National Energy Board | Office national de l'énergie

Canadian **Electricity**

Trends *and* Issues

electricity electricity electricity electricity

An **ENERGY MARKET ASSESSMENT** • May 2001

National Energy Board

Office national de l'énergie

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Acronyms

BC Hydro - British Columbia Hydro and Power Authority

BCUC - British Columbia Utilities Commission

CERA - Cambridge Energy Research Associates (U.S.)

EPAct - Energy Policy Act (U.S.)

EUB - Alberta Energy and Utilities Board

FERC - Federal Energy Regulatory Commission (U.S.)

HYDRO - Newfoundland and Labrador Hydro

Hydro One - Hydro One Incorporated

IGO - Independent Grid Operator

IMO - Independent Market Operator

LDC - Local Distribution Company

MAPP - Mid-Continent Area Power Pool

MECL - Maritime Electric Company Limited

MEU - Municipal Electric Utility

NB Power - New Brunswick Power Corporation

NSPI - Nova Scotia Power Incorporated

OEB - Ontario Energy Board

OECD - Organization for Economic Cooperation and Development (International)

OEFC - Ontario Electricity Financial Corporation

OPG - Ontario Power Generation

PPA - Power Purchase Arrangements

PURPA - Public Utilities Regulatory Policy Act (U.S.)

RTO - Regional Transmission Organization

UARB - Nova Scotia Utility and Review Board

WKP - West Kootenay Power

Energy Units

Prefixes		*Equivalent*
k	kilo	10^3
M	mega	10^6
G	giga	10^9
T	tera	10^{12}
P	peta	10^{15}
E	exa	10^{18}

Energy Measures

GJ	gigajoule	= 10^9 joules
PJ	petajoule	= 10^{15} joules

Electricity Measures and Energy Content

Electricity Measures		*Energy Content*
MW	megawatt	
kW.h	kilowatt hour	0.0036 GJ
MW.h	megawatt hour	3.6 GJ
GW.h	gigawatt hour	0.0036 PJ
TW.h	terawatt hour	3.6 PJ

Metric to Imperial Units

1 gigajoule (GJ)	= approximately 0.95 million British thermal units (Btu)

FOREWORD

The National Energy Board (NEB), as part of its regulatory mandate, continually monitors the supply of all energy commodities in Canada (including electricity, oil, natural gas and their by-products) and the demand for Canadian energy commodities in both domestic and export markets. As a result of the increasing level of integration of energy markets, the Board has implemented a program of Energy Market Assessments (EMAs) to provide analyses of the major energy commodities - electricity, oil and natural gas - on either an individual or integrated commodity basis. Integrated analyses are reflected in the Board's periodic report on the long-term outlook for energy supply and demand.

This EMA, entitled *Canadian Electricity Trends and Issues*, addresses current developments in the Canadian electricity industry. The analysis has been undertaken in view of the recent volatility in energy prices, and specifically, electricity prices in some U.S. and Canadian regions. The report includes a brief overview of electricity demand and generation in Canada before addressing trade, regulatory developments (including restructuring initiatives) and electricity prices. It then examines the electricity markets across Canada on a provincial basis. The report is intended to contribute to the public's understanding of these matters.

During the preparation of this report, a series of meetings and discussions was held with people representing a variety of interests, including generation, transmission and distribution companies, marketers, end-users, consumer groups and government agencies. The Board appreciates the information and comments it received.

EXECUTIVE SUMMARY

This National Energy Board Energy Market Assessment (EMA) focusses on current trends and issues in Canadian electricity markets.

The EMA has been undertaken as part of the Board's regulatory mandate with respect to the monitoring of Canadian supply of energy commodities, including electricity. The timing of the report is influenced by the recent volatility in energy prices, specifically, electricity prices in some U.S. and Canadian regions, and the significant changes occurring in the Canadian electricity sector. The report is intended to contribute to the public's understanding and awareness of current developments.

The EMA starts with an overview of the current Canadian electricity situation before moving to a general discussion of electricity restructuring and related issues. It follows with analyses of the provincial markets, covering several aspects including supply and demand, trade, market structure, regulation and pricing. The final chapter contains a number of observations which result from the analysis.

Highlights of the report include the following:

A key feature of the Canadian electricity market is its regional diversity, as indicated by the differences in fuels used for power generation, market structure, regulation and pricing.

Even with rising electricity demand in recent years, most provincial electricity markets seem to be adequately supplied. In Alberta, where supply has been relatively tight, new generation capacity is expected to become available over the next few years.

While the share of natural gas in Canadian electricity production is relatively small (four percent), most new generation projects in Canada are expected to be gas-fired. Many of these projects were planned before the sharp increase in gas prices, and the prospect of continued high gas prices has renewed some investor interest in constructing coal-fired power plants. Moreover, a high energy price environment could support increased investments in newer, more environmentally-benign generation technologies.

Canadian electricity generation is predominantly hydro-based and as such is generally cost-competitive with other North American jurisdictions. Due to the operations of hydraulic systems, most hydro-rich provinces have surplus energy available for domestic and international trade. Canadian legislation requires that exports must be authorized by the NEB, and that interested Canadian electricity buyers be provided the opportunity to purchase the electricity, for use in Canada, on similar terms and conditions as the proposed export sale. Exports to the U.S. have generally accounted for less than nine percent of domestic generation in recent years.

The electricity transmission interests in several provinces are considering membership in regional transmission organizations (RTOs), which are expected to facilitate access by Canadian exporters to

U.S. markets and access by Canadians to U.S. supplies. RTO formation could lead to more north-south trade and further integration of U.S. and Canadian electricity markets. To the extent that Canadian competitiveness can be maintained, higher export revenue would result. Market integration could also result in upward price pressure in some provinces.

The EMA comments on the phenomenon of convergence between natural gas and electricity markets as the result of the increasing use of gas in power generation. An important aspect is that gas prices and power prices have become closely related in these markets. Convergence is demonstrated by some recent trends: high natural gas prices throughout the U.S. affecting Canadian electricity export revenues; the price of natural gas influencing electricity prices in the Power Pool of Alberta; and electricity demand in California contributing to relatively high prices for gas exports from British Columbia.

Some provinces are undergoing fundamental changes with respect to the restructuring of their markets. However, the unbundling of generation, transmission and distribution services is occurring at an uneven pace across the country. Alberta introduced full retail access (when all consumers have choice among electricity marketers) 1 January 2001, while in April 2001, Ontario stated that it will implement full retail access in May 2002 (initially scheduled for 1 November 2000). New Brunswick has recently announced plans for electricity market reforms. While some provinces currently provide, or plan to provide, wholesale access, there are no definitive plans at this time to extend full retail access beyond Ontario.

Jurisdictions that have opted for restructuring have pursued two main objectives, i.e., lower prices and more customer choice. Competition may result in lower prices; however, upward price pressures may result from higher costs resulting from the risk faced in a competitive market environment.

Canadian residential electricity prices are among the lowest of the industrialized countries, and prices tend to be lower in hydro-rich provinces. In all provinces, with the recent exception of Alberta, consumer prices have been generally stable, or have increased by relatively small amounts, over the past several years. This can be attributed, to some extent, to the stabilizing effect of cost-of-service regulation and, in some provinces, the implementation of price freezes. Another factor that may have contributed to electricity price stability is that, electricity prices, unlike oil and natural gas, are less subject to fluctuations resulting from international market forces. Therefore, in the Canadian context, volatile energy prices do not necessarily mean volatile electricity prices.

When prices are not market-based, as is now the case for most Canadian electricity markets, consumers may not receive the appropriate price signals to guide their consumption behaviour. Growing reliance on market forces in other sectors of the economy and in other electric power jurisdictions in North America is causing Canadian provinces to consider the adoption of market-based structures. However, the record of low electricity prices, provided for the most part by provincially-owned utilities under the traditional market structure, and the recent experience with price volatility in California, have caused most provinces to move cautiously toward developing comprehensive restructuring plans.

INTRODUCTION

The year 2001 marks the beginning of a new era for the Canadian electricity sector. For the first time, all residential, commercial and industrial consumers in Alberta have a choice of power suppliers; this is referred to as retail access. The province of Ontario plans to provide full retail access starting in May 2002 which, together with Alberta, will result in almost 40 percent of Canada's electricity market providing full retail competition. Major initiatives have been taken in several other provinces to allow restructuring to occur and to maintain competitiveness in export markets.

The recent California experience with restructuring of its electricity industry has included volatile prices and actual shortages of electricity. Early in 2001, the state experienced its first power blackouts since World War II. In addition, natural gas prices throughout North America reached record highs this past winter. Given these events, along with the trend towards restructuring in other regions, Canadian electricity consumers have expressed concerns about whether the power supply industry will continue to provide Canadian electricity requirements at reasonable prices.

This report provides an assessment of the current state of Canada's electricity market. The report draws on the NEB's internal resources, information in the public domain and consultations carried out with stakeholders in the electricity industry across the country. The report is intended to assess the changing structure of the Canadian electricity industry, demand and generation trends, market functioning and price determination.

A notable feature of the industry is its diversity. Canadian provinces and territories differ in natural resource endowment, energy market structure and regulatory framework. Interest in electricity restructuring also varies among the provinces. Therefore, the analysis of electricity market trends and issues is conducted on a province-by-province basis.

The report begins with a brief overview of the Canadian electricity industry, outlining the current situation and recent trends with respect to demand, electricity generation, trade, market structure and regulation, and electricity prices. The following chapter provides background information on restructuring and reviews key issues associated with the topic. Chapter 4 provides an assessment of the electricity market situation by province. The final chapter contains observations on the current state of the Canadian electricity industry. A glossary is included at the end of the report.

Overview of the Canadian Electricity Industry

This chapter presents an overview of the Canadian electricity industry, starting with a review of recent trends in demand, generation and international and interprovincial electricity trade. The market structure and regulatory backdrop are then discussed before concluding with a discussion on electricity prices.

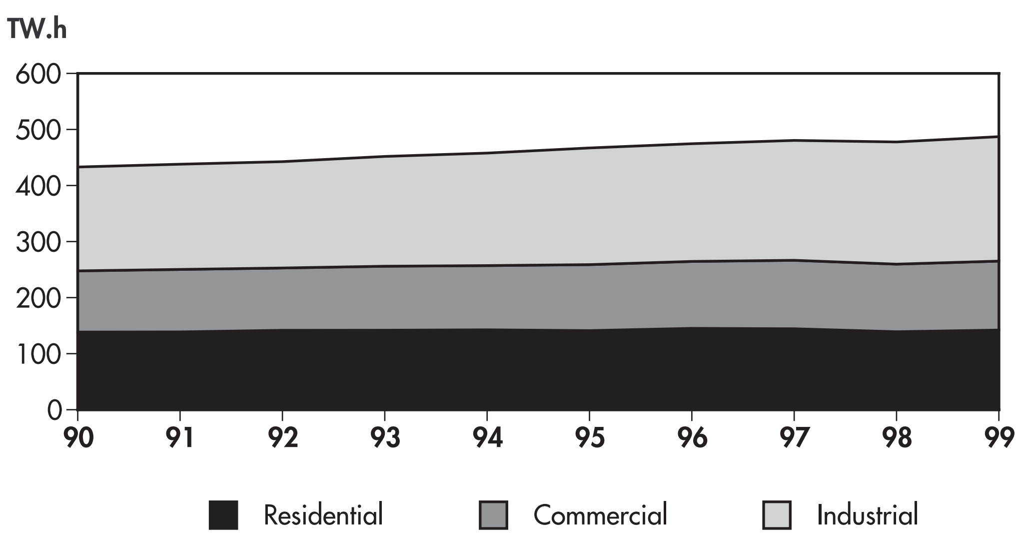
2.1 Demand

In 1998, Canadian end-use energy demand, comprising the residential, commercial and industrial sectors, amounted to 8 205 petajoules (PJ), of which electricity accounted for 21 percent or 478 terrawatt hours (TW.h).

Electricity demand grew at an average annual rate of 1.3 percent during the 1990s (Figure 2.1), reflecting relatively strong growth in the more energy intensive industries, particularly resource extraction, smelting and refining. The industrial sector showed the strongest growth, at 2.0 percent per year[1]. The residential sector had the least growth at 0.3 percent per year. This sector would normally be expected to grow in line with population and household formation. However, as the result of competition from natural gas,

FIGURE 2.1

Canadian Electricity Demand



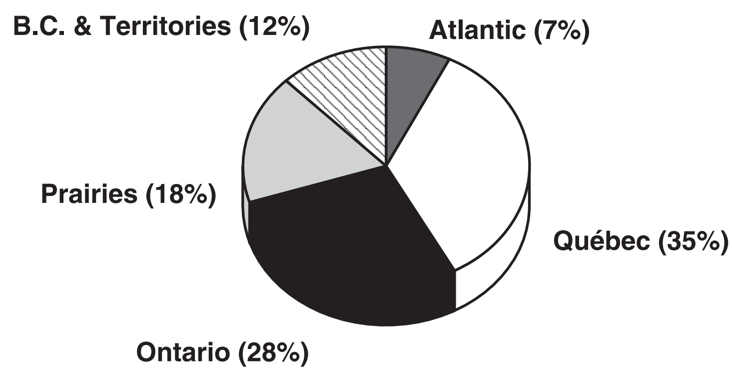
Source: NEB, Statistics Canada

1 Natural Resources Canada, *Energy Efficiency Trends in Canada, 1990-1998*, October 2000.

Ontario's residential electricity consumption actually declined during the 1990s. Excluding Ontario, residential demand increased by 0.9 percent per year, which was close to corresponding population growth[1]. Canadian commercial demand increased by 1.3 percent per year.

FIGURE 2.2

Provincial Shares of Electricity Demand, 1999



Source: NEB, Statistics Canada

On a regional basis, Québec is the largest market, accounting for 35 percent of Canadian electricity demand in 1999, followed by Ontario at 28 percent (Figure 2.2). However, during the 1990s, growth was highest on the Prairies, led by resource activity in Alberta and Saskatchewan, and was lowest in Ontario.

2.2 Electricity Generation

While hydro accounts for 61 percent of Canadian electricity generation, there is pronounced diversity, with generation coming from a number of other sources, including coal (18 percent), nuclear (13 percent), natural gas (four percent) and oil and renewables (four percent) (Figure 2.3). The generation base varies by region: thermal (coal and oil) generation on the east coast; hydro in Labrador, Québec, Manitoba and B.C.; nuclear in Ontario and to a lesser extent in Québec and New Brunswick; and coal in Saskatchewan and Alberta.

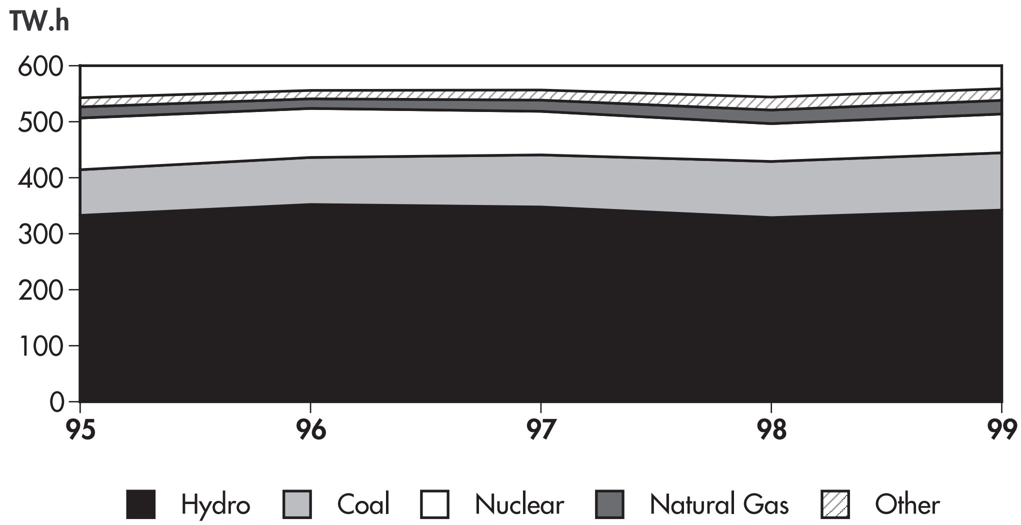
The natural gas share is currently small, but its advantages, such as low capital cost, high energy efficiency achievable in combined-cycle plants and relatively short approval and construction periods, have made it the preferred fuel for most new generation capacity. When making decisions on the installation of new generation, the combined-cycle natural gas plant has become a benchmark against which other projects are compared. This technology has also brought about a closer relationship between the gas industry and electricity generation in the phenomenon known as convergence. Depending on the price of gas compared with electricity, industry players with both gas and electricity marketing interests can sell gas or use it to produce electricity. As a result, the pricing of gas and electricity become closely related in these markets.

Some of the unique features of hydroelectric generation are important when determining how electricity markets work. The first feature is that hydro generation is dependent on precipitation. Provinces that depend on hydro generation generally build facilities that will be able to meet a low-water year, leaving them with surplus electricity to export in normal years. The second feature is that since water is inexpensive compared to other energy sources, the incremental or "marginal" cost of hydro power is relatively low. Of these factors, the dam determines how much water is available and thus how much energy can be generated, while the generators determine the plant's capacity, or how much energy can be generated at any one time. Enlarging a dam is expensive and difficult, but in some cases it is possible to add new capacity at an existing facility.

1 During the 1990-1999 period Canadian population grew by 1.1 percent per year, while Ontario's population increased by 1.3 percent per year.

FIGURE 2.3

Canadian Electricity Generation by Fuel



Source: Statistics Canada

2.3 Electricity Trade

For the most part, electricity trade occurs because of the price differences between interconnected markets or because of insufficient generation in some specific markets. Typically, power flows originate from the low-cost, hydro-rich provinces when surplus is available.

Trade can also occur because of the generator's efforts to optimize the use of its generation resources. For example, when a province has both thermal and hydro generation, or when it has hydro and is able to trade with a province or state with thermal generation, the hydro facility can be used for a process called energy banking. In this process, thermal generation is run when demand is low (and power is cheaper). The water that would normally be used for generation is stored behind the dam and used when demand is high (and power is more expensive).

Another factor influencing trade is seasonal diversity. Demand in most regions of Canada is high during the winter, while most regions in the U.S. have their peak demands during the summer. This difference can lead to U.S. systems importing from Canada more electricity in the summer than in the winter.

2.3.1 Interprovincial Trade

Interprovincial electricity flows account for about 10 percent of total Canadian electricity consumption. Flows have remained at close to 50 TW.h in the last three years. Eastern Canada (east of Manitoba) accounts for over 80 percent of the total transfers, while Western Canada accounts for the balance (Figure 2.4). The largest transfers are between Labrador and Québec (30 TW.h to 35 TW.h annually). In the last two years, higher flows in Western Canada reflected strong demand growth in Alberta. Additional transmission capacity that is currently planned between Ontario and Québec, and between Alberta and Saskatchewan, would allow for more interprovincial trade.

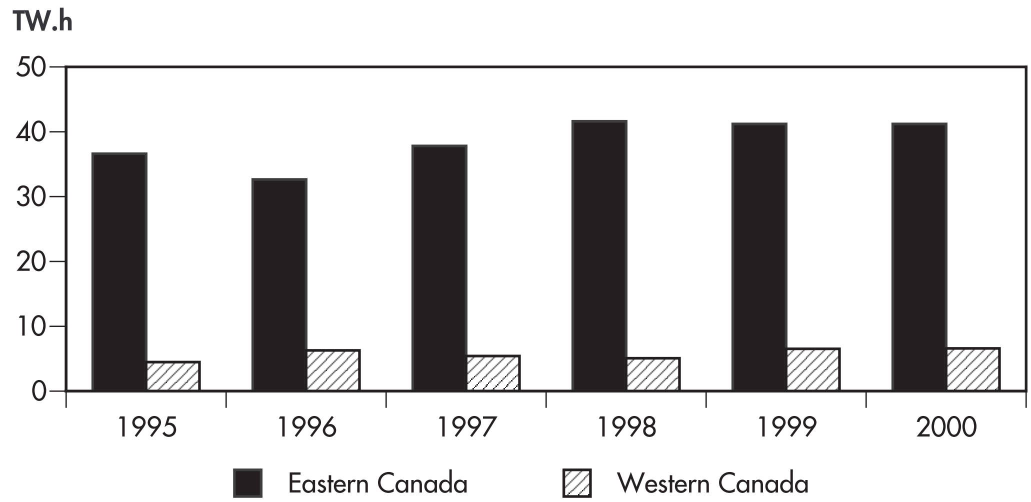
2.3.2 U.S. Trade

Canada has historically been a net exporter (exports exceed imports) of electricity to the U.S. Export levels have been relatively stable in recent years, accounting for generally less than nine percent of total Canadian generation (Figure 2.5). Exports mainly originate from the hydro-rich provinces of Québec, Manitoba and British Columbia, which together with Ontario and New Brunswick, accounted for 94 percent of total exports in 2000.

In 2000, electricity imports accounted for less than three percent of total annual electricity consumption. The two largest importers were British Columbia and Québec. Over the period 1998 to

FIGURE 2.4

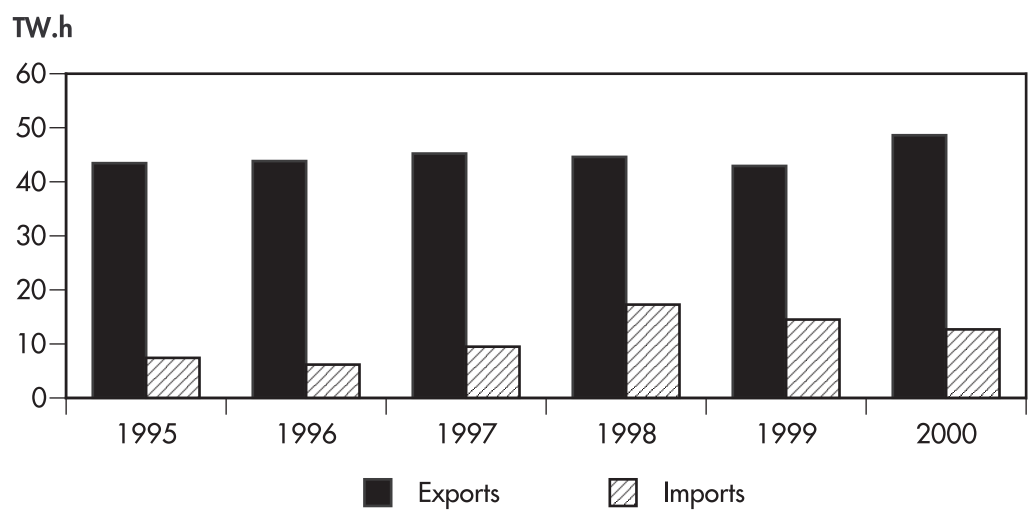
Interprovincial Transfers of Electricity



Source: Statistics Canada

FIGURE 2.5

International Transfers of Electricity



Source: NEB

2000, imports have been noticeably higher than in previous years. Provinces with hydro generation and storage capability can benefit from trade by importing electricity during the lower-price off-peak periods and exporting hydro-generated electricity during the higher-price peak periods.

2.4 Market Structure and Regulation

Currently, most of the electricity in Canada is generated by vertically-integrated utilities, i.e., companies that own and operate generation, transmission and distribution facilities.

Under Canada's constitutional framework, electricity matters are primarily within the jurisdiction of the provinces. Thus, the provinces and territories have jurisdictional authority over the generation, transmission and distribution of electricity within their boundaries. The major areas subject to regulatory review by the regulatory bodies established in each of the provinces and territories are electricity price setting and the construction of new facilities. The nature of provincial regulation is covered in Chapter 4.

The federal government has jurisdiction over electricity exports, international power lines and nuclear energy. Parliament may designate, by order, a particular interprovincial power line for regulation in the same manner as international power lines.

