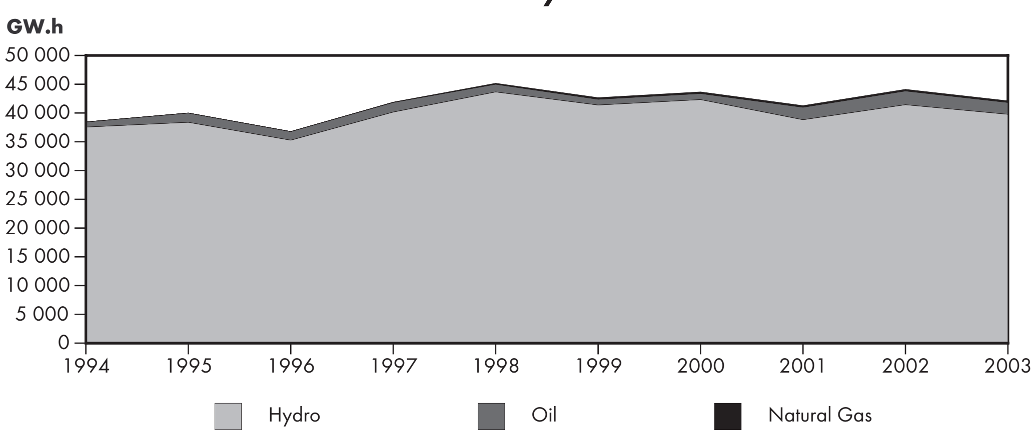
Newfoundland and Labrador 2003 Generating Capacity by Fuel (7 462 MW)



Source: Statistics Canada

FIGURE 3.11.2

Newfoundland and Labrador Generation by Fuel



Source: Statistics Canada

Recent increases in demand on the Island were met by the addition of the 40 MW Granite Canal hydro electric generating station, the Corner Brook Pulp and Paper 15 MW cogenerator (burning a mixture of heavy fuel oil and wood bark) and the 32 MW hydro plant at the Abitibi Consolidated pulp and paper mill in Grand Falls. The cost of Island generation is affected significantly by the consumption and price of the heavy fuel oil used at the Holyrood thermal plant. To minimize consequent swings in electrical rates a stabilization fund was established in 1986. In recent years oil prices were consistently above the value forecast for the rate case, which resulted in significant deficits in the plan. Changes were made to improve the plan's responsiveness, and the accumulated deficit is being recovered from customers through 2008. In the past, the province has used an RFP process for new generation. It is currently forecast that the Island system will need new generation to meet demand growth in the 2010 time frame.

Transmission

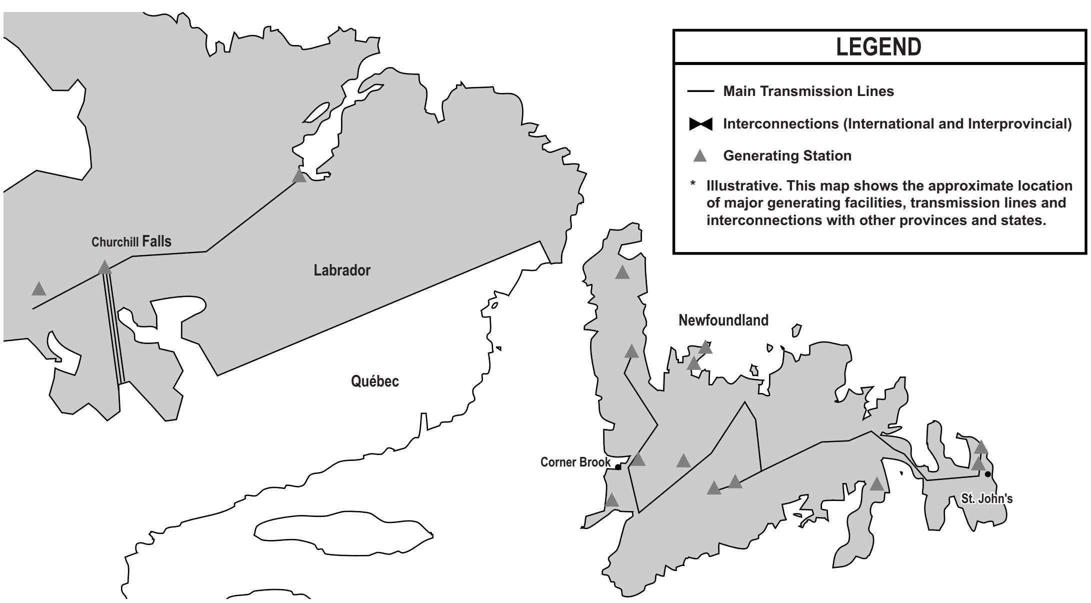
The Island system links most population centres to generation, while in Labrador the Churchill Falls hydro complex is linked to population centres and to the Province of Québec (Figure 3.11.3). Any major expansion in transmission is contingent on further developments at Churchill Falls. Isolated communities in Labrador and on the Island depend on diesel generators.

