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North American Electricity
Escalating Prices Possible Unless Infrastructure Investment Barriers are Eased

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Synopsis

This report is the third in the Fraser Institute's Continental Energy Strategy for North America series. It provides a current and comprehensive overview of the electricity sector in Canada, the United States, and Mexico, and an assessment of the required infrastructure development over the next decade.

Market-driven development of the continent's energy resources and endowments can bring economic benefits to North Americans in the form of expanded employment opportunities and income, improved living standards, energy price stability, and greater security of energy supply. This report addresses the magnitude of investment that will be required in electricity infrastructure in North America and also identifies some of the market, regulatory, and other challenges associated with the materialization of such investments.

The report concludes with a series of policy recommendations that, if implemented, will help alleviate and solve some of the identified challenges associated with the required proper, cost-efficient, and timely development of electricity infrastructure in North America. The main goal of the policy recommendations is to ensure that policy and institutional frameworks are as conducive as possible to the development of North America's energy resources in light of current market conditions, legitimate environmental concerns, and global investment opportunities.

Foreword

This report is the third in a series of papers being produced by the Fraser Institute in the course of developing a Continental Energy Strategy for North America. The first and second papers focused on crude oil and natural gas issues in relation to a continental energy strategy. This paper focuses on the outlook for North American investment in the electric generation capacity, transmission, and distribution sector and on non-market barriers and obstacles that stand in the way of such investment. It then examines means for removing and lowering these barriers.

The primary objective of the continental energy strategy research program is to ensure that policy and institutional frameworks are as conducive as possible to the development of North America's energy resources in light of current market conditions, legitimate environmental concerns, and global investment opportunities (Klein and Tobin, 2008). This goal is predicated on the economic benefits that market-driven development of the continent's energy resources (crude oil, natural gas, coal, and other energy endowments, including uranium and hydro resources) can bring to Canadians, Americans, and Mexicans in terms of expanded employment opportunities and income, improved living standards, energy price stability, and greater security of energy supply.

Executive summary

Canada, the United States, and Mexico combined currently have approximately 1,206 gigawatts (GW) (or 1,206,062 megawatts [MW]) of electric generation capacity (Statistics Canada, 2010c and 2010d; National Energy Board, 2009a; Energy Information Administration, 2010e and 2010f; Comisión Federal de Electricidad, 2010). In spite of persistent progress in energy efficiency initiatives, continued population and economic growth, as well as the production of new and more electricity-consuming products such as cell phones, laptops, tablets, and even electric automobiles, mean that substantial investment in new electric generation, transmission, and distribution facilities will be required in the future.

According to a recent National Energy Board forecast, Canadian electric generation capacity is projected to increase by 15 percent (or 19,835 MW) from an estimated 131,418 MW in 2010 to 152,903 MW in 2020, with a total of 26,793 MW of gross capacity additions (National Energy Board, 2009a; Statistics Canada, 2010c and 2010d). In the United States, electric utilities will need 52,175 MW of gross electric generation capacity additions from 2010 to 2020 (Energy Information Administration, 2010a). In Mexico, 23,323 MW of generation capacity will need to be added from 2010 through 2020 (Comisión Federal de Electricidad, 2009, Secretaria de Energía, 2009). As a whole, electric generation capacity in North America is projected to increase by 102,291 MW by 2020 (8 percent) compared to current levels.

Substantial investment will also be required in new and expanded electricity transmission and distribution facilities to transport the increased volume of electricity from where it is generated to where it is used. The need to connect wind power and hydroelectric capacity being built in remote regions to consumption centers will add to these investment requirements and will include international, cross-border connections. Further, to remain reliable as electricity production and consumption increases, interregional transmission connections throughout North America will need to be strengthened. Also, the deployment of new smart-grid, energy efficiency, and other management technologies will mean that a greater share of North American electricity infrastructure investment will be allocated to distribution.

Based on estimated costs from energy agencies, industry groups, and consultants, the required investment in North American electricity infrastructure from 2010 to 2020 will be approximately US$858 billion (in 2010 dollars), or the equivalent of $86 billion per year. Expressed in "as spent," or nominal dollars, the required investment will approach US$1 trillion.[1]

The magnitude of the investment will largely depend on the mix of technologies used for generation capacity increases. A lower share of renewable energy projects could substantially lower the amount of investment required. Yet, regardless of the composition of the investment, the magnitude is large.

Unfortunately, non-market barriers threaten to prevent this required investment from being realized. Unnecessary obstacles or specific technology requirements that delay or increase investment in incremental generation and transmission facilities will result in higher electricity costs for end-users. That is because power rates will have to be adjusted (by regulators or market forces) to ration limited electricity supplies, or to cover higher investment requirements. Moreover, failure to achieve the required level of capital spending on such facilities and the resulting higher electricity costs will dampen growth of industrial production.

These factors would cause North American economic growth to be constrained and improvements in living standards arising from growth in the electricity sector to be fewer. Further, roadblocks to electric generation capacity and transmission investment threaten the reliability of the continental electricity system and increase the possibility of blackouts.

Investment barriers in this sector include energy policy risk. Prospective investors in a capital-intensive industry are wary of energy policy changes and modifications that would impinge upon their expected returns. Examples of this type of risk include the possibility that the electricity generation sector may be re-regulated or that a government directive could place a project in jeopardy (as in Ontario when, in the fall of 2010, the government decided not to allow a gas-fired generation plant to be constructed in Oakville after the application by TransCanada Corporation to build the plant had been approved). Similarly, uncertainty regarding environmental regulations (as with possible severe constraints on greenhouse gas emissions, including so-called cap-and-trade schemes) makes it difficult for proponents of coal-fired and even natural gas-fired generation to determine the extent to which such projects could compete. Uncertainty about whether or when new transmission facilities would be constructed, and how and to what extent the investor is expected to bear part of the cost of expanding the transmission system, poses another obstacle to investment in electric generation capacity.

Other barriers to investment include: land access disputes with native groups or landowners; the time and cost involved in obtaining necessary regulatory approvals, especially across multiple jurisdictions, and particularly when a proposed transmis-

1 The conversion from constant to "as spent" dollars assumes an annual inflation rate of 2.5 percent in the US and Canada, and 3.5 percent in Mexico.

sion line would cross international boundaries; nuclear plant approval issues; inadequate returns on investment because of allowed rates of return on equity that are low relative to other jurisdictions or sectors; the time, costs, and uncertainty of regulatory processes; regulated electricity markets; and unclear or unstable price signals, amongst others.

Investment in nuclear power plants faces a particularly high hurdle because of the myriad approvals that are required from different agencies. In the end, all these approvals usually lead to a cost of construction that is considerably more than the initial estimates. This is of particular concern given the high capital costs required to build a nuclear power plant (ie., billions of dollars in capital and lead times or construction times of 10 years or more), yet the benefits of such investments (reliable, efficient electricity over several decades) are not often taken into consideration by the regulators.

Where generation is regulated, the often low available return on equity may also be a barrier to investment. On the other hand, where electricity generation has been deregulated but wholesale electricity market conditions are not competitive, the prices may not reflect the revenue stream that investors in new generation capacity expect to realize. An expectation of uncertain or highly volatile prices may keep wary investors at bay.

Further, where ownership of electric generation facilities is for the most part reserved for the state and generation is regulated, as in Mexico, there is little opportunity for private investment to expand. Moreover, the mix of generation capacity is essentially determined without the benefit of decisions that are based on market signals. This means that there is virtually no assurance that, in the long-run, the expansion of electricity supply will be achieved at lowest cost.

This study recommends that policymakers in Canada, the United States, and Mexico eliminate or reduce barriers to investment in electric generation and transmission facilities with policies that:

- Reduce the risk to investors from unnecessary or sudden changes to energy policies and regulations;
- Reduce environmental policy uncertainties such as, for example, those related to potential severe constraints on carbon emissions, providing potential investors with sufficient time and information to adjust their business plans;
- Establish ongoing consultative processes and mechanisms to ensure that policymakers have a sound understanding as to how any proposed changes in energy policies will affect stakeholders;
- Defuse land access issues with private landowners and native groups by establishing public consultation and dispute resolution processes that allow sufficient time for pro-

ject developers to inform and educate the involved parties and to resolve disputes as quickly as possible;

- Streamline the regulatory approvals processes for new nuclear plants by delegating one agency to deal with all the necessary paperwork and regulatory approvals wherever practical, in order to reduce the number of federal and state or provincial agencies that project proponents must liaise with, and thus eliminate unnecessary duplication and speed up decisions;
- Improve the efficiency of transmission project approval processes where numerous jurisdictional levels and more than one state or province are involved. Establishing joint approvals processes and procedures would help secure approval for potential international transmission projects;
- Require regulatory agencies to streamline their application processing procedures to reduce the time and cost required for them to make decisions pertaining to electric transmission and distribution project applications;
- Deregulate the electricity generation business in Mexico and in those US states and Canadian provinces where this has not yet been done to allow electricity to be priced by market forces that provide meaningful signals to potential investors. With market-based signals to guide development, electricity supply costs will, in the long run, reflect the cost and availability of competing technologies;
- Privatize government-owned electric generation, transmission, and distribution companies, including Mexico's Comisión Federal de Electricidad, if the necessary constitutional reforms can be achieved;
- Ensure that investment in regulated transmission and distribution is attractive relative to other jurisdictions and industries by reviewing the methodologies for determining allowable rates of return on equity to ensure that they result in regulated rates of return closely similar to those that would be realized with competitive, open market conditions;
- Facilitate investment in merchant transmission facilities (lines that are physically independent from a regulated transmission grid) to interconnect markets and regions where such services would improve the electricity supply options that are available to consumers;
- Establish transparent rules that determine who will pay for the transmission system expansions that will be required if proposed renewable and other electric generation facilities are built.

These recommendations constitute important elements of the Institute's continental energy strategy.

About the Continental Energy Strategy initiative

The Fraser Institute's Continental Energy Strategy research program, as it relates to electricity, is to lay out policy recommendations that will help to ensure that North America's energy resources, such as natural gas, coal, uranium, and hydro resources, which are used to generate electricity, are developed as efficiently and as extensively as possible given market requirements, science-based environmental concerns, and international competition (Klein and Tobin, 2008). Increased development and production of the continent's energy resources arising from free-market decisions, along with free energy trade with the rest of the world, would generate extensive employment, labor income, and economic growth benefits, and thereby contribute to improvements in the quality of life of North Americans. Further development of the continent's energy resources under free market principles would also bolster the security of energy supply by increasing the range of energy supply options available to North America's consumers who, ultimately, would benefit from greater choice and competitive rates.

Because market forces best determine the most efficient allocation of North America's energy resources, development of a continental energy strategy *does not* include identifying energy investment, production, and trade targets. Rather, the focus is on ensuring that government policies pertaining to energy resource investment, development, consumption and trade are stable, fair, and appropriate. Government intervention in energy investment decisions must be avoided as the allocation of resources is best left to those who are motivated by free market investment opportunities, have in-depth knowledge of the advantages and disadvantages of competing energy production technologies, and are thus prepared to take the associated risks based on their understanding of future energy requirements.

By fostering conditions that will allow free markets to function effectively, public policy settings and institutional arrangements will be conducive to investment in the expansion of the continent's energy supply capacity. In relation to a particular energy commodity, such as electricity, this means that non-market barriers to investment in electric generation, transmission, and distribution infrastructure, such as unnecessarily complex regulatory approval processes and procedures, must be removed. Policy frameworks must also support energy market competition and innovation and, subject to appropriate environmental restrictions, allow investors freedom of choice to determine energy resource and electricity production locations and to define the scope of their business plans in accordance with market conditions. Further, the continental energy strategy must be supported by legislation that ensures that access to the capital and labor pools required for the financing and construction of new energy production and transportation facilities is not constrained by inefficient market regulations or distortions.

Introduction

This third report in the Institute's Continental Energy Strategy research program focuses on policy initiatives that would facilitate private ventures in electric power generation and transmission capacity, as well as promote wholesale electricity trade by removing or lowering investment barriers and regulatory hurdles in electricity generation and transmission facilities.

Electricity is a very important component of North America's energy mosaic. Having the capacity to generate sufficient electricity to meet power requirements at prices that are globally competitive is important for the continent's economic prosperity. Growth of electric power generation capacity, which uses the continent's vast coal, natural gas, and uranium resources, as well as hydro and other renewable energy sources, together with further strengthening of electric transmission systems and distribution networks, will bring considerable employment, labor income, and other economic benefits.

Further, strengthening the electricity transmission grid by upgrading and extending existing facilities and constructing new transmission lines will reduce the likelihood of a widespread electric power blackout, such as that which affected about 50 million people in Ontario and parts of the US Northeast and Midwest in August 2003 (Northeast Power Coordinating Council, 2004). The resulting improvement in electricity system reliability will, in turn, help to improve the security of continental energy by increasing the range of supply options that are available to energy consumers.

The first segment of this report provides an overview of the electric generation capacity and electricity consumption and outlooks for Canada, the United States, and Mexico. The second section provides a brief discussion of transmission ownership models, as well as an overview of the transmission systems in the three countries and some indication as to where those systems will need to be expanded. A brief discussion of how electricity prices are determined in the three countries follows. The fourth part examines trends in Canada-US and US-Mexico electric power trade. This is then followed by a discussion of the magnitude of investment in electric generation capacity and transmission that will be required from 2010 to 2020. Regulatory and other barriers which could impede or delay that investment are then examined. The paper concludes with a number of policy recommendations aimed at lowering barriers to investment in the electricity sector. If implemented, these recommendations would help to ensure that required electricity sector investment is achieved.