The *National Energy Board Act* (NEB Act) provides for, among other things, the regulation of electricity exports and international power lines. When deciding whether electricity exports should be approved, the Board takes into account:

- the effect of the electricity exports on provinces other than the exporting province;
- the impact of the export on the environment; and
- whether the applicant has provided interested Canadian electricity buyers the opportunity to purchase the electricity, for use in Canada, on similar terms and conditions as the proposed export sale.

Providing Canadians the opportunity to buy electricity on similar terms and conditions is referred to as Fair Market Access. If Canadian electricity buyers believe that they have not had Fair Market Access, they may make a formal complaint to the NEB.

2.5 Electricity Prices

Electricity prices in Canada are regulated at the provincial level. Since electricity in most provinces is regulated on a cost-of-service basis, prices reflect the costs of generation, transmission and distribution. These costs vary among provinces.

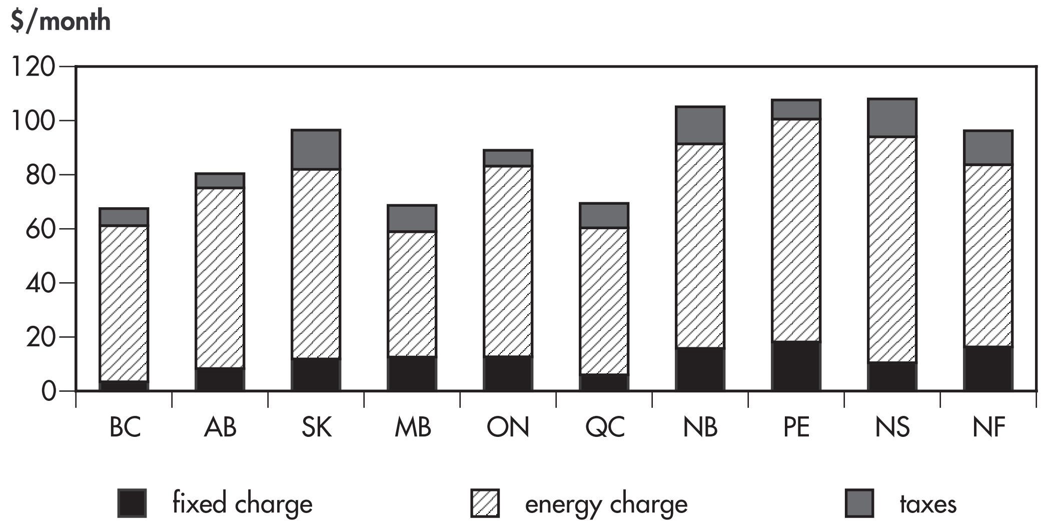
Typically, a residential bill includes a fixed monthly charge, an energy charge based on consumption, and the applicable sales taxes. In 2000, based on a monthly consumption of 1 000 kW.h, the electricity cost to a Canadian residential customer was estimated to be in the range of $65 to $110 per month (Figure 2.6). Electricity rates tend to be lower in the hydro-rich provinces (B.C., Manitoba, Québec) and higher in Atlantic Canada (thermal-based generation).

The recent North American experience with highly volatile energy prices does not necessarily imply volatile electricity prices in Canada. With the exception of Alberta during the latter part of 2000 and early 2001, electricity prices paid by consumers in Canada have been generally stable, or have increased by relatively small amounts, over the past several years. This stability has been achieved in an environment where domestic electricity prices, unlike oil and gas, remain mostly unaffected by continental and international market forces. In addition, export revenue can be used by the exporting utilities to contribute to domestic price stability for customers in their respective franchise areas. With a few exceptions, which are discussed in Chapter 4, the recent increase in natural gas prices has had little impact on electricity prices in Canada.

Canadian electricity prices are low by international standards. In recent years, Canadian residential prices have been at the bottom of the range of 6¢ to 18¢/kW.h reported for the industrialized countries (Figure 2.7).

FIGURE 2.6

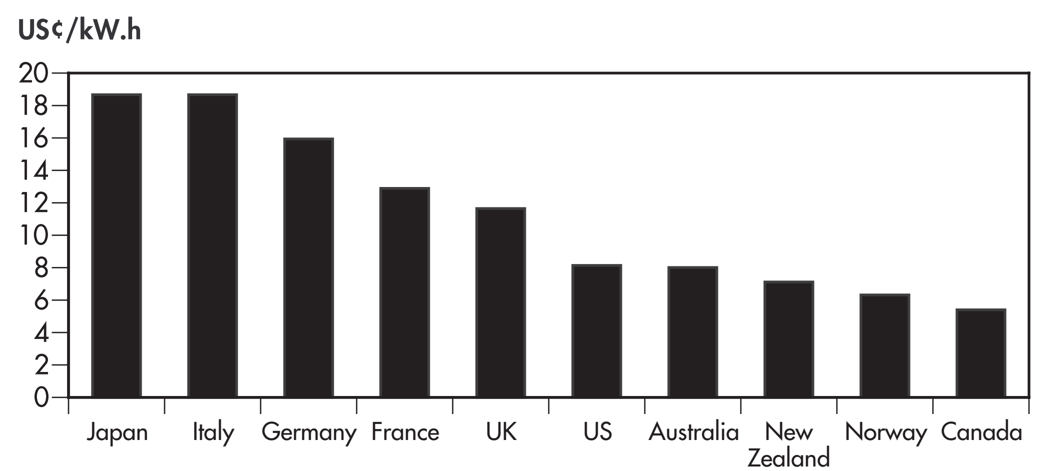
Illustrative Residential Electricity Costs, 2000



Energy Charge: based on 1 000 kW.h per month includes generation, transmission, and some distribution costs.
Fixed Charge: Fixed portion of distribution costs.
Source: Hydro Québec, Arthur Andersen/CERA

FIGURE 2.7

Residential Electricity Prices International Comparison, 1999



Japan, Germany, France - 1988 data; Australia - 1997 data
Source: OECD, Arthur Andersen/CERA, NEB

Restructuring of the Electricity Industry

3.1 Background

In the traditional market structure of the electricity industry, generation, transmission and distribution of electricity are owned and managed by vertically-integrated monopolies. This form of market structure, which still prevails in much of Canada today, was widely adopted because the electricity supply industry was regarded as a natural monopoly. With respect to generation, this meant that lowest costs could be achieved by building large scale power plants. The nature of long-distance transmission systems and local distribution systems also fit the natural monopoly model. Even if competition were possible in generation, it would still not be economically feasible to build competing transmission and distribution facilities to serve the same market, i.e., lowest costs would be achieved by one facility.

Because of the concern that monopolies would be able to exercise market power, their operations were either overseen by regulatory bodies acting in the public interest or, in the case of most Canadian provinces, public ownership was established in the form of Crown corporations.

The utilities in each province tended to develop their own generation, transmission and distribution systems consistent with provincial energy requirements. In addition, interprovincial and international transmission ties were made to achieve anticipated benefits such as:

- cost savings due to lower installed reserve requirements;
- the ability to install larger, more economical generating units;
- seasonal diversity and economy energy exchanges;
- the ability to enter into firm power contracts; and
- other anticipated benefits such as service reliability and emergency assistance.

In Canada and the U.S., a number of trends began to emerge in the late 1980s and early 1990s that caused several jurisdictions to question the traditional market structure:

(i) Technological advances in generation made the construction of smaller gas-fired generating units feasible, particularly combined-cycle natural gas turbines. These units can provide incremental supply at lower capital costs, and can be built more quickly than conventional fossil fuel or nuclear plants. At the same time, it was profitable for industrial electricity consumers to purchase natural gas to simultaneously produce process heat and electricity (cogeneration) and to sell any surplus electricity into the electricity grid.

(ii) Many jurisdictions, for example in the U.S. Northeast and California, took the view that access to a utility's transmission lines should be made available to other service providers to provide access to cheaper supplies from neighbouring regions, and regions further afield. This would require obtaining non-discriminatory access to transmission systems.

(iii) Experience with deregulation and restructuring in other industries such as telecommunications, natural gas and the airlines suggested that competition between producers and service providers would lower costs and provide a broader selection of services to consumers.

3.2 Restructuring Defined

Restructuring refers to reorganizing electric utilities from vertically-integrated monopolies into separate generation, transmission and distribution service companies. This separation, or unbundling (Figure 3.1), is intended to promote competition between generators, and to "open" the transmission and distribution systems, eventually increasing competition in the supply and marketing of electricity. Increased competition offers more choices to consumers such as choice of supplier, expanded metering services and options with respect to "green power."

Two essential aspects of restructuring are wholesale access and retail access. Wholesale access refers to generators having the ability to obtain access to transmission systems to compete in for wholesale markets, which may include distribution companies or independent marketers. Retail access refers to marketers having the ability to obtain access to distribution systems to sell to end-use consumers, and conversely, allowing end-use consumers a choice among marketers. Full retail access occurs when all end-use consumers have this choice. Wholesale access can occur without retail access; however, retail access requires wholesale access.

FIGURE 3.1

Unbundled Electricity Service

Generation **Transmission** **Distribution** **Customers**

3.3 Restructuring Initiatives

Canada

In Canada, the movement toward restructuring the electricity industry has been uneven, as each province assesses its own unique regional circumstances and issues. Alberta restructured its electricity market over a five-year period culminating in full retail access on 1 January 2001. Ontario plans to implement full retail access in May 2002.

Most other provinces, including New Brunswick, Québec, Manitoba, Saskatchewan, and B.C. have implemented, or are planning to implement, wholesale access. Aside from Ontario and Alberta, no other provinces are planning to implement full retail access.

The status of restructuring in each province is described in Chapter 4.

U.S.

In the U.S., competition in generation was introduced when the *Public Utilities Regulatory Policy Act* was passed in1979. This allowed, under various restrictions, independent power producers to sell into wholesale markets, thus ending utility monopoly over generation.

Significant legislation emerged in the *Energy Policy Act of 1992*. This act mandated the U.S. Federal Regulatory Commission (FERC) to implement open access to transmission systems and eventually resulted in FERC Order 888 (1996). The order requires that "transmission customers of jurisdictional utilities who take service under the open access tariff and who own, control, or operate transmission facilities must, in turn, provide open access service to the transmitting utility[1]." Order 888 has implications for Canadian electricity exporters. It effectively requires that Canadian transmission companies provide U.S. marketers access to their transmission facilities so that Canadian exporters utilizing those facilities, and open access systems in the U.S., may obtain a licence from FERC to market electricity in U.S. wholesale markets. This is referred to as the reciprocity requirement of Order 888.

Most recently, to further facilitate competitive wholesale markets, FERC Order 2000 (December 1999) required transmission companies under FERC jurisdiction to form Regional Transmission Organizations (RTOs) by December 2001, and defined the characteristics and functions that qualify an RTO. In view of the interconnections between U.S. and Canadian transmission systems, FERC encouraged Canadian participation. In Canada, the tariffs of electricity transmission systems are in the purview of the provinces. Thus the NEB does not have FERC-like jurisdiction.

While FERC regulates interstate transmission, and has a mandate to ensure that consumers have access to electricity at fair and reasonable rates, retail access is largely the responsibility of individual states. As of mid-2000, approximately 21 percent of U.S. electricity customers had retail access; however, less than one percent, accounting for 1.5 percent of load, have exercised the option. The reason for the low participation is that, to date, the new marketers have not been able to compete successfully with the incumbent utilities[2].

1 *The Changing Structure of the U.S. Electric Power Industry 2000: An Update*, U.S. Energy Information Administration, October, 2000.

2 *Electric Power Trends 2001*, Arthur Andersen and Cambridge Energy Associates, 2000.

Other Countries

In addition to the initiatives undertaken in Canada and the U.S., restructuring of the electricity industry has been underway in several other countries during the past decade. In Australia, New Zealand and the United Kingdom this required the unbundling of government-owned monopolies.

3.4 Restructuring Issues

Stranded Costs and Benefits

An initial concern regarding the restructuring of electricity markets was that some generating plants would not be economic in a competitive environment and that they would become "stranded" from the system. Consequently, their market value would be below book value, resulting in potentially large losses for the utilities owning these plants. The issue arose as to how these costs would be recovered.

In Ontario, the outstanding debt from Ontario Hydro has been referred to as a stranded cost. The debt is being managed by a successor company to Ontario Hydro and will be recovered from Ontario electricity customers based on consumption.

In the U.S., stranded costs were associated with some nuclear facilities and older, less-efficient fossil fuel plants. Various ways have been designed to recover stranded costs, such as securitization[1] and direct recovery through transition charges[2] on electricity transmission and distribution.

Overall, as events have unfolded in the U.S., stranded costs have not been an impediment to restructuring. Initially, many utilities expected they would face burdensome stranded debt that they might not be able to recover, either because of market conditions or because some states would not allow these costs to be passed on to consumers. In fact, state regulators have allowed for full recovery and, because prices in bulk power markets have been stronger than anticipated, prices have tended to support higher values for these assets[3].

Stranded benefits can occur when the market value of divested assets is greater than the book value. In Alberta's restructuring scheme, a stranded benefit was associated with older generating plants. The value was established at auctions that sold the rights to market the power from these plants. The residual value between the prices bid for the power and the cost of operating the plants is being returned to Alberta consumers in the form of deductions from their monthly electricity bills.

Market Power

When considering restructuring for their respective jurisdictions, regulators have been concerned that market power might be exercised in some segments of the electricity market. For example, generators that own substantial amounts of capacity (province-wide or at strategic locations) could be in a position to prevent competing suppliers from entering a particular marketplace. Transmission facility owners might be able to withhold transmission access from competitive generators. In a restructured

1 This refers to the issuing of a financial instrument, such as a long-term bond, equivalent in value to the stranded asset. The debt is then serviced by the issuer from future revenues.

2 For example, the California utility Pacific Gas and Electric has a Competition Transition Charge to recover its stranded costs.

3 *Electric Power Treends 2001*, Arthur Andersen and Cambridge Energy Associates, 2000.

environment, incumbent distribution utilities may be in a position to take greater advantage of new market opportunities than their competitors because they have better access to customer information.

Ontario and Alberta have each taken steps to mitigate market power. In Ontario, the *Market Power Mitigation Agreement* established Ontario Power Generation's licence conditions and an Independent Market Operator has been established to assure non-discriminatory access to transmission. Alberta's approach to mitigate market power includes the creation of an independent power pool and an independent transmission administrator, as well as the auctions of power plant output to reduce the market share of incumbent generators.

Reliability

Traditionally, electric generating utilities operated with high reserve margins, often in the range of 20 to 25 percent above peak demand. This was deemed necessary and prudent because of potential unscheduled plant outages. In restructured markets operating margins tend to be lower; therefore, other things being equal, the prospects of supply disruptions are greater, although costs are lower. With the unbundling of the generation, transmission and distribution functions, reliability becomes more of a shared responsibility between these entities and is reflected in their tariff provisions (terms of service).

Marginal Cost versus Average Cost Pricing

In the traditional market structure electricity prices are established by average cost pricing. Average cost pricing reflects a regulated generator's approved costs for less expensive and more expensive supply sources.

In restructured markets, where there is competition among generators, prices are based on market forces. Buyers and sellers can be brought together to settle a price in a number of ways. One way is a negotiated bilateral arrangement between a generator and a buyer. Another is the formation of a power pool where many buyers and sellers interact to establish the market price.

The power pool approach as adopted in Alberta and contemplated for Ontario employs marginal cost pricing, i.e., the pool price is set by the cost of the last unit of supply required to meet market demand.

An important point about marginal cost pricing is that all producers receive the same price even though their own costs may be lower and they might even have offered supply into the pool at a substantially lower price. This means that, all else being equal, when marginal costs are greater than average costs, the market price will be higher in the restructured environment.

If prices generally equate to marginal costs, prices will change to match the marginal cost of generation, and thus spot prices could be quite volatile. However, prices need not always reflect marginal costs. If the regulatory regime permits, buyers and sellers may negotiate bilateral arrangements for volume, price and time period. Depending on market conditions, the pricing terms could be less than the marginal cost. A well developed forward market, where standardized contracts for the future delivery of electricity are traded according to established rules and regulations, would also provide a similar price risk management function.

Most jurisdictions embarked on restructuring with the anticipation that electricity prices would decline over time, or at least not rise as much as in the regulated environment. The basic driving forces behind that anticipation were technology, which was expected to reduce generation costs, and competition, which was expected to improve efficiency.

Time-of-Use (TOU) Rates

As indicated above, a feature of competitive wholesale markets is that prices may fluctuate significantly, subject to market conditions and competitive forces. Further, because electricity cannot be easily stored prices can exhibit pronounced hourly swings. Consumers can take advantage of these hourly swings by altering their consumption patterns. For example, industrial consumers can reschedule production into off-peak times. Conceptually, residential consumers could also reschedule activities, for example, away from the morning and evening peaks. In the traditional regulated market, utilities use moral suasion to perform that function, because there is usually no economic incentive. A number of observers have pointed out that real-time price signals, i.e., higher prices during peak hours, would be necessary to induce consumers to reduce consumption.

3.5 Advantages and Disadvantages of Restructuring

By moving from a cost-of-service environment to the competitive environment implied by restructuring, there are a number of advantages and disadvantages.

Advantages include:

- increased competition, more customer choice, possible service improvements;
- potentially lower costs, if competition results in improved efficiency;
- marginal cost pricing better reflects market conditions and gives better price signals to market participants; and
- trade will tend to promote price convergence between regions: high-price regions could experience lower prices.

Disadvantages include:

- price uncertainty due to changing market conditions;
- possible upward pressures on prices due to increased costs for some market participants (e.g., higher costs of capital because of higher risks);
- higher risks mean uncertainty for new investment compared with cost-of-service regulation;
- marginal cost pricing means more volatility, potential for price spikes; and
- trade will tend to promote price convergence between regions: low-price regions could experience higher prices.

3.6 Summary

Restructuring of the electricity industry has been taking place in Canada and the U.S. for much of the 1990s. Individual provinces have considered restructuring and have chosen to implement changes to their markets in varying degrees, depending on their circumstances. These changes are addressed in the following chapter.

PROVINCIAL ANALYSES

This chapter provides an assessment, by province, of the market situation in terms of demand, electricity generation, transmission and trade, market structure and regulation, and electricity prices.

4.1 British Columbia

The province of British Columbia (B.C.) relies predominantly on hydroelectric power for its electricity production. The low cost of hydro power has allowed B.C. electricity generators, primarily the British Columbia Hydro and Power Authority (BC Hydro), to be competitive in export markets and maintain constant electricity rates to all consumers during the past several years.

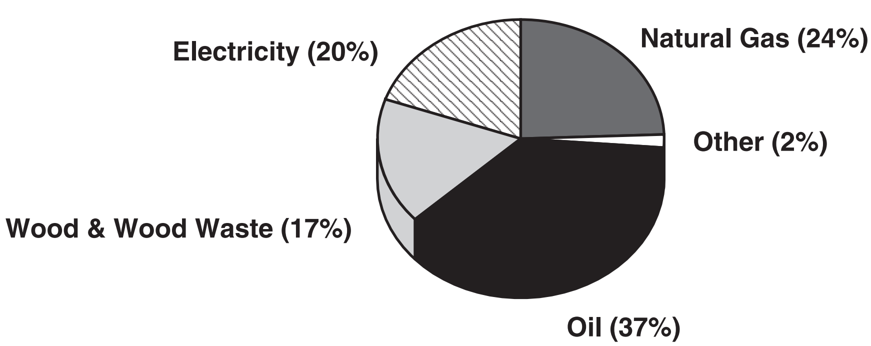
4.1.1 Demand

Electricity demand in B.C. accounts for 20 percent of the energy consumed by end-use consumers (Figure 4.1.1). About 50 percent of the usage is attributable to the industrial sector, mainly in five major industries: pulp and paper; pulp chemicals; metal mining; coal mining; and wood processing. Residential demand accounts for 28 percent and the remainder is consumed by the commercial sector (Figure 4.1.2).

In contrast with most other provinces the residential sector grew the fastest during the 1990s; this growth is mostly associated with an increase in population. Industrial sector growth lagged overall growth during most of this period, due to the impact on the resource industries of the Asian economic slowdown, but recovered in 1998 and 1999.

F I G U R E 4 . 1 . 1

B.C. End-Use Energy Demand by Fuel, 1998



Other: LPG, Ethane, Coal, Coke, Coke Oven Gas
Source: NEB, Statistics Canada

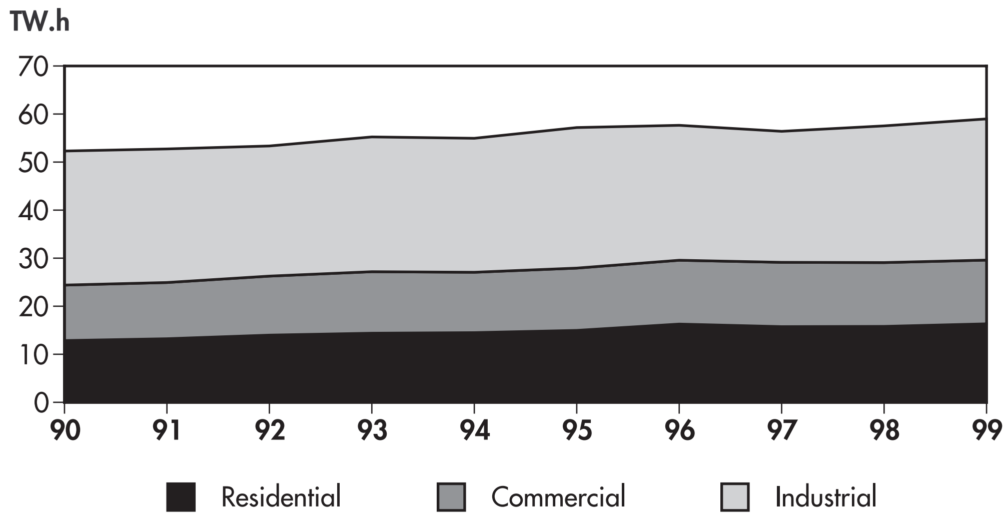
During the 1990s, total electricity demand increased by 1.3 percent per year. Growth has been strongest on southern Vancouver Island, the Lower Mainland and the Okanagan Valley.

4.1.2 Electricity Generation

In 1999, B.C. generated 90 percent of its electricity from hydro resources with the remainder split between wood, wood waste and natural gas (Figure 4.1.3). Due to the limited prospects for developing new large scale hydro projects, incremental growth in generation capacity is expected to be natural gas-fired. On Vancouver Island, the Island Cogeneration Project, a combined-cycle plant near Campbell River, is expected to commence commercial operation this year. Another generation facility near Port

FIGURE 4.1.2

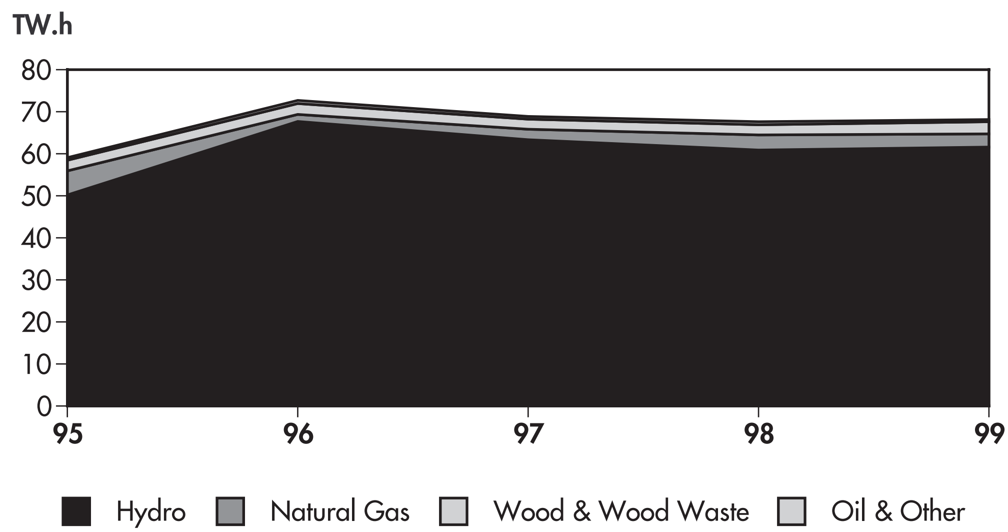
B.C. Electricity Demand by Sector



Source: NEB, Statistics Canada

FIGURE 4.1.3

B.C. Electricity Generation by Fuel



Source: Statistics Canada

Alberni is planned for completion in 2003. Both these plants have capacities of about 240 MW. In addition, BC Hydro is upgrading its plant at Burrard Inlet (current capacity 950 MW) to reduce emissions.