Consumption

Provincial electricity demand has grown by less than one percent over the last few years, mainly in the residential and commercial sectors. These make up approximately half of the total demand (Figure 3.11.4). Electric baseboard heating is a large component of residential demand, used by about 60 percent of existing homes, and is being installed in over 80 percent of new homes. The next major increase in industrial demand (more than 10 MW) is not expected until 2012, when there are plans to build a processing facility on the Island to refine ore from the Voisey Bay nickel development. This will add about 50 MW to industrial demand.

FIGURE 3.11.3

Newfoundland and Labrador Electric Transmission Systems



Source: Newfoundland and Labrador Hydro

Customer rates are set by class (e.g., residential, general service, industrial) for each electrical system. Customers connected to the grid in Labrador pay low rates due to relatively inexpensive hydro power provided by Churchill Falls. Hydro rates vary slightly by location but are being harmonized. Customers connected to the grid on the Island pay a rate that reflects the cost of generation on the Island (Figure 3.11.5). Finally, isolated customers not connected to the grid, on the Island and in Labrador, are guaranteed a basic amount of power at the same rate as interconnected Island customers, but pay a higher, though still subsidized, rate for any energy above this amount. Currently the subsidy amounts to about $40 million per year.

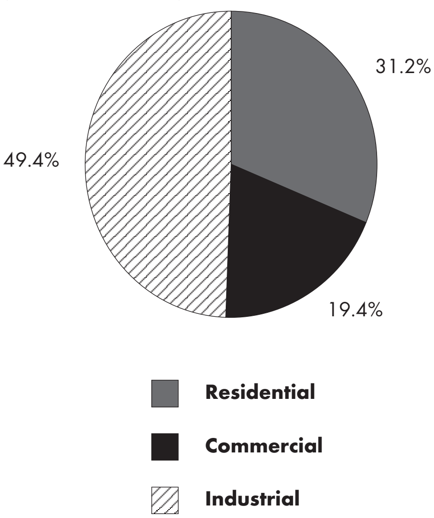
Rates in Labrador are among the lowest in Canada. Electricity prices on the Island are slightly lower than those in the rest of Atlantic Canada but higher than those in other hydro rich provinces, such as Québec, Manitoba and British Columbia. Wholesale and retail rates on the Island system have increased in the period 2002 to 2004, driven by high oil prices, recovery of the deficit accumulated in the rate stabilization plan and the addition of new generation to the system (Figure 3.11.5).

HYDRO has a DSM program in place to encourage conservation of energy by isolated customers not connected to the grid, which reduces overall costs of providing electricity to this category of consumer. Additionally, in 2003 HYDRO launched Hydrowise, an educational initiative aimed at raising awareness of energy conservation and assisting electricity consumers to manage their energy use. Newfoundland Power also has a significant energy efficiency initiative in place, its Bright Ideas Program. It is targeted at all customers, with a special focus on residential customers. Among its components are information, financing and rebate elements.

