ELECTRICITY IN CANADA – WHO NEEDS IT? WHO'S GOT IT?

TD Economics

Special Report

March 7, 2005

TD Bank Financial Group

ELECTRICITY IN CANADA – WHO NEEDS IT? WHO'S GOT IT?

Executive Summary

A reliable electricity system and an abundant supply of power have been important drivers of Canadians' standard of living and overall quality of life. Yet, recent highly-publicized events have cast some doubt about the ability of the country to maintain its solid track record down the road. The power blackout in Ontario and eight U.S. states in August 2003 sent shock waves from coast to coast. And, if that wasn't enough to elevate concerns, the Ontario government has issued warnings that if current trends prevail, underlying demand for electricity will outstrip supply in the province as early as 2007. These developments raise the question of whether other regions are experiencing similar challenges on the power front.

Some of the key findings in this study by TD Economics include:

- All provinces in this country – even Ontario – currently enjoy adequate supply of electricity, as evidenced by almost 100 per cent availability of distribution systems and very low rate of power interruptions.
- At the same time, however, *most* regions are already confronting – or are likely to encounter – deteriorating supply-demand positions. This fact has been reflected in a combination of declining exports, rising imports, and dropping reserve margins of electricity in recent years.
- What might surprise some is that the risk of weakening supply-demand positions appears to be the case even in provinces such as Quebec and British Columbia, which rank as leaders in the area of hydroelectricity potential.
- The challenge facing electricity sectors across the country doesn't stop at merely scouting out new sources of supply. Following a decade of under-investment, major outlays in transmission and distribution infrastructure will be required to upgrade aging fleets in most regions, while in some areas, sizeable amounts of spending will be needed just to accommodate booming growth, such as in Alberta, Newfoundland & Labrador and the NWT.

$150 billion investment needed

Addressing these hefty challenges – a shortfall in supply and inadequate transmission/distribution infrastructure – will be necessary in order to ensure that Canadians continue to enjoy a reliable electricity system down the road. And, an assurance of reliability will come with a big price tag. The Canadian Electricity Association (CEA) has estimated the combined public and private cost across Canada's regions to be $150 billion over the next two decades, or $7.5 billion per year – hardly chunk change.

Governments edging in the right direction

In recent years, there has been widespread recognition among provincial-territorial governments of the need to turn the tables around on the power front. Most jurisdictions have developed long-term strategies that aim to achieve – among other goals – new supplies of power, led by "green" sources. For example, in addition to looking at requests for proposals (RFPs) for renewable and natural gas energy projects within its own province, Ontario has been exploring the possibility of developing a large hydroelectricity project in northern Manitoba in partnership with the neighbouring provincial government and may be interested in participating in a development at Lower Churchill in Newfoundland & Labrador. Above all, there is an acknowledgement by governments – and in some cases backed up by initiatives – that a good part of the solution to eliminating emerging gaps between power supply and demand rests in demand-side management (DSM). The objective of DSM is to reduce demand for electricity and/or shift demand from peak to off-peak times.

Prices may need to rise before they fall

Still, despite the recent moves by governments, there have been only limited efforts to address one of the key barriers that remains in place – namely, the practice of pricing electricity below its cost. Historically, many governments across the land have opted to heavily subsidize the price of electricity, in part as an implicit industrial strategy. Although the gap between price and cost has narrowed in recent years – in lockstep with price increases engineered in provinces such as Quebec, Manitoba and Ontario – there is still a good argument that the size of the gap remains significant in a number of jurisdictions.

The authors acknowledge that the extent of the subsidy offered in Canada is difficult to calculate precisely. Research by Pierre Fortin at the Universite du Quebec a Montreal has shown that if Quebecers would have paid the export rate tied to the province's U.S.-bound shipments on the power they consumed at home, they would have paid roughly $8 billion more in 2003. TD Economics extended Professor Fortin's methodology to Manitoba, and found that a subsidy also exists, abeit a smaller one on a per-customer basis. And, while these were the only provinces assessed in this regard, we believe that similar results would be obtained in several other jurisdictions.

Further progress in realigning prices with cost, and in moving to more market-price systems in general, would appear to be a competitive strike against business. However, to the extent that prices increase in the short run, they would ultimately help to raise efficiency, attract investment in new generation capacity, and hence assist in averting a full-blown power crisis in the longer run. And, the emergence of a crisis would almost certainly entail a more painful adjustment and more significant economic impacts. Case in point is the experience in Alberta, where deregulation and the removal of the artificial price ceiling in the late 1990s initially drove up prices by about 60 per cent. Since that time, prices have fallen back close to their pre-deregulation levels, spurred by a surge in private-sector investment in new generation. Even if prices rise over the next few years, Canada will continue to enjoy a competitive advantage in this area on an international scale.

Include the private sector

Finally, there is a need to throw the door open more widely to private-sector involvement in the area of electricity. Already, there is significant private sector involvement across the provinces, although amounts vary widely from jurisdiction to jurisdiction. Still, with governments facing the growing tab for health care and large debt burdens, moves to take further advantage of the deep pockets and expertise of the private sector could go a long way in covering the huge investment requirements. And, here, we are not just talking about private ownership of assets, but in areas where it makes sense, government ownership augmented with private-sector partnerships to design, build and/or finance power projects.

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A reliable electricity system and an abundant supply of power have been important drivers of Canadians' standard of living and overall quality of life. Yet, recent highly-publicized events have cast some doubt about the ability of the country to maintain this solid track record down the road. The power blackout in Ontario and eight U.S. states in August 2003 – the largest in North American history – sent shock waves from coast to coast. And, if that wasn't enough to elevate concerns, the Ontario government has issued warnings that if current trends prevail, underlying demand for electricity will outstrip supply in the province as early as 2007. These recent developments in the country's largest province raise the question of whether other regions of Canada are experiencing similar challenges on the power front.

In this report – *Electricity in Canada: Who Needs It? Who's Got It*? – we provide a general assessment of the electricity situation across the country, with a particular focus on the adequacy of supply. Future studies by TD Economics will delve more fulsomely into the specific problems and opportunities presented in this all-important electricity sector – an area that will almost certainly remain front and centre on Canada's public-policy radar screen in the 21st century.

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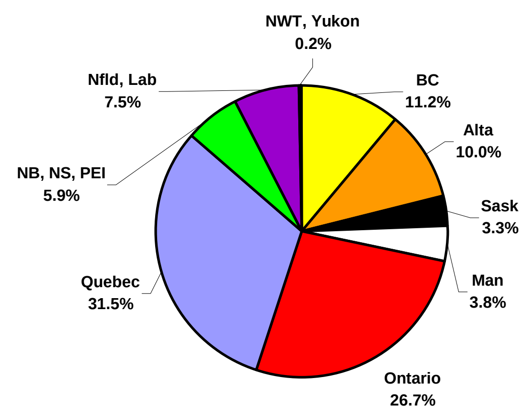


Source: Statistics Canada

Electricity – not your everyday market

Our point of departure is a quick snapshot of the structure of Canada's electricity sector. Unlike the vast majority of Canadian industries, electricity has traditionally been considered well-suited to a **monopoly** structure. Accordingly, most of the activities in power generation, transmission and distribution have been provided through vertically-integrated, provincially-owned Crown corporations. In recent years, provincial governments have been revisiting this traditional model. But, while there has been significant progress made in restructuring and, to a lesser extent, deregulating electricity markets – and, in particular, opening up access in the wholesale market to new players – both transmission and to a lesser extent, retail distribution remain largely within the purview of government monopolies.

Status of restructuring in Canada

Although the term "deregulation" is often used synonymously with restructuring, the former can be misleading because it implies the absence of regulations, which is not the case. The more appropriate term is restructuring, which essentially involves reducing the reliance on regulations so that market forces can operate.

More specifically, restructuring involves unbundling vertically-integrated electric utility monopolies into separate generation, transmission and distribution companies. The separation is designed to promote competition among generators and open the transmission and distribution systems to other suppliers and marketers of electricity.

In Canada, Alberta and Ontario are furthest along in restructuring their electricity markets. Alberta restructured its electricity market over a five-year period, culminating in the introduction of full competition of the retail market in January 2001. Ontario reorganized the former Ontario Hydro into five separate units in 1999, and the wholesale and retail markets were opened to competition at the same time in May 2002. However, due to some complications during the implementation process, the province backed off partially from the initiative in November 2002. It kept open the wholesale market but the retail market was essentially closed to competition by adopting a fixed price for the end-consumers.

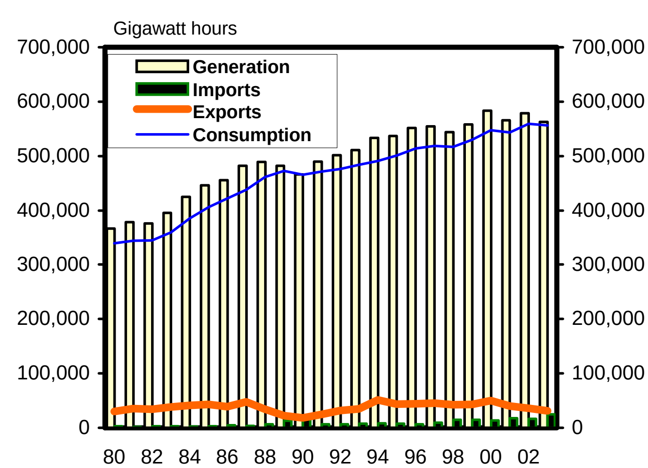
British Columbia and Quebec have also restructured their electric utilities but so far, they have no plans to establish a wholesale market. While a wholesale market can exist without an open retail market (as shown in Ontario), a competitive retail market requires an open wholesale market.