There are several proposals by cogenerators at other locations. While the outlook seems largely focussed on gas-fired projects, developers are examining other options including run-of-the-river, other small hydro plants (less than 10 MW) and wind. Including wind and wood waste projects, "green" options could account for 10 to 20 percent of B.C.'s incremental generation over the next several years.

The development of gas-fired generation will be influenced by the difference between electricity and gas prices, i.e., the electricity price needs to be high enough to cover the cost of the gas input and other operating costs. More efficient capacity, such as combined-cycle plants, can be economic with smaller price differentials. Access to the export market where electricity prices have generally been higher would tend to improve the economics of these projects.

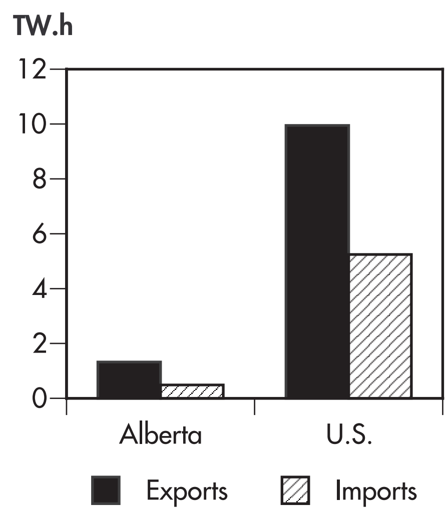
B.C. has another source of supply available to it through the "return" of the downstream benefits from the Columbia River Treaty. Under the Treaty, which has been in effect since 1968, dams were built in B.C. that enabled flood control and incremental electricity to be generated on the Columbia river on the U.S. side of the border. In return, half the increase in electricity generation at those facilities belongs to B.C. For the first 30 years of the agreement the Canadian rights to the power were sold to the U.S. In 1998, B.C. began taking its share of the downstream benefits in the form of electricity, which it could use to meet demand in B.C. or sell in the U.S. market. Powerex, a subsidiary of BC Hydro, which deals with export and trading activities, markets this electricity for the B.C. government.

4.1.3 Trade

In recent years, net exports to Alberta and the U.S. have accounted for eight to 12 percent of generation (Figure 4.1.4). Exports are driven by the market conditions at export destinations and local hydro conditions in B.C., i.e., exports tend to be higher in high-water years.

FIGURE 4.1.4

B.C. Electricity Trade, 2000



Source: NEB, Statistics Canada

B.C.'s hydro resources provide an advantage in trade. Because of the relatively low cost of increasing output from hydro facilities, the hydro facilities can meet peak demands at lower costs than thermal systems, such as Alberta's coal and gas-fired facilities. On a daily cycle, B.C. can export electricity to Alberta during peak hours, such as in the late afternoon to early evening, and then Alberta utilities can return power to B.C. in the off-peak period, later at night. Prices in the peak period tend to be higher; however, Alberta's requirement for peak-load facilities is reduced.

B.C.'s low-cost resources also provide an advantage in trade with the U.S. Often, electricity export prices are determined by the cost of generation from natural gas in the U.S. Pacific Northwest and California. Recent high natural gas prices have improved the attractiveness of exporting electricity to that market. In 2000, export revenues increased to $2 billion, about quadruple those in 1999, even though exports were down slightly.

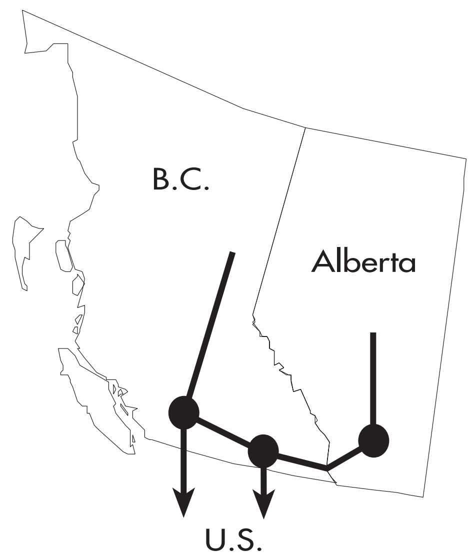
To allow trade, B.C. is connected by transmission lines to the United States and Alberta (Figure 4.1.5). The connections to the U.S. have a nominal capacity of 3 000 MW in either direction, though this is often constrained to 1 100 to 2 000 MW depending on the situation in the Seattle Light and Power service area. Trade in electricity flows both ways due to seasonal diversity and energy banking, although, in years with adequate water, B.C. tends to be a net exporter.

The connections with Alberta have a nominal capacity of 1 000 MW to B.C. or 1 200 MW to Alberta though this is limited in operation due to system constraints. Transfers from B.C. to Alberta are limited to 800 MW, while transfers from Alberta to B.C. are limited to 100 to 200 MW during peak load hours or 600 MW during off-peak hours. Trade flows in both directions, due to both energy banking and wheeling power from Alberta to the United States through the BC Hydro system.

There are no current plans to expand either link.

FIGURE 4.1.5

B.C. / Alberta / U.S. Illustrative Transmission Interconnections



4.1.4 Market Structure and Regulation

BC Hydro, a provincial Crown corporation, is the largest electricity generator in the province, accounting for more than 90 percent of production. It also owns and operates most of the transmission and distribution systems in the province. The City of New Westminster is the sole municipal distributor in BC Hydro's service area.

West Kootenay Power (WKP) is a wholly-owned subsidiary of Utilicorp United Inc. that operates generation, transmission and distribution in the vicinity of Trail, Nelson, and the Okanagan Valley. There are eight municipal distributors in WKP's service area.

BC Hydro and WKP are regulated by the B.C. Utilities Commission (BCUC). Independent power producers, such as Cominco, and some municipal utilities are not subject to regulation by BCUC unless they sell retail electricity outside their service areas.

Restructuring Initiatives

Currently, the BC Hydro and WKP transmission systems provide open access. As a result, independent power producers in B.C. can move electricity to the export market or to municipal utilities within the province. Also, companies from outside the province (e.g., Alberta or U.S. suppliers) can wheel power through B.C., to export markets, or to municipal distributors in B.C. WKP initiated retail access for large volume customers in its service area in 1999.

To improve access to the U.S. market, in addition to other benefits, BC Hydro and WKP have expressed interest in becoming part of RTO West, the regional transmission organization proposed by entities in the U.S. Pacific Northwest in response to FERC Order 2000. They are considering forming an Independent Grid Operator (IGO) to oversee transmission in the province. In this proposal, BC Hydro and WKP would continue to own their transmission, but the IGO would run the transmission system to ensure equal access for all parties. The IGO would become part of RTO West.

4.1.5 Electricity Prices

In BC Hydro's service area, consumer rates for electricity in all sectors have been frozen since 1993 (Figure 4.1.6). In 2000, B.C. electricity rates were among the lowest in North America. In February 2000, the freeze was extended to September 2001. The revenue earned by BC Hydro from export sales is used to reduce its revenue requirement, thus reducing the amount that needs to be recovered from domestic consumers. The benefits of stable rates are also flowed through to B.C. consumers outside BC Hydro's service area. This applies to 200 MW of capacity provided to WKP (under the provisions of BC Hydro's Tariff 3808).

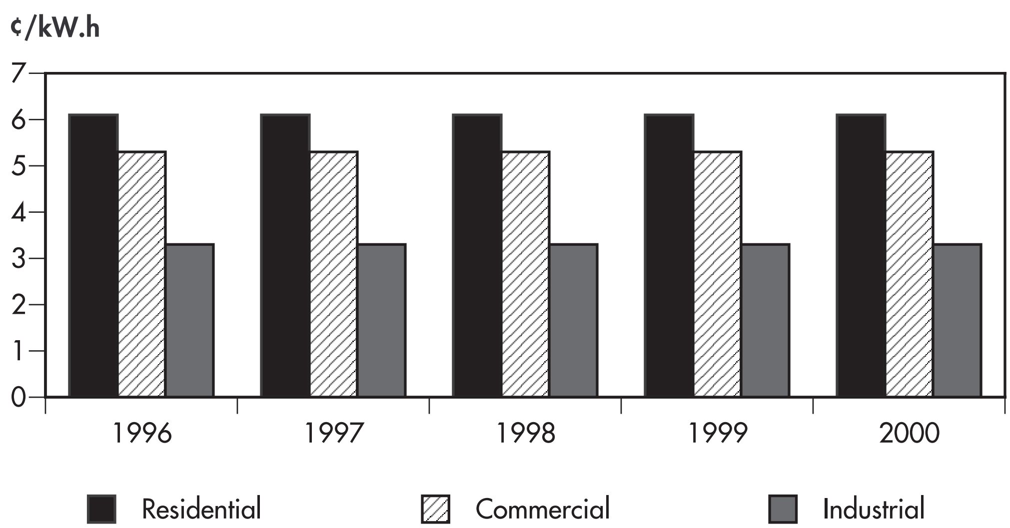
Tariffs designed after the freeze first came into effect, such as the Real Time Pricing tariff for industrial customers, are not subject to the freeze. Another example is the Price Dispatch Curtailment tariff, which allows BC Hydro to curtail service to a domestic customer to make more electricity available for export. The incremental revenue on the export sale is shared evenly with the customer after deduction of costs.

4.1.6 Summary

Due to the low cost of its hydro resources, B.C. has among the lowest electricity prices in North America. The province has a competitive advantage in electricity trade with the U.S. Pacific Northwest and California. Incremental revenue from export sales can be used to keep domestic prices lower than they might otherwise be. B.C. offers wholesale access on its transmission systems. Apart from WKP's service area, however, there are no immediate plans to introduce retail access.

FIGURE 4.1.6

B.C. Electricity Rates — BC Hydro Service Area



Source: BC hydro Annual Report 2000

4.2 Yukon Territory, Northwest Territories and Nunavut

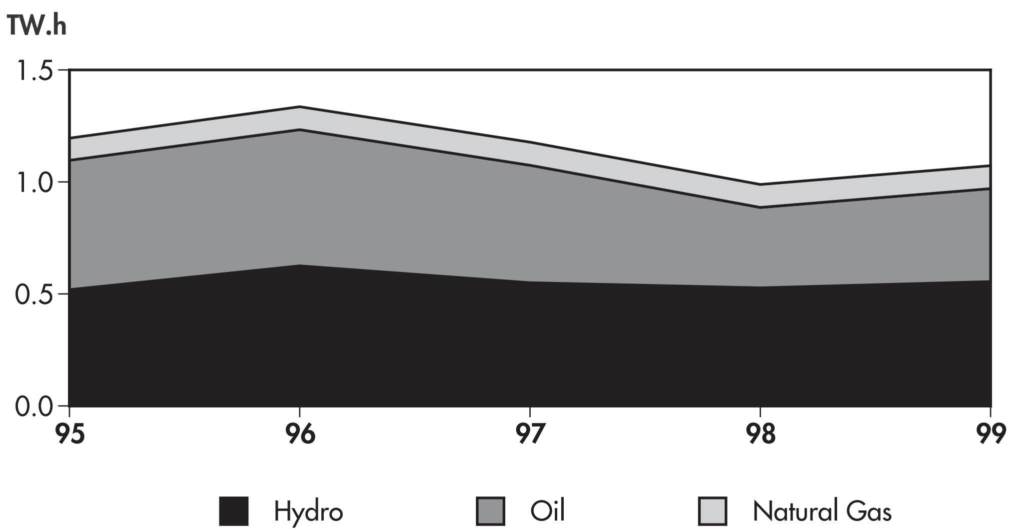
In contrast to the rest of Canada, the large land area and small populations in the Yukon Territory, Northwest Territories and Nunavut (the Territories) have precluded the development of an integrated electrical network.

Instead of a centralized system, northern Canada has a mixture of isolated small hydro plants, oil-fired turbines and internal combustion plants located at northern communities and industrial developments. Almost half the electricity in the Territories is generated by oil and natural gas (Figure 4.2.1). The high cost of shipping fuel to these communities makes alternative sources of generation such as wind attractive, but before this can become widespread, the reliability and cost of these alternatives need to be addressed.

The construction of new facilities and rate changes in the Yukon are regulated by the Yukon Utility Board. In the Northwest Territories (N.W.T.), the Northwest Territories Power Corporation and Northland Utilities Enterprises Limited fall under the jurisdiction of the N.W.T Public Utilities Board. There are no municipally owned utilities in the N.W.T. On 1 April 2001, the assets of the Northwest Territories Power Corporation located in Nunavut were transferred to the new Nunavut Power Corporation. Current plans call for it to be regulated by the Nunavut Public Utilities Board, but the role of this body is currently under review.

FIGURE 4.2.1

Territories Electricity Generation by Fuel



Source: Statistics Canada

4.3 Alberta

During the past five years Alberta's electricity industry has been in a state of transition, moving from a regulated utility structure to a structure that features wholesale and retail access. This means that there is competition in the generation and marketing of electricity and that consumers are able to choose among energy service providers. Alberta is the province furthest along the road to electricity industry restructuring.

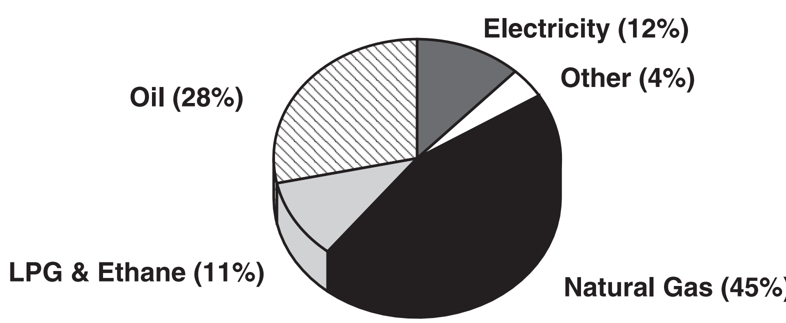
4.3.1 Demand

Electricity accounts for about 12 percent of energy consumed by residential, commercial and industrial consumers (Figure 4.3.1). This share is small compared with other provinces due to the widespread use of natural gas in space heating, water heating and industrial applications, especially in oil, gas and other resource industries.

Electricity demand grew by an average of 3.6 percent per year during the 1990s, supported by robust economic growth of 3.0 percent per year and steady population growth. The strongest growth has recently been in the commercial and industrial sectors (Figure 4.3.2).

FIGURE 4.3.1

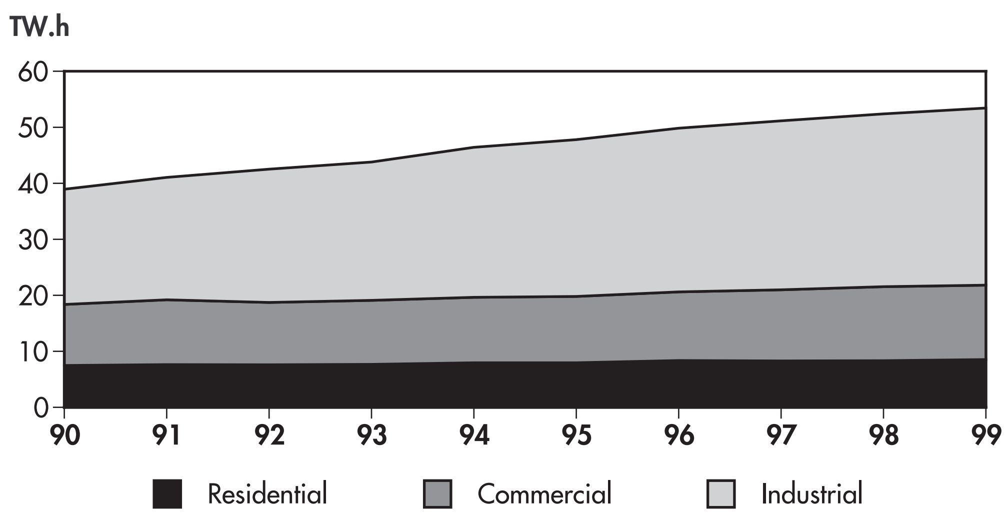
Alberta End-Use Energy Demand by Fuel, 1998



Other: Wood & Wood Waste, Steam, Coal, Coke, and Coke Oven Gas
Source: NEB, Statistics Canada

FIGURE 4.3.2

Alberta Electricity Demand by Sector



Source: NEB, Statistics Canada

4.3.2 Electricity Generation

In 1999, Alberta generated 79 percent of its electricity from coal, 15 percent from natural gas, and the remainder from hydro and other sources (Figure 4.3.3).

In recent years, growth in generation capacity has not kept up with demand growth, causing the province to rely more on imports. However, domestic generation still satisfies about 95 percent of consumption. In response to the need for additional generation capacity in the near term, project sponsors have announced additions of 2 300 MW during 2001-2003 to current (early 2001) capacity of about 8 300 MW. Total additions proposed during 2001-2005 are about 4 500 MW. These announcements include a number of gas-fired cogeneration plants, three large coal plants and a number of wind projects[1].

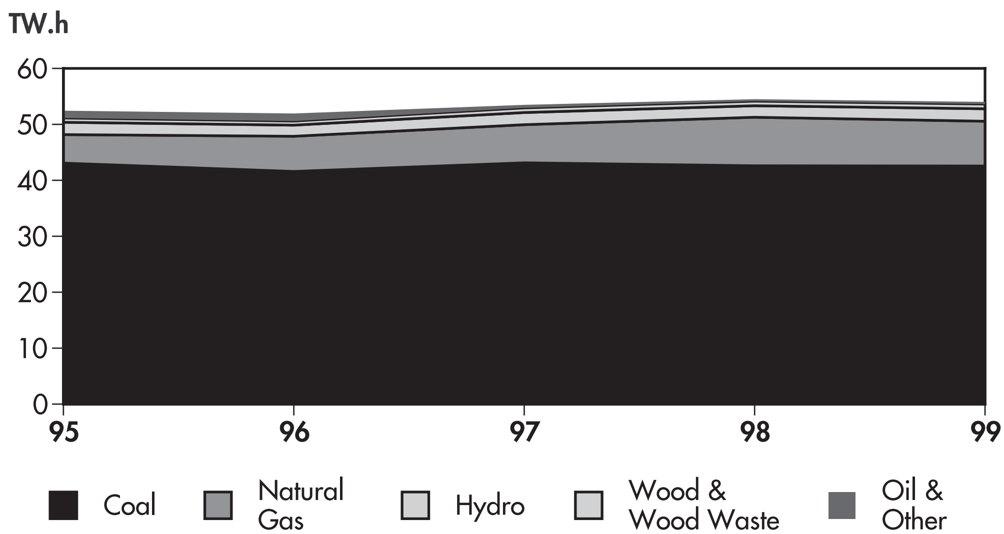
Planned new power projects in the south, around the Calgary area, will benefit from location-based incentives that reduce the transmission costs payable by the plant once it is in operation. These incentives encourage power plant developers to build new facilities closer to load centres, thus saving on the need to build transmission infrastructure.

4.3.3 Trade

Alberta has become a net importer of electricity, primarily from B.C. and Saskatchewan (Figure 4.3.4). One factor that underlies trade between Alberta and B.C. is the difference in generation systems. Alberta has mostly thermal facilities powered by fossil fuels, whereas B.C. has a predominantly hydro-based system. Because of the relatively low cost of increasing output from hydro facilities, B.C. has an advantage in meeting peak demands. On a daily cycle, B.C. can export electricity to Alberta during peak hours, such as in the late afternoon to early evening, and Alberta utilities can return power to B.C. in the off-peak period, such as later at night. Prices in the peak period will tend to be higher; however, Alberta's requirement for peak-load facilities is reduced.

FIGURE 4.3.3

Alberta Electricity Generation by Fuel

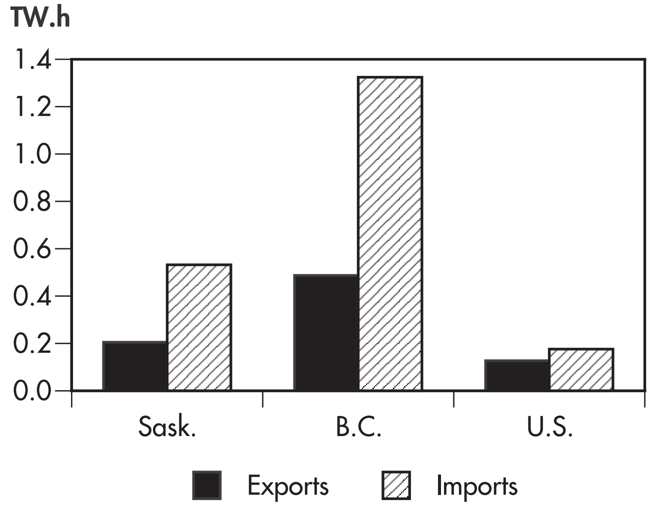


Source: Statistics Canada

1 Source: Alberta Department of Resource Development, public announcements

FIGURE 4.3.4

Alberta Electricity Trade, 2000



Source: NEB, Statistics Canada

The connection to British Columbia has a nominal capacity of 1 000 MW for exports to B.C. or 1 200 MW for imports from B.C., although this is limited in operation due to system constraints. Transfers from B.C. to Alberta are limited to 800 MW, while transfers from Alberta to B.C. are limited to 100-200 MW during peak load hours or 600 MW during off-peak hours. These limitations are the result of restrictions moving power from the Edmonton region, where most of Alberta's energy is generated, to the Calgary region, where the connection to B.C. begins.

The connection to Saskatchewan has a capacity of 150 MW, and is used for security and to trade economy energy as available. No firm plans have been made, but an expansion of this link to 300 to 450 MW is under discussion.

While Alberta has transmission links to B.C. and Saskatchewan, it has no direct connection to transmission systems in the U.S. Exports to the U.S. mainly occur by wheeling electricity over BC Hydro's system, which has large interconnections with U.S. utilities in the Pacific Northwest and California.

To facilitate Alberta exporters' access to U.S. markets, those with transmission interests are considering joining an RTO. One possibility being considered is RTO West, comprising transmission companies in the U.S. Pacific Northwest, B.C. and Alberta. The terms for joining an RTO would be developed by the Transmission Administrator, the Power Pool of Alberta and the Alberta Government in consultation with stakeholders.

4.3.4 Market Structure and Regulation

Before Alberta embarked on its restructuring program, most of Alberta's electricity was produced by three major utilities: Edmonton Power, now EPCOR (primarily in the Edmonton Area); TransAlta Utilities (Calgary and southern Alberta); and ATCO Electric (mostly in rural areas and northern Alberta). These companies were also involved in transmission and to some extent distribution. A number of municipalities and rural co-ops were involved in distribution. The City of Medicine Hat also generated its own electricity.