A glossary at the end of this report following the "References" section explains some of the terms used in this report.

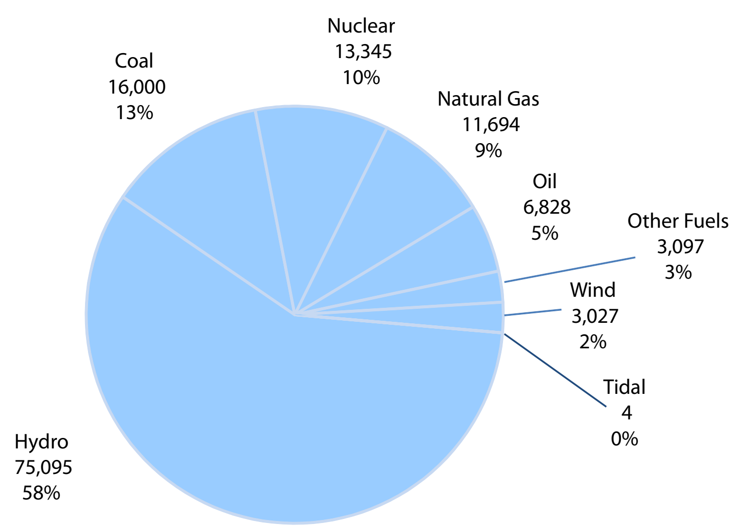
Electric generation capacity and electricity production

Canadian overview and outlook

Figure 1 illustrates the composition of Canada's electric generation capacity[2] of 129,090 megawatts (MW) as of year-end 2009.

Hydro capacity accounts for 58 percent of Canada's electric generation capacity followed by coal thermal (13 percent), nuclear power (10 percent), and natural gas thermal stations (9 percent). Fuel oil and diesel combustion units represent about 5 percent of the total, while wind and tidal power, accounted for 2 percent and less than 1 percent, respectively.[3]

Figure1: Electric power generation capacity in Canada (MW), by source, 2009



Source: Statistics Canada, 2010c and 2010d; figure by authors.

2 The glossary distinguishes between the concepts of *generation capacity* and *electricity generation*.

3 According to the Canadian Wind Energy Association, as of December 2010, there were 3,549 MW of installed wind power generation capacity in Canada (Canadian Wind Energy Association, 2010).

Hydro resources are used to power hydraulic turbines, while uranium is used to power nuclear steam turbines. Conventional steam turbines (26,493 MW) are mainly powered by coal (60 percent) and oil (18 percent), but also use natural gas (10 percent) and other sources of fuel (11 percent). Combustion turbines (10,333 MW) are mainly fueled with natural gas (84 percent) and oil (16 percent). Tidal power turbines at Canada's only tidal power plant in Nova Scotia, the Annapolis station, account for the country's tidal power generation capacity (Statistics Canada, 2010c and 2010d).

Because new electric generation facilities are increasingly being located further away from the large consuming centers than in the past (as, for example, in the case of the hydro developments underway or in the planning stages in Manitoba and Quebec), other things being equal, the delivered cost of electricity is bound to increase due to greater transmission costs. Public policies that encourage the development of renewable energy sources, such as wind generation (generally more costly than electricity from conventional sources, such as gas-fired thermal plants) will also put upward pressure on electricity costs.[4] These factors underscore the need for policies that will help private investors develop electricity production capacity on the basis of their knowledge of the available technologies and future market requirements.

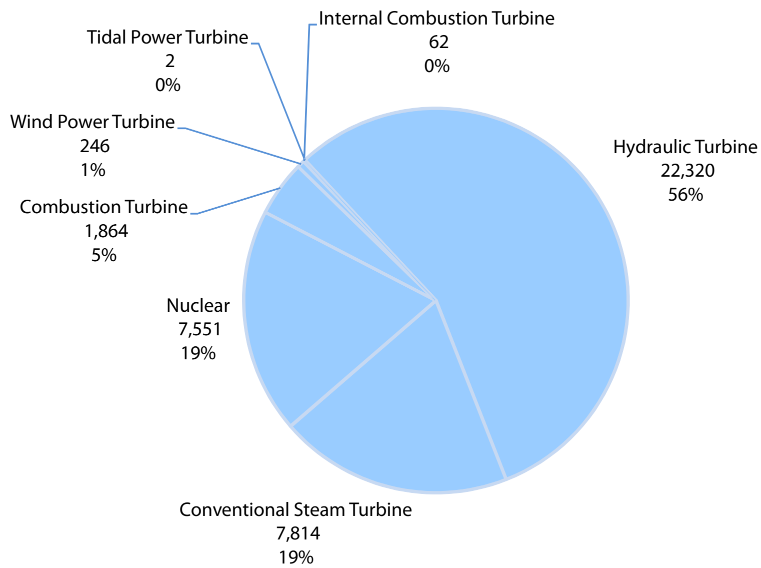
Canadian electricity production in September 2010 was 39,860 gigawatt-hours (GW-h). As figure 2 illustrates, 22,320 GW-h, or 56 percent of the electricity, was produced by hydroelectric facilities. Production from oil, natural gas, and coal combustion plants (9,739 GW-h or 24 percent)[5] as well as from nuclear power plants (7,551 GW-h or 19 percent) was also significant. Electricity generation from tidal, wind, and other renewable energy sources except hydro facilities was less than 1 percent of total generation (240 GW-h)(Statistics Canada, 2010b).

Canadian electric generation capacity is projected to increase by 19,835 MW from 2010 to 2020 in the National Energy Board's *2009 Reference Case Scenario* (National Energy Board, 2009a: chapter 8 and Appendix table 5.1).

4 One indication of this is a recent analysis by Aegent Energy Advisers Inc. for the Canadian Manufacturers and Exporters, which indicates that the "Feed-in Tariffs" (FIT) in Ontario, or the guaranteed prices that are paid to generators using specific renewable energy technologies such as solar and wind, will substantially boost Ontario electricity prices from 2010 to 2015. Alone, the subsidy amounts (i.e., the differentials between the amounts paid for energy from renewable sources that are eligible for the FITs, and the projected wholesale spot electricity prices) are likely to increase Ontario's electricity costs by almost $27 per MW-h (excluding the HST); or fully half of the total projected increase in costs of $54 per MW-h. Of the projected increase in residential electricity costs, the FIT subsidies (including the HST) will add about 3 cents/kW-h to consumers' unit electricity costs. But this is only part of the story. If the incremental transmission costs resulting from adding renewable generation capacity in remote areas and other renewable energy costs are included, Ontario's renewable energy program accounts for nearly 69 percent of the projected increase in electricity costs from 2010 to 2015 (Aegent Energy Advisors Inc. 2010). (For further discussion of this and related issues, see Angevine and Murillo, 2011.)

5 Conventional steam turbines (7,814 GW-h) + combustion turbines (1,864 GW-h) + internal combustion turbines (62 GW-h) = 9,739 GW-h.

Figure 2: Electric power generation in Canada (GW-h), by plant type, September 2010



Source: Statistics Canada, 2010b; figure by authors.

The National Energy Board's capacity projections reflect government announcements as well as plans announced by investors before the *Reference Case* forecast was finalized in 2009. The anticipated impacts of the Board's energy price assumptions on the choice of generation capacity technologies are also captured in the *Reference Case*.

Generation capacity decommissions and retirements over the 10-year period are expected to total 6,958 MW, with 78 percent (5,437 MW) expected to come from the decommissioning of coal-fired power plants, mainly in Ontario (4,055 MW) and Alberta (909 MW). Decreases in generation capacity from oil-fired and natural gas-fired steam turbines accounts for 22 percent of overall decommissions and retirements. Oil-fired steam turbines (490 MW) are assumed to be replaced with more efficient oil-fired combined cycle turbines (540 MW), mainly in Atlantic Canada as well as in remote locations. Natural gas-fuelled steam turbines (1,031 MW) are assumed to be replaced with gas-fired combined-cycle turbines mainly in British Columbia and Alberta.

Figure 3 illustrates the projected changes in Canadian electric generation capacity by type of technology from 2010 to 2020.

Gross electric generation capacity additions (that is generation capacity additions, without deducting estimated plant and unit retirements), are projected to total 26,793 MW over the 10-year period. Over 42 percent of that increase is indicated as

Figure 3: Net changes in electric generation capacity in Canada (MW) from 2010 to 2020

Source: National Energy Board, 2009a, Chapter 8 and Appendix Table 5.1; figure by authors.

coming from wind power capacity.[6] In fact, the NEB assumed that some 11,279 MW of wind capacity would be added by 2020, with the largest additions occurring in Quebec (5,000 MW or 44 percent), Ontario (2,600 MW or 23 percent), Alberta (1,200 MW or 11 percent), and Manitoba (1,000 MW or 9 percent). This reflects a push by governments to be seen as *green,* with little if any regard to the cost of displacing fossil fuels.

Evidence of this is demonstrated by the policy initiatives (e.g., calls for bids) that have been launched in British Columbia, Ontario, and Quebec to attract investment in electric generation facilities that rely only renewable energy sources, such as wind, in

6 This increase in wind power generation capacity in turn accounts for 57 percent of the 19,835 MW net increase in overall generation capacity over the 10-year period.

spite of the fact that less costly non-renewable generation options are available which, in many cases, can be located close to existing transmission facilities thus avoiding the expense of building new transmission capacity.[7]

In its *2009 Reference Case Scenario*, the National Energy Board assumed that there would be extensive development of major hydro projects over the 10-year period in Quebec (2,441 MW), Newfoundland & Labrador (2,260 MW), and British Columbia (1,865 MW). Together, these account for 92 percent of the combined (large and small) hydropower capacity additions projected to occur in Canada.[8]

In British Columbia, large hydro projects include a 500 MW addition to the Revelstoke generation station, a 465 MW addition to the Mica station, and construction of a 900 MW facility at the Site C Peace River location. In addition, the 200 MW Wuskwatim facility in Manitoba,[9] and the 2,260 MW Lower Churchill Falls facility in Labrador (which the government of Newfoundland & Labrador has been promoting), are assumed to be built (Government of Newfoundland & Labrador, 2010). Including all hydro generation capacity, a total of 7,366 MW (a 15 percent increase) of additional hydro capacity, including 600 MW of small hydro and ocean energy (wave and tidal) generation capacity combined, are assumed to be installed by 2020 (National Energy Board, 2009a: 35, and Appendix table 5.1 and 5.2).

Generation capacity from biomass, solar, and geothermal sources combined is expected to more than double (by 1,938 MW) from 1,812 MW in 2010 to 3,750 MW in 2020. The authors estimate that the increase will be comprised as follows: 34 percent biomass, 27 percent solar, and 39 percent geothermal (see Angevine and Murillo, 2011).

The National Energy Board assumed that nuclear plant additions would be located in Alberta (a 1,000 MW plant in 2020) and New Brunswick (a 680 MW addition at Point Lepreau). Also, four 540 MW nuclear units (a total of 2,160 MW) at Pickering Station B in Ontario were assumed to be replaced with two 1,000 MW units, effectively reducing the plant capacity by 160 MW. Capacity added as a result of new nuclear plant construction was assumed in the *Reference Case* to total 1,520 MW, as highlighted in figure 3 above (National Energy Board, 2009a: ch 8).[10]

7 This trend and issues pertaining to the development of renewable energy in North America will be explored in a separate, upcoming Fraser Institute report.

8 That is, conventional (large) hydropower generation additions (6,766 MW) + small hydro/ wave/ tidal generation additions (600 MW) = 7,366 MW.

9 Construction of the Wuskwatim generation station is underway. The first phase of excavation has been completed and a transmission line constructed (National Energy Board, 2010a).

10 Since the National Energy Board's 2009 projections were published, the outlook for nuclear power capacity additions has become clouded for three reasons. First, the Canadian government has decided to sell the Atomic Energy of Canada Limited's CANDU reactor division. Second, the Ontario government has put

The National Energy Board also assumed that about 4,150 MW of new natural gas-fired electric generation capacity would be put in place by 2020, comprised of 1,821 MW of combined cycle facilities,[11] and 2,329 MW of combustion turbine and cogeneration combined heat and power units[12] (National Energy Board, 2009a).

In terms of coal-fired capacity, the only new coal-fired facilities that are assumed will be built are the 450 MW Keephills 3 plant and a 270 MW integrated gasification combined cycle pilot plant in Alberta (National Energy Board, 2009a: 36-37).

If the capacity mix were to change according to the National Energy Board's July 2009 projections, the hydro power share of total capacity would fall from 56 percent in 2010 to 53 percent by 2020, and the coal share, from 11 percent to 6 percent. However, the share of wind and other non-hydro renewables in the capacity mix would increase to 13 percent from 5 percent. The nuclear share would remain at about 11 percent, while the capacity share of natural gas and oil-fired power plants combined would fall from 17 percent to 16 percent (National Energy Board, 2009a: Appendix table 5.2)

Precisely how the composition of Canadian electric generation capacity evolves will, however, depend on how the relative costs and efficiencies of the competing technologies change. It will also depend on whether and to what extent the provincial governments, which have been dictating the energy supply mix (except for Alberta), opt to let private investors (responding to market signals) determine how the electric generation capacity mix will evolve.