At the same time, while development of other energy sources such as crude oil and natural gas has been heavily geared towards export markets, electricity has been oriented largely towards **satisfying domestic consumption.** Combined exports and imports of electricity account for a rather small 9-10 per cent of the total volume of generation. Still, this share has been rising, albeit slowly, driven in part by changes in U.S. policy. In 1996, the U.S. Federal Energy Regulatory Commission required open access to transmission lines for interstate commerce and in 1999, it extended this requirement to international trade. For example, if Quebec wishes to export to the United States, it has to offer open non-discriminatory access on its own transmission grid. Furthermore, the increase in two-way trade of power between Canada and the U.S. has also been fuelled by a desire of utilities to improve production efficiency, optimize resources raise financial performance. Instead of making costly new investments to meet peak domestic demand, Canadian utilities, for example, often enter into exchange agreements with U.S. utilities so that electricity can be imported during the winter when consumption at home tends to peak and exported during the summer when U.S. demand shoots up.

Another interesting characteristic of the Canadian electricity sector is the extent to which it has evolved on a **regional basis,** which partly reflects the loss of power as it is transmitted over longer distances. As already mentioned, a major step forward in promoting trade and the co-ordination of electricity policies occurred when the United States introduced open access to its transmission grid, starting with interstate commerce in 1996. Since then, a number of regional transmission organizations (RTOs) have sprouted. Although Manitoba is the only province to have formally entered into an RTO – namely, the Midwest Independent Transmission System Operator – a number of other provinces have also been exploring the possibility of participating in one.

It is worth noting the wide variance in **sources of power** generation. Hydroelectricity accounts for the vast majority of the total power produced – at least nine out of every 10 terawatt hours – in Quebec, Manitoba, Newfoundland & Labrador, British Columbia and the Yukon. In contrast,

CANADA: ELECTRICITY GENERATION AND CONSUMPTION



Source: Statistics Canada

Kyoto and Canada

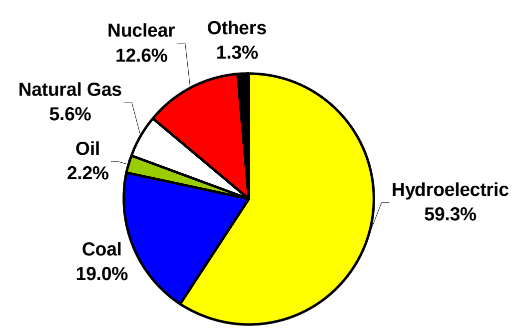
- The Kyoto Protocol entered into force on February 16, 2005, seven years after it was adopted in December 1997.
- Under the Kyoto Protocol, industrialized countries agreed collectively to reduce their emissions of greenhouse gases by at least 5 per cent below 1990 levels during the first commitment period 2008-2012. The targets vary by countries, ranging from cuts of 8 per cent to increases of 10 per cent. Canada has agreed to a reduction of 6 per cent.
- Greenhouse gases trap the earth's outgoing radiation and warms the atmosphere. Six greenhouse gases have been identified: carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons and sulphur hexafluoride. The first three gases, which can occur naturally or created by humans, account for 99 per cent of the total emissions. The latter three gases are all man-made.
- The Kyoto Protocol provides for three mechanisms by which countries can meet their reduction targets. Two are project-based. Under the Clean Development Mechanism, if an industrialized country finances emission reduction projects in developing countries, it can receive credits that can be used to meet its commitments under the Kyoto Protocol. Under Joint Implementation, industrialized countries can acquire emission credits by financially supporting projects in other industrialized countries. The third mechanism is emission trading, which allows countries that expect their emissions to be above target to buy unused quotas from others.
- Canada wanted to be given credit for its clean energy exports, i.e., natural gas and hydroelectricity, but it had not been successful so far. More than 70 per cent of Canada's electricity exports to the United States come from hydroelectricity and the country still has significant undeveloped hydro resources. Canada has continued to press for the recognition of the role of clean energy exports. It has asked the Conference of the Parties (COP), the decision-making body for the Kyoto process, to consider this matter during the negotiations for targets for the second commitment period.
- The United States, which signed the Protocol, withdrew from the Kyoto process in 2001 because it excluded the developing countries from compliance and might harm the U.S. economy. In the wake of this U.S. decision, other countries have rallied strongly around the Protocol. Nonetheless, the non-participation of the United States continues to hang over the success of the Protocol.

conventional thermal generation, which includes coal, natural gas and crude, are the dominant sources of electricity in Alberta, Saskatchewan, Nova Scotia and P.E.I. Meanwhile, in Ontario and New Brunswick, nuclear power is used in addition to hydro and conventional thermal sources, making those two provinces the most diverse in terms of electricity orientation. In all regions, non-hydro renewable sources (i.e., wind and solar power) account for a small but growing share of generation.

Undoubtedly, the composition of power sources across Canada owes largely to a region's natural endowments. For those regions that are blessed with a system of large flowing rivers, **hydroelectricity** can offer many advantages, including a relatively low operating cost and – since water levels can be adjusted to affect output flows – flexibility in matching demand with supply. Furthermore, hydroelectricity is a clean-burning fuel that could assist in meeting the nation's commitment to reduce greenhouse gas emissions (GHGs) made under the Kyoto Accord. Yet, the table on the next page shows that hydroelectricity is not free of some pitfalls. At the other end of the spectrum, **coal-fired** generation is a low-cost technology, but generates GHGs along with emissions of nitrogen oxide, sulphur dioxide and lead. On the plus side, there are efforts underway in both Canada and the United States to develop new technologies that would greatly reduce the emissions from the burning of coal. As the table shows, other power sources also offer a blend of advantages and disadvantages.

A final defining feature of electricity is the fact that

CANADA: ELECTRICITY GENERATION BY FUEL SOURCE, 2003



Source: Natural Resources Canada, Statistics Canada

ADVANTAGES AND DISADVANTAGES OF DIFFERENT FUELS FOR ELECTRICITY GENERATION

	Advantages	Disadvantages
Coal	Coal plants are very economical	Large GHG emissions
Natural gas	Less GHG emissions than coal Low capital costs More fuel- efficient than existing coal plants	A more expensive fuel than coal
Oil	Less GHG emissions than coal	A more expensive fuel than coal
Nuclear	Fuel is inexpensive Less GHG emissions than coal	High capital cost for emergency and for containing and storing radioactive waste
Hydro	No GHG emissions Low cost after dam is built Can be stored	High capital cost Dams can cause flooding, affect fish and cause environmental damage
Biomass*	Low level of GHG emissions	Inefficient if small plants are used Not cost competitive
Wind power	No energy cost Non-polluting	High upfront capital costs An intermittent unpredictable source Not cost competitive Few areas are suitable for wind generation
Solar power	No energy cost Non-polluting Sustainable	Sun's position changes continually so most solar generators have to include an expensive machinery to make them follow the sun Not cost competitive

* Organic matter such as pulp wastes that can be converted to energy

once generated, it cannot be stored. This will explain why to ensure reliability, there is need for reserve capacity, which can be called upon in case of unexpected interruptions in supply – say, due to technical problems – or a sudden surge in demand during cold winters and hot summers.

Canada's electricity system has been reliable …

Households and businesses in the world's industrialized economies share an expectation – that the electricity system in their communities will remain reliable. Reliability refers to a system that encounters few interruptions to the service and delivers acceptable power quality, free of "sags", "swells" or "surges". Happily, Canadians have been the beneficiaries of among the most reliable power systems in the world. In fact, according to the Canadian Electricity Association (CEA), over the period 1998-2002, the distribution system in Canada was available 99.95 per cent of the time, the average number of interruptions was only 2.4 times per year, and the average length of each interruption was less than two hours.

At the heart of Canada's success in developing an electricity system that can be counted on has been the ability to meet residents' electricity needs through domestic generation. In fact, since 1980, Canadian power generation has exceeded consumption in every year, with the difference, roughly 8 per cent of generation, exported to the United States. Even in 2003 – a year that was marked by the Ontario blackout – the nation managed to retain its position as a net exporter of power.

Another useful indicator of supply adequacy is the reserve margin, or the amount by which the installed capacity exceeds the demand in the system during peak times. While excessive reserve margins may signal problems of over-capacity and inefficient investment, a moderate level – between 15-25 per cent of total installed capacity – is needed in order to ensure that the system can meet unusual demand or deal with unforeseen outages and shutdowns. In 2002, the average reserve margin in Canada was 19 per cent, which suggests that the country's electricity sector, on balance, has room to maneuver.

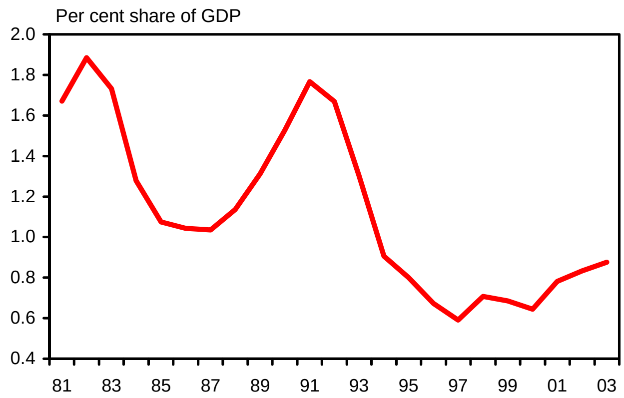
… but some red flags pop out of the data

In spite of the fact that Canada's electricity picture remains strong overall, a closer look at the data reveals some worrisome trends percolating below the surface:

- Growth in electricity consumption has been outstripping that of generation. Since the mid-1990s, demand for power has risen by about 1.5 per cent per annum, more than twice the anemic 0.6-per-cent rate of generation expansion.
- The increasing supply-demand squeeze has been reflected in a combination of declining exports (down 3.4 per cent per year) and rising imports (up 20 per cent per year). Accordingly, Canada's surplus in electricity trade in volume terms has narrowed from 7 per cent of generation in the mid-1990s to 1-3 per cent over the past few years.
- The reserve margin has fallen by 15 percentage points since its peak since the mid-1990s. While it can be argued that the levels of roughly 35 per cent recorded a decade ago were on the high side – suggesting some over-investment in capacity – the current downtrend is troubling.