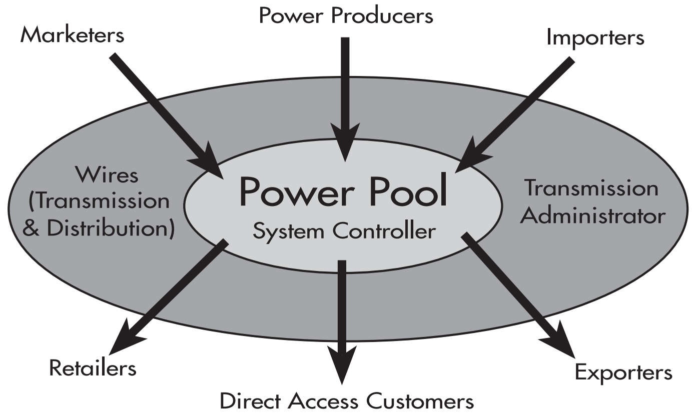
Independent power producers, usually cogenerators, sold power into the grid but not directly to retail customers. Power was sold to the main generators at rates that reflected what the generator's own costs would have been to produce that power (its "avoided costs"). The retail price of electricity was determined on a cost-of-service basis for generation, transmission and distribution. The Alberta Energy and Utilities Board (EUB) approved the costs for most generation and transmission and some distribution. In those cities and towns with separate local distribution companies (e.g., the cities of Edmonton, Calgary, Red Deer and Medicine Hat), the municipality approved distribution costs.

The Restructured Alberta Market

Alberta began restructuring its electricity market in 1996 (Figure 4.3.5). The enabling legislation was the *Electric Utilities Act* (EUA), 1995 and as amended in 1998. The essential elements are:

FIGURE 4.3.5

Alberta's Restructured Market



- The formation of the Power Pool of Alberta. Since 1 January 1996, prices have been determined by supply and demand. The market price is established by marginal cost pricing, i.e., the last supply source offered into the Power Pool needed to meet market demand sets the price. The Power Pool establishes a competitive wholesale price on an hourly basis.
- The appointment of an independent Transmission Administrator. The Transmission Administrator operates the transmission system with the purpose of ensuring open access. This appointment was the result of a competitive bidding process won by ESBI Alberta Limited.
- Increased competition in electricity generation. This was accomplished by two power auctions in 2000. In August, the rights to sell the power from the pre-1996 power plants, known as Power Purchase Arrangements (PPAs), were auctioned to the highest bidders. The terms of the arrangements were from three to 20 years, depending on the expected life of the plant. The plants would continue to operate as regulated utilities on a cost-of-service basis. In December, power not sold in the August auction was auctioned on a short-term basis, one to three years, in blocks as small as two MW. The province gained approximately $2.0 billion from these auctions, which represent stranded benefits from Alberta's restructuring program. It is expected that most, if not all, of these benefits will be rebated to consumers to help offset the impact of higher electricity prices.
- Retail access was introduced on 1 January 2001; this entitles independent marketers to sell electricity in the former service areas of the incumbent utilities and entitles the utilities to compete in other service areas (e.g., ENMAX, the Calgary utility, can sell in Edmonton and EPCOR, the Edmonton utility can sell in Calgary).

4.3.5 Electricity Prices

The electricity price paid by Alberta consumers consists of:

- a wholesale price determined in the Power Pool;
- transmission costs;
- distribution costs; and
- a fixed monthly billing charge.

During late 1999 through early 2001 wholesale prices escalated substantially because of pressures exerted by the tight supply/demand balance, higher natural gas costs and higher electricity import prices. Higher import prices reflected to some extent the electricity shortage in California that worsened in the year 2000, culminating in rotating blackouts early in 2001. High demand in California for B.C. electricity created upward pressures on prices charged to Alberta importers.

To mitigate price volatility in the power pool, a number of measures have been taken, for example, moderating the impact of imports in setting the pool price (effective December 2000) and establishing a forward market (the WATT exchange) to allow buyers and sellers to manage price risk by contracting for longer periods than permitted in the power pool (one day). In addition, over-the-counter instruments are emerging that enable forward contracting outside the power pool.

The escalation of wholesale prices in 2000 would have resulted in substantial retail rate increases for residential and small business consumers (Figure 4.3.6). However, the distribution utilities could not pass on the full impact of increased costs to consumers under the terms of Alberta's restructuring initiative. These deferred costs will be collected starting in 2002.

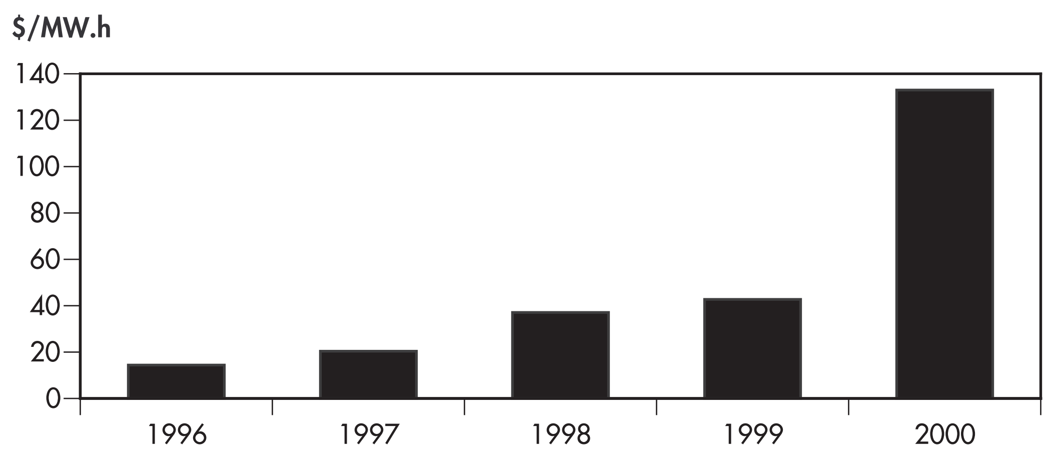
In 2001, the energy charge that can be passed through to small consumers has been capped at 11¢/kW.h, compared with 6.4¢/kW.h in the latter part of 2000. The impact of this increase will be largely offset by a government rebate of $40 per month to all residential customers. For a residential customer in EPCOR's market area, consuming 500 kW.h per month, the cost per kW.h could actually be lower on average in 2001 than 2000 (Figure 4.3.7). In ENMAX's market area (Calgary) the cost per kW.h, after the rebate will be about the same as the rates established in September 2000 (the City of Calgary approved a 25 percent increase at that time).

Large business consumers have experienced substantial increases in their electricity bills because their rates have not been subject to price caps. However, recent price increases are partially offset by rebates of up to 7.6¢/kW.h

Retail access has resulted in a number of choices becoming available to consumers, including time-of-use (TOU) rates, especially for large commercial and industrial customers. Discussions with retailers suggest that these customers, usually larger industrial customers who can scale down at peak times and purchase power in the off-peak, will be in a better position to take advantage of TOU rates. In

FIGURE 4.3.6

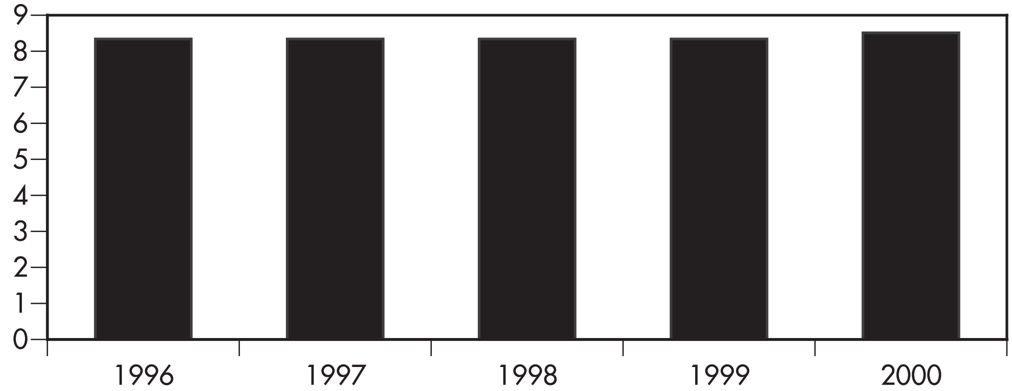
Power Pool of Alberta Price



Source: Power Pool of Alberta

FIGURE 4.3.7

Edmonton Residential Electricity Rates



Source: EPCOR

Alberta, peak times tend to be around the supper hour to early evening in summer and early afternoon and evening in the winter. The winter peak demand is higher than the summer peak. Currently, due to high metering costs, it is not practical for residential customers to adopt TOU rates on a broad scale.

4.3.6 Summary

Alberta has restructured its electricity market over a five-year period, and introduced increased competition in generation and retail access on 1 January 2001. The tight supply/demand balance in the province, somewhat exacerbated by the electricity shortage and escalating prices in California, and high natural gas prices, have caused wholesale prices to spike in the last 18 months. The province is using the proceeds from its two power auctions to mitigate the impact on end-use consumers. Higher electricity prices seem to be stimulating the private sector to build more electric generation capacity and a forward market is emerging to help buyers and sellers address price volatility.

4.4 Saskatchewan

Saskatchewan is the second largest oil producer and the third largest natural gas and coal producer in Canada. This primary energy resource base also provides the fuels required to generate electricity. The Saskatchewan Power Corporation (SaskPower), the sole provider of electricity in the province, tends to be a relatively high-cost supplier of electricity in Western Canada due to its low customer density, long transmission distance to end-users, and minimal hydro resources.

4.4.1 Demand

In 1998, the total energy demand in Saskatchewan was 348 PJ. Natural gas and oil make up the largest portion of end-use energy demand with 39 percent each, followed by electricity at 17 percent (Figure 4.4.1). During the 1990s, electricity demand grew by an average of three percent per year.

The highest growth rate was in the industrial sector, primarily due to the consumption of electricity by the oil and gas sector.

In 1999, the industrial sector accounted for 51 percent of electricity demand, while the residential and commercial sectors made up 24 percent and 25 percent, respectively.

The relatively modest growth in residential and commercial electricity demand during the 1990s (Figure 4.4.2) can be attributed to the low population growth of 0.3 percent per year.

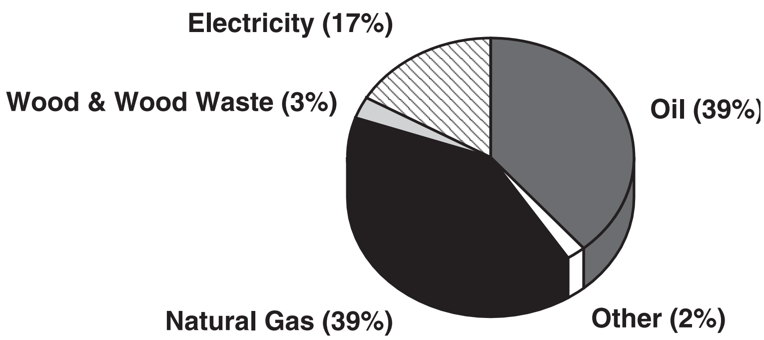
4.4.2 Electricity Generation

Approximately two-thirds of the total electricity generation in Saskatchewan is from coal-fired facilities (Figure 4.4.3). There are limited hydro resources in Saskatchewan available for development.

There has been growth in electricity generated from natural gas, increasing from 816 GW.h in 1995 to 1 448 GW.h in 1999, an annual growth rate of 15.4 percent. During this period, the Meridian Cogen plant was added at Lloydminster, and the Landis natural gas peaking station expanded from 60 MW to 80 MW. The Queen Elizabeth power station will be re-powered in early to mid-2002 for a net gain of approximately 170 MW. The 228 MW Cory cogeneration project is scheduled to come into

FIGURE 4.4.1

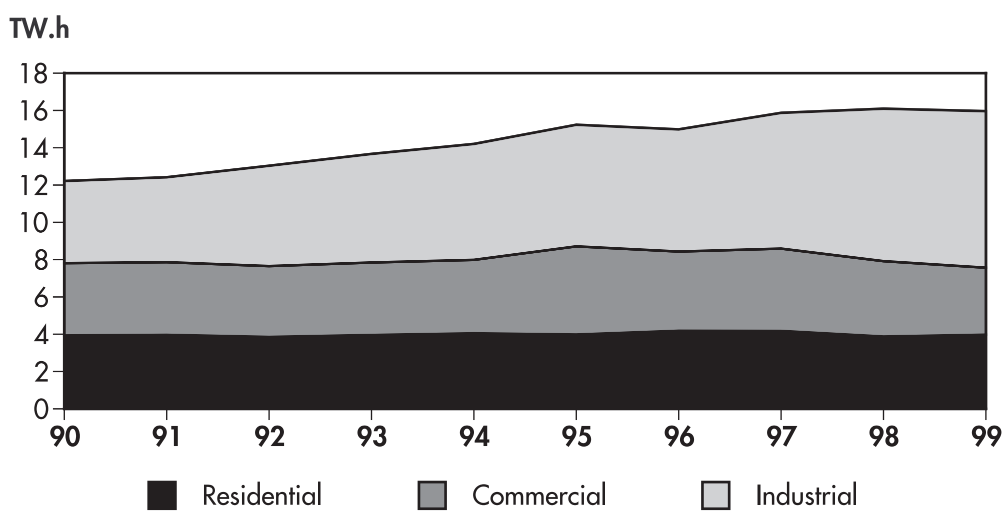
Saskatchewan End-Use Energy Demand by Fuel, 1998



Other: LPG, Ethane, Coal, Coke, Coke Oven Gas
Source: NEB, Statistics Canada

FIGURE 4.4.2

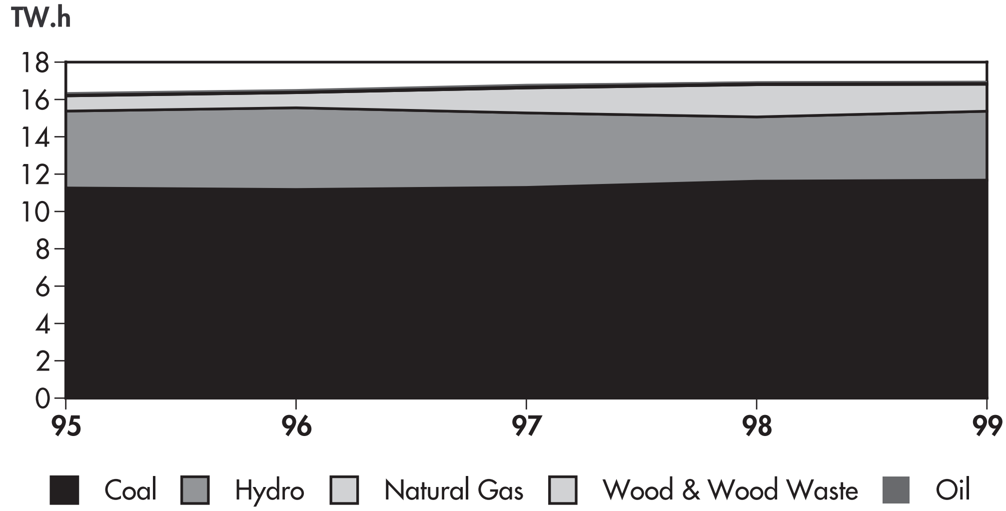
Saskatchewan Electricity Demand by Sector



Source: NEB, Statistics Canada

FIGURE 4.4.3

Saskatchewan Electricity Generation by Fuel



Source: Statistics Canada

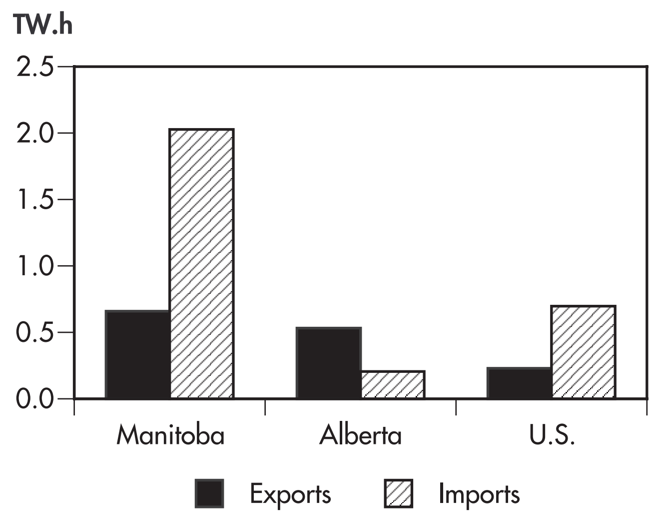
service in November 2002. With the exception of the cogeneration facilities, natural gas facilities are primarily for peaking purposes. Given this increased activity, SaskPower is likely to have no difficulty in meeting its customer requirements over the upcoming years.

4.4.3 Trade

Electricity requirements in Saskatchewan are also supported by purchases and sales of electricity with the neighbouring provinces of Alberta and Manitoba and the state of North Dakota. Most interprovincial trade is with Manitoba (Figure 4.4.4).

FIGURE 4.4.4

Saskatchewan Electricity Trade, 2000



Source: NEB, Statistics Canada

Saskatchewan has one 110 kV double circuit and three 230 kV lines of interconnection with Manitoba which provide 500 MW of design transfer capability. In the case of Alberta, Saskatchewan has one 230 kV line interconnection with a design transfer capability of 150 MW. These transmission connections were developed for:

- system reinforcement;
- reserve sharing;
- emergency; and
- short-term economic power transfers.

Saskatchewan has one 230 kV line interconnection with North Dakota. Exports of electricity to North Dakota have varied from 122 GW.h in 1990 to 229 GW.h in 2000.

Manitoba Hydro provides a hydro-based resource for electricity generation, while the provinces of Saskatchewan and Alberta, as well as North Dakota, are thermal based. The diversity of these resources, as well as winter peak demand in Canada versus summer peak demand in the U.S., allows for electricity trade beneficial to Saskatchewan and its bordering utilities.

4.4.4 Market Structure and Regulation

SaskPower is a vertically-integrated utility and the sole provider of electricity to customers in Saskatchewan.

On 27 July 2000, the Saskatchewan Rate Review Panel of the Ministerial Advisory Committee was created to conduct reviews and prepare opinions on the fairness and reasonableness of any proposed Crown corporation rate changes that are referred to it by the Minister of Crown Investments Corporation through Cabinet. Only rate changes for monopoly services are referred to this panel. Prior to the creation of the committee, proposals for rate increases were submitted for approval to a government-appointed Board of Directors responsible for managing and operating the Crown utility.

SaskPower is currently creating an Open Access Transmission Tariff (OATT). This initiative will provide access for third parties to SaskPower's transmission. The transactions contemplated include:

- buying and selling electricity for export or internal requirements; and
- purchasing power supplies by wholesale customers from sources other than SaskPower. (This market segment consists of the cities of Saskatoon and Swift Current which can opt to purchase electricity from a third party.)

Due to its interconnection with other utilities, SaskPower was of the view that it would face increased economic and political pressure to deregulate its electric industry. SaskPower restructured some of its internal operations in anticipation of deregulation. However, at this time, there are no plans to further deregulate its electricity operations beyond the OATT initiative. SaskPower is closely monitoring electricity market events in other jurisdictions.

4.4.5 Electricity Prices

Electricity prices in Saskatchewan are bundled prices, i.e., they are not broken down into transmission, distribution, and generation price components. Under Saskatchewan's regulated regime, the bundled residential energy price was 7.01 cents/kW.h over the period 1995 to 2000. From 1 January 1996 to 31 March 2000, basic monthly charges were $9.87. A separate item for residential customers, called the reconstruction charge ($2.00), was billed separately. Effective 1 April 2000, this reconstruction charge was rolled into the basic monthly charge of $11.87. In effect, there were no rate increases and bundled energy prices have essentially remained frozen during this period. For comparative purposes, the following table provides some of the base monthly charges and bundled energy prices provided for the following urban rate classes, effective 1 April 2000.

	Residential	Commercial	Industrial
Basic Monthly Charge	$11.87	$13.93	$12.14
Energy Charge (cents/kW.h)	7.01	7.82*	6.75*
Total (cents/kW.h)	9.01	7.96	6.87

*First 10 000 kW.h/month

Although there are a number of other rate classes within the SaskPower electric system, such as oil fields and farms, the rate within a class is uniform throughout the province.

It might be expected that electricity rates in Saskatchewan would be lower, given that the majority of SaskPower's generating resource is coal based. However, Saskatchewan lignite coal is a low grade coal for producing electricity. Additionally, SaskPower's generating resource base is in the southern portion of the province with widely-dispersed load centres throughout the province, resulting in high transmission system losses.

There does not appear to be a movement towards electricity and gas price convergence within the province. Electricity prices are regulated and have been relatively unaffected by changes in natural gas prices. Furthermore, in general, customers do not have the ability to switch between electricity and gas based upon burner tip prices. Although it is expected that electricity prices will remain relatively stable, the dramatic increase in gas prices has affected SaskPower's cost of electricity generation.

4.4.6 Summary

In general, the SaskPower electric system is "lightly" interconnected to electricity markets/regions of diverse resources, i.e., a hydro-based system in Manitoba and thermal-based systems in Alberta and North Dakota. By forward supply planning, SaskPower has historically tended to bring on new generating capacity to meet its domestic electricity requirements, limiting the amount of surplus energy for trade. From time to time, this internal resource balancing requires SaskPower to purchase outside of its market at market rates which are more costly than SaskPower's cost of production. These two factors might suggest that buying and selling activities involving adjacent markets could have a modest impact on electricity pricing within Saskatchewan over the mid-to-longer term. Overall, SaskPower's residential rates are in the mid-range when compared with other provinces.

4.5 Manitoba

Electricity in Manitoba is provided by Manitoba Hydro, a provincial Crown corporation, and Winnipeg Hydro, a utility owned by the City of Winnipeg. Winnipeg Hydro serves the central area of Winnipeg, while Manitoba Hydro serves the remainder of the City of Winnipeg and the rest of the province. Manitoba is Canada's fourth largest producer of hydroelectricity (following Québec, British Columbia, and Ontario).

4.5.1 Demand

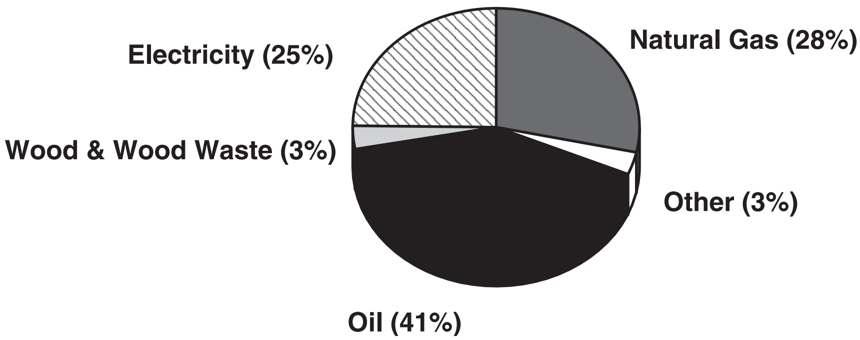
Approximately 25 percent of Manitoba's energy needs are met by electricity (Figure 4.5.1). Oil and natural gas comprise the most significant energy components. The remaining six percent of Manitoba's energy is provided by other fuels.

Electricity demand increased modestly during the 1990s (Figure 4.5.2). Residential and commercial demands have been stable due to Manitoba's low population growth and Manitoba Hydro's "Power Smart" program, which encourages the efficient use of electricity. Slow growth in the residential and commercial sectors is expected to continue in the near term.