To realize the potential for improved efficiency on the system and send a proper price signal by tracking system costs as they are incurred, the rate for power supplied

FIGURE 3.11.4

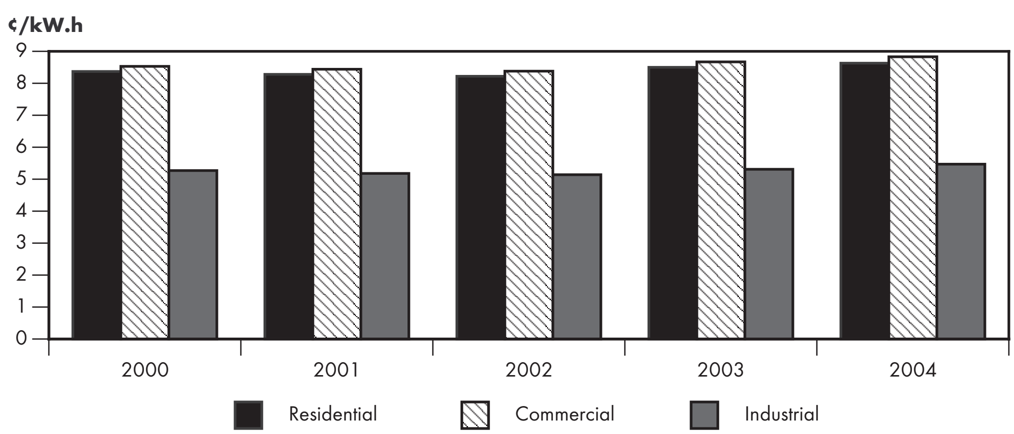
Newfoundland and Labrador 2003 Electricity Demand by Sector (10 987 GW.h)



Source: NEB, Statistics Canada

FIGURE 3.11.5

Newfoundland and Labrador Electricity Prices in St. John's (excluding taxes)



Source: Hydro-Québec

to Newfoundland Power by HYDRO was changed to include a weather-adjusted demand charge as well as an energy charge.[28] The new rate is cost neutral as it will not change the total amount paid to HYDRO by Newfoundland Power in 2005.

Trade

The province continues to sell the output of the Churchill Falls generating station to Québec under a long-term contract that expires in 2041 (Figure 3.11.6). Sales of power from Churchill Falls, which has a generating capacity of 5 400 MW, are limited only by the amount of water available, which varies from year to year based on precipitation. A small amount of power is purchased from Hydro Québec to help supply communities on the north shore of the Labrador Straits.[29]

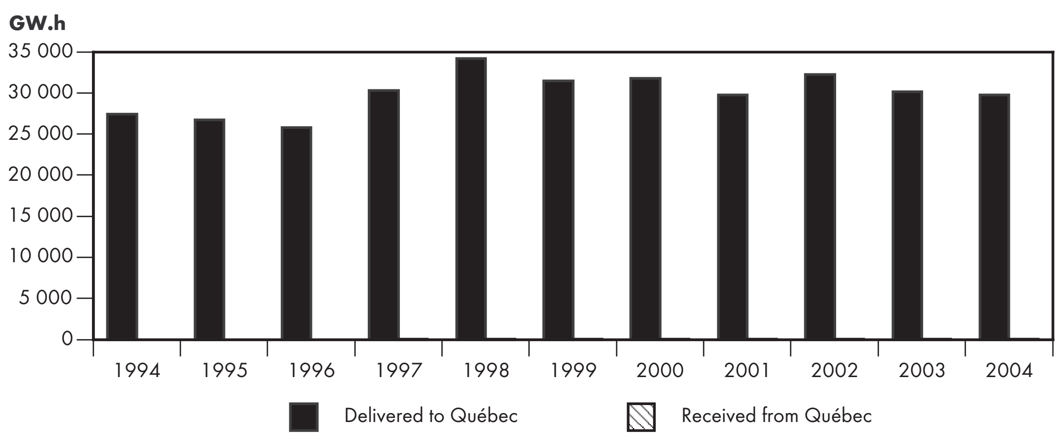
Under the terms of the Churchill Falls agreement, Newfoundland and Labrador is entitled to recall up to 300 MW of generation and the associated energy for its own use, which it does. About 200 MW of this is used to meet demand in Labrador. The remaining 100 MW is currently sold to Québec at 3.6 cents per kW.h.[30]

3.11.3 Outlook and Issues

Labrador has considerable excess capacity and will have no need for new generation to meet domestic demand in the foreseeable future, although there is an opportunity to build more generation for sales outside of the province. The Island also has sufficient generation in the short term but faces a challenge in deciding how to meet its energy needs in the longer term. Probable on-Island generation options include small-scale hydro, wind and thermal. However, there is no access to natural gas supply at present (although there are significant offshore gas resources awaiting development), so currently