The recent signs of deterioration square up with the trends in public- and private-sector investment. The CEA estimates that total capital outlays within the electricity sector have dropped since 1991, when the amount invested peaked at $11.8 billion. And, not all of the investment drop can be chalked up to cuts in funding allocated to new and existing generating plants. Notably, there have been sizeable reductions in amounts spent on the system of high-voltage wires and transformers that form the transmission highway. Meanwhile, congestion problems in many areas of Canada's transmission network have abounded.

CAPITAL INVESTMENTS IN THE ELECTRIC POWER SECTOR AS PER CENT SHARE OF CANADIAN GDP



Source: Statistics Canada

How does the supply situation in each province measure up?

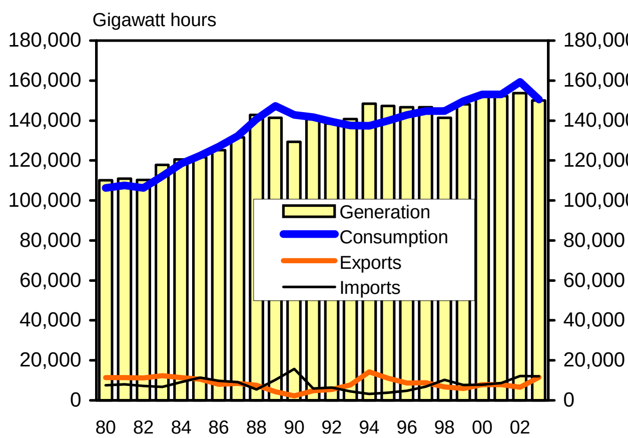
The previous section touched on some recent trends in Canada's overall electricity system. But, given the regional orientation of the sector, a more interesting question is how the tightening supply-demand balance is playing out across the various markets across the country. The two tables on pages 18 and 19 provide a regional breakdown on a number of key statistics, including generation, trade and reserve margins. At the same time, it is important to keep in mind that exports and imports have been defined to encompass both inter-provincial trade and flows between provinces and U.S. states.

Ontario squeeze poised to hit in 2007 if ...

Fears about a looming supply crunch in Ontario's electricity sector have increased over the past few years, especially after the August 2003 blackout that hit the province along with eight U.S. states. But, the truth of the matter is that Ontario's current electricity supply position remains sound. First, last year's power blackout reflected a number of problems – including failures Stateside related to transmission and adherence to industry policies – but inadequate generation capacity was not one of them. And, secondly, Ontario is largely self-sufficient in this area, with imports from the provinces and the United States accounting for a relatively small 8.0 per cent of consumption in 2003.

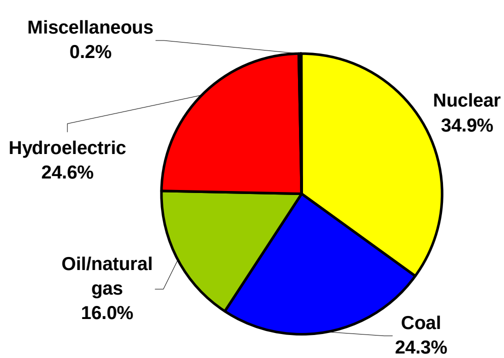
Unfortunately, the current electricity picture in Ontario is at serious risk of deteriorating. For one, trends over the past decade have not been running in the province's favour, as evidenced by a slipping trade-surplus position and a tightening reserve margin, with the latter indicator tipping the scales at a low 5 per cent in winter of 2001-02. Although there have been some new investments in generation capacity in Ontario in recent years, these outlays have not been sufficient to keep up with growth in the economy and in power demand, leading to a tightening in the supply-demand balance. The abrupt swings in provincial government policy during the shift to a more open electricity market during the early 2000s dampened the appetite for new capital outlays.

ONTARIO: ELECTRICITY GENERATION AND CONSUMPTION



Source: Statistics Canada

ONTARIO: EXISTING INSTALLED GENERATION CAPACITY, January 2005



Source: The IMO (now called IESO) 18-Month Outlook, Jan. 2005

COAL-FIRED PLANTS: ECONOMIC AND ENVIRONMENTAL IMPACTS

According to a recent study by the Canadian Energy Research Institute, coal-fired plants remain the lowest cost of technology for generating base load electricity for Ontario (base load operates on a 24-hour basis). The study, however, only compared coal with natural gas and two nuclear technologies. Hydro power, which is usually the least expensive if capital costs were excluded, was not included in the study because of the limited number of potential sites for large hydro projects in the province.

The Ontario government's pledge to phase out its coal-fired power plants stems from coal's contribution to air pollution. Industry participants have responded to this criticism. In 2001, the industry, with the support of the governments of Alberta and Saskatchewan and the federal government, formed a coalition to develop projects that will demonstrate the technology that will reduce all emissions in existing facilities or for use in new plants. Phase 1 of that project was completed in early 2004. It showed that the carbon dioxide emissions from coal-powered plants can be reduced to the equivalent of those emitted by natural gas power plants. However, the costs will be at least 50 per cent higher than the current rates. The next phase of the project will concentrate on this drawback. Phase 2 will aim to lower the costs of the technology. At the moment, the project appears to be suitable for new projects, rather than for retrofitting an existing plant.

What's more, the squeeze is poised to worsen significantly over the medium term for two main reasons: first, the government's election promise to shut down its five coal-fired plants by the end of 2007, and second, the uncertainties surrounding Ontario's nuclear units.

The sheer enormity of the task of taking coal-fired generation out of service is highlighted by the fact that this source accounts for a whopping one-quarter of total provincial generation capacity. Indeed, facing worrying prospects of a future supply crunch and heightened concerns by businesses in the province of a substantial jump in power prices down the road, the Ontario government has subsequently softened its position with respect to closing its five coal stations. While the Lakeview unit, the oldest among the existing coal plants, will close definitely in April 2005, the government is considering keeping some of the remaining coal plants in reserve. The government has reiterated that it remains committed to closing the coal plants but it has hedged its position by saying that it will not put Ontario consumers in jeopardy. This implies that unless adequate replacements are in place, the shut down of all the coal plants by the end of 2007 is not a certainty. Without the assurance of adequate supplies, the grid regulator itself (the Independent Electricity System Operator, formerly known as the Independent Electricity Market Operator) may also refuse to close the plants.

Even more daunting is the challenge posed by Ontario's nuclear units. Firstly, five of the eight reactors that were shut down in the mid-1990s due to safety concerns remain idle. Based on the experience of refurbishing unit 4 of the Pickering A station, which was brought back into service in September 2003, refurbishing the idle units could be very costly and face unexpected delays. Secondly, as the operating units age, it is estimated that up to 10,000 MW of nuclear capacity, or more than 70 per cent of the installed capacity, will need to be refurbished or replaced within the next decade. Thirdly, the province is already highly dependent on the nuclear source, with the 15 operating reactors providing 35 per cent of the current installed electricity generation capacity and half of the generation last year.

In view of the looming supply crunch, the Ontario government has decided to bite the bullet. In July 2004, it elected to proceed with a plan to restart another reactor at Pickering A, which is scheduled to start up in September 2005, and has also begun negotiations to rebuild the two laid-up units at Bruce A station (see text box for data on Ontario's nuclear stations). A related issue to refurbishing is whether the Ontario government wants to decommission some of the existing ones and build entirely new reactors. If this decision is taken, the need to act is now since building a new reactor requires a long lead time of between eight to ten years. The possibility of building a new one, however, looks remote at the moment.

Yet another challenge facing Ontario is the congestion problem in parts of the transmission grid, which ultimately limits the capability of the province to service its end users. On the bright side, the transmission facilities in the downtown Toronto area will be upgraded as will the line between Niagara Falls and Hamilton. Nonetheless, with 74 of the province's 273 transmission connection stations reaching or exceeding their capacity by 2013, further significant capital investments will be required in the coming years.

The next few years will likely prove to be a crucial period in placing the province's electricity sector on a more sustainable footing. The Ontario government has devised a multi-pronged power strategy, which includes major thrusts towards both encouraging conservation and boosting investment in renewable sources of power. Moreover, in order to secure additional sources of supply, opportunities with other regions will be explored. For example, the

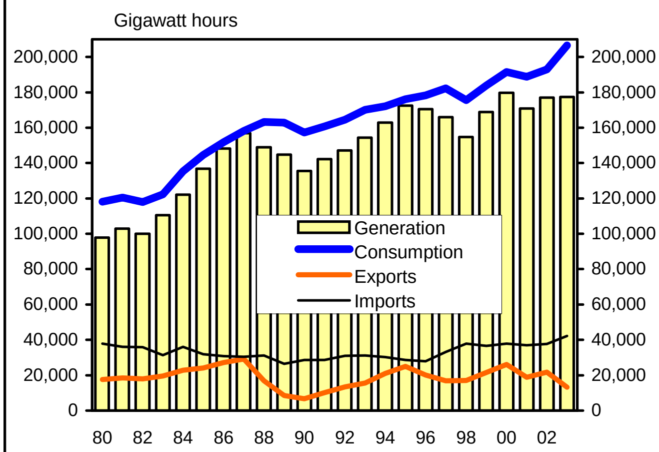
DATA ABOUT ONTARIO'S NUCLEAR REACTORS

	Year Brought Into Service	Year Taken Out of Service	Net Capacity (MW)	Current Status
Nuclear: Total (20 units)			**13,788**	
1) Pickering (8 units)			**4,124**	
Pickering A (4 units)			2,060	
Unit 1	1971	1997		Being refurbished; target completion-Sept. 2005
Units 2-3	1971-72	1997		Laid up
Unit 4	1973	1997		Returned to service in September 2003
Pickering B (4units)			2,064	
Units 1-4	1983-86	-		Operating
2) Bruce (8 units)			**6,140**	
Bruce A: total			3,000	
Units 1-2	1977	1997/1995		Laid up; feasibility study underway for potential restart
Unit 3	1978	1998		Restarted January 2004
Unit 4	1979	1998		Restarted December 2003
Bruce B: total			3,140	
Units 5-8	1984-87	-		Operating
3) Darlington (4 units)			**3,524**	
Darlington 1-4	1990-93	-		Operating