Growth in the industrial sector has been the major driver of growth in electricity demand. A large hog processing plant, commercial hog farms, and petrochemical processing have been the major

F I G U R E 4 . 5 . 1

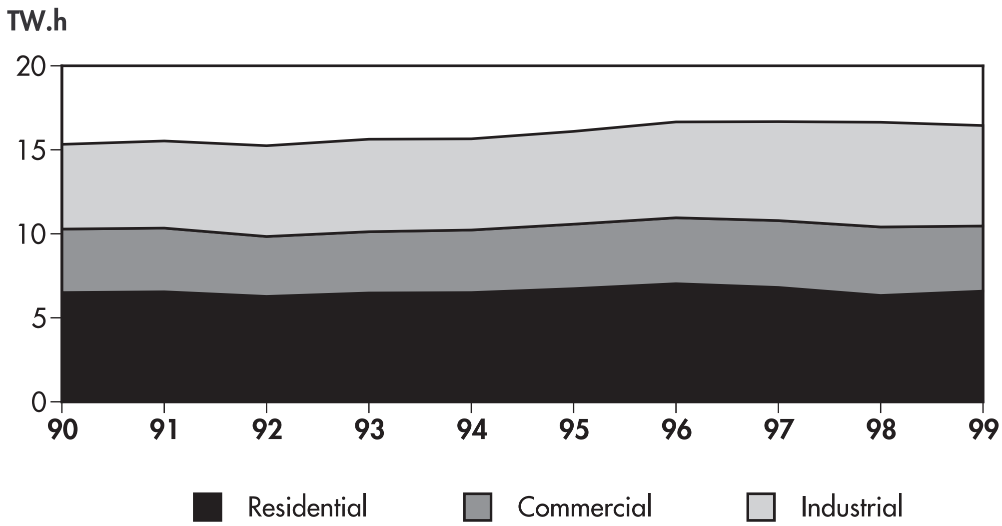
Manitoba End-Use Energy Demand by Fuel, 1998



Other: LPG, Ethane, Coal, Coke, Coke Oven Gas
Source: NEB, Statistics Canada

F I G U R E 4 . 5 . 2

Manitoba Electricity Demand by Sector



Source: NEB, Statistics Canada

contributors. Although industrial growth has been increasing steadily in the province, many existing industrial consumers have achieved significant reductions in their electricity consumption by adopting energy efficiency strategies. Manitoba Hydro encourages conservation, as power not used by provincial customers can be sold at higher prices in the export market. Industrial audits are conducted to locate areas where efficiencies can be gained, allowing industrial users to benefit from reduced power consumption.

4.5.2 Electricity Generation

Beginning in the 1960s, with the development of high voltage direct current, Manitoba Hydro was able to begin the first phase of full development of the Nelson River system in the northern reaches of the province. High voltage direct current is the most cost effective and efficient method of transmitting electricity over long distances. This process allowed Manitoba to capitalize on its significant water resources to produce low-cost electricity.

Approximately 95 percent of Manitoba's electricity is produced by 14 hydroelectric generation facilities. The remaining five percent is produced by thermal generation, from two coal-fired generating stations and four small diesel sites, and alternative energy sources[1]. Thermal generation is used only for peaking and as back-up in case of a significant failure in the hydro system or due to water shortage. Manitoba Hydro has a generation capacity of about 5 118 MW, accounting for almost all of the province's capacity of 5 141 MW. In 1999, generation in the province totaled 29.7 TW.h (Figure 4.5.3).

4.5.3 Trade

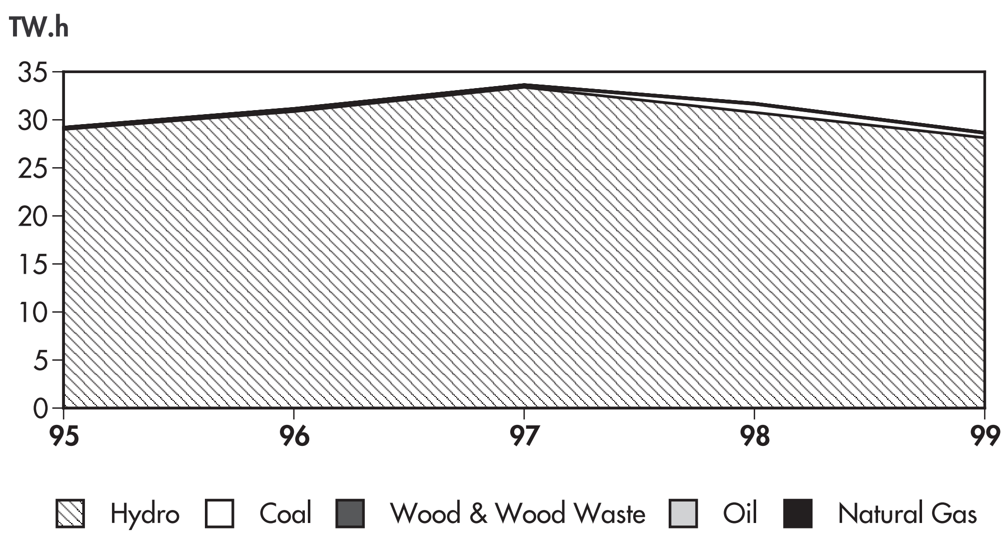
To enable the transfer of electricity to and from other provinces and states, there are 10 interconnection points: four with Saskatchewan, three with Ontario, and three with the United States. To further facilitate access to transmission, Manitoba Hydro is a member of the Mid-continent Area Power Pool (MAPP) and is presently evaluating its options regarding membership in an RTO.

Manitoba produces more electricity than needed for domestic consumption. This surplus has been available for export. Manitoba Hydro derives, on average, 25 percent of its revenues from exported electricity. In the year ending March 31, 2000, approximately 33 percent of the utility's revenue was earned by selling power outside of the province's borders, mostly to the U.S. As a low-cost producer, Manitoba Hydro is able to capture significant profits by selling electricity to mid-western states (Figure 4.5.4).

Hydro-electricity production emits virtually no greenhouse gases. Those states importing hydro are avoiding or postponing construction of additional thermal generation capacity, which would emit significant amounts of greenhouse gases. As in the case of Québec and B.C., Manitoba's hydro exports contribute to the global effort to reduce greenhouse gas emissions. Manitoba Hydro estimates that between 1970 and 2000 its hydro exports have displaced approximately 1.6 billion tons of CO_2 emissions.

FIGURE 4.5.3

Manitoba Electricity Generation by Fuel

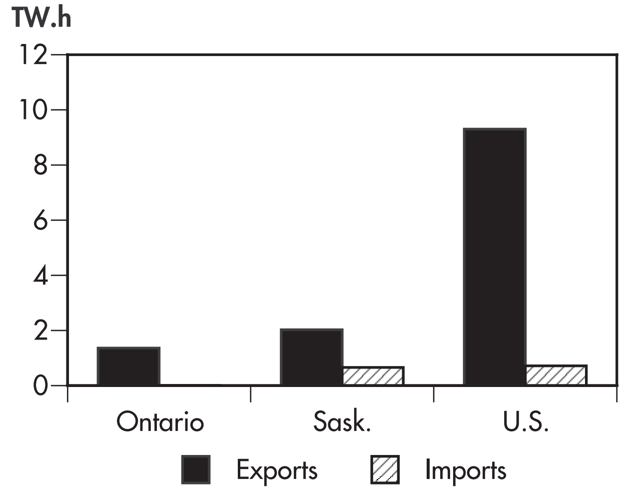


Source: Statistics Canada

1 One of the coal plants, the Selkirk plant, is to be converted to natural gas by April of 2002.

FIGURE 4.5.4

Manitoba Electricity Trade, 2000



Source: NEB, Statistics Canada

To maintain its ability to meet the continued expected demand for power exports, Manitoba Hydro is constructing a 225 MW gas-fired combustion turbine at Brandon, and is evaluating three potential sites for future hydro-electric generation facilities. Manitoba Hydro has signed an Agreement in Principle with the Tataskweyak Cree Nation regarding the potential future development of the Gull Rapids Generating Station and is working towards an agreement concerning the Wuskwatim and Gull Generating Stations. Power from these new hydro-electric stations is not expected before 2008.

4.5.4 Market Structure and Regulation

Manitoba Hydro and Winnipeg Hydro are vertically-integrated utilities. Winnipeg Hydro produces approximately 45 percent of its power and purchases the balance required from Manitoba Hydro.

Manitoba Hydro is regulated by the Manitoba Public Utilities Board, which sets the rates that the utility is permitted to charge for electricity. Winnipeg Hydro's rates are governed by The City of Winnipeg Act and an agreement between the City and Manitoba Hydro (currently being renegotiated). Although there are no plans to deregulate within the province, The Manitoba Hydro Act was revised in 1997 to allow for open access to the transmission system on a wholesale basis. Manitoba Hydro is also able to enter into joint ventures and alliances, and form subsidiaries under the new regulations. These changes were implemented to allow Manitoba Hydro to further develop its export markets.

Manitoba Hydro retains the profits from its operations after payment of transfers to various governments, including water rentals, sales tax, capital tax, and the provincial debt guarantee fee.

4.5.5 Electricity Prices

As a low-cost producer of hydro-electricity and with rates based on cost-of-service, Manitoba Hydro is able to provide electricity to domestic consumers at the lowest prices in North America. Prices have remained unchanged since 1997 for all of Manitoba Hydro's electricity consumers. In 1999, residential consumers paid 6.09 cents per kW.h, and general service customers paid 4.18 cents per kW.h.

According to Manitoba Hydro's *2000/01 Prospective Cost of Service Study*, its domestic cost structure can be broken down as follows: 43 percent generation; 18 percent transmission; and 39 percent distribution and customer service.

4.5.6 Summary

Manitoba Hydro is able to capitalize on the province's ample water resources to produce low-cost electricity. As a result, the province has the lowest electricity prices in Canada. Manitoba Hydro, through its "Power Smart" program, encourages all domestic customers to use electricity efficiently. This allows the utility to maximize the surplus available for export at significantly higher export prices.

4.6 Ontario

Ontario is currently in the process of restructuring its electricity market. Upon restructuring, the price of electricity supply, or the commodity, will be subject to market forces, similar to other commodities. The transmission and distribution of electricity will be regulated by the Ontario Energy Board.

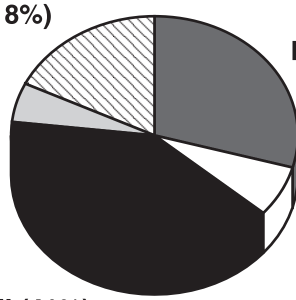
4.6.1 Demand

In 1998, Ontario energy consumption amounted to 2 695 PJ. Oil held the largest share, 41 percent of end-use demand, while natural gas accounted for 29 percent (Figure 4.6.1). Electricity represented approximately 18 percent of end-use energy demand.

Total annual demand for electricity in Ontario decreased during the recession in the early 1990s and then grew as the economy recovered to reach 136 TW.h in 1999 (Figure 4.6.2). Residential demand declined from about 47 TW.h in 1990 to approximately 43 TW.h in 1999. This decline was due to increases in the price of electricity that favoured the use of natural gas as well as energy efficiency regulations. Demand in the commercial sector now represents the largest share of the market at 34 percent. Industrial demand has recovered from its 1993 low and is now 33 percent of the market. Over the past 10 years, electricity demand in Ontario has shifted from a single winter peak (heating) to peaks occurring in both the winter and summer (air conditioning) seasons.

FIGURE 4.6.1

Ontario End-Use Energy Demand by Fuel, 1998



Other: Wood and Wood Waste, LPG, Ethane and Steam
Source: NEB, Statistics Canada

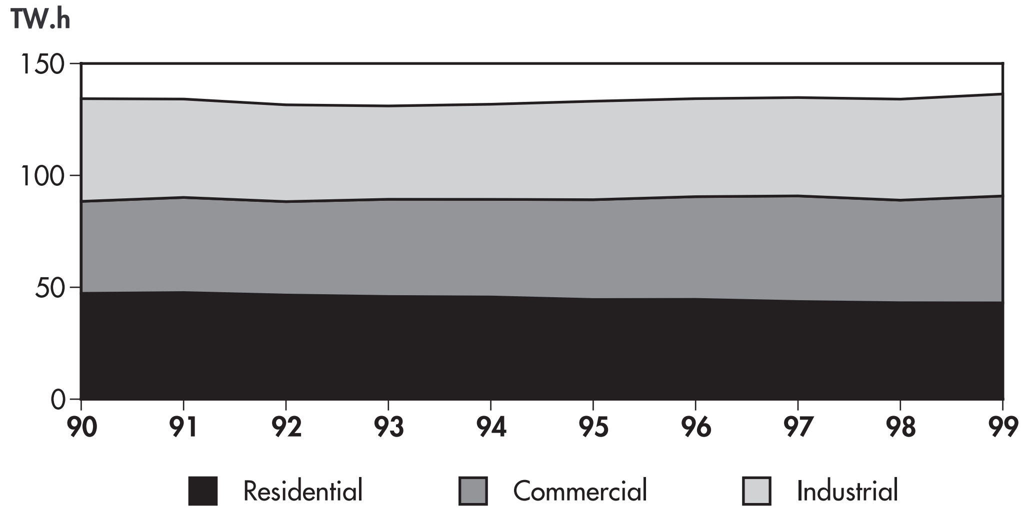
4.6.2 Electricity Generation

Ontario has a total of 29 500 MW of available generation capacity. This excludes 5 100 MW of laid-up nuclear capacity at the Bruce A and Pickering A generating stations.

While nuclear generation has declined from 57 percent of the market in 1995 to 41 percent in 1999, nuclear power still dominates the Ontario generation market (Figure 4.6.3). Hydro and coal account for 25 percent and 24 percent, respectively, and together with nuclear power, provide 90 percent of the electricity generated in Ontario. Hydro has remained relatively stable over the past five years. However, the use of coal has increased significantly to offset declining nuclear production. While

FIGURE 4.6.2

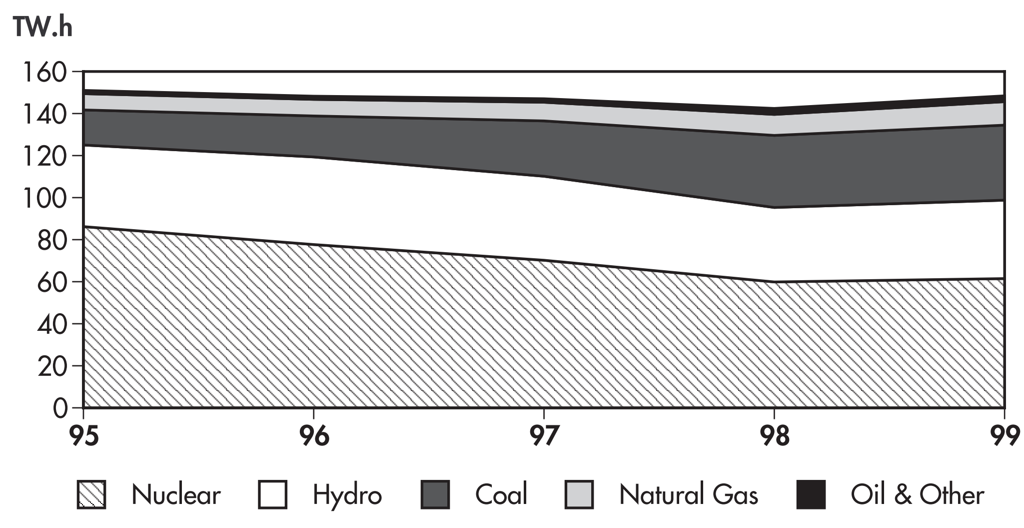
Ontario Electricity Demand by Sector



Source: NEB, Statistics Canada

FIGURE 4.6.3

Ontario Electricity Generation by Fuel



Source: Statistics Canada

natural gas generation currently represents eight percent of the market, the use of natural gas has been increasing at an annual average rate of 10 percent.

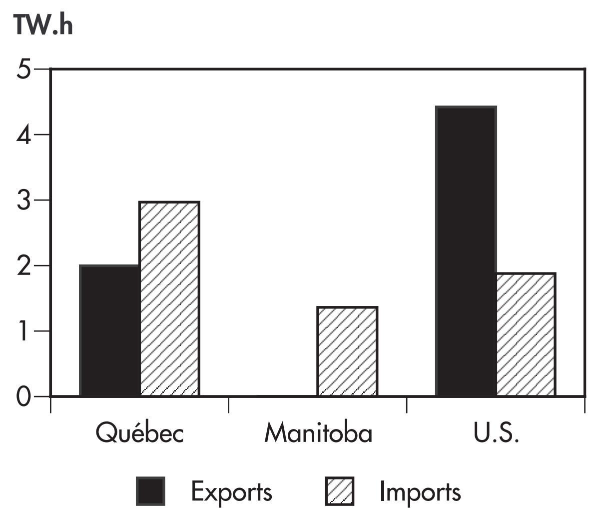
There is a consensus that Ontario has sufficient capacity for near-term demand requirements. Another 3 000 MW of new generation capacity has been announced. These include: two proposals by Sithe Energies Inc. to build 800 MW combined-cycle gas-fired facilities in Brampton and Mississauga (2002 start-up); and the construction by TransAlta of a 440 MW addition to a 210 MW gas-fired cogeneration facility in Sarnia (fall 2002 start-up).

4.6.3 Trade

In 2000, Ontario imported 6.2 TW.h of electricity and exported a total of 6.4 TW.h (Figure 4.6.4). Imports from Québec and Manitoba totalled 4.3 TW.h, representing approximately 70 percent of total imports. While the U.S. accounted for 30 percent of total imports, nearly 69 percent of Ontario's electricity exports go to the U.S. market. Interprovincial transmission connections have provided Ontario with the ability to import lower priced electricity from hydro producers in Manitoba and Québec and export surplus power to higher priced markets in the U.S. Compared with generation, imports and exports are relatively low; they account for approximately five percent and four percent, respectively, of annual generation.

FIGURE 4.6.4

Ontario Electricity Trade, 2000



Source: NEB, Statistics Canada

4.6.4 Market Structure and Regulation

The electricity industry in Ontario is currently in transition from a monopoly to a competitive market. The market was initially scheduled to open in November 2000; however, the Minister of Energy, Science and Technology announced in June 2000 that, since many market participants would not be prepared on time, market opening would be delayed by at least six months. In April 2001, the Minister announced a target date of May 2002.

Until recently, generation and transmission of electricity was generally provided by Ontario Hydro while distribution services were largely provided by Ontario Hydro and the municipal electric utilities. Upon full restructuring, consumers will have the opportunity to contract with any licensed energy retailer to obtain electricity supply. Competition and customer choice will only apply to the energy component of the electricity bill, which accounts for approximately one-half to two-thirds of the total delivered price to a residential customer. Transmission and distribution, which account for the other one-third to one-half of the delivered price, will not be subject to competition and will be regulated by the Ontario Energy Board (OEB).

Restructuring in Ontario began in 1997, when the Government of Ontario released a white paper identifying its plans to reform the provincial electricity market. The following year, the Ontario Legislature passed *The Energy Competition Act*, 1998, and *The Electricity Act*, 1998, to provide a framework for a restructured market.

The Energy Competition Act mandated the separation or unbundling of electricity services in Ontario. Accordingly, in April 1999 Ontario Hydro was split into five separately managed business entities: Ontario Power Generation Inc. (OPG); Hydro One Inc.(Hydro One); the Independent Electricity Market Operator (IMO); the Ontario Electricity Financial Corporation (OEFC); and the Electrical Safety Authority.

Ontario Power Generation Inc.

OPG took over ownership and operation of the former Ontario Hydro generation facilities. Due to concerns raised with respect to OPG's market power and the ability to manipulate prices, the *Market Power Mitigation Agreement* (MPMA) was developed to reduce OPG's share of the generation market. The main features of the 10-year, three-stage plan follow:

- A large portion of OPG's production sold in Ontario would be subject to an average annual revenue cap of 3.8 cents/kW.h for a period of four years after opening of market. Any revenue in excess of the cap would be rebated pro rata to all electricity consumers in Ontario.
- OPG is required to reduce its share of generation capacity (fossil) that has the most influence on spot market prices to 35 percent or less within 42 months of market opening.
- Within 10 years of market opening, OPG would be allowed to control no more than 35 percent of total generation capacity and no other supplier would be able to accumulate more than 25 percent of total generation capacity in Ontario.

In response to the MPMA, OPG announced in 2000 its intent to decontrol its 2 140 MW oil/gas-fired Lennox generating station and its 1 140 MW coal-fired Lakeview generating station. The lease of the Bruce Nuclear Generating station could potentially decontrol another 6 200 MW of OPG's generation capacity. OPG is planning the return, beginning in early 2002, of 2 060 MW of power from the four nuclear generating units at Pickering A.

Hydro One Inc.

Hydro One assumed the ownership and operation of the transmission, distribution and energy retailing businesses of Ontario Hydro. Hydro One Networks, a subsidiary of Hydro One, owns and operates about 97 percent of the high-voltage transmission facilities within the province. Two smaller transmission systems, Great Lakes Power and Canadian Niagara Power, provide localized transmission service. Hydro One also owns and operates 17 interconnections with transmission systems in neighbouring provinces and the U.S.

The MPMA also requires Hydro One to increase its interconnection capability by 2 000 MW within three years of open access. Hydro One currently has two planned projects to achieve this increase. The Michigan Phase Shifter Project would provide 500 to 600 MW of additional capacity into Michigan and is expected to be in-service in May 2001. A new Ontario-Québec Inter-Tie is expected to be in-service by December 2002, and would provide an additional 1 250 MW of capacity between the two provinces.

Independent Electricity Market Operator

While Hydro One Networks would continue to own and maintain the province's power transmission system, the IMO would be responsible for:

- directing the operation of an open access transmission system;
- establishing and operating the competitive wholesale electricity market;
- authorizing market participants;
- monitoring market activities to ensure fair competition;
- forecasting supply requirements; and
- encouraging additional investment by providing information to the market participants and stakeholders.

Ontario Electricity Financial Corporation

Prior to deregulation, Ontario Hydro had an accumulated debt and other liabilities in excess of $38 billion. The servicing of this debt currently accounts for approximately 40 percent of electricity bills. Ontario Hydro's successor companies were restructured to have debt and equity structures comparable to similar commercial enterprises. The remaining debt was passed to the Ontario OEFC to ensure that it is properly managed and efficiently retired. Upon market opening, the corporation would start collecting revenue from principal and interest payments; payments-in-lieu of taxes; and a Debt Reduction Charge. A Debt Reduction Charge of 0.7 cents per kilowatt hour would be collected by all entities that bill electricity consumers until the debt has been retired.

Distribution

Prior to deregulation, distribution services in rural areas were primarily provided by Ontario Hydro, while municipal electric utilities (MEUs) provided them to urban areas. Under restructuring, all MEUs were required to separate their "wires only" businesses from their other energy businesses to avoid cross-subsidization. The resulting stand-alone distribution companies were required to sell their assets or incorporate under the *Ontario Business Corporations Act*. Due to expanding urban centres, municipal amalgamations, and a transfer tax holiday to November 2000, many MEUs have been motivated to consolidate. From over 300 a few years ago, their number will be reduced to about 92, assuming that the mergers and acquisitions currently before the Ontario Energy Board are approved.

The corporatisation of the MEUs has initially resulted in an increase in distribution costs to enable distribution utilities to earn a market rate of return. Over the longer term, the rationalization of distribution assets through mergers and acquisitions may result in increased efficiencies and lower costs for distribution services.

Regulation - Ontario Energy Board

With respect to electricity, the OEB is responsible for:

- licencing electricity market participants including the IMO, generators, transmitters, distributors, wholesalers and retailers;
- determining the rates to be charged for Standard Supply Service and the distribution and transmission of electricity in Ontario;

- market monitoring and reporting to the Minister of Energy, Science and Technology on the competitiveness and market power, efficiency, fairness and market transparency; and
- reviewing the IMO market rules and considering appeals of IMO orders.