FIGURE 3.11.6

Newfoundland and Labrador Interprovincial Electricity Transfers



Source: NEB, Statistics Canada

28 When an electricity rate includes a demand charge, the consumer's bill is based in part on their peak demand. Since capital facilities (generating plants, transmission and distribution lines, etc.) have to be built to meet peak demand, a demand charge helps ensure these costs are met. Demand can depend, not only on the actions of the consumer but, on outside factors such as weather as well. A weather-adjusted demand charge removes the impact of weather so that consumers are not penalized by weather extremes.

29 The quantity of energy involved typically ranges from 10 to 16 GW.h annually, an amount too small to show on the graph.

30 The 2004 agreement with Hydro-Québec includes a two percent annual price increase.

thermal options are either heavy fuel oil or combined-cycle systems fuelled by light oil. As global forces continue to exert an upward pressure on the price of oil, the cost of oil-fired generation on the Island will also increase. Although the potential for large-scale hydroelectric development on the Island is limited by environmental sensitivity, there remains the possibility of interconnecting the Island with Labrador to provide access to some of the hydropower potential there.

The Lower Churchill River hydro development encompasses construction of new hydro generation stations and associated transmission facilities. As the project would be very large in size and cost, the provincial government has developed a multi-phase approach, beginning with a request for expressions of interest. One response has been a joint proposal by the Ontario Government, Hydro-Québec and SNC-Lavalin. The next steps will likely involve feasibility studies, followed by a Memorandum of Understanding and finally a commercial agreement. There are potential markets for Lower Churchill power in Ontario, Québec, the Maritimes, New England and New York. Depending on the targeted markets, a number of different transmissions alternatives would need to be assessed.

Wind power is under consideration for environmental reasons and as a way of increasing diversity of supply. There is a demonstration project at Ramea, a small island off the south coast of the Island, and feasibility studies have identified many potential sites for wind generation on the Island. However, there could be concerns with system stability, depending on the total wind power capacity. Work is under way to evaluate the system limitations and to develop a suitable strategy for wind power development.

There is also significant potential for small hydro on the island of Newfoundland, although the number of sites that can be developed is limited by environmental concerns. The present moratorium on small hydro development, which was established to protect salmon habitat, will be reviewed as part of the comprehensive energy plan currently under development. As more natural gas is found, in the Hibernia and other potential offshore fields, there is also the potential that part of this supply could be used for new natural gas-fired generation. However, at this time, the economics are not favourable.

Potential actions to reduce greenhouse gases present an opportunity to develop the hydro potential on the Lower Churchill River. However, this is not without challenges since preliminary indications are that policies to reduce CO_2 emissions may encourage the replacement of older thermal units with newer, more efficient generation. The three existing thermal units at Holyrood are ageing, but have only been operated periodically, so they still have considerable service life remaining. It would be costly to replace them with combined-cycle oil-fired facilities.

3.11.4 Summary

Geography presents significant challenges for Newfoundland and Labrador as its ample hydro resources in Labrador are remote relative to both domestic and export markets. Nevertheless, the province is motivated to further develop its hydro. Connecting generation to load centres in the rest of Canada and the U.S. may be a significant challenge. The Island currently relies on high-priced imported oil for a significant part of its generation. The availability of natural gas in the future or export revenues earned by the proposed Lower Churchill hydro project could mitigate the impact of oil prices on Island rates if various challenges can be overcome.

Conclusions and Recommendations

Canada's electricity markets have developed along provincial or regional boundaries. Although the organization of the market and the degree of restructuring varies, governments and electric utilities across the country are endeavouring to balance three common objectives in meeting the needs of consumers: adequate and reliable supply; environmental sustainability; and acceptable electricity prices. Recognizing the diverse strategies and specific initiatives being pursued to achieve these objectives, this report has identified a number of issues and challenges. The analysis developed in this report leads to the following conclusions:

Supply is adequate in all regions during the 2005-2006 period; however, tight supply conditions could emerge as early as 2007

There will be adequate supply to meet domestic demand in all Canadian regions in the time frame of this EMA. Uncertainties in the outlook pertain to precipitation levels in hydroelectric generating regions, extreme weather conditions and unexpected generation outages. As demand continues to grow, however, generation and demand management measures may not be sufficient to ensure supply adequacy in some regions. Because significant lead times may be required to develop new supply (e.g., construction lead times from two to ten years) and implement demand-side measures, actions must be taken soon to ensure resource adequacy in the future.