provincial governments of Ontario and Manitoba announced that a detailed technical study would be carried out on a proposed $5-billion plus Conawapa hydroelectric project in northern Manitoba and accompanying transmission infrastructure. (The two provinces struck a similar deal in the 1980s but the Ontario government later backed out due to concerns over cost.) And, speculation has mounted that the province may be interested in participating in a development of Lower Churchill Falls in Newfoundland & Labrador. Above all, the government – facing a deficit and still-high debt load – is keenly turning to the private sector for new investment in generation capacity within the province, seeking request for proposals (RFPs). Success in responding to RFPs, evaluating them, and converting these ideas into construction projects over the near term will be vital to ensuring a high level of private-sector interest going forward. So far, the government has issued two RFPs. In April 2004, it called for 300 MW of new renewable power capacity and last September, it issued a second one – this time for 2500 MW of clean energy and demand conservation measures. Those requests received a very positive response from private investors. The government has approved ten projects totaling 395 MW relating to the first RFP and some of these projects are expected to come on line over the next 18 months. The government is also expected to issue shortly its decision related to the second tranche. However, the simple arithmetic shows that these RFPs are not nearly enough to offset the 6420 MW of coal capacity that is slated to be closed. At present, renewables (excluding hydro) account for less than one per cent of the province's generation capacity, a share that the government aims to increase to 5 per cent by 2007 and 10 per cent by 2010.

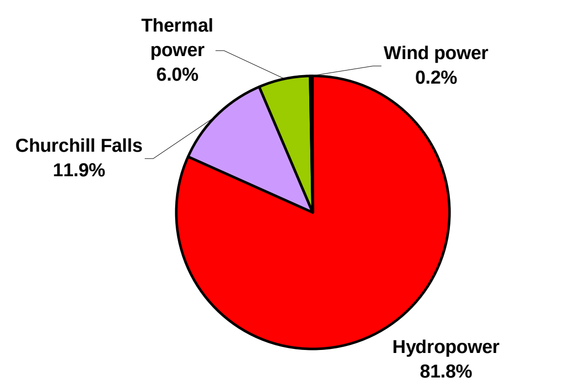
In any event, the only technology that stands a fighting chance of quickly replacing the coal units is natural-gas-fired generation. Some 600 MW of new gas-fired generation, all from private investors, came on line last year. There were several on the drawing board that had been stalled by the run-up in natural gas prices in recent years and the concern over adequate supplies of this fuel. Nonetheless, these gas-fired projects appeared to have received renewed momentum in the wake of the second RFP, which has excluded both oil and coal as fuel sources in new generating facilities and which guarantees a long-term power procurement agreement between the supplier and the Ontario Power Authority, a new non-Crown Corporation.

QUEBEC: ELECTRICITY GENERATION AND CONSUMPTION



Source: Statistics Canada

QUEBEC: TOTAL ELECTRIC POWER GENERATING CAPACITY, 2003



Source: Ministere des Ressources naturelles, de la Faune et des Parcs

Quebec experiencing supply-demand pressures

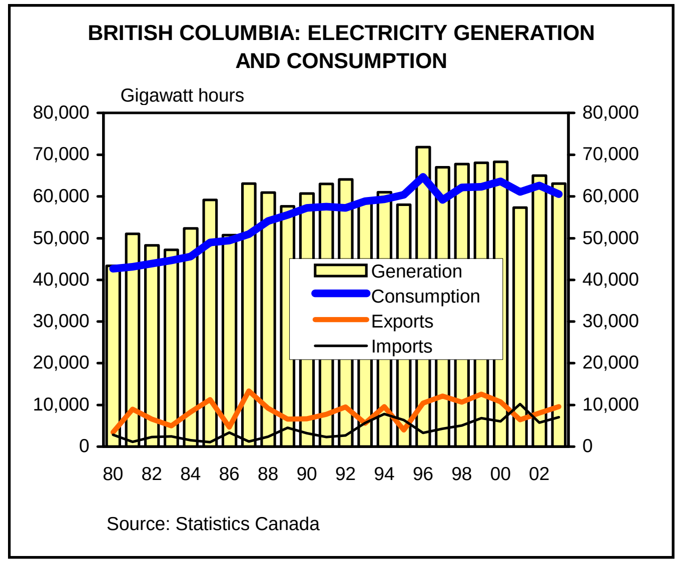
While Ontario's challenges on the electricity front have hit the front page of the newspaper, less widely recognized is the tightening supply-demand balance in the province of Quebec – the number-one producer and consumer of power in Canada. And, although Hydro-Quebec's five-year strategic plan anticipates a relatively tight supply-demand balance by 2007, this squeeze already appears to be taking place. This year, generation is likely to cover only about 82 per cent of consumption, a far cry from the levels of just below 100 per cent recorded in the mid-1990s. Furthermore, exports as a share of total generation have shrunk to about 5 per cent from 12 per cent a decade ago, while the import share – which is driven by huge inflows from Churchill Falls in Newfoundland and Labrador under a long-term fixed contract – has increased to 22 per cent of consumption from roughly 17 per cent. In contrast, the reserve margin has actually increased over the past 10 years, from 8 per cent to a more comfortable 21 per cent.

Recognizing the tightening electricity noose, the Quebec government has moved aggressively on a plan to develop new sources of supply, which are expected to gradually close the gap between domestic generation and demand over the next five years. In particular, a historic agreement in October 2001 between the northern Cree Indians and the Quebec government has opened the door to development at Eastmain in northern Quebec. Other projects in the works include a natural gas-fired co-generation plant in Becancour and 8 wind-power projects that will be built in the eastern part of the province between 2006 and 2012 at an estimated cost of $1.9 billion.

Still, the Quebec government has greater ambitions than to merely plug a hole between domestic supply and demand. Rather, in a recent speech, Quebec Premier Jean Charest championed the goal of turning Quebec into an export powerhouse in the area of hydroelectricity, which in turn is poised to benefit from the continental-wide push toward cleaner-burning energy, the Kyoto Accord and prospects for continued lofty prices of competing fossil-fuel sources. Although the Premier stopped short of explaining how the province would ramp up its electricity capacity, the spotlight has been turned back on reaping the potential opportunities for large-scale hydroelectric development at Great Whale in Quebec and Lower Churchill Falls in Labrador. Nonetheless, these projects are not free of significant obstacles. For example, any plans to develop Great Whale in northern Quebec would require co-operation with aboriginal communities in the area, while development at Lower Churchill would require kick-starting previously failed talks with the government of Newfoundland & Labrador.

British Columbia in good shape … for now

Although British Columbia experiences annual gyrations in domestic power generation – given the fact that output from its hydro-based system is highly dependent on water levels – the province currently enjoys ample supplies of electricity. In fact, with the exception of only one year over the past ten (i.e., 2001), the province has consistently recorded generation-to-consumption ratios of more than 100 per cent, a sizeable surplus in trade with the United States, and reserve margin of between 20-30 per cent.



Despite the fact that British Columbia can more than satisfy its own needs through domestic generation, the province tends to make more use of imported power than all other provinces and territories with the exception of P.E.I. and Quebec. Last year, for example, 12 per cent of consumption was imported from other provinces and the United States. The strong reliance on imports is due to the fact that B.C. Hydro makes use of inter-connections with Alberta and neighbouring U.S. states as part of its overall planning strategy. In some instances, it is more economic to use imports rather than to draw down the reservoir levels or increase thermal generation. Since the mid-1990s, B.C.'s power exports to the U.S. have been buoyed by the opening of access to the grid south of the border and by the Californian electricity crisis in 2000.

Still, there are some potential impediments along the medium-term path. In particular, BC Hydro's 2004 integrated electricity plan anticipates that "status-quo" demand in the province will exceed supply by 2007. In order to fill the gap, the government has set a goal to raise generation capacity. Particular focus on new supply will be in the area of clean energy, where the government has proposed that 50 per cent of new power over the next 10 years be derived from wind, solar, co-generation, hydro-electricity, fuel cells among other sources. Moreover, the government plans to implement the Power Smart Program, which is a conservation program aimed at encouraging both residential and business customers to reduce their energy consumption by replacing existing inefficient technologies with energy-efficient ones.

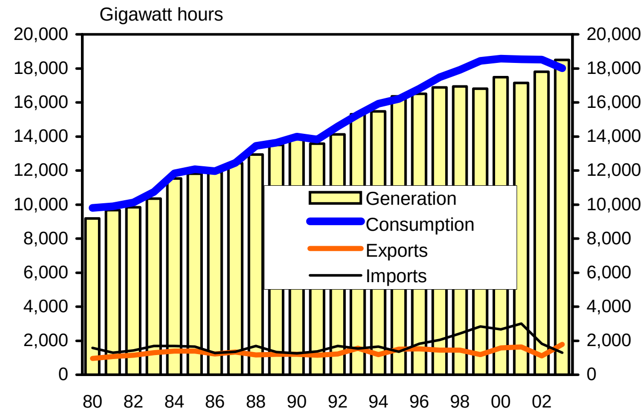
With much of B.C.'s transmission system put in place in the 1940s-1970s, and with the province recording significant growth over the past few decades, there will be a need for substantial investment in the province's grid down the road. Some projects that are currently being discussed are a transmission line from the interior to the Lower Mainland, a cable project within metro Vancouver, a supply line to Vancouver Island, and a new Langley area substation. Moreover, in order to ensure reliability, the B.C. Tranmission Corporation is looking into participating into the regional transmission organization, referred to as Grid West.