According to the National Energy Board's *Reference Case Scenario*, the share of Canada's electric generation capacity represented by all renewables, including hydro, is projected to increase from 61 to 67 percent by 2020. If controls are placed on greenhouse gas emissions, Canada will be in an enviable position relative to the United States (as will be observed in the following section), because of Canada's much greater reliance on, and availability of, hydroelectric power. Nonetheless, the sharp reduction in low cost coal-fired capacity, little increase in the extent of reliance on relatively inexpensive natural gas fueled generation capacity that is assumed, and much greater reliance on expensive wind and other renewable energy sources, point to rising electricity costs in Canada.

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on hold plans to have new nuclear power facilities built in the province. And third, the recent problems with radiation at Japanese nuclear plants affected by the major earthquake and resulting tsunami.

11 According to the National Energy Board, combined cycle generation is the production of electricity using combustion turbine and steam turbine generation units simultaneously (see the Glossary of Terms at the end of this study).

12 According to the National Energy Board, a cogeneration facility produces electricity and another form of useful thermal energy, such as heat or steam as a by-product of generation (see the Glossary of Terms at the end of this study).

The National Energy Board projects Canadian electricity production to reach 705 terawatt hours (TW-h) in 2020, or 96 TW-h (16 percent) greater than in 2010 (608 TW-h) (National Energy Board, 2009a: Appendix table 5.3). The share of power generation from renewable energy sources (excluding hydro) as a percentage of overall generation is forecast to increase from 4 percent in 2010 (22 TW-h) to 8 percent in 2020 (55 TW-h). Canadian electricity demand (as measured by electricity production minus net exports) is projected to increase by 10 percent (57 TW-h) from 572 TW-h in 2010 to 631 TW-h in 2020.

Net electricity exports to the US are forecast by the National Energy Board to more than double from nearly 36 TW-h in 2010 to more than 73 TW-h in 2020.[13] Net exports from Quebec and Manitoba are projected to increase by 19 TW-h and 8 TW-h from 2010 to 2020, respectively. Combined, net power exports to US markets from British Columbia, Ontario, and New Brunswick are forecast to be about 11 TW-h greater in 2020 than in 2010 (National Energy Board, 2009a: table 5.5). If realized, these trade developments will be of considerable economic benefit to the source regions because of the employment and income that they will generate. For their part, the importing regions will benefit from the lower cost of imported power as well as greater system reliability resulting from a more diverse supply mix.

US electric generation capacity and production overview and outlook

As table 1 indicates, at only 8 percent, hydroelectric generation capacity constitutes a much smaller share of generation capacity in the United States (US) than the 58 percent share it has in Canada. On the other hand, natural gas (39 percent) and coal-fired generation (31 percent) represent much larger shares of total capacity in the US than in Canada, accounting for 70 percent of capacity on a combined basis, compared with only 20 percent in Canada. The nuclear share, in the vicinity of 10 percent, is about the same in both countries, as is the nearly 6 percent share of petroleum-fired (oil, diesel, petroleum coke, and other oil derived fuels) generation capacity. In fact, 85 percent of the existing generation capacity in the US is powered by non-renewable energy sources such as coal, crude oil, natural gas, and uranium combined, compared to 37 percent in Canada.

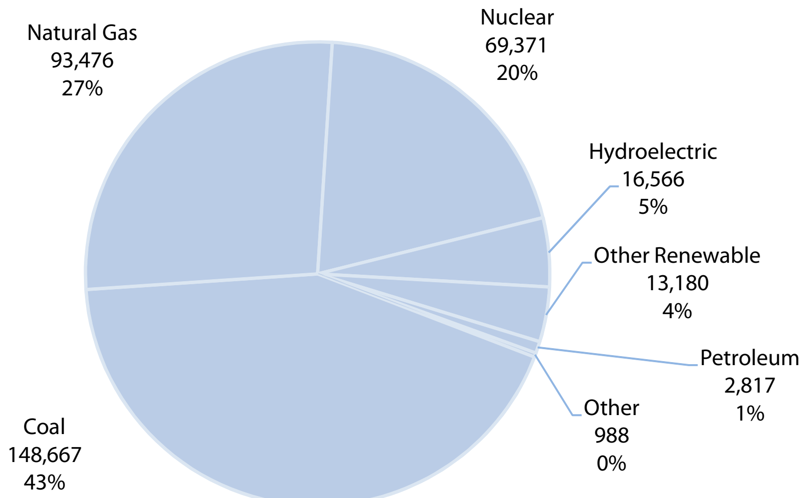
13 Canadian electricity exports and imports are illustrated in figure 12 in the "Electricity Trade" section.

Table 1: Electric power generation capacity in the United States (MW) by source, 2009

Source	MW	% of Total
Natural gas	401,244	39%
Coal	314,294	31%
Nuclear	101,004	10%
Hydro	78,518	8%
Petroleum	56,781	6%
Wind	34,296	3%
Pumped storage	22,160	2%
Wood and wood-derived fuels	6,939	0.7%
Other biomass	4,317	0.4%
Geothermal	2,409	0.2%
Other gases	1,932	0.2%
Other	888	0.1%
Solar (thermal and PV)	619	0.1%
Total	1,025,401	100%

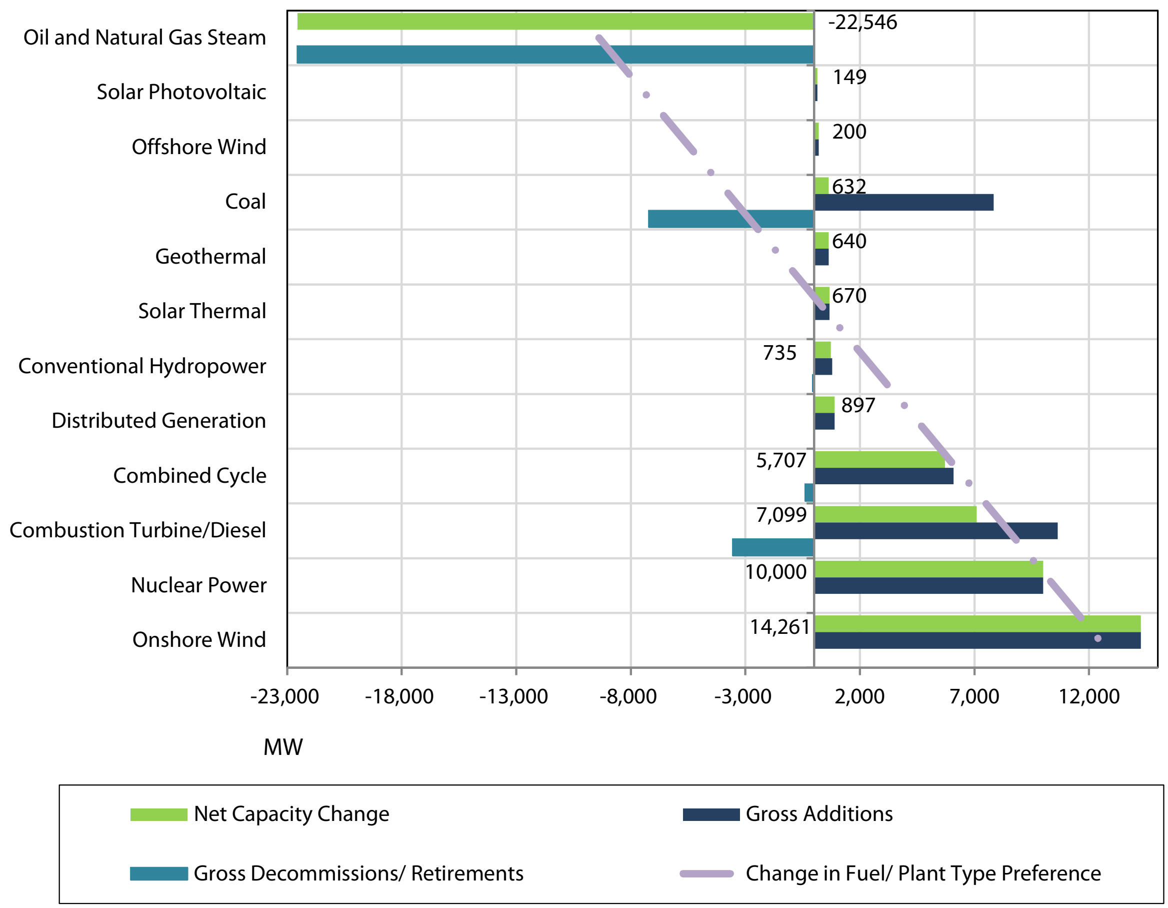
Source: Energy Information Administration, 2010e and 2010f; table by authors.

Figure 4: Electric power generation in the United States (GW-h), by source, September 2010



Source: Energy Information Administration, 2010e; figure by authors.

Figure 5: Net changes in electric generation capacity in the United States (MW) from 2010 to 2020



Source: Energy Information Administration, 2010a: tables 9 and 16; figure by authors.

The 5 percent share of non-hydro renewables generation capacity (wind, biomass, etc.) in the US is also similar to that in Canada, but total electric generation capacity is close to 8 times that in Canada (Energy Information Administration, 2010f).

Turning to electricity generation or production (as opposed to the capacity to generate power), US electricity generation from all domestic sources, including commercial and industrial operators as well as electric utilities and independent power producers, totaled 345,065 GW-h (or 345.1 TW-h) in September 2010, close to 9 times the volume of electricity generated in Canada in the same month (Energy Information Administration 2010e).

As indicated in figure 4, 43 percent (148,667 GW-h) of US electricity generation in September 2010 came from coal-fired electric generation facilities. Natural gas combustion (93,476 GW-h) and nuclear plants (69,371 GW-h) generated 27 percent and 20 percent of the total, respectively. Combined, electricity generation from fossil fuels (coal, oil, and natural gas) and nuclear powered generators accounted for 314,331 GW-h or 91 percent of total electricity production in that month.

Unlike Canada, where it plays a much more significant role in the power supply picture, hydro was the source of only 5 percent of the electricity generated. Other renewables (predominantly wind generation) were the source of about 4 percent of the power that was generated in the United States during September 2010 (Energy Information Administration, 2010e).

In its *2011 Annual Energy Outlook,* the US Energy Information Administration (EIA) projects that US electricity sector generation capacity will increase by 18,442 MW, or 2 percent from 2010 to 2020 (Energy Information Administration, 2010a).[14]

However, because of projected unit retirements amounting to 31,733 MW—mainly from oil and natural gas steam turbines, combustion turbines or diesel generators, as well as coal-fired plants—52,175 MW of new capacity will be required from 2010 to 2020. That would correspond to approximately 5,217 MW of gross capacity additions per year from 2010 to 2020 (Energy Information Administration, 2010a: tables 9 and 16).

Figure 5 illustrates the changes in fuel and plant type preferences that correspond to the expected changes in generation capacity from 2010 to 2020 in the United States. The pattern is similar to that seen in Canada, which shows a shift from coal and older oil- and natural gas-fired technologies toward cleaner combustion and steam technologies, such as natural gas combined cycle and nuclear power, but also, to a greater extent, a push towards renewable energy sources for electric power production (wind in particular).

In the Energy Information Administration's outlook for electric generation capacity up to the year 2020, hydro and other renewable energy sources represent 32 percent of the 52,175 MW of gross additions, and oil- and natural gas-fired technologies almost 34 percent. Coal facilities are projected to account for 15 percent of gross capacity additions, while new and expanded nuclear facilities will add about 19 percent (Energy Information Administration, 2020a: tables 9 and 16).

The projected 16,654 MW net gain in renewable energy electric generation capacity from 2010 to 2020 is led by new onshore wind generation facilities which will account for 86 percent of the increase. The EIA assumes that nearly all of the increase in wind capacity will be in place by 2013 because of current government incentive programs. As a consequence, a remarkable 90 percent (14,902 MW) of the total increase

14 Excludes electricgeneration by plants in the commercial and industrial sectors and small, on-site generating systems in the residential, commercial, and industrial sectors which are used primarily for own-use generation, but which may also sell some power to the grid.

in renewable energy capacity that is projected to take place by the end of 2020 is forecast to occur before 2014. Solar energy capacity (thermal and photovoltaic combined) is projected to account for close to 5 percent of the increase in renewable energy capacity, and both geothermal energy and conventional hydro close to 4 percent (Energy Information Administration, 2010a: table 16).

The Energy Information Administration projects electric sector power generation to increase by 218 TW-h (or 6 percent) from 3,965 TW-h in 2010 to 4,182 TW-h in 2020. This implies a compound annual growth rate of 0.5 percent over the 10-year period (Energy Information Administration, 2010a).

The EIA projects the electricity generation or production mix to change somewhat from 2010 to 2020. Most importantly, generation from renewables (including hydro) is expected to increase by 48 percent from 2010 to 2020,[15] and the renewables share of overall generation by over 4 percentage points from 10.5 percent in 2010 to 14.6 percent in 2020. Wind power accounts for 32 percent of the increase, followed by hydro (31 percent) and biomass (28 percent). Among the non-renewable energy technologies, only nuclear power's share of generation is projected to increase (by 0.8 percentage points) from 2010 to 2020 (Energy Information Administration, 2010a: table 85).