To address prospective supply tightness in the near term, several regions have opted for natural gas-fired generation over traditional generation sources such as large hydro projects, nuclear power and coal. In response to high natural gas prices and price volatility, plans to develop natural gas-fired generation are being reconsidered.

Longer term solutions are likely to include a diversity of options, based on regional resource endowments, increased inter-regional trade, renewables and demand-side initiatives. Along with natural gas-fired generation, options include new nuclear plants and nuclear refurbishments, and clean coal developments. Government-industry partnerships may be necessary to complement technological advances to make these options commercially feasible and socially acceptable.

Alternative and renewable resources and demand management are becoming more important in addressing air quality issues and supply adequacy

Due to concerns about air quality and greenhouse gas emissions in all regions, growth of alternative and renewable resources, particularly wind, is accelerating. Drivers include regional renewable portfolio standards, production incentives such as the WPPI, the coming into force of the *Kyoto Protocol* and the general public desire for clean air. Apart from the direct environmental benefits of "green" power generation, the potential also exists for the development of equipment manufacturing and service industries.

Currently, most alternative and renewable energy sources are more costly than thermal-based generation; however, this comparison does not take into account environmental externalities (e.g., the environmental costs associated with thermal-based generation), which are not fully reflected in energy prices. In addition, the cost for many alternative and renewable resources continues to decline as a result of technological innovations.

There is increasing recognition, by the public and the electric industry, that managing energy demand is part of addressing supply adequacy issues. Many entities have, or are in the process of developing, demand-side initiatives that will effectively reduce or defer the need to construct new facilities. Barriers to successful demand management programs include the lack of clear price signals to foster energy conservation. For example, electricity prices are often based on historical costs, which are the legacy of previous investments in "heritage assets," such as large hydro projects and other facilities where investment costs have been recovered. Thus the cost based on heritage assets is less than the cost of new supply needed to meet rising demand. Additionally, there is often no difference between peak and off-peak prices, even though there is a significant difference in generation costs.

Uncertainty could delay timely investment and development of new infrastructure

Several provinces face uncertainty that could affect longer term supply adequacy. Uncertainty is related to changing market structures, the lack of clear pricing rules, fuel costs and the impact of environmental initiatives. As well, the general resistance from parties that might be impacted, the so-called NIMBY effect, is often cited as a reason for delay in obtaining approvals to construct new facilities. From the standpoint of facilitating infrastructure development, these uncertainties add risk, cause delays and increase the cost of making investments in new technology and infrastructure.

In all regions, there are forces that will exert an upward pressure on electricity prices

Canadian consumers will face continuing upward pressure on electricity rates. Factors influencing rate increases include fuel prices, development of higher-cost generation resources and the costs of enhancing transmission and distribution systems. Fossil fuel prices are market determined and have risen due to global influences. To the extent that gas, coal and petroleum products are used to produce electricity, higher fuel costs will impact electricity prices and make it difficult to maintain rates close to levels established by heritage assets.

To ensure that regional transmission infrastructures are adequate, several provinces are developing new plans to maintain and expand transmission networks. The 14 August 2003 blackout emphasized electric system reliability as a priority industry issue. Depending on the timing of specific investments, costs will be passed along to consumers in the form of higher electricity prices.

Since electricity is generally perceived to be an essential service, there is a political motivation to ensure entitlement to electricity at acceptable prices through regulation. Such prices may or may not be sufficient to induce appropriate responses by investors in generation and by consumers to balance supply and demand. Decisions as to what may constitute acceptable or reasonable prices are influenced by the need to establish supply adequacy and environmental sustainability. Informing consumers about these objectives, and the choices that are implied, may assist consumers in understanding why prices will be rising.