Red-hot growth creating challenges in Alberta

Rapid growth in the Alberta economy over the past decade has placed significant upward pressure on electricity demand. And, with growth in demand outstripping that of domestic supply, the province has shifted from being a net exporter of power (in volume terms) to net importer – in stark contrast to its massive trade surpluses recorded in crude oil, natural gas and coal. It is important to keep in mind that imports still only constitute a small 2-4 per cent share of Alberta's consumption, indicating that the province remains relatively electricity self-sufficient. Furthermore, Alberta records a hefty reserve margin of about 29 per cent.

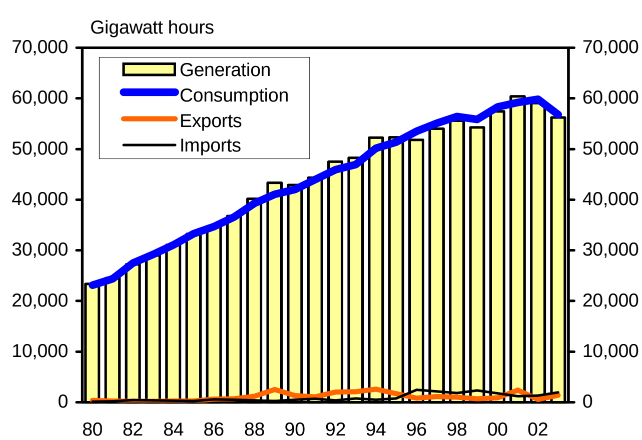
Looking ahead, the pressures from continued rapid expansion in the Alberta economy are unlikely to let up. Congestion is expected to get only worse in certain areas of the transmission grid such as out of Fort McMurray – the center of oil sands development – and along the Calgary-Edmonton Corridor, which is the most rapidly-expanding urban region in Canada. As a result, the province will require significant new investment in its electricity sector over the next few decades. On a bright note, the Alberta government's move to deregulate its electricity market starting in the 1990s, combined with the province's large endowments of natural gas and coal and bright growth potential, should lay the groundwork for substantial private-sector participation in new electricity projects over the long run. In the meantime, however, the path is likely to contain some bumps in view of uncertainty related to how the federal government will proceed with plans to implement the Kyoto Accord. Moreover, the volatility and relatively high level of gas prices and shortages of supplies could deter the development of new gas-fired facilities. Nevertheless, the Alberta government is mindful of these challenges, and is focused on developing a means to enhance the longer-term predictability of the province's power industry.

SASKATCHEWAN: ELECTRICITY GENERATION AND CONSUMPTION



Source: Statistics Canada

ALBERTA: ELECTRICITY GENERATION AND CONSUMPTION



Source: Statistics Canada

Saskatchewan has abundant power

Saskatchewan is bucking the national trend on the supply front. While most provinces experience weak growth in generation and a tightening supply-demand balance, Saskatchewan is enjoying solid growth in generation, and a rising surplus in electricity trade. In 2003, the generation-to-consumption ratio reached 103 per cent – about 10 percentage points above where it stood in the late 1990s and a record high. Meanwhile, the import-to-consumption ratio dropped to a low of 7 per cent last year, about one half its recent peak of 15 per cent recorded in 1999.

Saskatchewan's abundance of available power has been partly attributable to additional generation capacity, all publicly funded, being put in place in recent years. Moreover, the province has built up its transmission networks to accommodate increasing trade. Not only has it complied with FERC requirements for open access, which allows trade within the United States, but it plans to join the regional Midwest Reliability Organization down the road. And, while about one-third of its transmission grid is more than 30 years old, regular maintenance has extended the useful life of the assets. As a result, the Saskatchewan government foresees only limited need for the construction of new lines to replace age-related deterioration.

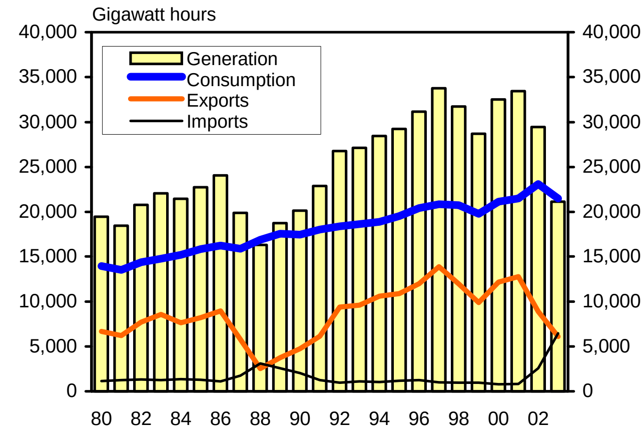
Electricity a competitive advantage in Manitoba

This year, Manitoba's power sector has started to recover from drought conditions that sent water levels tumbling and hydroelectric generation down sharply in 2002 and 2003. When water levels are normal, however, the province boasts among the strongest supply positions among Canada's regions. Over the past decade, generation-to-consumption ratios have averaged about 150 per cent – ranking only second to Newfoundland & Labrador. Typically, the province exports about one quarter to one third of its generation, while imports are limited to about 4-6 per cent.

Rather than concerns about persistent supply shortfalls, challenges in the province's electricity sector revolve more around the overall reliability of the system. More specifically, the bulk of the province's generation is sent across two transmission lines from the north part of the province, where it is produced, to southern markets. Hence, any damage to these lines resulting from, say, extreme weather, could cause significant disruptions in service, highlighting the need for an alternative transmission route. On the plus side, the province joined the Midwest Independent Transmission System (MISO) – the first Canadian province to enter in a U.S.-initiated regional transmission organization.

Recently, as we noted on page 8, there has been interest shown by both the Ontario and Manitoba governments in resuscitating plans for a large hydroelectric project at Conawapa river, which is located 800 km north of Winnipeg. The momentum to develop a dam and transmission line has been fuelled by Ontario's desire to secure additional supplies of electricity. And, with a project capacity of 1250 MW, the project would cover about one-fifth of the forecast supply-demand gap in Ontario resulting from its plan to close coal-fired plants by 2007. Since the existing grid between the two provinces is limited to a maximum of about 200 MW – much less than Manitoba's 1850 MW transfer capacity to the United States – new transmission facilities will be needed to ship the new power from Manitoba to Ontario.

MANITOBA: ELECTRICITY GENERATION AND CONSUMPTION

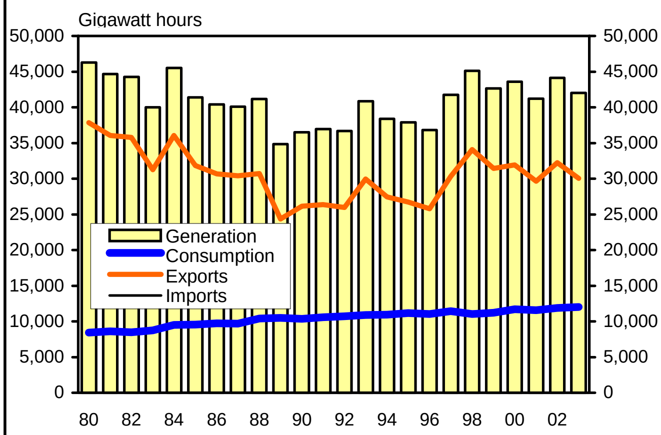


Source: Statistics

Newfoundland and Labrador looking at Lower Churchill

On the surface, it seems that Newfoundland and Labrador has more than enough generation to cover its domestic requirements. The province generates more than three times its consumption (the highest ratio among the regions), exports more than 70 per cent of its generation, and has low reliance on imports. However, most of the output from the province is committed to Quebec through a long-term contract that will last up to 2041 and is not available to the province. What's more, about 75 per cent of the province's generation capacity is located on the mainland – at Upper Churchill Falls in Labrador. Hence, while Labrador is interconnected to the North American grid through Quebec, the island of Newfoundland remains isolated. Among the solutions that have been bandied about to relieve demand pressures stemming from a strongly-growing Newfoundland economy is the development of a multi-use fixed-link between Labrador and the island, which would not only carry transport vehicles but also

NEWFOUNDLAND AND LABRADOR: ELECTRICITY GENERATION AND CONSUMPTION



Note: Negligible imports
Source: Statistics Canada

high voltage electricity. Regardless, Newfoundland & Labrador will almost certainly require new generation facilities to meet its future domestic needs.

One potential hydroelectric project that could accomplish the two-headed aim of addressing Newfoundland's own power challenges as well as strengthening the province's position as a net exporter is Lower Churchill Falls at the Gull Island site and Muskrat Falls. Not that this opportunity is new – negotiations with Quebec to develop the resource have been on again off again. However, the provincial government is showing a renewed appetite in powering ahead with the project, and in January 2005, issued a Call for Expressions of Interest in partnering with interested parties. And, it appears that the timing could not be any better, in view of the tightening supply-demand power balance in North America and the need by large jurisdictions such as Ontario and Quebec to secure additional electric power supplies.

New Brunswick faces some supply obstacles

New Brunswick has ample generation resources, at least for now. This is evident from the generation-to-consumption ratio which is currently about 130 per cent, imports which constitute a mere 1 per cent of consumption, and exports which exceed more than 20 per cent of generation. The reserve margin – at close to 30 per cent – suggests that capacity is not stretched during peak periods. Through an extensive transmission network, significant exports move to New England (notably Maine), P.E.I. and Nova Scotia. Meanwhile, imports to New Brunswick are minimal.