Mexican electric generation capacity and production overview and outlook

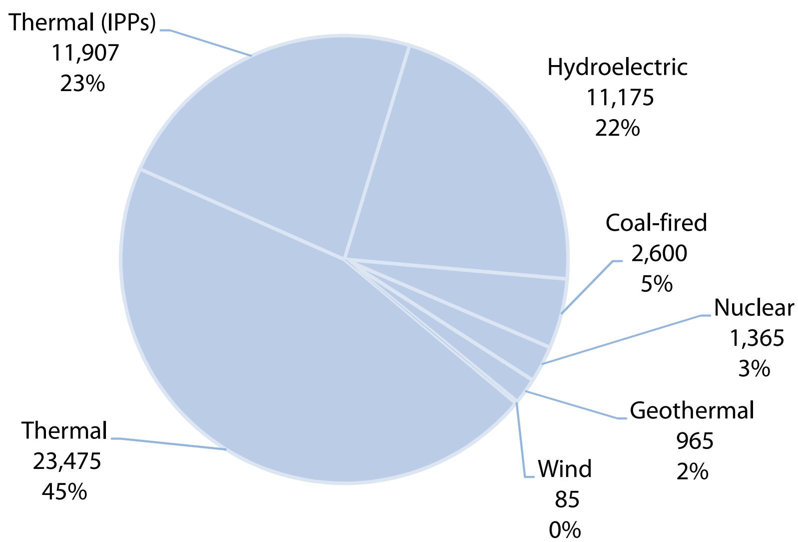
As figure 6 shows, as of September 2010 the Comisión Federal de Electricidad (CFE) (Mexico's national electric public utility) had a total installed generation capacity of 51,571 MW,[16] including 11,907 MW of natural gas or fuel oil (thermal)[17] generation capacity from independent power producers (IPPs) under contract to the CFE (Comisión Federal de Electricidad, 2010).

15 Power generation from renewables accounts for 91 percent of the total increase in power generation from all sources over the period.

16 The Comisión Federal de Electricidad provides electric energy and service to most of Mexico. Luz y Fuerza del Centro (LyFC), the federal district's utility, was dissolved by presidential decree on October 11, 2009 (Diario Official de la Federación, 2009). Responsibility for the company's electric generation, transmission, and distribution services was assigned to the CFE.

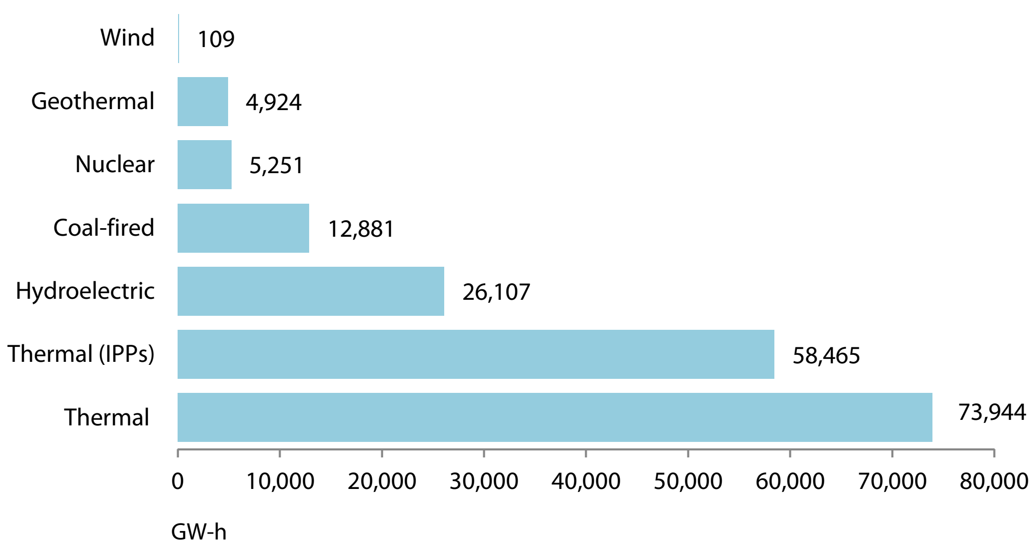
17 For the purpose of this section on Mexico, the *thermal* category is used in the case of the capacity of or output from natural gas- and fuel oil-fired power plants combined. Coal plant capacity and output are reported separately.

Figure 6: Electric power generation capacity in Mexico, by source (MW), September 2010



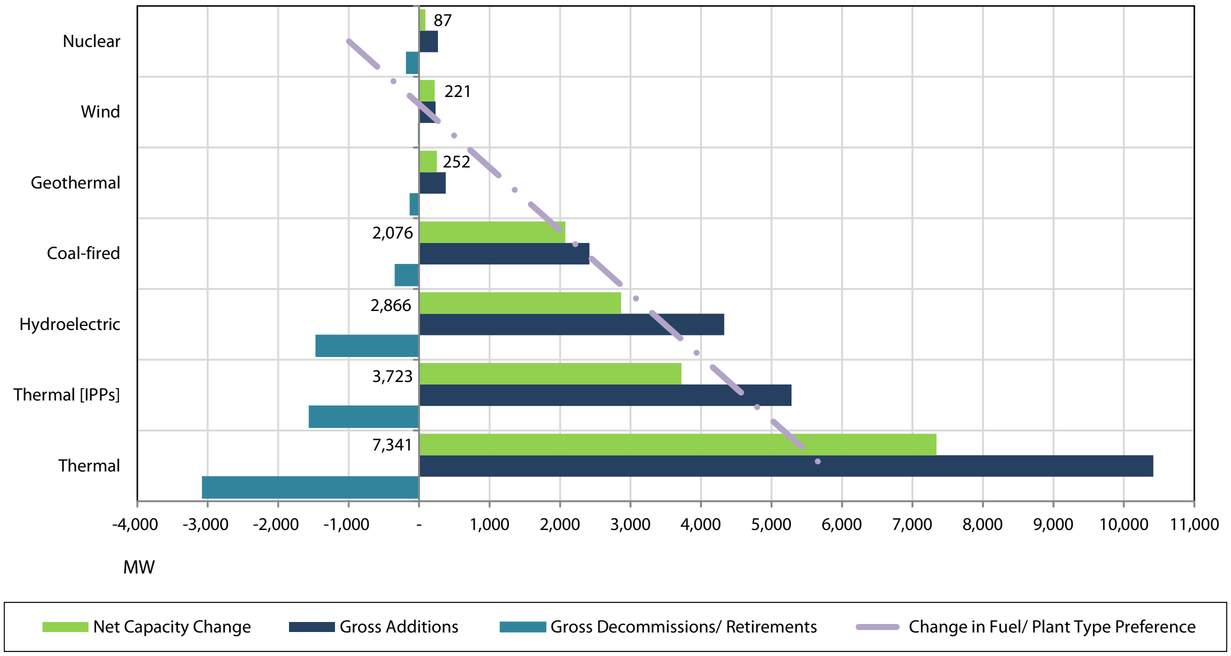
Source: Comisión Federal de Electricidad, 2010; figure by authors.

Figure 7: Electric power generation in Mexico, by source (GW-h), January to September 2010



Source: Comisión Federal de Electricidad, 2010; figure by authors.

Figure 8: Net changes in electric generation capacity in Mexico (MW) from 2010 to 2020



Source: Comisión Federal de Electricidad, 2009; Secretaria de Energía, 2009; figure by authors.

About 46 percent of the generation capacity of the CFE, including the capacity which LyFC owned, relies on natural gas or fuel oil combustion (thermal capacity). Hydroelectric facilities constitute about 22 percent of the CFE's total generation capacity and coal-fired generation plants about 5 percent. Nuclear power (1,365 MW) represents less than 3 percent of the CFE's total generation capacity. Mexico's one nuclear plant, Laguna Verde, has two units, each with capacity of 682.4 MW. Non-hydro renewable generation facilities, mainly wind and geothermal, constitute only about 2 percent of overall capacity (Comisión Federal de Electricidad, 2010).

During the first nine months of 2010, close to 73 percent of Mexico's public sector power production of 181,680 GW-h came from natural gas and fuel oil combustion (both from the CFE assets and independent power producers combined), followed by hydro (14 percent), coal (7 percent), and nuclear (3 percent), while geothermal and wind power combined accounted for only 3 percent (see figure 7).

Based on information from the CFE and the 15-year plan from Mexico's Energy Secretariat (SENER), electric generation capacity is projected to reach 68,136 MW by 2020. The 32 percent gain from 2010 levels implies a compound annual growth rate of 2.8 percent (Comisión Federal de Electricidad, 2009, Secretaria de Energía, 2009).

Given that a number of plant retirements are planned between 2010 and 2020 (6,758 MW in total), the CFE has indicated that gross public sector capacity additions of 23,323 MW, the equivalent of about half (or a 45 percent increase) of the CFE's current generation capacity (51,571 MW), will need to be put in place during that period (Comisión Federal de Electricidad 2009, Secretaria de Energía, 2009).

The largest share (67 percent) of the net addition to electric generation capacity is forecast to occur from new natural gas- and oil-fired thermal power plants, where a shift is forecast to occur from natural gas- and oil-fired combustion turbine power plants to natural gas combined cycle power plants. Thirty-three percent of total net oil- and gas-fired generation capacity additions are assumed to come from independent power producers (IPPs). This highlights the growing importance of smaller players in electric power generation during the coming decade (see figure 8).

Net additions to hydroelectric generation capacity (19 percent of the total) are also projected, as well as additions from coal-fired power plants (11 percent). But generation capacity additions from other non-hydro renewable energy sources and nuclear power plants combined are assumed to increase only slightly.

In terms of electric power generation, the commencement of gas imports at the Manzanillo Liquefied Natural Gas (LNG) facility and the construction of a gas pipeline from there to Guadalajara will facilitate the replacement of oil as an electricity source on Mexico's west coast. In total, the share of electricity produced from fuel oil combustion is projected to decrease and the natural gas-fired generation share to increase more or less correspondingly. The CFE forecasts that improved efficiencies in natural gas combined cycle combustion technology will result in net reductions in hydrocarbon usage, in spite of increased reliance on coal for electricity generation (Comisión Federal de Electricidad, 2009).

North American generation capacity gross additions outlook

Overall, 102,291 MW of (gross) new electric generation capacity is projected to be added in the 3 countries from 2010 to 2020, implying an average addition of 10,229 MW of capacity per year over the 10-year period. Of the total amount, about 26 percent is projected to be added in Canada, 51 percent in the United States, and 23 percent in Mexico (see table 2).

Based on the projections that have been discussed, 41 percent of overall gross additions in electric generation capacity would be met by renewable energy technologies. In fact, 25 percent of total gross generation capacity additions (or 62 percent of the additions from renewables) are projected to come from wind energy (mainly in the

Table 2: Gross generation capacity additions in North America, by fuel type (MW) from 2010 to 2020

	Canada	United States	Mexico	North America	% of Total
Wind	11,279	14,461	232	25,972	25%
Hydro	7,366	785	4,330	12,482	12%
Geothermal	750	640	378	1,768	2%
Solar	535	818	—	1,353	1%
Biomass	653	—	—	653	1%
Renewables	20,583	16,704	4,941	42,227	41%
Natural gas and oil	4,690	17,627	15,700	38,017	37%
Nuclear	1,520	10,000	266	11,786	12%
Coal	—	7,844	2,416	10,261	10%
Total	26,793	52,175	23,323	102,291	100%

Sources: National Energy Board, 2009a: chapter 8 and Appendix table 5.1; Energy Information Administration, 2010a: tables 9 and 16; Comisión Federal de Electricidad, 2009; Secretaria de Energía, 2009; table by authors.

United States and Canada), with the majority being onshore wind turbine facilities rather than offshore installations.

Hydroelectric projects are expected to make significant contributions to the increase in generation capacity, especially in Canada and Mexico. Natural gas and oil fueled power plants, with the majority being natural gas combustion turbines and combined cycle plants, are projected to compose 37 percent of the total increase in new electric generation facilities.

New nuclear power plant capacity is an important element of the outlook in both the United States and Canada. Coal-powered electric generation stations are expected to constitute a portion of the gross capacity additions in the United States and Mexico.

Electricity transmission

Understanding the North American outlook for electric generation capacity and electricity production is helpful for understanding the challenges the electricity sector faces. However, to fully understand the extent of these challenges, one also needs to consider the investment in electricity transmission infrastructure that will be required.

Transmission ownership models

Electricity transmission lines are generally regarded as natural monopolies since the unit cost of transmission drops as the capacity of a transmission line increases such that it is generally not economic to install multiple connectors. For this reason, transmission lines are usually only built if the regulator determines that they are needed and the transmission tariffs are regulated. In this regard, regulators strive to ensure that allowed rates of return (on investment) approximate those that would be realized under competitive market conditions. This is the case whether the regulated transmission service provider is public or privately owned.

Traditionally, regulators in Canada and the United States have employed two basic approaches when determining allowable rates of return on equity (ROE) for regulated utilities. The "yield plus growth," or discounted cash flow approach, involves examining how the company's dividend is expected to perform in relation to the price of its stock (i.e., the dividend yield) and how the company is expected to grow as measured by analysts' expectations of its share price. In the "yield plus growth," case, the ROE is calculated by simply discounting the anticipated stream of future dividends.

The "equity risk premium" approach involves estimating the extra risk associated with holding equity in the company in question, compared with holding a risk-free (i.e., long-term government) bond. Using this approach, the ROE is calculated by adding that risk-free rate and the relationship that the company's stock price bears to the stock market as a whole (or to an index of stock prices of similar companies), multiplied by the "market rate of return." Regulators examining a particular company generally use both approaches before determining the rate of return to be allowed during the period in question (National Economic Research Associates, Inc., 2008).