Ontario provides an example of the attempt to balance the objectives of supply adequacy, environmental sustainability and reasonable prices. The Province currently has initiatives in place to remove 7 500 MW of coal-fired generation by the end of 2007 (including the Lakeview generating station which was shutdown on 30 April 2005). This initiative could increase both regional prices and supply concerns in the province. However, the Province has indicated that the coal phase-out will only occur if there is no impact on reliability of supply to Ontario consumers.

Exports and imports continue to benefit Canadians; interprovincial energy transfers should be further explored

Under normal operating conditions, transmission interconnections between regions provide opportunities to engage in trade and contribute to reliability of the interconnected systems. The strongest ties have been north-south between the provinces and adjacent U.S. states. These have enabled the hydro-based provinces to earn export revenue, during periods of surplus supply, and have enabled power purchases during off-peak times or when required to supplement domestic generation. The Board's analysis suggests that the benefits of north-south trade are expected to continue.

While there are important power transfers between provinces, the historical tendency for the provinces to supply their own markets has limited the extent of interprovincial transfers; the main exception has been the large power transfer (under long-term contract) from Labrador to Québec.

The concept of expanded east-west interconnections, or an "East-West Grid" in Canada, was raised a number of times in the past, but typically was not considered economically attractive. Recent regional developments such as the CETI initiative (Manitoba to Ontario), the prospect of developing the Lower Churchill River (from Labrador through Québec to Ontario), and possibly expanded interconnections between Alberta and B.C. suggest that specific opportunities may be imminent. Factors favouring these developments include prospective increases in power prices, the goal of reducing emissions from power generation (including greenhouse gases) and technological advances in long-distance transmission.

Recommendations

In formulating these conclusions, the Board found an opportunity to make recommendations in five areas. With a view to informing policy makers, the Board is prepared to cooperate in providing further advice if there is interest in pursuing these recommendations.

1) Given concerns about supply adequacy and the need for some major investments, governments and regulators should strive to provide clarity and predictability in the investment environment. Clarity of rules is necessary to encourage investment that is required to meet the goals of supply adequacy, environmental sustainability and acceptable prices.

2) While there is considerable potential for demand management, electricity prices paid by most Canadian consumers are below the incremental cost of supplying electricity, muting incentives to use electricity efficiently. Some provinces, such as Ontario, are phasing in time-of-day pricing and other strategies to encourage more efficient use of electricity. Governments, regulators and load serving entities should promote the use of clear price signals to encourage efficiency in electricity consumption.

3) Governments, industry and consumers recognize the benefits of clean generation. Policy makers should continue to support diversity in the generation mix, particularly with respect to clean generation options. For example, Canada has large coal resources and further investigation of and support for clean coal technologies may be warranted.

4) Governments should strengthen their partnerships with industry and other stakeholders in the development of alternative and renewable energy. Resources should be focused

on public awareness, incentive programs such as the federal Wind Power Production Incentive, and financial assistance to support research and development of promising technologies.

5) East-west transmission expansion needs to be considered in the context of alternative markets for the resources to be developed and alternative generation options for the target markets. Policies or incentives in support of east-west transmission development should be considered from a multi-jurisdictional perspective.

Alternating Current (AC)	An electrical current that reverses direction at regularly recurring intervals with alternately positive and negative values, averaging zero. Almost all electric utilities generate AC electricity as its voltage is easily transformed to higher or lower values.
Alternative Technologies or Alternatives	New and emerging technologies used in the production and consumption of energy, such as electric and fuel cell vehicles and clean coal technologies.
Arbitrage	The simultaneous purchase and sale of a commodity in two different markets in hope of gaining a profit from price differences.
Atlantic Provinces / Atlantic Canada	New Brunswick, Nova Scotia, Prince Edward Island, and Newfoundland and Labrador.
Average Cost Pricing	A pricing mechanism based on the average total system cost of providing a unit of electricity (per megawatt hours for wholesale, per kilowatt hours for retail) during a specific period.
Biomass	Organic material (such as wood, crop waste, municipal solid waste, hog fuel and pulping liquor) processed for energy production.
Capacity	The maximum amount of power that a device can generate, utilize or transfer, usually expressed in megawatts.
Capacity Factor	The ratio of the gross electricity generated for the period of time considered, to the energy that could have been generated at continuous full-power operation during the same period.
Cogenerator	A generating facility that produces electricity and another form of useful thermal energy, such as heat or steam.
Combined-Cycle Generation	The production of electricity using combustion turbine and steam turbine generation units simultaneously.