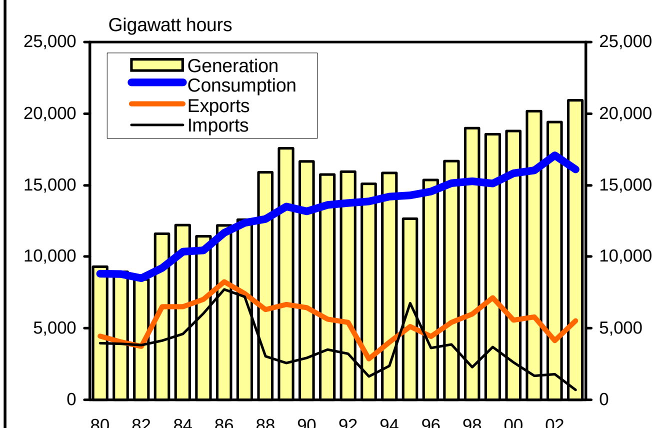
There are some question marks, however, about supply adequacy in the future. The province has yet to decide whether it will refurbish its lone nuclear facility at Point Lepreau, which alone is responsible for about a quarter of the province's electricity generation. If the facility is not refurbished, it will likely be shut down in 2010. Alternatively, the plant could be refurbished at a hefty cost of $1.4 billion in public funds, although even under that scenario, alternate supplies would be required while the plant is temporarily under renovation between 2008 and 2010. The big question facing the government in making a decision about Point Lepreau's fate is whether there are less costly ways of generating supply.

At the same time, another potential source of supply in New Brunswick is in jeopardy. The Coleson Cove generating station – the province's largest power plant – has been converted to use a fuel called Orimulsion, which is a mixture of bitumen (a tar-like substance) and water. This fuel can only be purchased from Venezuela. But, not only does New Brunswick have no formal fuel supply contract with Venezuela, but that country's state-run oil company plans to get out of the money-losing Orimulsion business.

Nova Scotia's power market poised to change

While other electricity markets have looked at export opportunities to varying degrees, Nova Scotia has continued to concentrate the bulk of its efforts on its domestic market. The ability to meet rising domestic needs has been supported by its abundant coal and natural gas resources. The inward focus is partly due to its geographic location,

NEW BRUNSWICK: ELECTRICITY GENERATION AND CONSUMPTION



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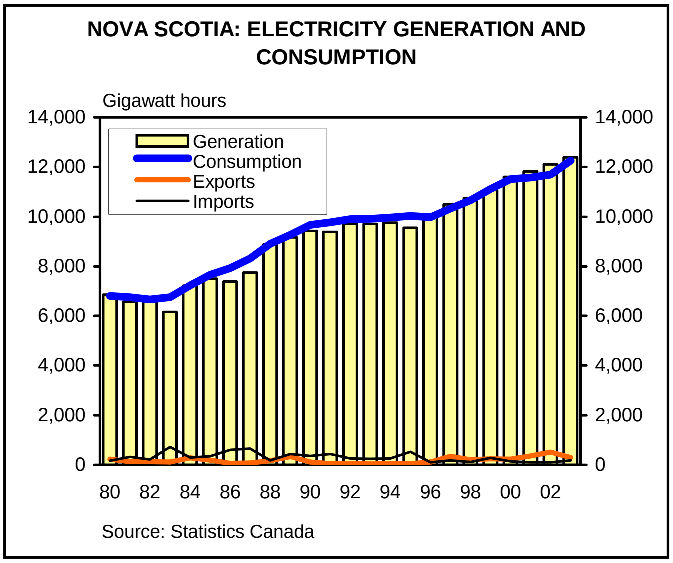


as the province has no direct transmission access to the United States and, therefore, it generally does not trade electricity with U.S. states. It does rely on a modest amount of power from New Brunswick during peak periods, and sends limited exports to Maine through New Brunswick.

Given that coal-fired generation is a major source of greenhouse gas emissions, the possibility of early retirement of coal-fired power plants has raised some concerns related to supply adequacy going forward. An accelerated coal phase-out could imply significant investments in new generation capacity and/or more reliance on imports. The government has already indicated a shift away from fossil fuels to renewable sources, which will play an increasingly important role in meeting the province's long-term energy objectives. Moreover, further uncertainty relates to the imminent restructuring of the province's power sector. The province, which has been among the holdouts in restructuring its electricity market, plans a "staged" approach to market re-design, which would include opening up wholesale access.

PEI to raise domestic supply capacity

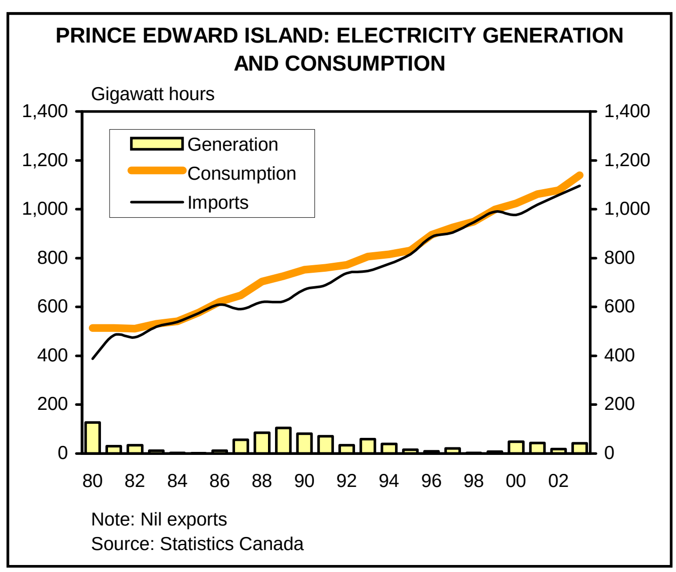
At 4 per cent of consumption, PEI generates the smallest amount of its own needs among Canada's regions. Instead, the province relies on its imports from New Brunswick, via submarine cables, to satisfy its rapidly-growing electricity requirements. This adds an element of risk to reliability. Case in point is the fact that PEI's supply contract with New Brunswick is due to end in the fall of 2005, and NB Power has yet to commit to an extension. In response, PEI plans to install a new 50 MW light oil-fired generator to prepare for that contingency. The unit is capable of being converted to natural gas if this fuel becomes available on the island.

Meanwhile, the government is looking at increasing domestic generation through an ambitious plan to expand wind energy production, with an objective of providing 200 MW from this source over ten years. A wind farm on the northern tip of the island already produces about 5 per cent of the power used on the island. A report done for the provincial government estimated a $300 million investment would be needed to reach the wind power goal.

NWT sitting on enormous hydro potential

In the north, electricity is generated by way of a mixture of small hydro plants, oil-fired turbines and internal combustion plants, often located in isolated communities and industrial developments. Unlike its neighbours to the south, the large land area and small population base of the territories have impeded the development of an integrated electrical system within the region and with the provinces.

The north's relatively primitive electricity system conceals the fact that the largest of the territories – the Northwest Territories (NWT) – is home to an enormous hydroelectricity potential. In fact, it has been estimated that the territory could generate more electricity than James Bay in Quebec or the Churchill Falls in Labrador. Unfortunately, the NWT's geographical remoteness and the problems in transmitting power over long distances have been major barriers to realizing the industry's true potential. But, the NWT is making progress in leveraging its strength in available supplies of power, spurred in part by rapid



growth underway in the territory's diamond industry and prospects for the development of the Mackenzie Valley Natural-Gas Pipeline. For instance, a project at Talston River is currently in the engineering feasibility stage, with construction work targeted for completion by 2008. And, NWT Energy Corporation is exploring further hydroelectric projects on the Great Bear River together with the possibility of exporting some of the power south to Alberta.

Major development projects in the north have come under particular scrutiny in view of environmental concerns. Consistent with the goal of minimizing environmental disruptions, these projects on the table would use modern run-of-the-river technology that will eliminate the need for colossal dams and avoid massive flooding. A run-of-the-river project is defined as a development where no or little impoundment of water takes place and the natural river flow is used with no seasonal regulation.

Putting it all together

Ontario's challenges on the power front have captured the most attention, but the province is far from alone in facing electricity supply constraints over the next several years. In fact, *most* regions of the country are either already confronting – or could be looking at – deteriorating supply-demand positions. This appears to be the case even in provinces such as Quebec and British Columbia, which rank as leaders in the area of hydroelectricity potential. And, the challenges don't stop at merely scouting out new sources of supply. Following a decade of under-investment, major outlays in transmission and distribution infrastructure will be required to upgrade aging fleets in most regions, while in some areas, sizeable amounts of spending will be needed just to accommodate booming demand growth, such as in Alberta, the NWT and Newfoundland & Labrador.

Addressing these hefty challenges – a shortfall in supply and inadequate transmission/distribution infrastructure – will be necessary in order to ensure that Canadians continue to enjoy a reliable electricity system in the future. But, do we have a sense as to what kind of price tag will be associated with an assurance of reliability? While making such projections is never an easy game, the CEA has estimated the combined cost across Canada's regions to be $150 billion over the next two decades, or $7.5 billion per year – hardly chunk change. The CEA did not specify where that capital requirement will come from but it is

A word on demand side management

While there is need to add generation and transmission resources, much can also be done to make demand more efficient. Demand Side Management (DSM) refers to a wide range of actions to reduce demand for electricity and/or to shift demand from peak to off-peak times. It is an important tool not only to help balance supply and demand in electricity markets but also to reduce price volatility, increase system reliability and security, and to rationalize investment in electricity supply infrastructure. DSM was used traditionally in electricity businesses as a load and investment management tool. While this aspect continues in some countries, DSM is increasingly finding new applications as a market offering in restructured energy markets.

Ontario will actively use demand side management as part of its strategy to address its looming tight supply/demand balance. The province plans to install "smart meters" in 800,000 homes over the next three years and in 4 million homes and small businesses by 2010. The smart meters will record the amount of power consumed and the hours at which it is drawn from the system. The pricing of electricity will be modified to reflect differing demand at different times of day. Consumers who elect to use major appliances at off-peak hours, usually between 8 p.m. and 6 a.m., would benefit from lower prices. Such a change in consumption habits would reduce the need for new power plants, which are intended to meet demands at peak periods.