4.6.5 Electricity Prices

Since 1993, the commodity portion of the electricity price has been frozen in Ontario. While the commodity portion will remain frozen until market opening, the OEB has approved new distribution rates that have increased the total delivered price to end-users. In March 2001, OPG applied for a rate increase of 0.7 cents/kW.h in the wholesale price of electricity. If approved, this would result in an eight percent increase for the average residential consumer.

Wholesale Markets

Restructured wholesale electricity markets in Ontario would consist of three main components: a real-time energy market (spot market); a forward market; and bilateral contracts.

With respect to the spot market, the IMO would collect offers from generators within both Ontario and interconnected markets to supply electricity. Each offer would specify an amount of power and its price for each hour of the day. The IMO would then stack the offers in order of rising price and accept each offer until demand is met. The last offer accepted would establish the Market Clearing Price (MCP) or spot price for the entire Ontario market. The IMO would establish a new MCP every five minutes. From these five-minute prices, a weighted hourly average price would be calculated and charged to wholesale customers.

Wholesale purchasers may bid into the market by specifying a maximum price they would be willing to pay for specific amounts of electricity at each hour of the day. Should the MCP exceed the bid limit, consumer loads would be curtailed by the specified bid amounts. However, a consumer would not be required to bid and could simply assume the role of a price taker and pay the hourly MCP.

Initially, all spot market customers will pay the same price for power during the same hour regardless of the location. During the first 18 months of market opening, the IMO will monitor constraints on the transmission system to assess the merits of implementing locational marginal pricing in Ontario. If implemented, locational marginal pricing would be added to the hourly MCP in areas where the demand exceeded the capacity of the transmission system.

The forward market has been deferred for at least one year after market opening. It is intended to provide participants with the opportunity to make their offers and bids for their next-day power supply. Physical and bilateral contracts would be available to hedge against price volatility for periods in excess of one day.

Retail Markets

When the market opens, consumers will have the choice to buy electricity from competing energy retailers, or to continue to receive electricity from their LDC. The retail electricity market would consist of three components: standard supply service; retail contracts; and financial bilateral contracts. Standard Supply Service is the default option for consumers who choose to continue to buy electricity from their LDC. The price paid for electricity supply would either be based upon the hourly MCP, or an average annual LDC forecast price which would then be subject to retroactive adjustments, or “true-ups”, based upon the MCP. The OEB is currently considering options for Standard Supply Service other than the direct pass-through of the MCP.

Energy retailers can purchase electricity from the spot market or directly from generators or wholesalers and then sell that electricity to end-use customers. They may provide other products and services, including various pricing plans and incentives. While all energy retailers must be licensed by the OEB, the prices they charge for electricity and other services are not regulated.

The financial bilateral arrangement does not involve the LDC and is settled between the two parties based on the difference between the contract price and the rate for Standard Supply Service. Under financial bilateral arrangements, customers would take delivery of their power through standard supply service and would continue to pay their bill to the LDC.

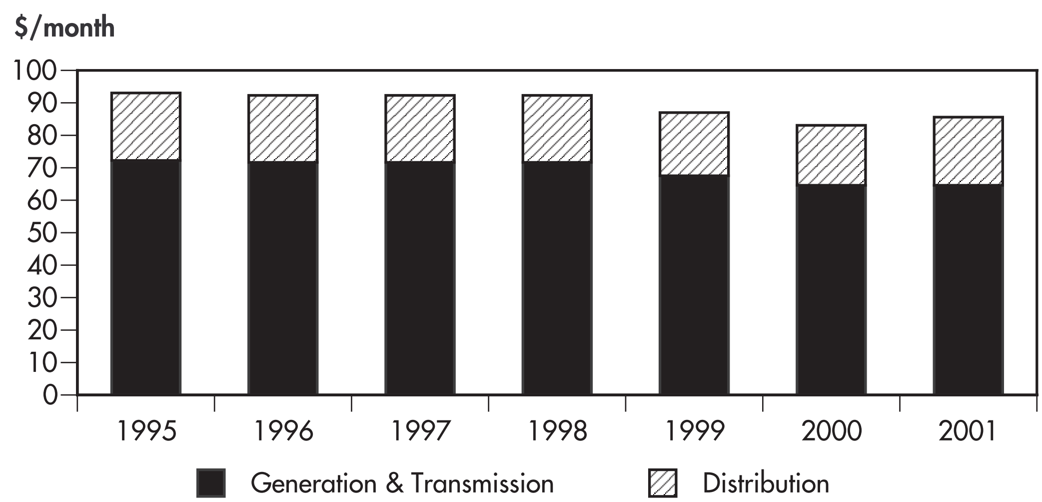
When the market opens an LDC will be required to separate its bill into four separate parts:

- Monthly Fixed Charge - recovery of fixed distribution costs;
- Variable Distribution Charge - recovery of variable distribution costs;
- Electricity Commodity Charge - recovery of the costs of electricity supply, standard supply service or collection of the retailer commodity charges; and
- Non-Competitive Electricity Charge - recovery of energy transmission, IMO fees, and possibly the Debt Reduction Charge (however, separate disclosure of the Debt Reduction Charge may also be possible).

Based on a monthly consumption of 1 000 kW.h, a residential customer in the City of Toronto would pay $85.60 for electricity supply, transmission and distribution during 2001 (Figure 4.6.5). The decrease in end-use prices since 1995 is due primarily to the merger between Toronto Hydro and surrounding MEUs with lower average costs. Until 2000, electricity supply and transmission represented approximately 78 percent of the end-use price while distribution accounted for 22 percent of the total. As the newly corporatised distribution companies move toward market rate of return on equity, currently approved at 9.88 percent, the distribution component is expected to increase. For example, distribution rates for Toronto Hydro have increased by 13.6 percent, resulting in a three percent overall increase in end-use price. Under the 2001 rate schedule, distribution accounts for about 25 percent of the end-use price. In the future, Toronto Hydro expects higher distribution costs to be offset by declining costs for electricity supply.

FIGURE 4.6.5

Toronto Residential Electricity Costs



Source: NEB, Statistics Canada

4.6.6 Summary

Ontario is the second largest provincial electricity market and has a relatively diversified generation base with many fuel options. The supply and demand situation is expected to improve with the planned recovery of laid-up nuclear capacity and the construction of additional gas-fired generation. Additional interconnections with Michigan and Québec will provide more flexibility for power exchanges and trade.

The province has established the framework for its restructured market which will implement market pricing for electricity and retail access. The framework contains key measures to mitigate market power and minimize the risks of price volatility.

4.7 Québec

The province of Québec is rich in hydraulic resources and is the largest electricity market in Canada. This market is almost entirely supplied by Hydro-Québec, a vertically-integrated corporation wholly owned by the government of Québec.

4.7.1 Demand

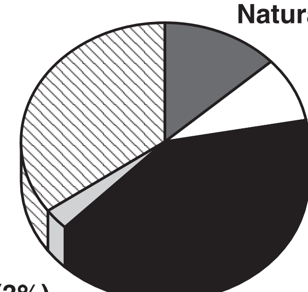
In 1998 end-use energy demand in the province was 1 705 PJ. Electricity plays a significant role to satisfy Québec's energy requirements and accounts for about 35 percent of the total (Figure 4.7.1).

During the 1990s, electricity consumption increased by less than one percent per year. The industrial sector has been the largest consumer, accounting for approximately 50 percent, followed by the residential and commercial sectors with 30 and 20 percent, respectively (Figure 4.7.2).

As a competitively-priced fuel in Québec, electricity has achieved significant market penetration in the residential, commercial and industrial sectors. Over 70 percent of Québec's residences are now heated using electricity, compared with about 40 percent in the early 1980s. Industrial sector demand has increased 26 percent over the last decade, from 68 TW.h in 1990 to 85.9 TW.h in 1999. Nearly 75 percent of industrial demand is in the smelting and pulp and paper industries.

F I G U R E 4 . 7 . 1

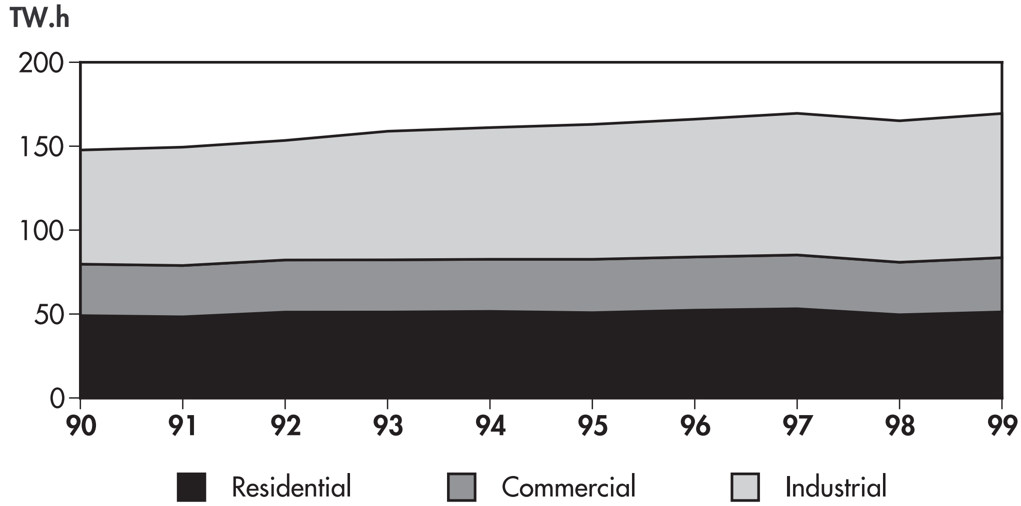
Québec End-Use Energy Demand by Fuel, 1998



Other: Coal, Coke, Coke Oven Gas, LPG, Ethane and Steam
Source: NEB, Statistics Canada

F I G U R E 4 . 7 . 2

Québec Electricity Demand by Sector



Source: NEB, Statistics Canada

4.7.2 Electricity Generation

Québec accounts for approximately one-third of the total generation capacity in Canada. In early 2001, installed capacity was about 35 500 MW, comprised of 93 percent hydro and seven percent thermal and nuclear. Hydro-Québec controls 89 percent of the total, while the balance is controlled by private ownership. It is anticipated that Hydro-Québec's current generation capacity will be adequate to meet rising demand in the province over the next few years.

Québec is the largest electricity producer in Canada. In 1999, electricity generation in the province totaled 170 TW.h, of which 96 percent was hydroelectric generation (Figure 4.7.3). Hydro-Québec produced 143 TW.h, while private producers and municipalities accounted for 27 TW.h. In recent years, generation has fluctuated substantially due to variable hydraulic conditions.

A key feature of the industry is that the main generation sources are concentrated in areas far removed from the major load centres. This distance has led to the development of 735 kV lines and one of the most extensive transmission networks in North America with 32 144 km of power lines. The province also has a major interconnecting network of 7 393 MW to enable imports and exports from and to other Canadian provinces and to the United States.

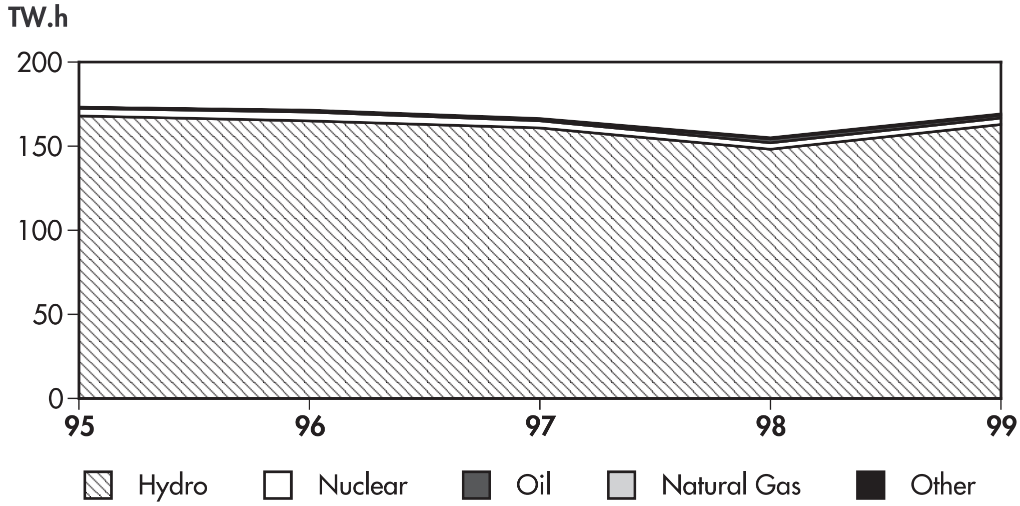
4.7.3 Trade

Interprovincial Trade

Under long-term supply arrangements between Québec and Newfoundland, more than 30 TW.h annually flow from Labrador to Québec. In 2000, these flows accounted for 84 percent of total interprovincial transfers to Québec. Ontario and New Brunswick are also traditional trading partners (Figure 4.7.4). In recent years, Québec's net transfers to those markets have totaled less than three TW.h. It is expected that more exchanges between Québec and Ontario would result from the planned addition of a 1 250 MW interconnection.

FIGURE 4.7.3

Québec Electricity Generation by Fuel



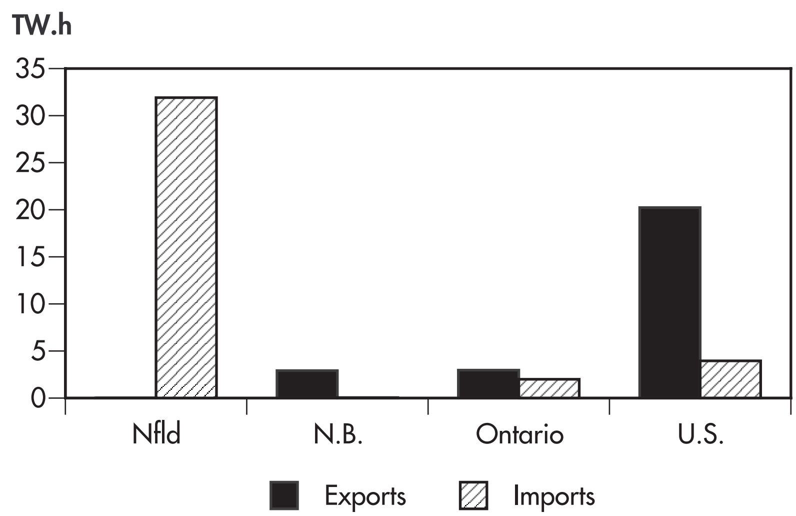
Source: Statistics Canada

International Trade

Québec has generally registered the largest provincial share of Canadian electricity exports. Its main export markets are New England and New York state. Total exports to the U.S. reached a record level of 20 TW.h in 2000. The low cost of Québec's hydroelectricity has contributed to its strong competitive position in export markets.

FIGURE 4.7.4

Québec Electricity Trade, 2000



Source: NEB, Statistics Canada

Historically, exports were based on long-term supply contracts. As of the time of writing, most long-term contracts were expected to expire by April 2001. As a result, Hydro-Québec has to rely on short-term transactions to maintain its export market share.

4.7.4 Market Structure and Regulation

Electricity plays a particularly important role in Québec. Not only does it satisfy a significant portion of Québec's energy needs but it also serves as an instrument for regional and economic development. Over the years, Hydro-Québec has played a role in the social and industrial development of the province through its investments, its employment and its contribution to government revenue in the form of taxes and dividends.

As the principal generator, transmission owner and distributor, Hydro-Québec operates as a monopoly, for the most part. It has exclusive rights for electric power distribution in the province except for a few municipalities and small private systems. In addition, the province has one cooperative and nine municipal networks which are not operated by Hydro-Québec, and which together provide distribution service to 125 000 customers. In 1998, the total length of the distribution lines within Québec was 105 705 km.

Regulatory Framework

In 1996 the Government of Québec adopted a new energy policy, called *Energy at the Service of Québec*. The policy reinforced key provisions of the Social Compact established in the early 1960s during the nationalization of the electricity industry in Québec. The Social Compact gave four mandates to Hydro-Québec: electrification of Québec's entire territory; utilization of the hydraulic resource endowment to the benefit of the people of Québec; establishment of uniform rates; and adjustments to rates to cover only Hydro-Québec's investments and operational costs.

As part of its reforms, and in response to stakeholders, the government created in June 1997 the Régie de l'énergie (Régie), an independent, quasi-judicial economic regulatory agency. The *Act Respecting the Régie de l'énergie* established the initial mandate for the Régie regarding the electricity sector:

- to regulate monopoly activities related to the supply of electric power;
- to ensure that market activity is to the advantage of consumers and to encourage healthy competition among businesses;
- to set the rates and service conditions for Hydro-Québec;
- to approve contracts for the purchase, trade and export of electricity; and
- to set rates and conditions for electricity transmission.

The role of the Régie was modified in June 2000 by Québec's Bill 116. The bill reaffirmed the mandate of the Régie over electricity transmission and distribution but maintained the provincial government's oversight for specific electricity matters including those related to large hydro projects, alternative and renewable energy, and special supply contracts.

The new legislation contains the following key provisions:

- *Price and quantity established for the Social Compact*. Bill 116 establishes 2.79 cents/kW.h as the average cost for the electricity produced in Québec, to be applied to an annual maximum volume of 165 TW.h for rate setting purposes by the Régie. This price cannot be increased but may be reduced upon government request.
- *Social Compact maintained*. Bill 116 confirms that cross-subsidization will be maintained in favor of residential customers. It also reaffirms the principle of uniform transmission and distribution rates in Québec.
- *Competitive supply for new electricity requirements*. Bill 116 requires that new electricity demand will be satisfied through an open bidding process which would be subject to the jurisdiction of the Régie. Hydro-Québec Generation will have to compete against alternative suppliers. The supply contracts between the successful bidders and Hydro-Québec Distribution must be approved by the Régie

Since its creation, the Régie has been asked to provide advice to the provincial government on specific matters. For example, in an opinion submitted to the Government of Québec concerning small hydro development in Québec, the Régie recommended a 4.5 cents/kW.h price cap for the incremental production with a maximum size quota of 150 MW.

Restructuring Initiatives

In 1997, Hydro-Québec decided to satisfy the FERC Order 888 reciprocity requirements and a wholesaler licence was issued to H.Q. Energy Services (U.S.), a subsidiary of Hydro-Québec. The licence allows direct access to the U.S. wholesale market and requires Québec to provide access to its wholesale market. Hydro-Québec also created a new division, TransÉnergie, to operate and administer its open access transmission network. However, since opening the wholesale market in Québec, there have been no direct wholesale transactions by competitors from outside the province (wheel-in), but there has been some wheel-out and wheel-through activity by traders on the TransÉnergie grid.

Given the relatively low electricity prices in the province, Québec is not under pressure to introduce more competition into the market. As a result, there are no imminent plans to further deregulate Québec's electricity market. The government has announced its intention to launch a pilot project to assess the merits of allowing retail competition. Under this plan, new industrial projects with potential consumption of more than 5 MW will be offered the choice of alternative suppliers, including Hydro-Québec.

4.7.5 Electricity Prices

Québec has relatively low electricity rates for all classes of customers, and particularly for the residential sector. Rates have been frozen until 2002 and are expected to remain stable until 2004.

Québec has uniform electricity rates throughout Hydro-Québec's network. Customers currently pay an average charge of 6.21 cents/kW.h for residential service, 7.87 cents/kWh for small commercial/industrial service, 6.14 cents/kW.h for medium commercial/industrial service and 3.38 cents/kW.h for large industrial service. Based on the price established in the Social Compact, it is estimated that the generation component would account for about 50 percent of the residential bundled rate, while transmission and distribution would account for the other half.

Hydro-Québec's rate structure reflects cross-subsidization to the benefit of residential consumers. According to a Merrill Lynch study commissioned by the Québec government and completed in 2000, if cross-subsidization were eliminated, Québec residential rates would increase by as much as 31 percent, while small power rates would decrease by 14 percent, medium power rates would decrease by 20 percent and, large power rates would decrease by 6 percent.

4.7.6 Summary

Surplus electricity supply in Québec allows it to continue to play an active role in export markets. Wholesale access has been provided in Québec but, due to relatively low electricity prices in the province, there is little incentive at this time to open the retail market. Provided unconstrained and economical access to the U.S. transmission system, Hydro-Québec appears to be positioned to expand its trading activities.

Due to abundant hydraulic resources, Québec's electricity prices are among the lowest in Canada. The passage of Bill 116 confirms the Québec government's intention to maintain advantageous prices for consumers, particularly in the residential sector. Elimination of cross-subsidization appears to be unlikely as that would be contrary to the Social Compact and would substantially raise residential rates.

4.8 New Brunswick

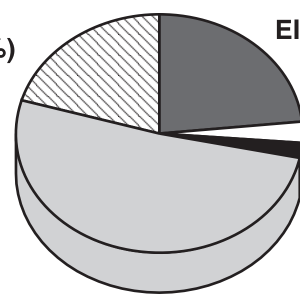
New Brunswick is the largest provincial electricity market in Atlantic Canada, accounting for about 40 percent of total electricity demand in the region. Electricity generation in the province is almost entirely provided by the Crown-owned New Brunswick Power Corporation (NB Power). With major competitive electricity markets just south of the border, a significant low-cost hydroelectric producer in Québec, and electricity supplied mostly by a vertically-integrated utility, New Brunswick is working towards restructuring its electricity sector.

4.8.1 Demand

In 1998, New Brunswick's end-use energy consumption totaled 214 PJ, with electricity accounting for 23 percent of the total (Figure 4.8.1). This share reflects the widespread use of electricity in space and water heating and industrial applications. About 60 percent of households are heated by electricity, followed by oil and wood at 20 percent each.

FIGURE 4.8.1

New Brunswick End-Use Energy Demand by Fuel, 1998



Other: LPG, Ethane, Coal, Coke and Coke Oven Gas
Source: NEB, Statistics Canada

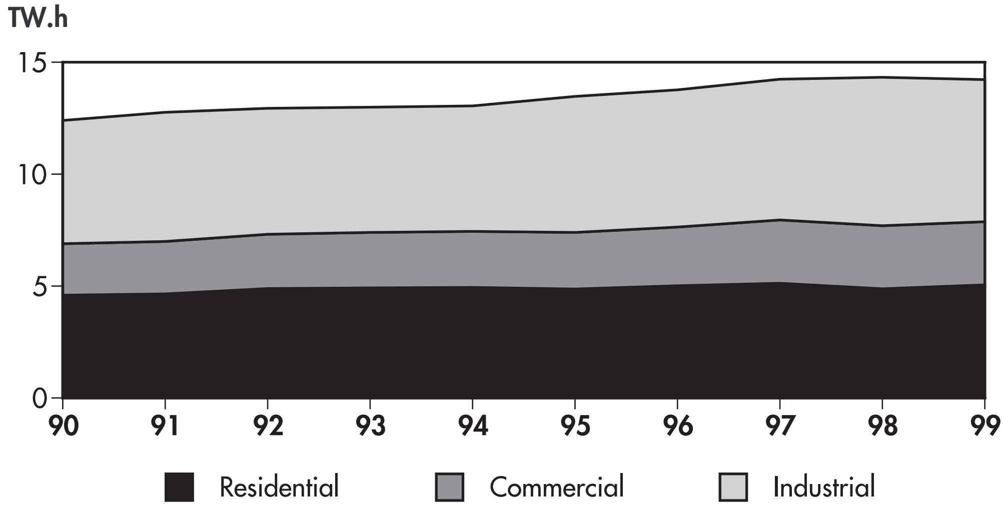
During the 1990s, the average annual electricity demand growth was just under two percent (Figure 4.8.2). Future growth may be constrained by competition from natural gas which has recently been introduced to the province.