Commercial Sector	The commercial sector is generally defined as non-manufacturing business establishments, including hotels, motels, restaurants, wholesale business, retail stores, and health, social, and educational institutions.
Congestion	Congestion occurs when a transmission system cannot accommodate all transactions that would normally occur, for example, due to capacity constraints or reliability considerations.
Convergence	Maximizing the value of marketing, trading and arbitrage opportunities through optimization of energy conversion capacity. Convergence commonly involves electricity and natural gas.
Cost of Service	The process of regulation whereby the regulator sets rates at a level that will cover operating costs and provide an opportunity to earn a reasonable rate of return on the invested property devoted to the business. Also known as rate-of-return regulation.
Cross-Subsidization	The practice of charging higher prices to one group of consumers in order to provide lower prices for another group.
Demand Response (DR)	Reduction in electricity use in response to peak pricing or request from the system operator or a Load Serving Entity.
Demand-Side Management (DSM)	Actions undertaken by a utility that result in a change and/or reduction in demand for electricity. This can eliminate or delay new capital investment for production or supply infrastructures and improve overall system efficiency.
Derated	Incapable of operating at full capacity due to physical or environmental limitations.
Direct Current (DC)	Electric current that flows in one direction with little or no voltage fluctuation.
Distributed Generation	Small scale generation situated closer to the end-user.
Distribution	The transfer of electricity from the transmission network to the consumer.
Energy Banking	The storage of water in a reservoir, during off-peak times, to be released for generation during peak times.
Generation	The process of producing electric energy by transforming other forms of energy; also, the amount of energy produced.

Green Power	Electricity generation deemed to be environmentally less intrusive than most traditional generation, usually in accordance with standards established by government or regulatory agencies. Green power sources include wind, water, landfill gas, solar and others.
Greenhouse Gases (GHG)	Gases such as carbon dioxide, methane and nitrous oxide, which actively contribute to the atmospheric greenhouse effect, i.e., increased temperatures in the earth's lower atmosphere.
Heritage Assets or Heritage Pool	An amount of energy and capacity determined by the existing generation assets which resulted from past decisions under a previous market regime. This energy is generally sold into the marketplace at a price reflecting historical costs.
High Voltage Direct Current (HVDC)	This technology is used to solve the problem of transmitting electricity over long distances. Direct current power loss over long distances is considerably less than alternating current. A higher voltage is used with direct current to increase energy transmission and reduce losses.
Independent System Operator (ISO)	An ISO is functionally separated from other electricity market participants, i.e., generators, transmission companies and marketers, and makes non-discriminatory access available to users of the transmission system. The ISO is responsible for monitoring and controlling the transmission system in real time.
Industrial Sector	The industrial sector is generally defined as manufacturing, construction, mining, agriculture, fishing and forestry establishments.
Investor Owned Utility (IOU)	A privately-owned electric utility whose stock is publicly traded. It is rate regulated and authorized to achieve an allowed rate of return.
Kyoto Protocol	The result of negotiations at the third Conference of the Parties in Kyoto, Japan, in December of 1997. The *Kyoto Protocol* sets binding greenhouse gas emissions targets for countries that sign and ratify the agreement. Gases covered under the Protocol include carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons and sulphur hexafluoride.
Marginal Cost	The cost of the last unit of energy produced.
Maritime Provinces	New Brunswick, Nova Scotia and Prince Edward Island.
Mid-Continent Area Power Pool (MAPP)	Refer to Midwest Reliability Organization.