Other provinces also have some DSM initiatives. BC Hydro operated a Power Smart incentive program about 15 years ago and revived that program recently. Manitoba launched a Power Smart program in 1991, which encouraged consumers to use less power. This program has been subsequently incorporated into a larger Provincial Government energy development initiative. Newfoundland Hydro has developed an energy conservation initiative called "Hydrowise". In partnership with the Conservation Corps of Newfoundland and Labrador, it provides specialized energy advice and energy audit services to customers. The Newfoundland Power, the main distributor in the province, provides energy use advice to its customers under its Bright Ideas initiatives, which include financing and rebates to customers for insulation upgrades and promotion of R2000 construction.

logical to assume that it will be a joint effort between the private and public sectors. The CEA's projection builds in the assumption that 40,000 MW in additional new generation will be required by 2020. These estimates could be on the conservative side, given the fact that Ontario alone, which is home to 40 per cent of the population, has estimated its needs at 25,000 MW.

The good news is that there is already a broad recognition among provincial-territorial governments that, first, the supply-demand picture for electricity is eroding and second, that without a reliable power system, regional economies would grind to a halt. As such, most jurisdictions have developed long-term strategies that aim to address the rising risk. While the plans for action released across the country highlight the fact that each region faces its own unique challenges, there are a number of common threads between them:

- A need to secure new supplies of power, and in particular, "green" sources such as hydroelectricity, cogeneration, wind power and other renewables.
- A push towards increasing trade links in order to take advantage of lower transmission costs, export opportunities and to boost reliability. With more provinces likely to participate in U.S.-initiated regional transmission operators, the recent trend towards regionalization of the electricity market will continue, and north-south trade will contribute an ever-growing share of overall provincial electricity generation. Nevertheless, there is also widespread acceptance across Canadian provinces of the need to strengthen east-west connections in order to mitigate the risk arising from possible supply disruptions from the United States.
- An acknowledgement that a good part of the solution to eliminating emerging gaps between electricity supply and demand rests in demand-side management (see text box on the previous page).

Hence, provincial governments in Canada appear to be moving largely in the right direction. At the same time, however, the progress is being made more in terms of baby steps than a quantum leap forward. In TD Economics' May 2004 report *Mind the Gap: Finding the Money to Upgrade Canada's Aging Infrastructure,* we identify a bold strategy to address the country's deteriorating infrastructure, of which electricity forms a key plank. And, topping the list of the recommendations in that report is the need to better align the price charged for infrastructure provision with the marginal cost of delivery.

Prices need to rise before they fall

Notwithstanding the wide range of electricity prices charged across Canada (see text box on page 16), OECD research has shown that prices in Canada rank among the lowest, on average, in the developed world. But, while the low level of prices has been supported to some extent by an abundance of cheap power sources in this country, public policy has also played a role. Notably, as discussed in a text box on page 17, governments have tended to heavily subsidize the price of electricity, in part as an implicit industrial strategy. This subsidization has helped the competitive position of businesses, but it has encouraged wasteful consumption of power and placed added strain on electricity systems.

At the same time, however, there have been some efforts to raise prices more in line with the cost of production and distribution in recent years. In Manitoba, which has the lowest power prices in the country and where rates had remained unchanged for several years, rates were raised by an average of 5 per cent in August 2004. Upward rate adjustments had also been seen in Quebec and in Ontario. Despite these moves, there is a good case to be made that a wedge remains between the cost of electricity and the price levied.

The ongoing resistance to full-cost pricing is reflected in recent DSM initiatives that have been laid out by a number of jurisdictions in Canada. These initiatives have primarily focused on the need to tinker with the pricing structure in an attempt to encourage a shift in daily power use from peak to non-peak periods. This is certainly a laudable goal, as it would help to ease pressure on electricity systems and boost reserve margins, but does little to tackle the over-riding issue – notably, reining in significant wasteful demand on a daily basis.

Further progress in realigning prices with cost, and in moving to more market-based pricing systems in general, would appear to be a competitive strike against business. However, to the extent that prices increase in the short run, they would ultimately help to raise efficiency, attract investment in new generation capacity, and hence assist in averting a full-blown power crisis in the longer run. And, the emergence of a crisis would almost certainly en-

ELECTRICITY PRICING VARIES ACROSS MARKETS

Based on data collected by Hydro-Quebec, there is a wide variation in electricity prices paid within the country. The lowest residential and industrial prices are charged in Winnipeg, Montreal and Vancouver. On the other hand, the highest residential and industrial rates are paid in Charlottetown, Toronto, Halifax and Ottawa.

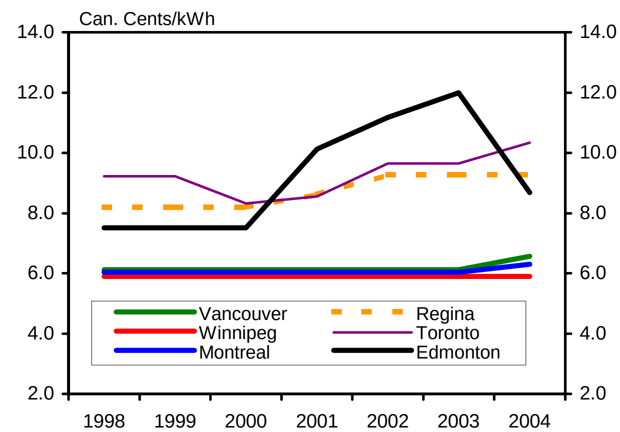
The lowest-cost cities – Winnipeg, Montreal and Vancouver – are notably where hydroelectricity accounts for a great proportion in power generation source. Those cities can offer those low rates because, after the capital costs of constructing the dam have been covered, hydroelectricity is the cheapest generation source since there is no fuel involved.

In all Canadian jurisdictions, industries pay less than residential users – by as much as 50 per cent in some cases. The lower prices to industries reflect in part the economies of scale of serving consumers who use relatively large amounts of electricity and in part because electricity pricing is being used implicitly as an industrial strategy. A good example of the latter would be Quebec, which in the past used its low-cost pricing of electricity to attract aluminum smelters. Quebec's recent reluctance to guarantee the same favourable terms, probably because of its own emerging supply constraints, led Alcoa to cancel its smelter expansion plans in the province.

There has also been a great variation in price trends over the years. Residential rates were remarkably stable in Winnipeg, Montreal and Vancouver except for modest increases of 4 and 7 per cent, respectively, last year in the latter two cities. The most significant hikes were experienced in Charlottetown and Ottawa, where prices jumped by more than 25 per cent over the period 1998-2004. The most dramatic change, however, took place in Edmonton, where deregulation initially lifted prices by almost 60 per cent between 1998 and 2003, and then suddenly dropping by 28 per cent in 2004 in response to an increase in new generation. Over that period, Toronto, Regina and Moncton experienced moderate increases of between 12-13 per cent while Halifax and St. John's recorded more modest hikes of just 3-4 per cent.

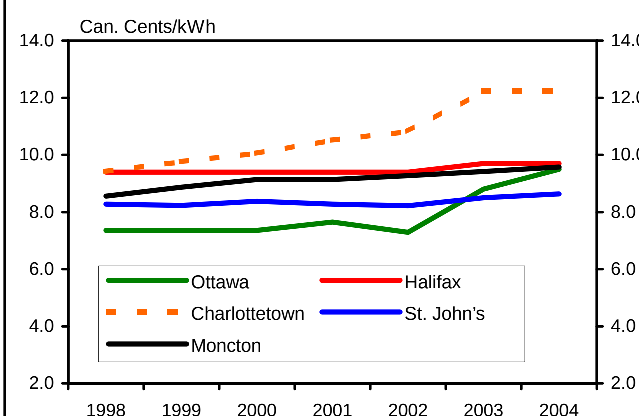
More or less the same trends prevailed in the prices paid by commercial consumers.

ELECTRICITY PRICES TO RESIDENTIAL CUSTOMERS ON MAY 1ST



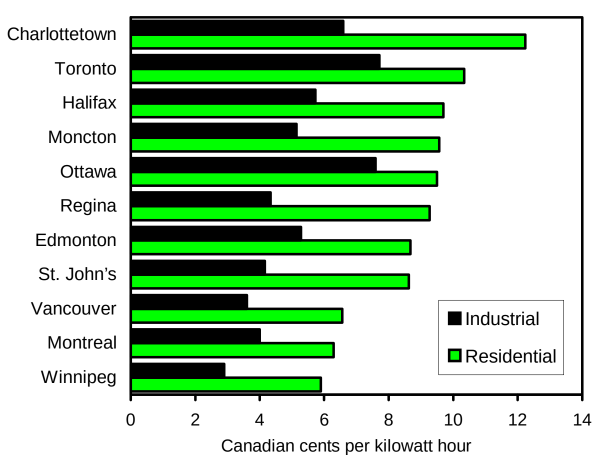
Source: Hydro-Quebec

ELECTRICITY PRICES TO RESIDENTIAL CUSTOMERS ON MAY 1ST



Source: Hydro-Quebec

ELECTRICITY PRICES IN MAJOR CANADIAN CITIES: RESIDENTIAL VERSUS INDUSTRIAL, 2004



Source: Hydro-Quebec

ELECTRICITY SUBSIDIES STILL APPLIED IN CANADA

To what extent do the rates charged to residential and industrial customers cover the cost of production? Provincial governments regulate retail prices in Canada. Pricing is based on the cost of service, which includes generation, transmission and distribution. However, the huge debt accumulated by some utilities (for instance, the defunct Ontario Hydro) suggests that among other reasons, prices charged to consumers probably do not fully cover the costs of providing the service. That would imply government subsidies in the provision of electricity.

The size of the subsidy is difficult to calculate precisely. One difficulty stems from the fact that in the days of vertically-integrated utilities, the costs of producing, transmitting and distributing electricity were all bundled up into one price.