Regulated transmission companies

Nearly all of the regulated electricity transmission companies in North America are vertically integrated companies which are also involved in electricity generation and distribution activities. One exception is the American Transmission Company that was formed in 2001 as the first multi-state, transmission-only utility in the United States. The company owns and operates the electricity transmission system in portions of Wisconsin, Michigan, Minnesota, and Illinois. Unlike most regulated electricity transmission utilities, the company has a single focus: transmission. The American Transmission Company is owned by municipalities, municipal electric companies, and electric cooperatives in the region.

A Canadian example of a privately owned transmission-only regulated utility is AltaLink, which was formed in 2002 when TransAlta Utilities decided to vacate the transmission business. AltaLink owns and operates about 60 percent of the Alberta electricity transmission system. The company is a partnership between SNC Lavalin and the Macquarrie Essential Assets Partnership.

There is a possibility that this model will be expanded in Canada, as the Ontario Energy Board is currently striving to develop a policy that will allow some degree of competition in transmission, allowing increased participation from private investors. The board's initiative is driven by the desire to minimize the cost of expanding the transmission grid to accommodate the connection of new-generation facilities being planned for remote locations (see Ontario Energy Board, 2010).[18] An open-bid process to determine which companies secure the right to build and own new transmission facilities would help to ensure that the capital costs of the facilities reflect market conditions.

Merchant transmission model

An alternative to having transmission charges determined by a regulator is to allow a transmission line proponent to offer to sell capacity on the line to marketers, distributors, and other potential users of the proposed service. The so-called "merchant transmission" model, in which transmission tariffs are essentially market-determined, fits best where electricity markets have been deregulated such that marketers and distributors have an incentive to secure capacity to move electricity from one

18 This could involve opening the door to merchant transmission, as discussed in the following section.

area to another. For this reason, merchant lines are sometimes referred to as "market connectors."

For the merchant model to work, there has to be a willing investor or group of investors to initiate and secure financing for the project. Further, there must be sufficient interest (usually determined by an "open season" call on prospective users) to ensure that a large enough proportion of the transmission capacity will be used to permit the investor(s) to realize a return that is sufficient to make the investment attractive. The line's users negotiate and pay for the cost of the transmission service.[19]

Instead of paying regulated transmission tariffs on the energy that is shipped through a merchant line, electricity consumers pay for the cost of that transmission service as negotiated by their distribution service provider or local distribution company. Given that merchant transmission lines are subject to free market conditions, competition from developers will result in the most efficient and lowest cost additions to the power grid, thus cascading lower rates to end-users.

Electricity generation and wholesale markets have only been deregulated in two Canadian provinces (Alberta and Ontario), and are controlled by the government in Mexico. Thus, North American opportunities for merchant transmission are mostly in regions of the US where there is a high concentration of state jurisdictions with deregulated electricity markets, as in the New England region as well as the States of New York, Pennsylvania, New Jersey, and Maryland.

The only Canadian merchant transmission line is the Alberta-Montana Tie Line, a 345-kilometer (216 mile), 230-kilovolt merchant transmission line that is being built between Lethbridge, Alberta, and Great Falls, Montana. The Alberta-Montana Tie Line is expected to lead to the development of wind power and other generation facilities on both sides of the Canada-US border and facilitate electricity exports and imports. The line was approved by the National Energy Board, the Federal Energy Regulatory Commission (FERC), and provincial and state regulatory bodies in both countries.

Several merchant transmission projects operate in the United States. These include the Cross-Sound Cable from Long Island, New York, to New Haven, Connecticut, the Neptune Regional Transmission System (RTS) line from Sayreville, New Jersey, to Newbridge, New York, and Path 15 in California. The Cross-Sound Cable Company owns a 24-mile submarine electricity transmission cable buried in Long Island Sound which has a capacity of 330 MW. The cable connects New England's electric transmission grids to the distribution system on Long Island, NY.

19 With conditions in place that facilitate the negotiation of transmission tariffs or fees based on market conditions, the need for regulation of tariffs on account of the monopoly power that exists where there is a single transmission facility owner and many customers without the means to negotiate is reduced.

The Neptune RTS is a 65-mile undersea and high voltage direct current (HVDC) transmission line that provides for 660 MW of electric power transmission capacity from New Jersey to Long Island. Neptune RTS, LLC, operates under a long-term agreement with the Long Island Power Authority (LIPA) which selected the company to build and operate the project in a competitive bidding process in 2004. At the time when the decision was made, LIPA determined that it was more economical to import power via the new line than to build additional power plants on Long Island. Neptune RTS provides LIPA with access to the PJM (Pennsylvania, New Jersey, and Maryland) deregulated power market, which has more than 160,000 MW of diversified power generation capacity.

The Path 15 Project is an 84-mile, 500-kilovolt transmission line upgrade in central California that was built 7 years ago to alleviate north-south transmission congestion. In September 2006, a Canadian company, Atlantic Power, acquired the company that owned 72 percent of the transmission service rights associated with the Path 15 upgrade. Those rights were then assigned to the California Independent System Operator in exchange for a regulated rate of return based on tariffs regulated and approved by the Federal Energy Regulatory Commission.

The Path 15 connector is a sort of hybrid, having been constructed as a merchant line but now operating as a regulated entity. There are also Australian examples of merchant connectors being built to meet a need recognized by market participants but later converted to regulated utilities. One is Terranora (formerly DirectLink) connecting Queensland and New South Wales. Another is the Murraylink connector which joins Victoria and South Australia. The only remaining merchant line in Australia is the Basslink.

Basslink is a 500 MW plus HVDC link crossing the Bass Strait. It connects the Loy Yang Power Station in Victoria on the Australian mainland to the George Town substation in northern Tasmania. Basslink consists of a 60.8 km overhead power line to the Victorian coast; a 6.6 km underground cable in Victoria; a 290 kilometre submarine power cable from Victoria to Tasmania; an 11 km overhead line section to the Tasmanian coast; and a 1.7 km underground cable in Tasmania. The system was constructed between 2003 and 2005 by National Grid Australia Pty Ltd. Since 2007, it has been owned by City Spring Infrastructure Trust.

Coordination of generation capacity, and transmission and distribution facility expansion

Where electricity generation continues to be regulated and the Crown-owned generator or the local investor-owned-utility is also responsible for building and operating transmission and distribution facilities, proposals to expand the electric transmission system are generally put before the regulator in conjunction with proposals to add to generation capacity. In such cases, it is unlikely that the transmission system will be under-built and that electricity consumers will be confronted with power supply shortages on account of transmission capacity constraints. This is because the regulator will be in a position to determine whether the generation and expansion plans are reasonable and consistent. If electricity generation is regulated but the generation and transmission facilities have different owners, the regulator is still in a position to coordinate generation and transmission capacity development. However, coordination can become challenging when generation has been deregulated such that the location and size of additions to generation capacity are essentially left to the investor, subject to compliance with environmental regulations and local by-laws.

In Alberta, the provincial government has sought to ensure that would-be investors in new-generation capacity are not confronted with inadequate transmission capacity by requiring that transmission capacity in the province be upgraded and expanded sufficiently to prevent congestion from occurring under normal circumstances. However, as examined in a recent Fraser institute study, a congestion-avoidance transmission policy such as Alberta's, which depends on wire-only solutions (i.e., expansion of the transmission system), may be costly to electricity consumers if less expensive solutions, such as locating new-generation capacity in regions where costly transmission system upgrades can be avoided, are available (Angevine and Boik, 2009).

Electricity transmission in Canada

Most of Canada's provinces and territories are joined in an interconnected electricity transmission system that crosses international and provincial borders.[20] There are important interprovincial transmission ties, such as those between Alberta and British Columbia, Ontario and both Quebec and Manitoba, and Labrador and Quebec. Hydro-Quebec's system extends more than 1,100 kilometers from Churchill Falls in Labrador to Montreal, and from James Bay to southern markets, including the US. In Manitoba, a large 500 kilovolt Direct Current (DC) system brings hydropower from the Nelson River to customers in the Winnipeg area. In Ontario and British Columbia, major 500 kilovolt systems bring electric power from northern generating sites to markets in the south. British Columbia, Manitoba, Ontario, Quebec, and New Brunswick each have high-voltage (345 kV or greater) transmission interties with systems in the United States (Industry Canada, 2001).

20 In general, "transmission" refers to the transportation of electricity at pressures or intensities of greater than 138 kilovolts (kV). Transmission therefore takes place from the sources of power generation to certain industrial sites and to the lower voltage distribution systems that deliver the energy to homes, institutions, and commercial and many industrial business locations.

The development of new electric generation facilities located at considerable distances from main electricity consumption centers, as with the various site-specific hydro projects that are being discussed in British Columbia, Manitoba, Quebec and Labrador, will require extensions to the transmission network. Similarly, development of wind power generation sites in remote areas of Ontario, Quebec, and southern Alberta, as well as the location of a nuclear power station in northern Alberta or Saskatchewan would require expansion of regional transmission systems. Development of stronger east-west interconnections between Quebec, Ontario, and Manitoba, with possible connections into Alberta, has also been under consideration by the government-owned electric utilities in Manitoba, Ontario, and Quebec for several years.

Additions to transmission systems will also be required to lower congestion that could prevent demand from being satisfied in spite of adequate electric generation capacity in a region. The Alberta Electric System Operator, for example, has proposed the construction of new, high-voltage connections from the coal-fired generating stations concentrated near Edmonton south to Calgary because of congestion on the existing north-south lines (Alberta Electric System Operator, 2009).

Within Canada, east-west transmission is less common than north-south transmission. Moreover, most of the interprovincial power transfers to date have occurred in Eastern Canada because of the agreement between Newfoundland & Labrador and Quebec with respect to energy from the large Churchill Falls hydroelectric facility, and Quebec exports to Ontario.

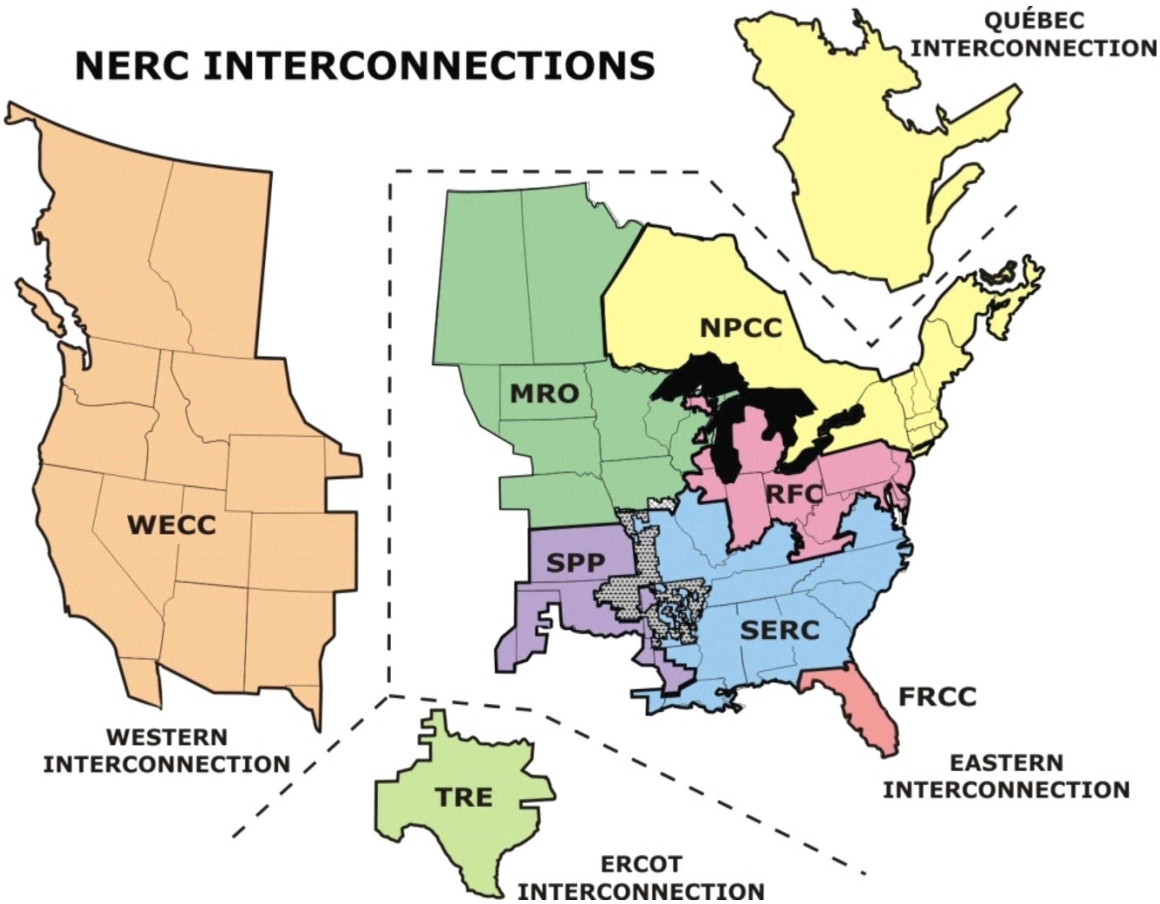
The National Energy Board authorizes the construction and operation of the Canadian portions of international power lines and of interprovincial power lines if the provinces through which the lines pass decide to have them regulated by the NEB. According to a National Energy Board report, no interprovincial power lines currently fall under its' scrutiny (National Energy Board, 2009b; 29). While power is being transmitted across provincial boundaries, each province regulates the transmission lines operating within its boundaries up to the points on its borders where they interconnect with lines in adjacent province(s).