Midwest Reliability Organization (MRO)	The MRO is one of the regional reliability organizations of the North American Electric Reliability Council (NERC). It includes Manitoba, Saskatchewan and all or parts of the states of Montana, Minnesota, North Dakota, South Dakota, Wisconsin, Iowa, Nebraska and Illinois.). Effective 1 January 2005, the MRO replaced the Mid-Continent Area Power Pool (MAPP) as the NERC regional reliability council.
Natural Monopoly	An industry characterized by sufficiently large economies of scale that one firm can most efficiently produce the output to supply market demand.
North American Electric Reliability Council (NERC)	NERC was formed in 1968 following the power blackout in Ontario and the U.S. Northeast in 1965. It is an industry organization whose stated mission "is to ensure that the bulk electric system in North America is reliable, adequate and secure." The organization develops reliability standards, which are voluntary and are enforced by peer pressure. NERC standards are implemented through ten regional reliability councils.
Open Access	Non-discriminatory access to electricity transmission lines.
Peak Load	The maximum load consumed or produced, by a unit or group of units, in a stated period of time.
Power	When energy is being transferred or changed from one form to another, the term "power" is used to mean the amount of energy transferred per unit time. The metric unit of power is the watt (W), defined as one joule per second.
Rate	The price charged for a commodity or service. Rates may be subject to regulatory approval or may be set by the marketplace.
Rate Pancaking (Pancaked Rates)	Charging multiple rates over a transmission path. An example of rate pancaking is charging a rate based on total costs (fixed plus variable costs) over one or more intermediate transmission systems between the "source" (of generation) and "sink" (the eventual market), when the actual costs of moving that power (e.g., the variable costs) are much lower.
Regional Transmission Organization (RTO)	A voluntary organization (of transmission owners, transmission users and other entities approved by FERC) to efficiently coordinate transmission planning and expansion, operation, and use on a regional and inter-regional basis.

Reliability (Electric Reliability)	The degree of performance of the elements of the bulk electricity system that results in electricity being delivered to customers within accepted standards and in the amounts desired. Reliability can be addressed by two basic and functional aspects of the electric system: adequacy and operating reliability.
Renewable Energy or Renewables	Energy sources that are capable of being renewed by the natural ecosystem (e.g., wind, biomass, solar and small hydro).
Renewable Portfolio Standard (RPS)	A standard where renewable energy provides a certain proportion of total energy generation or consumption.
Reserve Margin	The amount of unused available capacity of an electric power system at peak load as a percentage of total capacity.
Residential Sector	Private household establishments that consume energy primarily for space heating, water heating, air conditioning, lighting, refrigeration, cooking and clothes drying.
Restructuring	Reorganizing electric utilities from vertically-integrated monopolies into separate generation, transmission and distribution companies. This separation or unbundling is intended to promote competition between generators and to “open” the transmission and distribution systems, leading to increased competition in the supply and marketing of electricity.
Retail Access	A market in which electricity and other energy services are sold directly to consumers by competing suppliers. Also known as direct access.
Smart Meter	A smart meter records how much energy was used and the time interval when it was used.
Spot Market	Market where actual commodities or financial instruments are bought and sold for instant delivery. The spot market contrasts with the futures market, in which contracts are completed at a specified time in the future.
Supply Adequacy	One of the two basic functional aspects in defining the reliability of bulk power electric systems, which is the ability to supply the aggregate electrical demand and energy requirements of customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements. The other basic aspect is operating reliability (NERC).

Tariff	Terms and conditions under which a service or product will be provided, including the rates or charges that users of a service or product must pay. Tariffs are usually proposed by the service or commodity provider, and are subject to regulatory approval.
Thermal Generation	Electric generation using a steam turbine or combustion turbine driven by biomass, fossil fuels or nuclear power.
Time-of-Use Rates	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.
Transaction Costs	The costs in money and time incurred in the process of buyer-seller search, negotiation, and contract-enforcement activities.
Transmission	The movement or transfer of electric energy, over an interconnected group of power lines and associated equipment, between points of supply and points at which it is transformed for delivery to consumers, or is delivered to other electric systems. Transmission is considered to end when the energy is transformed for distribution.
Unbundling (see Restructuring)	Separation of the vertically-integrated functions of utility companies into generation, transmission, distribution and energy services.
Utility	An entity owning and operating an electric system and having the obligation to provide electricity to all end users upon their request.
Vertically-Integrated Utility (VIU)	A utility that combines the functions of generation, transmission and distribution.
Wheeling	The transmission of power belonging to one utility through another utility's transmission grid.
Wholesale Access	A distributor of power has the option to buy its power from a variety of power producers on a wholesale basis for resale on a retail level.