According to Professor Pierre Fortin of the Universite du Quebec a Montreal, one way of estimating the subsidy is to compare the average rate billed to domestic consumers and the average price for the exports of electricity outside the province. For example, in 2003, Quebec billed its domestic customers an average rate of 5.1 cents per kilowatt hour (c/kWh) while it obtained an average price of 8.8 c/kWh for its sales outside the province. If Quebecers had paid the export rate on the total amount consumed, they would have paid roughly $6.2 billion more. According to Professor Fortin, the implicit subsidy was even more, as much as $8 billion, since the domestic rate of 5.1 c/kWh rate included a distribution cost that was absorbed by Hydro Quebec, whereas the export rate did not. The same methodology can be used for the other provinces. For example, Manitoba could have gotten $159 million more in revenues from its domestic sales if the amount sold within the province in 2002-03 had been priced at the export rate.

It is important to note however, that this method of calculating the subsidy is just a rough approximation. Firstly, while the domestic rate tends to be stable, export prices vary widely from year to year, and therefore the subsidy will fluctuate with the level of export prices. In the example quoted above, the subsidy appeared to be inordinately high because export prices were much higher in 2003 compared to previous years. Secondly, there is a built-in upward bias to this method of calculation because exports are usually done at peak periods when prices are high.

Ontario moves to bring prices in line with costs

There is a subsidy of a different kind in Ontario in recent years. When the province backed off from “deregulation” in November 2002, six months after its introduction, the wholesale price of electricity continued to be determined by supply and demand but the retail price was fixed at 4.3 c/kWh. This fixed rate applied only to certain groups such as residences, small businesses, and some designated consumers (e.g., hospitals and charities). Large businesses were charged the wholesale price but they were entitled to a rebate under the province’s business protection plan. The weighted-average wholesale price of electricity, or that paid to suppliers, amounted to 5.76 c/kWh in 2003. Assuming that the fixed retail rate of 4.3 c/kWh applied to all consumers, and applying the amount consumed in 2003, the difference between the wholesale cost and the retail revenues amounted to as much as $2.2 billion (i.e., the gross subsidy).

However, the cost to the government of this subsidy has been reduced by the contribution coming from the Ontario Power Generation (OPG). Under an agreement reached prior to deregulation, the OPG could charge only 3.8 c/kWh for its power sales within the province and any extra revenue had to be refunded. About 70 per cent of OPG’s output was subject to that cap and only the remainder got the market rate. The OPG refund amounted to $1.5 billion in 2003. Thus, the net subsidy, or the cost of providing a fixed retail price of 4.3 c/kWh in Ontario, amounted to about $0.7 billion in 2003.

To reduce that financing burden, the Ontario government initiated a two-tiered retail pricing scheme effective April 1, 2004: 4.7 c/kWh for the first 750 kWh of electricity consumed each month and 5.5 c/kWh for any amount beyond that level. Those levels appeared to be well-chosen as the weighted wholesale price in 2004 came to 5.22 c/kWh, which was within the range of the new retail pricing structure. Since less than half of Ontario’s residential households consume below 750 kWh/month. the majority of residents were subject to the higher rate. Indeed, if we consider the fact that the OPG rebate to the government amounted to about $1 billion in 2004, it was likely that there was no net subsidy last year.

The two-tiered pricing structure, however, is only an interim arrangement until the government formulates a new plan, which should be available no later than May 1, 2005. As a prelude to that new plan, the government announced in February 2005 that the 3.8 cents/kWh cap on OPG’s revenues is being raised temporarily to 4.7cents/kWh until April 30, 2006. It was also announced that the OPG’s revenues from its nuclear and large hydroelectric generation, which account for roughly 40 per cent of the total generation in the province, will be set at 4.5 cents/kWh while its revenues from its other generation assets will be capped at 4.7 cents/kWh. The new prices will be in effect until the Ontario Energy Board develops mechanisms for setting prices no later than March 31, 2008.

tail a much more painful price adjustment and more significant adverse economic impacts. Case in point is the experience in Alberta in the late 1990s, where deregulation and the removal of former artificial price ceiling initially drove up prices by some 60 per cent. Since that time, prices have fallen back close to their pre-deregulation levels, spurred by a surge in private-sector investment in new generation. In any event, even if governments realign power prices more in line with cost, Canadian prices would still compare favourably on an international scale in light of the nation's abundance of cheap power.

Bring the private sector on board

The May 2004 TD infrastructure report also drew attention to the need to throw the door open more widely to private-sector involvement. Notably, with governments in Canada facing a growing tab for health care and already large debt-loads, leveraging the deep pockets and expertise of the private sector could go a long way in covering the huge investment requirements. And, in the case of electricity, where needed investments for generation and transmission are larger than in many other types of infrastructure, the case for private participation, in providing the commodity as well as financing the project, could not be any clearer.

There is already quite significant private involvement across the provinces and there is a wide range in the mode of participation. In British Columbia, the provincially-owned BC Hydro provides about 80 per cent of generation, with the remainder being provided by industries and independent power producers. In Alberta, about 68 per cent of generation is accounted for by three privately-run vertically-integrated utilities and the rest is supplied by the industrial sector and independent power producers. In Nova Scotia, the Nova Scotia Power Inc. is a virtual monopoly accounting for 95 per cent of generation, transmission and distribution but it is owned by Emera, a private company. In Newfoundland, the crown-owned Newfoundland Labrador Hydro exists side-by-side with Newfoundland Power, a subsidiary of Fortis, an investor-owned company. While the former is the principal generator and transmitter, the latter is the principal distributor. Fortis also operates utilities in PEI, Ontario, Alberta and British Columbia. In Ontario, new gas plants are entirely privately-owned and the government's only involvement is a supply contract from the Ontario Power Authority.

Given the scale of investment needs, it appears that more private participation will be needed, either in the form of private ownership of electricity assets or government ownership along with the use of the private sector in designing, building, operating and/or financing initiatives. Regardless of the path taken, given that the inherent risk of investing in large-scale power projects can be formidable, private sector investors will require the opportunity to earn commercial rates of return. As such, a shift towards market-based pricing of electricity would be consistent with a goal of increasing private-sector investment in the longer run. Furthermore, governments need to be mindful of the fact that unanticipated and sweeping changes in government policy can go a long way in stunting private-sector involvement, and hence limiting the long-term benefits to society that could otherwise have been enjoyed.

The fact remains, however, that electricity is an essential good, that the consuming public and businesses have little tolerance for significant price volatility that goes hand-in-hand with competitive markets, and that there is environmental impact in electricity generation and transmission. In this regard, government regulation of this market is unlikely to go by the wayside. Admittedly, the jury is still out on the most appropriate structure for the electricity sector. Economic theory suggests that competition leads to efficiency gains and thus lower prices. However, given some well-publicized failures with deregulation such as those of California and Ontario, there are those who argue that either we embrace competition fully in all three segments of electricity, or return to the old vertically-integrated model.

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Table 1

ELECTRICITY RATIOS

	Generation as % of Cons.			Exports as % of Generation			Imports as % of Consumption			Imports fr. US as % of Cons.		
	1990	2003	2004 YTD	1990	2003	2004 YTD	1990	2003	2004 YTD	1990	2003	2004 YTD
Ontario	90.6	99.7	107.1	1.7	7.7	12.8	11.0	8.0	6.6	9.3	5.1	2.6
Quebec	86.1	85.9	81.8	5.0	7.4	5.2	18.2	20.4	22.4	0.8	1.9	2.5
Newfoundland & Lab.	353.0	349.9	337.8	71.7	71.5	70.4	0.0	0.1	0.1	0.0	0.0	0.0
Manitoba	115.5	98.5	107.2	23.5	28.9	24.7	11.7	30.0	19.4	5.7	27.5	17.4
Saskatchewan	99.6	102.7	100.8	8.7	9.6	9.0	9.0	7.2	8.3	0.7	5.0	6.3
Alberta	102.0	99.1	98.7	3.1	2.5	2.5	1.2	3.4	3.7	0.0	0.6	0.5
BC	106.0	104.2	98.3	11.0	15.2	13.1	5.7	11.7	14.6	3.5	9.8	13.0
New Brunswick	126.5	129.9	128.5	38.6	26.3	23.3	22.3	4.3	1.4	1.2	0.4	0.3
Nova Scotia	97.4	101.0	99.1	1.2	2.4	1.1	3.8	1.4	2.0	0.0	0.0	0.0
PEI	10.7	3.7	1.4	0.0	0.0	0.0	89.3	96.3	98.6	0.0	0.0	0.0

Exports = to the United States and the provinces

Imports = from the United States and the provinces

YTD: year to date (January to July)

Source: Statistics Canada

Table 2

ELECTRICITY: RESERVE MARGIN BY PROVINCES

	Capability (MW)			Reserve Margin (MW)			% of Indicated Capability		
	Winter			Winter			Winter		
	1991-92	2000/01	2001/02	1991-92	2000/01	2001/02	1991-92	2000/01	2001/02
CANADA	99,744	103,637	104,332	18,503	18,656	20,256	18.6	18.0	19.4
Newfoundland	1,867	1,882	1,885	394	456	283	21.1	24.2	15.0
Labrador	1,120	1,253	1,377	756	880	990	67.5	70.2	71.9
PEI	157	194	246	28	40	76	17.8	20.6	30.9
NS	2,237	2,290	2,298	552	626	734	24.7	27.3	31.9
NB	3,394	3,817	4,193	649	473	1,170	19.1	12.4	27.9
Quebec	32,788	39,091	38,912	2,684	9,066	8,306	8.2	23.2	21.3
Ont	31,903	26,618	25,952	8,075	1,319	1,294	25.3	5.0	5.0
Man	4,468	4,723	4,806	1,070	1,072	804	23.9	22.7	16.7
Sask	2,933	3,233	3,467	699	355	621	23.8	11.0	17.9
Alta	8,231	9,030	9,738	2,072	1,453	2,846	25.2	16.1	29.2
BC	11,194	11,964	11,875	2,293	3,804	3,775	20.5	31.8	31.8
Yukon	98	123	130	14	43	59	14.3	35.0	45.4
NWT	184	164	159	82	72	56	44.6	43.9	35.2
Nunavut	0	71	79	-	32	51	-	45.1	64.6

Source: Statistics Canada

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