In a recent report, the National Energy Board identified various major (>100kV capacity) international power line proposals from 2010 to 2020 (National Energy Board, 2009b). The list of projects highlights the importance that Canadian utilities are giving to expanding access to electricity markets in the United States and indicates that the emphasis on north-south electricity will continue.

A long-term reliability assessment by the North American Electric Reliability Corporation (NERC),[21] indicates that from 2010 to 2020, an average of 458 transmission miles (>100kV) will need to be added across Canada annually. This is equivalent

21 The North American Electric Reliability Corporation is the organization in charge of maintaining and improving the reliability of North America's bulk power system.

Figure 9: Regional transmission entities and North American Electric Reliability Corporation interconnections



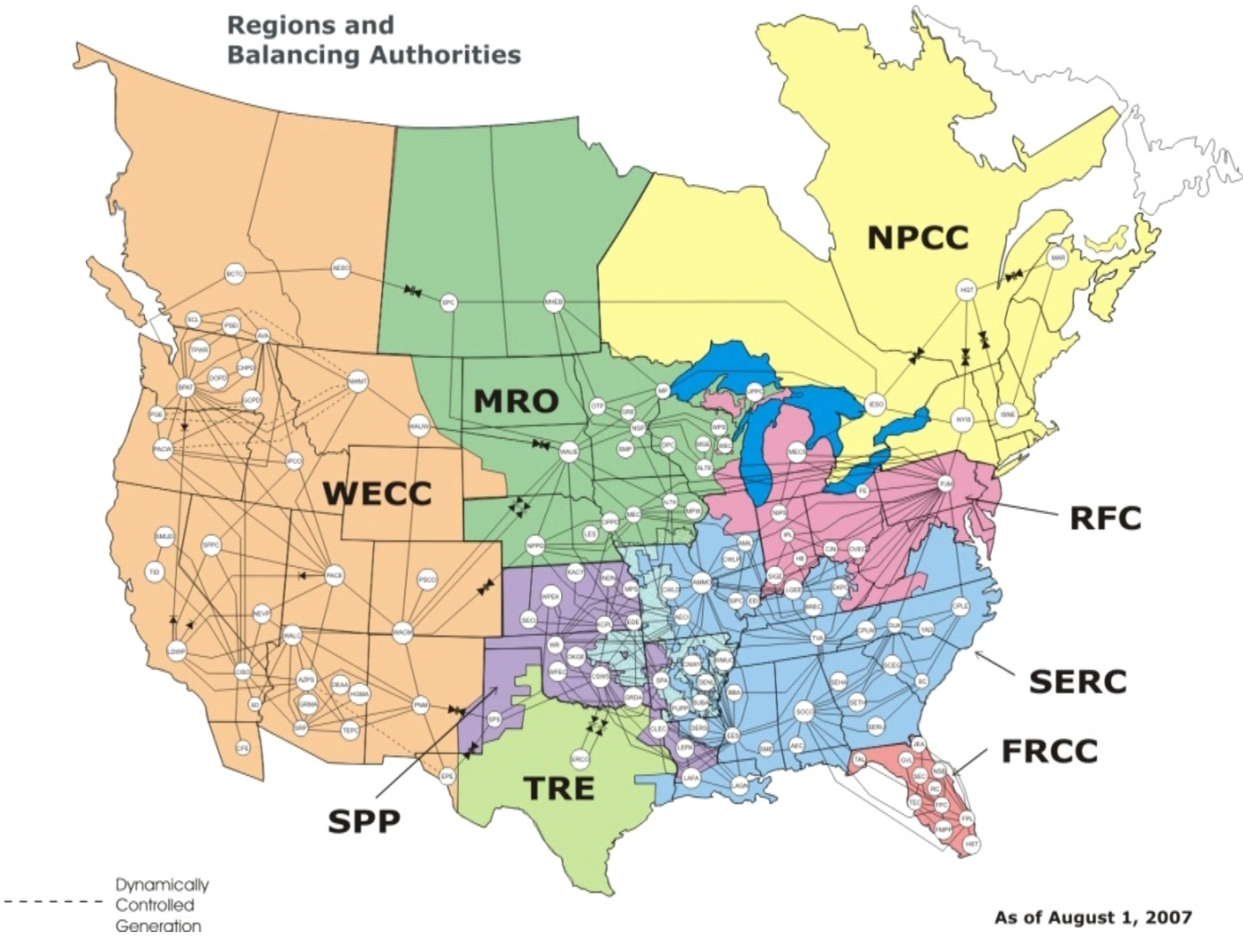
Source: North American Electric Reliability Corporation, 2010a. Reprinted with permission.

to about 4,586 miles of transmission lines over the decade, and will increase by 6 percent the transmission capacity from an estimated 79,541 miles of transmission lines in 2010 (North American Electric Reliability Corporation, 2010b).

Figure 9 illustrates the eight specific regional transmission entities[22] and four major market interconnections in North America as established by NERC. Figure 10

22 From west to east: Western Electricity Coordinating Council (WECC), Midwest Reliability Organization (MRO), Southwest Power Pool (SPP), Texas Reliability Entity (TRE), Northeast Power Coordinating Council (NPCC), Reliability First Corporation (RFC), SERC Reliability Corporation (SERC), and Florida Reliability Coordinating Council (FRCC).

Figure 10: North American Electric Reliability Corporation regions and balancing authorities



Source: North American Electric Reliability Corporation, 2010a. Reprinted with permission.

shows the particular regional entities with their respective major transmission connections and the corresponding balancing or trading authorities in each region.

Together, these figures illustrate the massive scope and complexity of the integrated North American electricity market and its transmission network.

All of the Canadian provinces except Newfoundland & Labrador (but not the territories) are included within the NERC's planning regions. In the United States, only Hawaii and Alaska are not part of a regional entity. Connections to Mexico's electricity grid are available through the TRE region (Texas) and the WECC region (California).

Electricity transmission in the United States

The United States has three large regional transmission interconnection systems: 1) The Western Interconnection composed of the 14 states that belong to the Western Electricity Coordinating Council, ranging from Washington to California, New Mexico, and Montana; 2) The Eastern Interconnection composed of the states that belong to the Northeast Power Coordinating Council, Reliability First Corporation, the Midwest Reliability Organization, the Southwest Power Pool, the Southeast Reliability Council, and the Florida Reliability Coordinating Council; and 3) The Electric Reliability Council of Texas (ERCOT) Interconnection.

The *US Energy Policy Act of 2005* amended the *Federal Power Act* by adding a section that requires the secretary of energy to conduct a nationwide study of electricity transmission congestion and constraints within the Eastern and Western Interconnections, every three years starting in 2006. *The American Reinvestment and Recovery Act of 2009* further directed the secretary to include an analysis of potential sources of renewable energy that are constrained by lack of adequate transmission capacity. The 2009 report, on the findings of the second study, identified a number of areas within both the Eastern Interconnection and the Western Interconnection where transmission investment is most likely to be required, either because of existing constraints or constraints that are expected to develop as additional generating capacity is put in place (US Department of Energy, 2009).

In the 2009 study, increased pathways into the Atlantic coastal areas from Metropolitan New York southward through Northern Virginia continued to be seen as critical congestion areas for the Eastern Interconnection, as identified originally in the 2006 version of the study (US Department of Energy, 2009: 66). As in the 2006 study, for the Western Interconnection the latest congestion study identifies the need for increased transmission capacity into Southern California to serve the Los Angeles, Riverside, and San Diego electricity consumption centers. This area has been identified as a critical congestion area. Also, transmission constraints in two other areas were identified as being of considerable concern: Seattle-Portland and San Francisco. The transmission capacity in each of these areas will require expansion or upgrading before long (US Department of Energy, 2009: 98).

The 2009 national electricity transmission congestion study also pointed out that transmission capacity will need to be expanded or upgraded in regions where large-scale new renewable generation, nuclear power, and coal-fired electric generation are expected to be developed. These include: the Southeast (nuclear); Illinois, Indiana and Upper Appalachia (coal); Montana and Wyoming (coal and wind); the Dakotas and Minnesota (wind); and Kansas and Oklahoma (wind).

A more recent report identified a number of major transmission projects that were being considered to transport electricity from new or proposed renewable energy projects (Democratic Policy Committee 2009). These include:

- A 1,900 km, 765 kV line running from Texas, through Oklahoma, to Kansas that would tie approximately 14,000 megawatts of new wind capacity into the Southwest Power Pool;
- A 4,800 km, 765 kV transmission line that would deliver electricity from renewable energy generating stations in the Dakotas, Minnesota, Iowa, Wisconsin, Illinois, and Indiana with an aggregate capacity of some 12,000 megawatts to high population centers in the Midwest, such as Chicago and Minneapolis;
- A 2,000 km, 500 kV transmission line in Wyoming, Colorado, New Mexico, and Arizona that would facilitate several things, namely, the production of renewable energy in Arizona and imports of energy from renewable sources in other states; the ability of Colorado and New Mexico to further develop in-state renewable energy production and exports; and Wyoming's capability to export wind power to Colorado and New Mexico.
- An 8,046 km, 765 kV expansion of the Midwest Transmission System from the Dakotas to the New York/New Jersey region.

The North American Electric Reliability Corporation's long-term reliability assessment indicates that on average, 3,486 miles of new transmission lines (>100kV) will need to be added annually over the next decade in the United States. This estimate is close to 8 times greater than that for Canada and the total addition during the 10-year period from 2010 to 2020 (34,862 miles) would represent a 9 percent increase from the 375,000 miles of electric transmission lines in the United States in 2010 (North America Electric Reliability Corporation, 2010b).

Electricity transmission in Mexico

Mexico has an extensive national electricity transmission system that stretches north and south from one end of the country to the other, as well as down the Baja Peninsula. As of September 2010, the transmission network was 30,764 miles long (Comisión Federal de Electricidad, 2010). The system has been expanded by close to 8,000 miles or 354 percent since 2001.

The Comisión Federal de Electricidad (CFE) is planning to expand the transmission system by 13,415 miles from 2010 to 2020 in order to meet an estimated annual average growth in electricity consumption of 3.6 percent. As the Commission's 2010, 14-year plan outlines, transmission system expansions, extensions, and upgrades (including modernization of many substations), are planned throughout Mexico (Comisión Federal de Electricidad, 2009: 4-3, table 4.1). By the end of 2020, the entire system is anticipated to stretch 44,179 miles, about 44 percent greater than in September 2010, effectively growing at a compound annual growth rate of 3.7 percent from 2010 to 2020.

Based on long-term reliability assessment estimates from the North American Electric Reliability Corporation, Mexican electric power lines that are connected to the NERC's regional entities in the United States (TRE and WECC), will be expanded by 18 percent (254 miles) from an estimated 1,402 miles in 2010, to 1,656 miles by 2020 (North American Electric Reliability Corporation, 2010b).

Electricity price and rate determination

The rates paid for delivered electricity generally reflect the costs of building and financing power plants and the required electricity transmission and distribution systems, as well as the costs of operating and maintaining those facilities, including fuel costs.

Generally, electricity rates are higher for residential and commercial consumers due to the higher costs needed to distribute electricity to them. Large industrial consumers, on the other hand, tend to consume greater volumes of electricity than other consumers. Also, as pointed out above, they are often able to accept higher-voltage deliveries, thus avoiding distribution costs. For these reasons, where generation is regulated, industrial consumers benefit from power rates that are closer to the cost of electric generation, including the regulated returns on debt and equity related to the generation and the transmission and distribution facilities. Where the electricity market has been restructured or opened to allow for competition, the cost of electricity to industrial consumers is the wholesale market price of electricity plus the regulated transmission and distribution tariffs.

The cost of generating electricity changes minute by minute as electricity in virtually all cases cannot be stored and must be produced in a fraction of a second when needed. Therefore, in open markets, wholesale electricity prices at the point of delivery to the transmission grid are highly responsive to supply and demand factors at the time of delivery. Prices are generally highest during those (peak-load) hours when consumption is greatest.

Electricity prices not only vary over time, but also by region according to local supply and demand conditions, the characteristics of the available infrastructure, and related fuel requirements (Energy Information Administration, 2010c).

Price differentials are important for understanding interregional and international electricity trade, which is discussed in the following section. According to the National Energy Board, inter-provincial and international trade has greater influence in determining local prices in a re-structured (unbundled)[23] market, than in the tradi-

23 Restructuring refers to the reorganization or unbundling of electrical utilities from vertically integrated monopolies (companies that own generation, transmission, and distribution facilities) into separate generation, transmission, and distribution service companies. Unbundling is intended to promote competition amongst generators and new entrants to the market, while providing more open access to transmission systems (wholesale). Unbundling also increases competition in the marketing of electricity (retail), making more choices available to consumers (National Energy Board, 2010b).

tional market structure (vertically integrated natural monopoly), because, with restructuring, regions with relatively high costs are more likely to have access to lower-cost electricity from other regions. Increased trade and the benefits that it brings to consumers are facilitated by open access to transmission systems (National Energy Board, 2010b). Free-market electricity also brings the advantages of increased competition and customer choice as identified in an earlier Fraser Institute report (Mullins, 2004).