4.8.2 Electricity Generation

New Brunswick has the most diversified generating base in Atlantic Canada, with thermal accounting for about 50 percent of the provincial capacity, and hydro, nuclear and biomass accounting for the other half (Figure 4.8.3). NB Power's generation capacity is about 3 850 MW and the winter peak demand is close to 3 000 MW. Nearly 900 MW is run-of-the-river hydraulic capacity, which has limited energy delivery capability during the peak winter season. Private producers have a generation

FIGURE 4.8.2

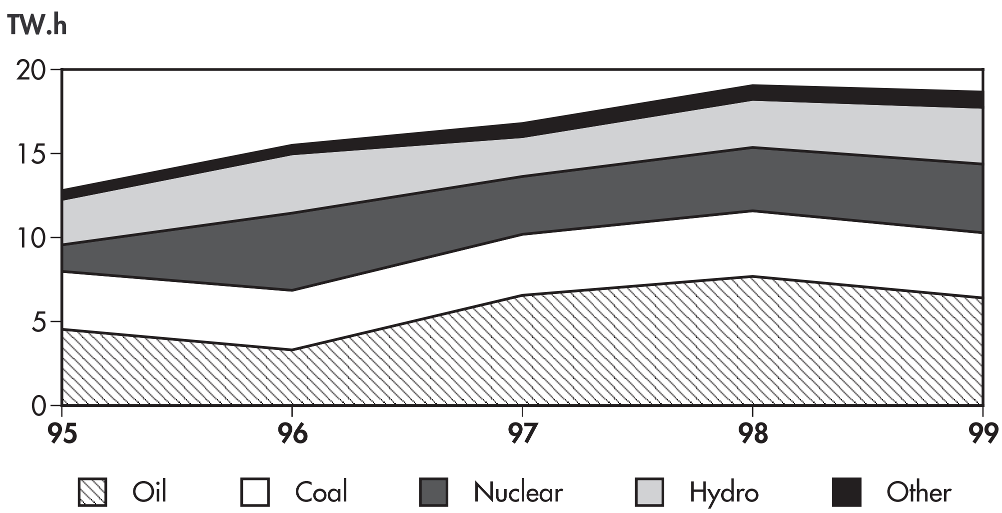
New Brunswick Electricity Demand by Sector



Source: NEB, Statistics Canada

FIGURE 4.8.3

New Brunswick Electricity Generation by Fuel



Source: Statistics Canada

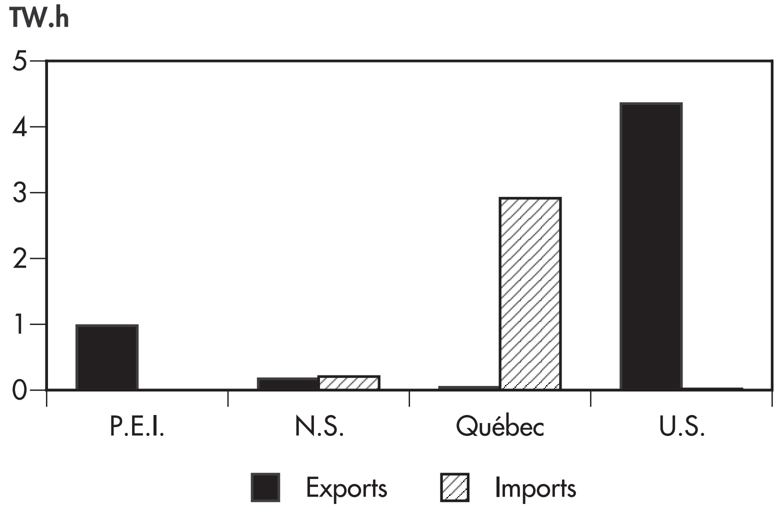
capacity of about 250 MW. This amount mainly includes pulp and paper industry cogeneration, and some small hydro facilities. NB Power has entered into an agreement with Westcoast Power to convert a 100 MW oil-fired unit at Courtenay Bay into a 260 MW gas-fired combined-cycle cogeneration plant by mid-2001. Westcoast Power will market the plant's spring, summer and fall energy to buyers in New England. NB Power will purchase the plant's winter output.

In 2000, the cities of Moncton, Fredericton and Saint John received natural gas service for the first time. The availability of gas from Sable Island is a significant development affecting New Brunswick's energy market. Gas is expected to gradually penetrate some market segments especially for heating and cooking applications, which may reduce existing or potential electric loads. Gas will also partially replace oil and coal resources serving existing loads. Recent increases in gas prices have raised concerns about its competitiveness for power generation.

4.8.3 Trade

FIGURE 4.8.4

New Brunswick Electricity Trade, 2000



Source: NEB, Statistics Canada

NB Power has the most extensive transmission network in Atlantic Canada, with over 6 600 km of high voltage transmission lines. The network has several interconnections allowing New Brunswick to supply and trade power and energy with adjacent provinces (1 945 MW) and with the state of Maine (815 MW). The utility is pursuing a second 345 kV interconnection with Maine. It is also assessing the opportunity to become part of an RTO.

New Brunswick is the principal electricity supplier to Prince Edward Island. Over the 1990 to 2000 period, flows to P.E.I. increased by almost 50 percent, reaching one TW.h in 2000 (Figure 4.8.4). New Brunswick imported nearly three TW.h of electricity from Québec in 2000. Some small exchanges also exist between New Brunswick and Nova Scotia.

Electricity exports from New Brunswick to the U.S. have increased since 1994, totaling about 4.4 TW.h in 2000. With an adequate reserve margin, a direct interconnection to Hydro-Québec which has low-cost power, and proximity to competitive New England electricity markets, it appears that New Brunswick is strategically positioned to play an increasing role in the export market.

Export revenues have increased in the last two years due to rising electricity prices in markets where supply is tight. In 1999, exports to the U.S. Northeast accounted for about 18 percent of NB Power's total revenue.

4.8.4 Market Structure and Regulation

NB Power is a vertically-integrated but functionally unbundled utility. It is also the dominant electricity supplier in the province (94 percent of total demand in 1999), serving more than 300 000 customers, including two municipalities.

Electricity rates and NB Power's operations are regulated by the provincial Board of Commissioners of Public Utilities (the PUB). Decisions by the PUB are generally referred to the provincial Cabinet, which can overrule a decision by the regulator. As a Crown corporation, NB Power reports to the provincial government through its chairman. A bipartisan Crown corporation committee also reviews utility rates and operations annually.

NB Power must apply to the PUB for major generation projects. The PUB is required to conduct public hearings and then make recommendations to the provincial Cabinet.

Electricity market and regulatory structures in New Brunswick may be subject to significant changes over the next few years resulting from the key initiatives contained in the January 2001 *White Paper on Energy Policy*. The white paper establishes, among other things, a detailed plan for electricity restructuring in New Brunswick under which the government will:

- introduce wholesale competition by permitting the electric distribution utilities and large industrial customers to procure power in a competitive market by a target date of April 2003;
- allow non-utility generation;
- periodically review market conditions before deciding whether to permit full retail competition; and
- appoint a new market design committee to address development of the electricity market, including its structure and rules, and to make recommendations to the provincial government by April 2002.

The white paper implies a significantly expanded role for the PUB. More specifically, the province will empower the PUB to approve Standard Offer Service and exit fees and regulate an open transmission tariff. In addition, the PUB will be given the authority to monitor the competitiveness of the wholesale market and address market power issues. It will also be required to adopt a light-handed, performance-based approach to regulation, and move towards the elimination of cross-subsidization among customer classes.

4.8.5 Electricity Prices

NB Power's rates are regulated by the PUB. Under the current regime, NB Power can increase its annual revenue requirement up to three percent or the rate of inflation (if inflation is higher than three percent), without a formal application to the PUB.

NB Power provides several classes of service, including residential, general service and industrial. As of April 2000, the residential rates include a fixed service charge of $15.79 per month for urban areas ($17.30 per month for rural areas), and an energy charge of 7.56 cents/kW.h for the first 1 000 kW.h and 5.69 cents/kW.h for consumption in excess of 1 000 kW.h. Declining block rates, which provide for discounts based on consumption, also apply to the other classes of service.

The cities of Edmundston and Saint John are serviced by local utilities which pay NB Power a wholesale rate averaging 6.25 cents/kW.h. Retail rates in Edmundston are the same as those of NB Power, while rates in Saint John are lower due to higher population density and a higher concentration of general service customers.

The current rate structure reflects cross-subsidization among the different classes of customers. As in many other jurisdictions, residential customers benefit from the fact that their rates do not cover the full cost-of-service, while general service rates are higher than the cost-of-service. This situation is expected to change as the province has asked NB Power to eliminate over time cross- subsidization between customer classes.

4.8.6 Summary

A diversified generating base, and revenue from exports have contributed to maintaining relatively low and stable electricity prices in New Brunswick. The availability of natural gas from Sable Island provides new opportunities and challenges, especially for provincial electricity providers. According to the *White Paper on Energy Policy*, the provincial electricity market is expected to move towards competition by 2003. A key challenge for stakeholders is to assure price stability during the transition period and thereafter.

4.9 Prince Edward Island

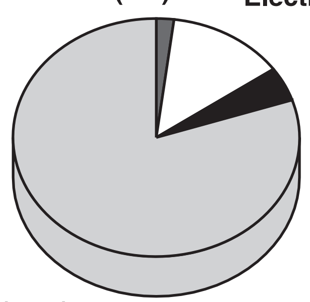
With no indigenous sources of energy, Prince Edward Island (P.E.I.) has, since its electrical interconnection with New Brunswick in 1977, imported virtually all its electricity requirements. As a result, P.E.I. relies almost exclusively on generation sources in New Brunswick to meet its load requirements.

4.9.1 Demand

P.E.I. has the lowest energy demand of all provinces in Canada and electricity only accounts for about 13 percent of the total end-use energy demand in the province (Figure 4.9.1). Oil comprises 80 percent of demand, and the remaining seven percent is made up of other fuels.

FIGURE 4.9.1

Prince Edward Island End-Use Energy Demand by Fuel, 1998



Source: NEB, Statistics Canada

Largely as a result of economic growth, total provincial electricity demand has increased by two to three percent annually in recent years, with industrial loads having the highest growth rates (Figure 4.9.2). Demand reached almost one TW.h in 1999. The commercial and residential sectors made up 45 percent and 40 percent, respectively, of the total, while the industrial sector accounted for the remaining 15 percent.

4.9.2 Electricity Generation

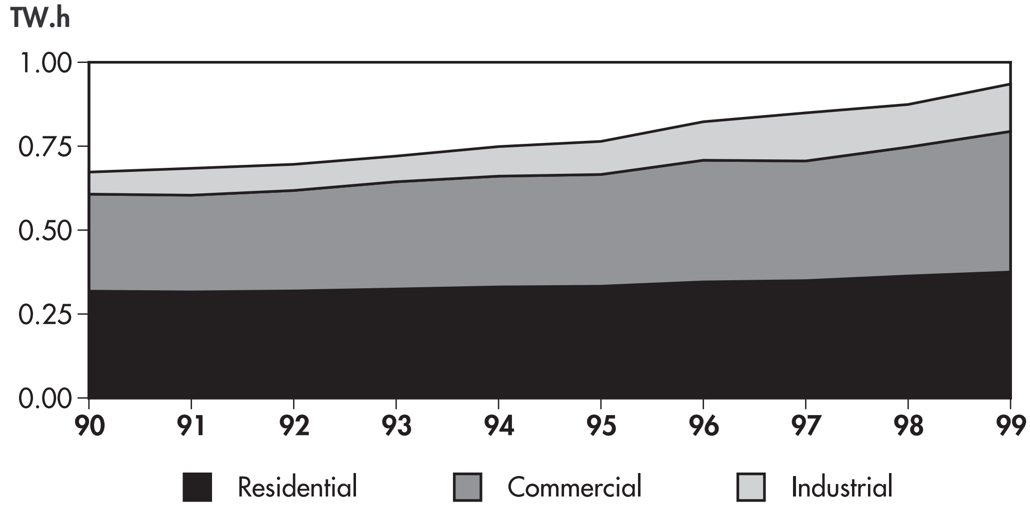
Maritime Electric Company Limited (MECL) is the primary electricity provider in the province. The City of Summerside has a municipal utility with a diesel plant, but purchases almost all of its electricity requirements from MECL. MECL generates about one percent (Figure 4.9.3) of the province's annual electricity requirement at its two oil-fired plants located on the Island. Natural gas service to P.E.I. is currently being evaluated by the Province in conjunction with industry. Natural gas would provide another source of power generation on the Island.

4.9.3 Trade

Nearly all of the provincial electricity demand is met through imports from New Brunswick (Figure 4.9.3) under several long-term contracts with NB Power. Electricity is transmitted to the Island through two submarine cables which have a total transfer capacity of 200 MW.

FIGURE 4.9.2

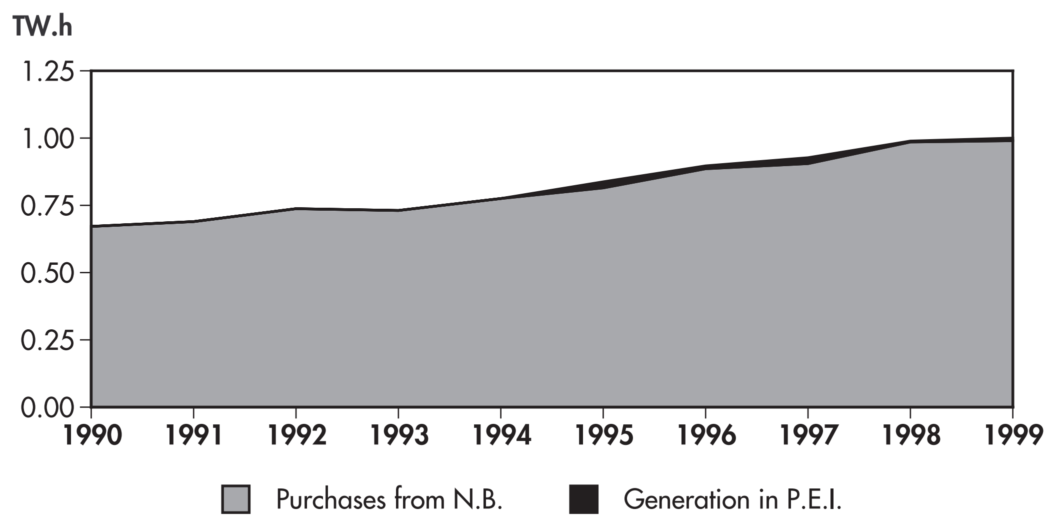
Prince Edward Island Electricity Demand by Sector



Source: NEB, Statistics Canada

FIGURE 4.9.3

Prince Edward Island Electricity Supply



Source: Statistics Canada

4.9.4 Market Structure and Regulation

MECL is an investor-owned company and a member of the Fortis group. It is a monopoly electricity provider and operates under the provisions of the *Maritime Electric Company Limited Regulation Act*. The company is regulated by the Island Regulatory and Appeals Commission.

The *Maritime Electric Company Limited Regulation Act* requires that MECL's rates do not exceed 110 percent of NB Power rates for comparable services. As a result, electricity prices in P.E.I. are linked to prices in New Brunswick.

Restructuring of electricity markets in New Brunswick may provide, over time, access to new competitive sources of power supply to the benefit of MECL and its customers. MECL is considering joining an RTO to obtain wider access to transmission systems.

4.9.5 Electricity Prices

Under the prevailing regulatory regime, electricity consumers on the Island are currently paying NB Power prices plus 10 percent. MECL has applied for a special increase of 4.53 percent, to be implemented retroactively on 1 January 2001. The matter is currently before the provincial regulatory commission.

4.9.6 Summary

Electricity consumers in P.E.I. have experienced stable electricity prices in recent years. Demand is expected to continue to grow, and electricity restructuring in New Brunswick may, over time, provide new power supply sources for MECL and its customers.

4.10 Nova Scotia

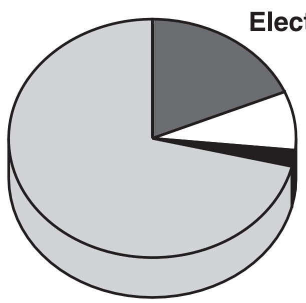
Nova Scotia has historically relied on oil and coal to meet a large part of its energy requirements. In recent years, activity resulting from the Sable Island natural gas development has contributed to strong provincial economic growth. The availability of gas provides new options for end-users and for power generators.

4.10.1 Demand

In 1998, electricity accounted for 19 percent of total end-use energy demand in the province (Figure 4.10.1). During the 1990s, electricity demand increased by 1.9 percent annually, reaching almost 11 TW.h in 1999 (Figure 4.10.2). The industrial sector has experienced the strongest growth followed by the commercial sector. Regional economic growth is expected to stimulate electricity demand further over the next few years.

F I G U R E 4 . 1 0 . 1

Nova Scotia End-Use Energy Demand by Fuel, 1998



Other: LPG, Ethane, Coal, Coke and Coke Oven Gas
Source: NEB, Statistics Canada

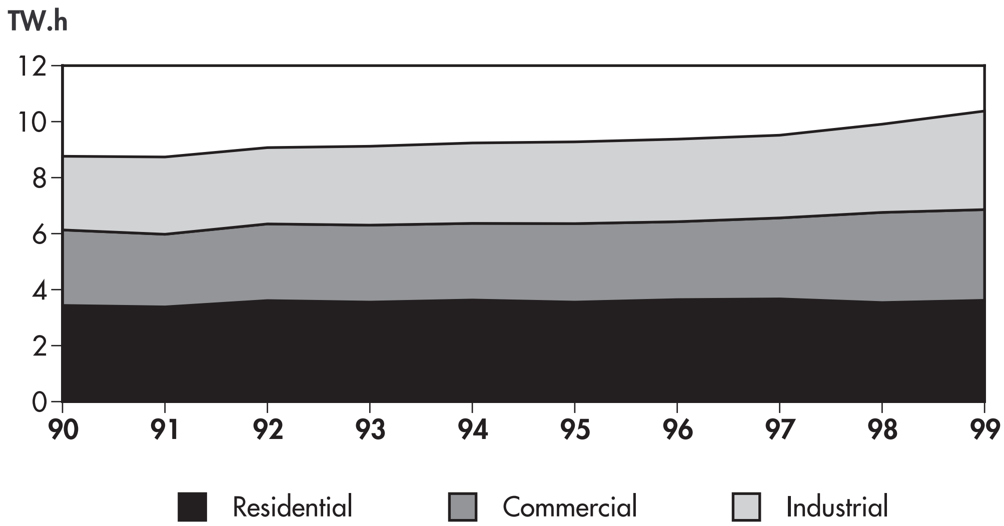
4.10.2 Electricity Generation

Nova Scotia's generation capacity is predominantly coal-fired, with some hydro, natural gas, oil and biomass (Figure 4.10.3). The Lingan generating station on Cape Breton Island, with a capacity of 620 MW, is the largest coal-fired facility in the province. Even with rising demand and the lack of new generation capacity since 1994, the reserve margin has remained at over 20 percent in recent years.

Since December 1999, the availability of Sable Island gas in Nova Scotia has provided an additional generation option for local power plants. The oil-fired Tufts Cove plant was converted to dual-firing with natural gas in November 2000. The recent sharp increase in gas prices has limited the use of gas in the plant since its conversion.

FIGURE 4.10.2

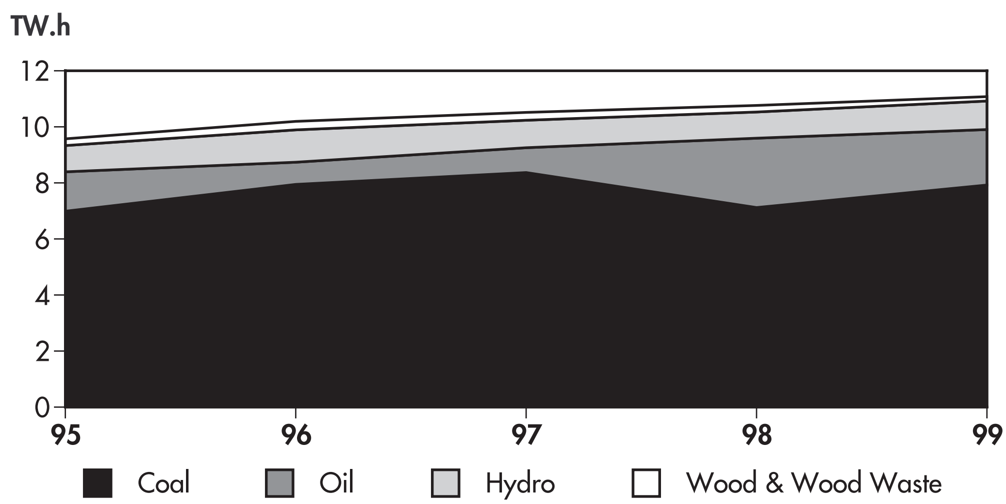
Nova Scotia Electricity Demand by Sector



Source: NEB, Statistics Canada

FIGURE 4.10.3

Nova Scotia Electricity Generation by Fuel



Source: Statistics Canada

Gas-fired generation remains an attractive long-term option. It is more energy efficient and less capital intensive than coal, and has environmental advantages. The Cape Breton Development Corporation, historically the primary coal supplier, permanently closed its Phalen mine in 1999. As a result, the province has to rely increasingly on imported coal, which, in 1999, accounted for about 50 percent of its requirements for power generation.

Historically, 65 to 80 percent of Nova Scotia's generation comes from coal-fired facilities. Fuel-switching back to coal may occur when oil and gas prices are relatively high. NSPI, like other utilities, dispatches its generation on an economic basis. Therefore, the mix between coal and other fossil fuels in any given year depends upon the relative prices of these fuels.

The availability of natural gas provides challenges and opportunities for electricity suppliers. A key challenge is how to retain electric loads. Sempra Atlantic Gas, which acquired the gas distribution rights in the province in 1999, has targeted gas penetration in several sectors, including the residential sector. It is expected that the recent increase in gas prices will, to a certain extent, constrain gas market penetration in the short term.

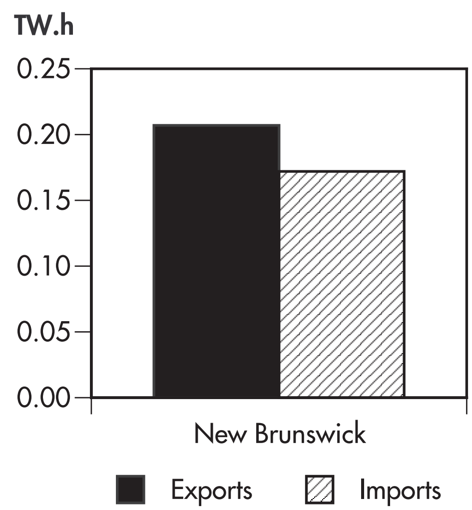
4.10.3 Trade

Nova Scotia's transmission network consists of 5 400 km of high voltage lines. There are three interconnections between New Brunswick and Nova Scotia with a total capability of 600 MW. Due to its geographic location, Nova Scotia does not have direct access to U.S. markets.

Although Nova Scotia and New Brunswick are both self-sufficient in electricity supply, trading between the two provinces occurs regularly whenever it is mutually beneficial. Over the last 10 years, Nova Scotia has generally been a net importer of electric power from New Brunswick. However, exports exceeded imports in 2000 (Figure 4.10.4).

FIGURE 4.10.4

Nova Scotia Electricity Trade, 2000



Source: NEB, Statistics Canada

4.10.4 Market Structure and Regulation

Electricity markets in Nova Scotia are primarily served by Nova Scotia Power Inc. (NSPI), which is a vertically-integrated utility and wholly-owned by EMERA (an investor-owned company). EMERA also markets petroleum products and has 12.5 percent ownership in the Maritimes and Northeast Pipeline. NSPI owns 97 percent of the generation, 99 percent of the transmission and 95 percent of the distribution assets in the province.