Pricing structures, rates, and regulations are key determinants of additions to generation capacity (i.e., the location, number, and type of new plants) as well as expansions and upgrades to the transmission and distribution systems. The existing regulatory framework indicates the regulatory hurdles that must be cleared by investors while the market-determined or regulated prices, as the case may be, provide an indication as to whether investors may be able to earn an acceptable return on their planned investments.[24] The National Energy Board acknowledges that in regions with restructured markets, prices could turn out to be higher or lower; the result largely depends on whether investors' responses to price signals leads to sufficient new electric generation and transmission capacity being put in place in time to meet the incremental demand (National Energy Board, 2010b).

Canada

In Canada, the provincial or territorial authorities regulate electricity prices (except in Alberta and Ontario, where market restructuring has occurred to different degrees), as well as electric transmission and distribution rates. The National Energy Board authorizes the construction and operation of international power lines as well as those interprovincial lines that fall under federal jurisdiction. The board is also in charge of administering electricity export permits (National Energy Board, 2010a).

Electricity pricing varies by province or territory according to the availability and sources of generation, and whether prices are set in a market-based or regulated environment. Alberta and Ontario are the only provinces that have taken steps towards market-based systems. In all other provinces and territories (and still to some degree in Alberta and Ontario at the retail level), prices are regulated by a quasi-judicial board

24 While in restructured market environments the prices of electric energy are determined by the principles of free-market economics, trade, and competition, regulated markets generally have pricing structures that allow electric generation investors to cover their costs of capital and operations, plus a specified rate of return. This rate is usually set by the local regulatory board or commission. However, if the rate is not reflective of market conditions, it may fail to provide an appropriate signal to investors to encourage them to invest.

or commission (National Energy Board, 2010b). In all of the provinces and territories, the transmission and distribution tariffs are regulated on a cost-of-service basis. This approach allows for transporters and developers to cover operating costs, plus earn a reasonable rate of return on their investments.

In Alberta, wholesale electricity prices are determined by market forces. In fact, the National Energy Board concedes that, of all the provinces and territories, Alberta has moved the furthest in restructuring its electricity market (National Energy Board, 2010b). At the retail level, Alberta electricity consumers can either contract for electricity with a marketer (retailer), or opt for a regulated rate option.

Ontario has chosen to partially restructure its electricity market by adopting a hybrid structure that combines elements of regulation (retail) and competitive markets (wholesale).

British Columbia, Quebec, and New Brunswick allow access to wholesale electricity supplies produced in their jurisdictions by would-be importers in nearby provinces and US States, as well as limited access to retail supplies. Manitoba and Saskatchewan also allow wholesale access (National Energy Board, 2010b).

Canada has some of the lowest prices for electricity in the world. This is largely because of the country's large natural resource endowment. Readily available competitively-priced supplies of hydro, uranium, coal, and natural gas are a clear advantage in the production of low-cost electricity.[25] The lowest electricity prices in Canada are found in British Columbia, Manitoba, and Quebec, which produce large volumes of power at large-scale hydroelectric sites that have relatively low unit costs.

There are several reasons why the cost of electrical energy per se and the delivered (all-in) cost of electricity vary so much from one part of the country to another. A fundamental reason is that in all of the provinces and territories except Alberta, where consumers can opt for a market-based price, the retail price of electricity is regulated and the regulated prices reflect the unique characteristics (e.g., type and efficiency) of the electric generation facilities in each jurisdiction. Similarly, the unit costs of electricity transmission and distribution are different in each jurisdiction because of unique characteristics of the transportation infrastructure, especially volume, and distance factors.

Electricity trading amongst provinces does not lead to much equalization of electricity prices across Canada. Opportunities for interprovincial electricity trade are limited because of the limited capacity of the transmission interties between the provinces. Also, in most of the provinces, all or most of the electricity infrastructure, including generation, is government owned, and the owners' main objective is to ensure that their constituents' electricity requirements can be met with a high degree

25 For a comparison of electricity rates in Canada and other countries around the world, see International Energy Agency, 2010b; and National Energy Board, 2010a, 2010b.

of reliability. Through the years the crown-owned utilities have preferred to accomplish this using their own, provincial energy resources, while obtaining as little power as possible from their neighbors.

On the other hand, provinces with large amounts of low-cost generation capacity (especially hydroelectric resources, but also nuclear power) such as British Columbia, Manitoba, Quebec, and New Brunswick have focused on developing strong transmission interties with adjacent US regions, such as the US northeast and the Pacific Northwest. The main reason that US markets have been targeted is that they have relatively large populations and are in close proximity to the Canadian border, which makes electricity exports attractive.[26] Transmission linkages with markets to the south have also been fostered to some extent by the advantages of so-called “seasonal diversity interchange,” which accommodates the export of power from Canada during the summer months when peak load is greatest in markets such as California and New York, and imports, if required, during the winter when Canadian electricity demand is greatest.

United States

In the United States, state public utility commissions regulate electricity markets, rates (where restructuring hasn’t occurred), approvals of generation facilities, as well as activities of municipal power systems, power marketing agencies, and most rural electric cooperatives. On the other hand, the Federal Energy Regulatory Commission (FERC) regulates the transmission and wholesale sales of electricity in interstate commerce, and in some cases reviews siting applications for electricity transmission projects. FERC also licenses and inspects private, municipal, and state-owned hydroelectric projects and related environmental matters (Federal Energy Regulatory Commission, 2010).

The manner in which electricity prices are regulated varies across states. For this reason and different underlying supply and demand characteristics and circumstances, retail prices vary widely. In open markets, electricity prices are determined by real-time market forces. Therefore, at times of high (peak-load) demand, the price of electricity is generally set by the cost per MW-h of production corresponding to the last generator brought on line. Typically that generator is a relatively high-cost producer, because the low-cost or base-load generators, such hydroelectric, coal-fired,

26 Transmission consumes a portion of the electricity being transported because of the resistance of the transmission cables. The longer the distance and the smaller line capacity, the greater the “line losses.” This physical characteristic of electricity transmission therefore favors short, high-volume flow patterns.

and nuclear plants, are usually brought on sooner. Consequently, natural gas prices typically affect electricity prices more in US states and Canadian provinces where market restructuring has occurred, than in other states (Energy Information Administration, 2010c).

The Energy Information Administration (EIA) keeps track of restructuring or market deregulation activity across the United States. Currently, restructuring is active in 16 jurisdictions: Oregon, Texas, Illinois, Michigan, Ohio, Pennsylvania, Maryland, Delaware, New Jersey, New York, Connecticut, Rhode Island, Massachusetts, New Hampshire, Maine, and the District of Columbia. Restructuring has been suspended in 7 states: California, Nevada, Montana, Arizona, New Mexico, Arkansas, and Virginia. Market restructuring is inactive in the remaining 28 jurisdictions (Energy Information Administration, 2010h).

From January to October 2010, the average retail residential price of electricity in the US was 11.6 cents per kW-h. According to the Energy Information Administration, 7.9 cents per kW-h of that corresponded to the price or rate for electric energy (generation costs); 0.8 cents per kW-h to the transmission cost; and 2.8 cents per kW-h to the cost of distribution. The three States with the highest residential price of electricity in 2010 (from January to October) were Hawaii (27.91 cents per kW-h), Connecticut (19.33 cents per kW-h), and New York (18.70 cents per kW-h). The 3 States with the lowest residential prices in 2010 were North Dakota (8.15 cents per kW-h), Idaho (8.00 cents per kW-h), and Washington State (7.95 cents per kW-h) (Energy Information Administration, 2010c).[27]

Mexico

Article 1 of Mexico's *Electric Energy Public Service Law* establishes that it is the exclusive responsibility of the state to generate, transmit, and distribute electricity for public service, through the Comisión Federal de Electricidad (CFE),[28] as established by the Mexican Constitution.

Electricity rates must be filed or proposed by the CFE, and are subject to approval by the department of finance and treasury, which in turn makes final decisions based on consultations with the department of energy, mines, and state industry, as well as

27 For a more detailed comparison of retail prices by end-use across a selected group of cities in the United States and Canada, see Hydro-Quebec, 2009.

28 Luz y Fuerza del Centro (LyFC), the public utility that supplied the federal district region, was also included in this law. However, the company was dissolved in 2009, and its assets and functions were transferred to CFE.

the department of commerce and industrial development.[29] According to the law, electricity rates must be determined in a manner that allows the CFE to adequately meet its financial requirements, taking into account necessary additions to the national electric system. Through this process, the department of finance and treasury is able to determine prices for both peak-load, and low demand (off-peak) periods (Cámara de Diputados, 1993).

The *Electric Energy Public Service Law* was last amended in 1992, at which point greater private investor participation was allowed, yet restricted to generation only, and only for activities that are not classified as for the provision of public service (Comisión Reguladora de Energía, 2010b). Such activities include: self-supply generation, small scale generation, or cogeneration, as well as generation for sale to CFE by privately owned and operated independent power producers, generation for the purpose of export (from cogeneration or small-scale production only), imports (for the purposes of self-supply only), and electricity necessary for supplying the grid during blackouts or similar emergency circumstances (Cámara de Diputados, 1993). All of these non-public service provision activities are in turn regulated by the Comisión Reguladora de Energía (CRE), Mexico's Energy Regulatory Commission, which was created in 1995.

The CRE grants permits and licenses for private imports and exports of electricity.[30] It not only regulates generation from the small market segment of privately-owned participants, but also the relationship between these power suppliers and the CFE, by setting the prices, terms, and conditions of CFE's purchases of electricity for public service use. By doing this, CRE ensures that electricity is purchased at the minimum possible cost while guaranteeing stability, quality, and safety in the provision of electricity to the public.

Since there is minimum participation from private entities in the Mexican electricity market, the CRE undertakes balancing and ancillary services requirements, such as voltage-level maintenance to prevent system collapse. The Comisión also has the authority to approve guidelines and methodologies for fees paid to the CFE by state governments, municipalities, and other beneficiaries of the public electric system, for the construction, expansion, or modification of transmission and distribution facilities when needed (Comisión Reguladora de Energía, 2009).

According to the International Energy Agency, in 2009, the average industrial electricity rate in Mexico was 8.46 cents per kW-h, while the residential rate was 7.86 cents per kW-h (International Energy Agency, 2010b). That report provides electricity

29 While the Comisión Reguladora de Energía (CRE), Mexico's energy regulatory commission, is also involved in this process, it only makes recommendations based on its assessments, as opposed to making any final decisions.

30 For a breakdown of permits granted by the CRE since 1994, by category, see table 3.

rates for 32 OECD countries. The fact that Mexico is the only country of the 32 in which residential electricity rates are lower than those of industrial end-users suggests that the residential rates are being cross-subsidized by the industrial electricity consumers.

According to a review by the Mexican department of energy, at the time of writing there were 17 different rates for residential, farm, and public utility consumers in different parts of the country; 11 different industrial and commercial end-user rates, and 9 miscellaneous rates, for a total of at least 37 different rates. The review highlighted various issues ranging from subsidized rates, inefficiencies, and complexities within the current rate system and recommended the need for a thorough examination of the rate-setting and approval process in Mexico (Secretaría de Energía, 2008). As a result, the CRE has commissioned a study, to be released in 2011, that is to recommend rate-determination processes that will allow for improved transparency and accountability.