NSPI is regulated by the Nova Scotia Utility and Review Board (UARB), in accordance with the provincial *Public Utilities Act*. The UARB is the final authority with respect to NSPI's electricity rates and development plans.

Under the current cost-of-service regulation, electricity rates are based on revenue requirements. Cost recovery by the utility for each class of customers is targeted in the range of 95 to 105 percent of the cost. The rate of return on assets is also regulated.

In response to prospective competition from natural gas, a new load retention program was granted to NSPI by the UARB in 2000.

TOU rates are also currently available in conjunction with home heating equipment. NSPI recently applied for a streamlined UARB approval process and for the introduction of additional energy solutions packages including flexible TOU pricing options. These programs are major steps by NSPI in its plan to provide more value to customers. Load retention is important to maintain price stability. Under the existing regulatory framework, load losses would result in fewer customers sharing the cost-of-service and, therefore, rates would likely increase.

Nova Scotia has recently launched the development of a new energy strategy for the province which is expected to be completed before 2001 year end. Electricity restructuring is an issue that will be addressed.

4.10.5 Electricity Prices

Electricity prices in Nova Scotia are relatively high but in line with other jurisdictions in Atlantic Canada. This situation reflects a major reliance on relatively high-priced domestic coal (coal prices in Atlantic Canada are about three times higher than in Western Canada), imported coal and heavy fuel oil for generation.

Under the current electricity rate structure approved by the UARB, residential customers in Nova Scotia pay a fixed charge of $10.50 per month and an energy charge of 8.35 cents/kW.h. This results in an average price of approximately 10 cents/kW.h., including sales taxes. Generation accounts for 50 to 60 percent of the energy charge and the remainder is split almost equally between transmission and distribution. Rates within a rate class are uniform in the province and have remained unchanged since 1996. Rates are expected to remain stable throughout 2001.

Rates reflect limited cross-subsidization, which mostly benefits residential customers. NSPI is the only utility in Atlantic Canada that offers its customers TOU rates, thus providing them options for minimizing their electricity costs.

4.10.6 Summary

Nova Scotia is self sufficient in electricity supply. The availability of Sable Island gas provides opportunities for diversifying the generation mix while achieving higher energy efficiency. Electricity rates in the province reflect the relatively high costs of fuels used for generation. NSPI has taken steps to offer customers more choice and flexible pricing options. Nova Scotia's electricity market is not closely linked to other markets, and restructuring is currently being considered by the province.

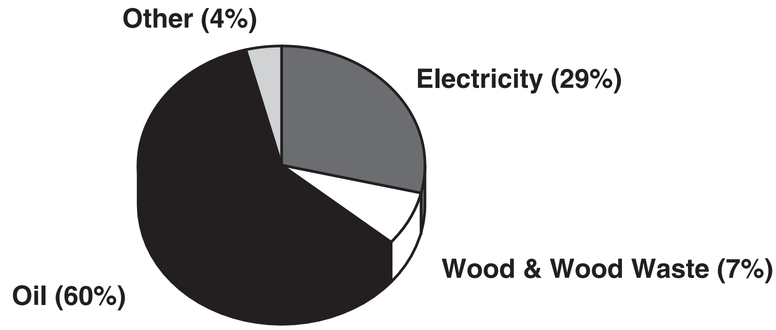
4.11 Newfoundland and Labrador

The province of Newfoundland and Labrador, the largest electricity producer and exporter in Atlantic Canada, has enjoyed exceptional Gross Domestic Product (GDP) growth in recent years due largely to offshore oil development. This growth has led to renewed growth in electricity demand, although at lower rates than in the past.

4.11.1 Demand

F I G U R E 4 . 1 1 . 1

Newfoundland End-Use Energy Demand by Fuel, 1998



Other: LPG, Ethane, Coal, Coke and Coke Oven Gas
Source: NEB, Statistics Canada

In 1998, electricity accounted for 29 percent of total end-use energy demand in the province (Figure 4.11.1). Total electricity demand reached almost 10 TW.h in 1999, of which about 50 percent is attributable to the industrial sector.

The Island of Newfoundland (the Island) accounts for about 75 percent of the total provincial electricity demand, while Labrador accounts for the remaining 25 percent. On the Island, about 50 percent of residences are heated by electricity, 35 percent by oil and the remaining 15 percent by wood. Although expected to vary somewhat by sector (Figure 4.11.2), the Island's load growth is expected to be about one percent annually over the next few years.

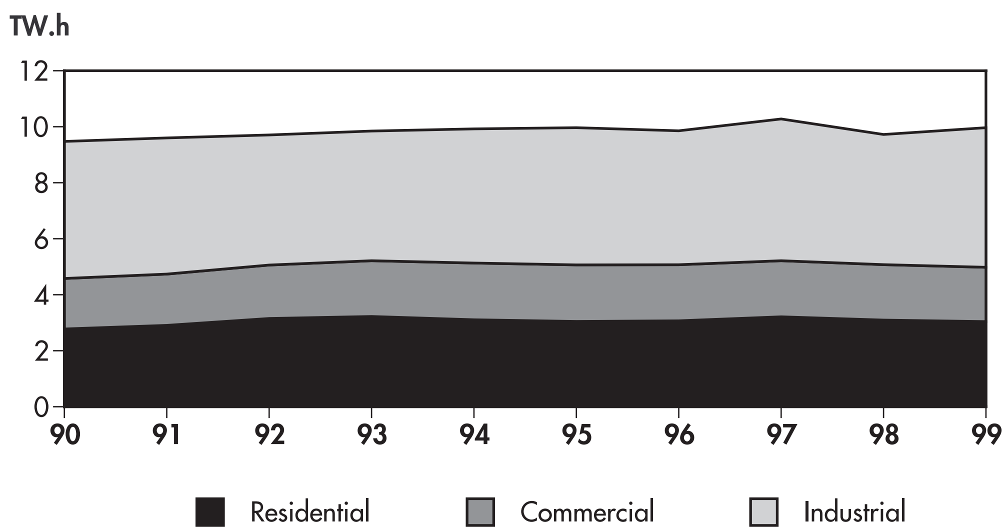
4.11.2 Electricity Generation

About 75 percent of total provincial generation capacity is located in Labrador, mainly at Churchill Falls (5 428 MW). The Island has over 1 800 MW of capacity, which is composed of 64 percent hydro and 36 percent thermal plants. By 2003, 87 MW in three new projects are expected to be added to the Island's interconnected system.

Newfoundland and Labrador accounts for approximately 60 percent of the total electricity produced in Atlantic Canada. Electricity generation in Labrador is predominantly hydroelectric (Figure 4.11.3) except for a number of isolated coastal communities that have diesel generation.

F I G U R E 4 . 1 1 . 2

Newfoundland Electricity Demand by Sector



Source: NEB, Statistics Canada

On the Island, generation is a mixture of hydro and oil-fired. Because of its relatively high cost, thermal generation is normally used to meet peak winter seasonal demand related to space heating requirements. There is some non-utility generation originating mainly from the two pulp and paper companies. As in Labrador, there are also isolated rural customers serviced by diesel generation.

4.11.3 Trade

Under the 1969 Power Contract, the province transfers most of the power generated at Churchill Falls to Québec. In 2000, these transfers amounted to approximately 32 TW.h, which are by far the largest annual interprovincial flows in Canada. Recent agreements with Hydro-Québec for the sale of 130 MW of recall power under the Power Contract, and the sale of 682 MW of additional capacity under the Guaranteed Winter Availability Contract, have had a positive impact on Newfoundland & Labrador Hydro's revenue from out-of-province sales.

The province has two separate transmission networks. In Labrador, transmission is interconnected to the North American grid through Québec via three 735 kV circuits, with a total firm capacity of about 5 500 MW. The Island's transmission is not connected to the North American grid and is one of the largest isolated networks on the continent.

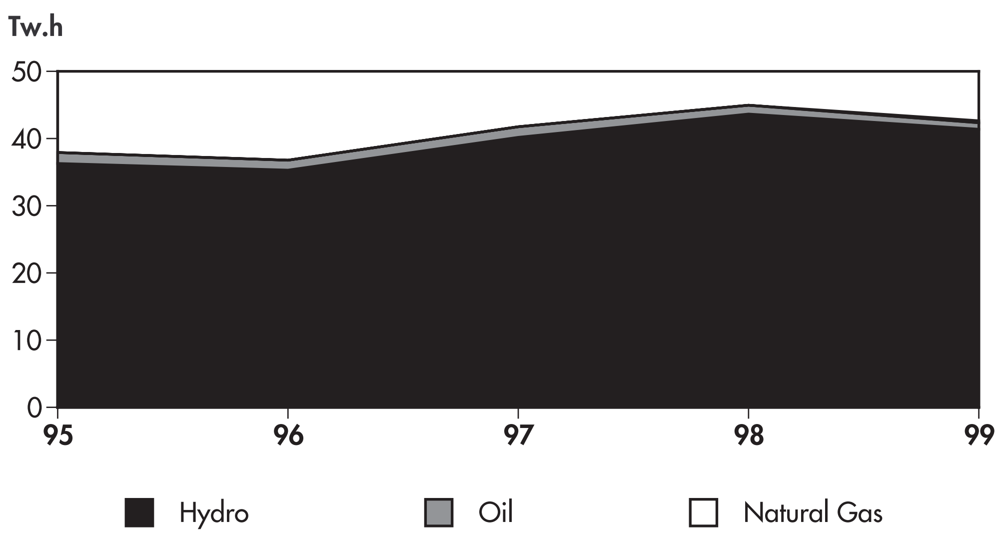
4.11.4 Market Structure and Regulation

Electricity markets in Newfoundland and Labrador are served by two regulated utilities. Newfoundland & 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, an investor-owned company (100 percent owned by Fortis Inc.), services about 90 percent of all retail customers on the Island. It purchases 90 percent of its electricity requirements from HYDRO and generates the remaining 10 percent from its own facilities. The residential sector

F I G U R E 4 . 1 1 . 3

Newfoundland Electricity Generation by Fuel



Source: Statistics Canada

provides approximately 60 percent of its operating revenue, due in large part to the extensive use of electric space heating on the Island.

Under the Public Utilities Act, HYDRO and Newfoundland Power are regulated by the Board of Commissioners of Public Utilities (PUB) with respect to electricity rates, capital budgets and construction of new facilities. Legislation requires that electricity rates be established on a cost-of-service basis. The provincial Cabinet has the power to give binding directions to the established PUB as to policies and procedures pertaining to utility rate structures. In 1998, the PUB approved a formula that is used to adjust Newfoundland Power's rates on an ongoing basis as a way to reduce rate hearing frequency. The adjustments are based on changes in long-term Canada bond yields.

A rate stabilization mechanism helps reduce large annual swings in electrical rates which can result from fluctuations in the cost of oil used at HYDRO's large thermal plant, the levels of precipitation affecting production from the hydroelectric facilities and load. The rate stabilization mechanism annually provides for a rolling three-year amortization of outstanding credit or debit balance in the stabilization fund.

The Government of Newfoundland and Labrador is presently reviewing all policies relevant to the electricity industry structure, regulation and pricing.

4.11.5 Electricity Prices

Newfoundland electricity rates are generally in line with other jurisdictions in the Atlantic region. Interconnected residential customers on the Island are currently paying a fixed charge of $16.31 per month plus a variable charge of 6.77 cents/kW.h (or an average effective rate of about nine cents/kW.h including the harmonized sales tax). Commercial and industrial customers pay a demand charge plus an energy charge, with volume discounts available. In isolated areas, rates are the same for the first block of 700 kW.h per month, and increases for volumes in excess of this initial block. Prices on the interconnected system in Labrador are lower than the Island's interconnected rates and vary along the system, while Labrador's isolated rural regions incur the same rate structure as the Island's isolated rural customers.

HYDRO's utility rate (the rate paid by Newfoundland Power) is currently 4.53 cents/kW.h. It is estimated that about 55 percent of the residential bill represents generation costs, while transmission and distribution account for 15 percent and 30 percent, respectively. The relatively high distribution cost reflects the province's low population density. From 1 January 2000, HYDRO's industrial customers were no longer required to contribute to the subsidy for rural and isolated customers. To finalize the interim rates implemented to achieve this, HYDRO will file a general rate application (its first since 1992) in May 2001.

The operation of the cost-of-service adjustment formula mentioned above, applied annually in November to determine Newfoundland Power's rates for the following year, resulted in a 1.1 percent increase in 1999, 0.7 percent increase in 2000 and did not change rates for 2001.

4.11.6 Summary

Newfoundland and Labrador is the largest electricity producing province in Atlantic Canada. Its largest generation source, the Churchill Falls hydroelectric facility, is located in Labrador while most major load centers are situated on the Island. Rate stabilization mechanisms have contributed to rate stability in recent years and rate cross-subsidization is being reduced.

OBSERVATIONS

The electric power industry in North America has been undergoing substantial change as many jurisdictions have introduced competition in generation and provide access to wholesale markets and some retail markets. However, the pace of restructuring varies across regions and the extent to which restructuring will occur is uncertain. A key concern is the impact on electricity prices. Volatile oil and especially natural gas prices during the past two years have also been cause for uncertainty about electricity prices, because of the increasing use of gas in power generation. Given these concerns, this report has provided a detailed analysis of Canadian electricity markets, which has led to the following observations.

Electricity Supply

Overall, Canadian electricity markets appear to be adequately supplied. Alberta has experienced relatively tight supply situations, particularly during periods of peak demand. However, recent announcements suggest that power developers are planning to make new supplies available over the next one to five years.

Across the country, with a few notable exceptions, new generation projects in the near term are expected to be gas-fired. These plans were, for the most part, made before the recent escalation in natural gas prices. Depending on the duration of higher gas prices, there could well be a shift toward other forms of electricity generation. In recent months, there have been announcements of new coal-fired generation projects in Alberta, which has abundant and inexpensive coal. Higher prices tend to make wind energy and other renewable technologies more feasible.

The nature of gas-fired generation plants allows them to be built closer to load centres. Although not a focus of this report, this could be an important consideration in provinces where the current coal and hydroelectric generation facilities are located far from markets, thus requiring the construction of transmission capacity (e.g., Alberta, Saskatchewan, Manitoba and Québec). A related matter is future trends in distributed generation; locating generation at industrial sites, for example, could reduce the need for both long-distance transmission and distribution facilities.

Convergence

Convergence of the natural gas and electricity markets is an outcome of the increasing use of gas in power generation. An important aspect is that gas prices and power prices have become closely related. Convergence is demonstrated by some recent trends: high natural gas prices throughout the U.S. affecting overall Canadian electricity export revenues; the price of natural gas influencing electricity prices in the Power Pool of Alberta; and electricity demand in California contributing to relatively high prices for B.C. gas exports.

The Role of Electricity Exports and Market Integration

A number of provinces have surplus energy available for export, and the country continues to be a net exporter of electricity. Exports comprised about nine percent of domestic generation in 2000.

Some Canadian entities have been granted wholesale trader status by FERC by satisfying the reciprocity requirements of open access under FERC Order 888. To further facilitate Canadian exporters' access to U.S. markets, and to facilitate access to U.S. supplies by Canadians, the transmission companies in several provinces are considering membership in RTOs. By consolidating the operations of a number of transmission systems into one independent entity, which would establish a standard tariff, RTOs further the objective of opening access to transmission. Canadian entities are not subject to FERC regulation, but due to the integrated nature of the North American transmission system, it appears that Canadian involvement in RTO formation could be potentially beneficial to all market participants, provided proper approaches for jointly overseeing a cross-border RTO are adopted.

Directionally, the formation of RTOs could lead to more north-south trade and increased integration of the U.S. and Canadian electricity markets. To the extent Canadian competitiveness can be maintained, higher export revenue would result. Market integration could also result in upward price pressure in some provinces.

Although market integration may be facilitated by access to current transmission facilities (as expected by the RTO initiative), persistent price differentials between regions with competitive wholesale markets may indicate that new transmission facilities are required.

Restructuring of Electricity Markets

The unbundling of generation, transmission and distribution services is occurring at an uneven pace across the country. Alberta completed its five-year program, introducing full retail access on 1 January 2001, after implementing wholesale access 1 January 1996. Ontario plans to implement full retail access in May 2002.

At this time, there are no definitive plans to introduce full retail access in the other provinces; the reasons for this vary. In many provinces, it appears that, with the historical record of relatively low and stable prices and the prospect that this will continue to prevail in the near term, there is limited incentive to change the current regulated regime. However, a number of provinces currently provide, or plan to provide, wholesale access. A prime motivation seems to be to satisfy the reciprocity requirements of FERC Order 888.

Two main objectives of restructuring are lower prices and more customer choice. Increased competition might be expected to result in lower prices. However, there may also be higher costs associated with the increased risk faced in a competitive market environment, as compared with a regulated environment. An example would be the increased cost of capital faced by electricity suppliers. There is substantial debate about whether restructuring will ultimately result in higher or lower prices; however, it is clear that, in any given region, the design of the restructuring program and the supply and demand situation will be important factors in establishing the eventual outcome.

Electricity Prices

Volatile energy prices do not necessarily mean volatile electricity prices. In all provinces, with the recent exception of Alberta, consumer prices have been generally stable, or have increased by relatively small amounts, over the past several years. This stability is largely the outcome of the provincial regulatory regimes which establish prices on a cost-of-service basis and, in some provinces, the implementation of price freezes. Prices tend to be lower in the provinces that generate most of their electricity from hydro resources (e.g., B.C., Manitoba and Québec). A comparison with residential electricity prices in other countries suggests that Canadian prices are among the lowest of the industrialized countries.

Continuing to establish electricity prices on the basis of regulated costs would be a departure from the pricing of other energy commodities, which is based on domestic and international market forces. To the extent there is a difference between the regulated cost and the market value of electricity, as measured, for example, by the prices of competitive fuels in the same market area or electricity prices in adjacent market areas, electricity consumers and producers may not receive the appropriate price signals for decision-making. A regulated price that is set below market value could result in too much consumption and/or insufficient production and a price that is set above market value would have the opposite effects.

Growing reliance on market forces in other sectors of the economy and in other electric power jurisdictions in North America is causing Canadian provinces to consider adopting market-based structures. However, the record of low electricity prices provided, for the most part, by provincially-owned utilities under the traditional structure, and the recent experience with price volatility in California, have caused most provinces to move cautiously toward developing comprehensive restructuring plans.

GLOSSARY

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.
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 specified period.
Bilateral Contract	A private commercial arrangement between a customer and a supplier, which may or may not be a generator. The terms including price, amount, source, delivery point and time of energy consumption are all subject to negotiation. In practice, most bilateral contracts tend to be variations on a few standard patterns.
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.
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 generating units simultaneously.
Commercial Sector	The commercial sector is generally defined as non-manufacturing business establishments, including hotels, motels, restaurants, wholesale businesses, retail stores, and health, social, and educational institutions.
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-Side Management	Actions undertaken by a utility that result in a reduction in demand for electricity. This can eliminate or delay new capital investment for production or supply infrastructure and improve overall system efficiency.
Direct Current (DC)	Electric current that flows in one direction with little or no voltage fluctuation.
Distribution	The transfer of electricity from the transmission network to the consumer.
Diversity	Refers to the difference in peak demand on a daily or seasonal basis between regions. For example, peak demand generally occurs during the winter in Canada, while it occurs in the summer in some States. Diversity can be used as a basis for trade (see energy banking).
Economy Energy	Energy sold by one power system to another, to effect a saving in the cost of generation when the receiving party has adequate capacity to supply the loads from its own system.
Energy Banking	The storage of water in a reservoir during off-peak times to be released for generation during peak times.
Firm Power	Power or power-producing capacity intended to be available at all times during the period covered by a guaranteed commitment to deliver, even under adverse conditions.
Forward Market	An organized exchange where standardized contracts for the future delivery of electricity are traded according to established rules and regulations.
Generation	The process of producing electric energy by transforming other forms of energy; also, the amount of electric energy produced.
Greenhouse Gases	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.
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.
High Voltage Direct Current	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.

Industrial Sector	The industrial sector is generally defined as manufacturing, construction, mining, agriculture, fishing and forestry establishments.
Interruptible Power	Energy or power made available under an agreement that permits curtailment or interruption of delivery at the option of the supplier.
Joule	A unit of work and energy. It is defined as the work done (energy transferred) in one second by a current of one ampere at a potential difference of one volt. One watt is equal to one joule per second.
Kilowatt hour	A measure of electric energy. It is the amount of electric energy required to operate a 100-watt light bulb for 10 hours.
Load Retention Rates	A rate which may be offered by an electricity supplier in order to retain existing customers. Normally the rate is only offered to large customers, which, if they were to switch to a lower-cost supplier or relocate to another power system, would "strand" significant generation assets on the host's power system. The rate is typically offered for a period adequate to provide the current supplier time to absorb the stranded generation onto its system, either through load-growth or contractual arrangements with other suppliers or customers.
Locational Marginal Cost Pricing	The variation in marginal pricing that may occur within a region due to the transmission distance. Ideally, the difference is the cost of transmission over a greater distance.
Marginal Cost	The cost associated with producing one additional unit of output, also known as incremental cost.
Market Power	The ability of a generator to establish a price on its own, without needing to compete with other suppliers.
Market-Clearing Price	The price at which there are no further gains to be made from further trading.
Moral Suasion	In the absence of price signals, or enforceable rules, utilities encourage or discourage particular consumption behaviour by informing consumers of the benefits of the desired behaviour.
Natural Monopoly	An industry characterized by sufficiently large economies of scale that one firm can most efficiently produce the output to supply market demand.
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.

Rate	The price charged for a commodity or service. Rates may be subject to regulatory approval or may be set by the marketplace.
Real Time Pricing	The instantaneous pricing of electricity based on the cost of the electricity available for use at the time the electricity is demanded by the customer.
Regional Transmission Organization (RTO)	A voluntary organization of transmission owners, transmission users, and other entities approved by the U.S. Federal Energy Regulatory Commission (FERC) to efficiently coordinate transmission planning (and expansion), operation, and use on a regional (and interregional) basis.
Reserve Margin	The amount of unused available capability of an electric power system at peak load for a utility system as a percentage of total capability.
Residential Sector	Private household establishments which consume energy primarily for space heating, water heating, air conditioning, lighting, refrigeration, cooking and clothes drying.
Retail Access	A market in which electricity and other energy services are sold directly to consumers by competing suppliers. Also known as direct access.
Run-of-the-River Plant	A hydroelectric plant which depends chiefly on the flow of a river as it occurs for generation, as opposed to a storage project, which has space available to store water from one season to another. Some run-of-river projects have a limited storage capacity which permits them to regulate streamflow on a daily or weekly basis.
Simple Cycle	A combustion turbine that burns natural gas (or some other fuel) to drive a turbine, which in turn drives a generator to produce electricity.
Spot Market	Market where people buy and sell actual commodities or financial instruments for instant delivery. The spot market contrasts with the futures market, in which contracts are completed at a specified time in the future.
Stranded Benefits	Benefits that are released as a result of deregulation. For example, an increase in the price of electricity following deregulation represents an increased profit for utilities and is a stranded benefit.
Stranded Costs	Costs that cannot be recovered from market prices. With respect to electricity competition, stranded investments are those assets owned by a utility that would become uneconomic in a competitive market.

Tariff	The 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.
Time-of-Use (TOU) Rates	The prices are based on the time of day when the electricity is actually used. These rates allow consumers to pay less for the electricity they use during "off-peak," or low electrical demand periods. Electricity used during the"on-peak" hours is more costly.
Transmission	The movement or transfer of electric energy over an interconnected group of 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.
Transmission Tariff	The authorized charge levied for provision and use of transmission services.
Unbundling	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 electrical service to all end users upon their request.
Vertically-Integrated Utility	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.

Canada