Electricity trade

Benefits of electricity trade

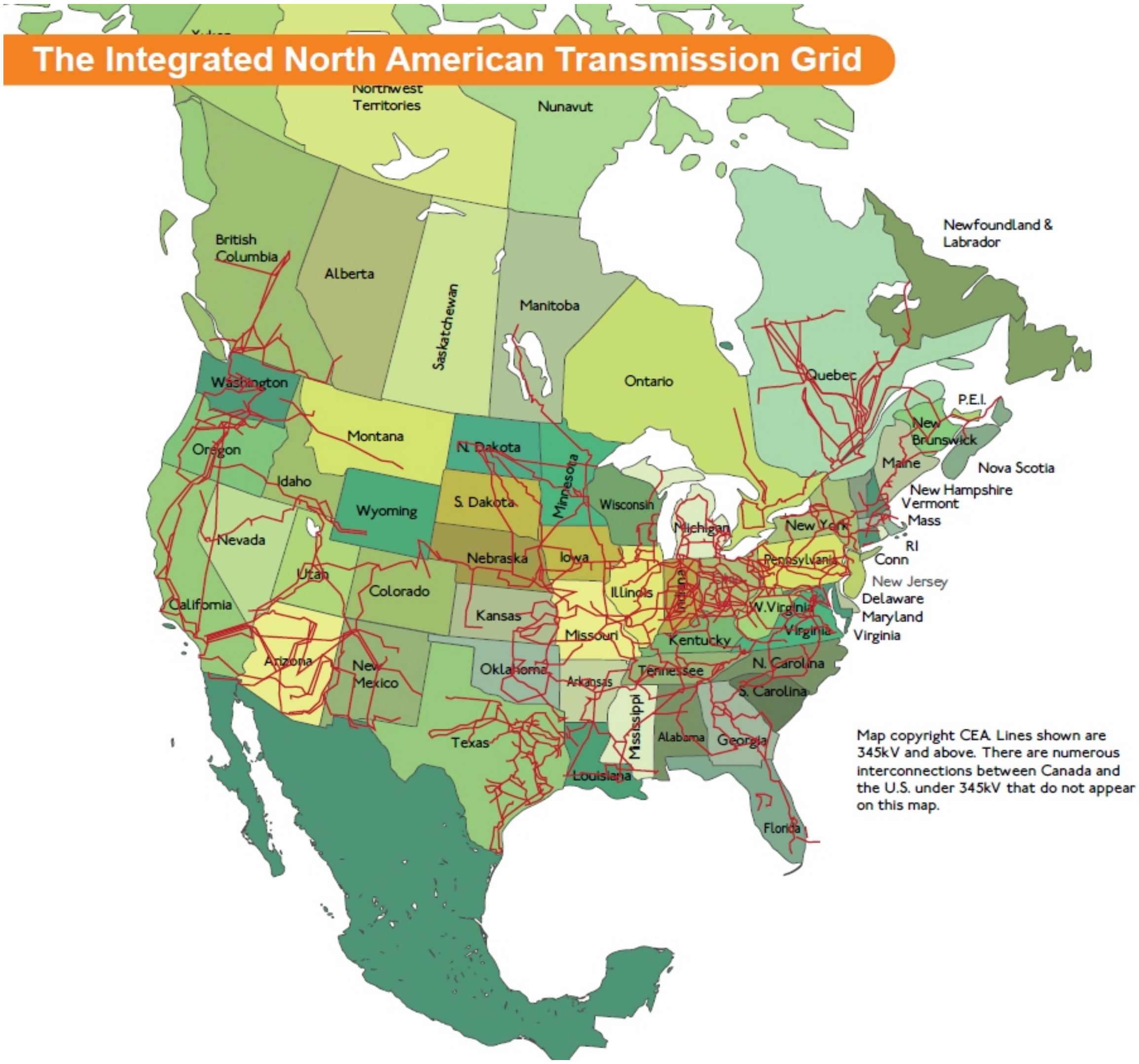
Whether interregional or international in scope, electricity trade should ultimately benefit electricity consumers through lower prices than otherwise. This is because trade results in lower electricity production costs for a number a reasons, such as reduced use of the higher cost generation units in the connected system and lower reserve requirements. Trade also enhances system reliability in the regions involved.

Opportunities for power trade are generally greater with respect to large hydroelectric facilities than with thermal power plants. One reason for this is that when a major new hydro plant comes on stream, a large new block of capacity is suddenly made available that is often greater than the incremental capacity immediately required in the region where the plant is located. Also, gas-fired power plants can be built on either side of an international boundary and the cost of fuel is generally much the same on either side as natural gas markets (and thus prices) are regional in scope.

Water flows are typically greater during the spring and summer, providing cross-border electricity sales opportunities, especially if the capacity of upstream storage reservoirs is limited. This can facilitate what is often referred to as seasonal diversity interchange. For example, a US state requiring more electricity during the summer months than in the winter because of air conditioning requirements may be able to benefit from importing power from a Canadian province that has surplus power generation capacity during the summer, and exporting power to that province during the winter. In this way, the amount of electric generation capacity required in the two jurisdictions combined could be less than what would otherwise be the case.

Figure 11 shows the major (≥345 kV capacity) North American electricity transmission interconnections that facilitate electricity trade between Canada and the United States, and between the United States and Mexico. Expanding the transmission grid would provide greater electricity supply options to North American power consumers and improve the security of electricity supply in various regions of the continent.

Figure 11: The Integrated North American transmission grid

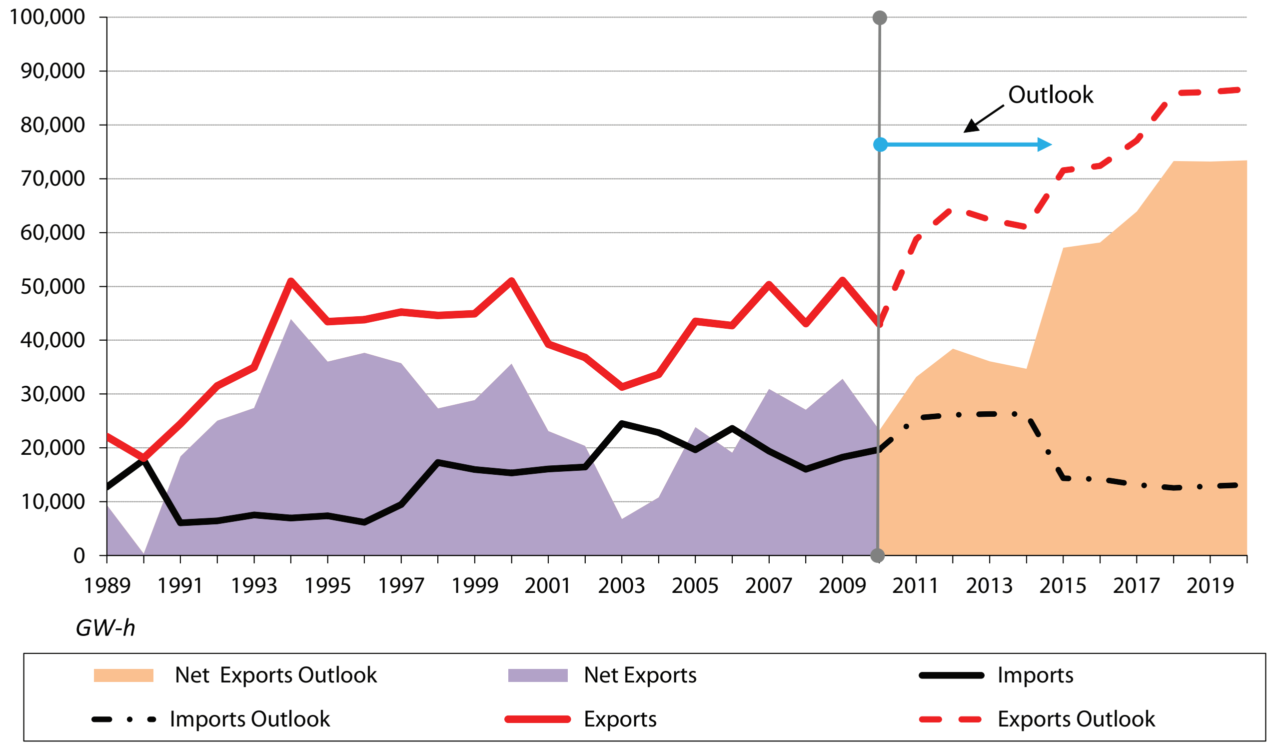


Source: Canadian Electricity Association, 2009. Reprinted with permission.

Canada-United States electricity trade

As figure 12 illustrates, since 1991 Canada has been a substantial net exporter of electricity to the United States. Canadian power exports mainly flow southward from British Columbia, Manitoba, Ontario, Quebec, and New Brunswick to electricity consumption centers in the United States. Imports flow through the same pathways.

Figure 12: Canada-US electricity trade (GW-h), 1989 to 2010 and outlook for the period from 2010 to 2020

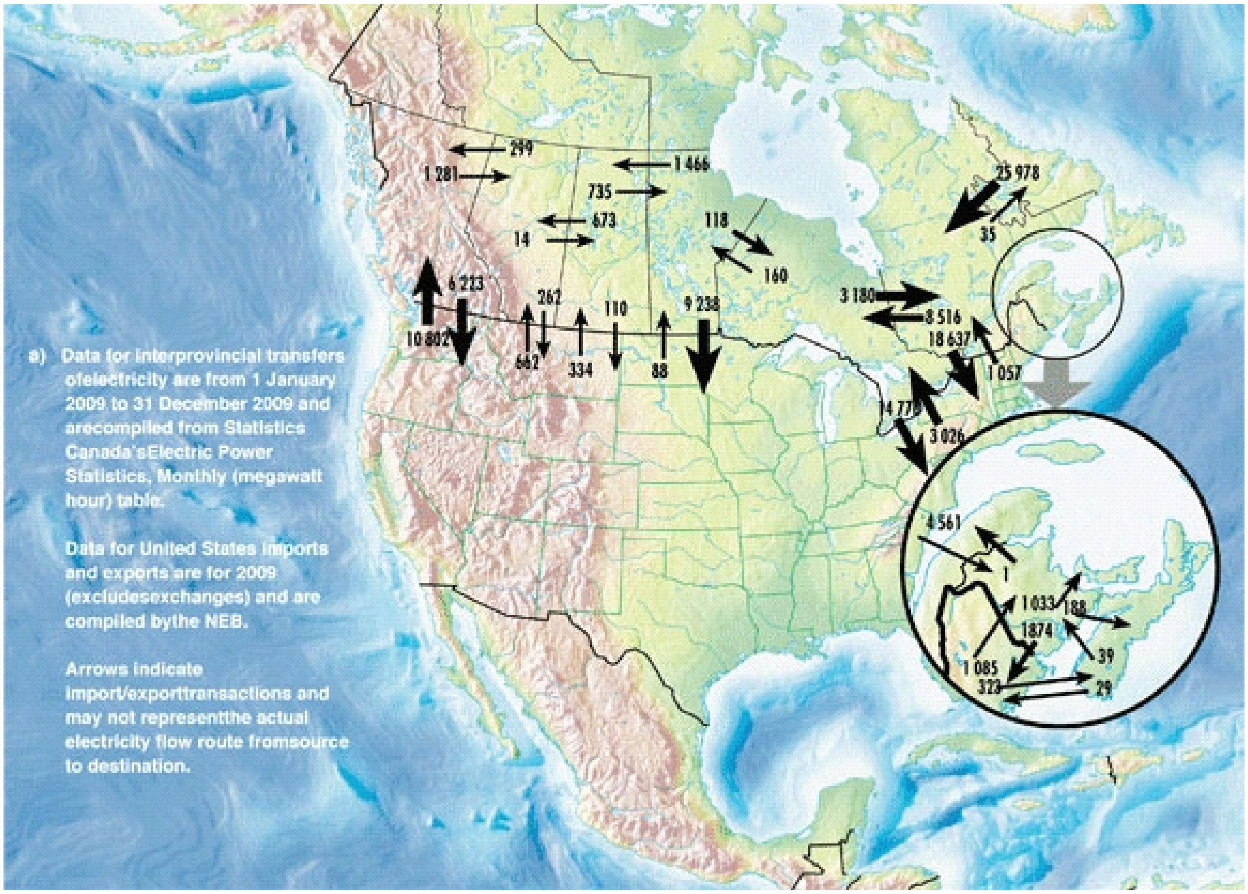


Sources: Statistics Canada, *Energy Statistics Handbook Third Quarter*, 2010a (for 1989-2008); National Energy Board, 2009a: Appendix table 5.4 (for 2009-2020); National Energy Board, 2010c. Figure by authors.

Canada's largest power exports are to the New England states, New York State, the Midwest, the Pacific Northwest and California. Except for electricity generated at the Churchill Falls development in Labrador and perhaps the more recent development of hydroelectric facilities in Quebec (e.g. James Bay), Canada's favorable position in electricity trade is largely a consequence of the overbuilding of capacity, as in British Columbia (hydro), in anticipation of future domestic consumption growth, rather than the targeting of export markets.

Economies of scale generally favor construction of larger hydro facilities than are needed at the time of construction. Consequently, during the initial years of operation of such facilities, the available capacity is often greater than provincial requirements. In Canada's case, much of the projected increase in Canadian hydro capacity from 2015-2020 that is embedded in the National Energy Board's *2009 Reference Case* projection appears to be aimed at the export market (National Energy Board, 2009a).

Figure 13: Canada-United States and interprovincial electricity trade (GW-h), 2009



Source: National Energy Board, 2010a.

Canadian net electricity exports (exports minus imports) to the US in 2009 were 32,821 GW-h (National Energy Board, 2010c). Figure 13 illustrates Canada-US and interprovincial trade in electricity in 2009, measured in GW-h.

In the National Energy Board's most recent projections, net exports mostly fluctuate in the 30,000 to 35,000 GW-h range until 2015, when they jump to 57,184 GW-h and then gradually rise further, reaching 73,418 GW-h by 2020, or close to a three-fold increase compared to the most recent (2010) estimate of about 23,000 GW-h of net exports (National Energy Board, 2009a: Appendix table 5.5; National Energy Board, 2010c).

The projected increase in Canadian power exports after 2014 and the reduction in imports is a result of the new hydro capacity that the National Energy Board projects will be added in British Columbia, Manitoba, and Quebec, plus the addition of another unit at the Point Lepreau nuclear installation in New Brunswick.[31]

According to the US Energy Information Administration's *2011 Annual Energy Outlook*, US net electricity imports from Canada and Mexico combined were about 34,300 GW-h in 2009 (Energy Information Administration, 2010a: table 10).[32] Net power imports to the US are projected to decrease by 21 percent (7,100 GW-h) from 2010 (34,300 GW-h) to 2020 (27,400 GW-h) at a compound annual reduction rate of 2.3 percent. Given that net US power imports from Mexico were only 434 GW-h in 2009 (less than 1 percent), and that the EIA does not project these to change much, this implies a marked reduction in US power imports from Canada. This is very different from the outlook for increased power exports to the US contained in the National Energy Board's *2009 Reference Case* (National Energy Board, 2009a). The main reason for this appears to be that the Energy Information Administration's projections do not reflect the significant additions to Canadian hydropower capacity that the National Energy Board has projected.

United States-Mexico electricity trade

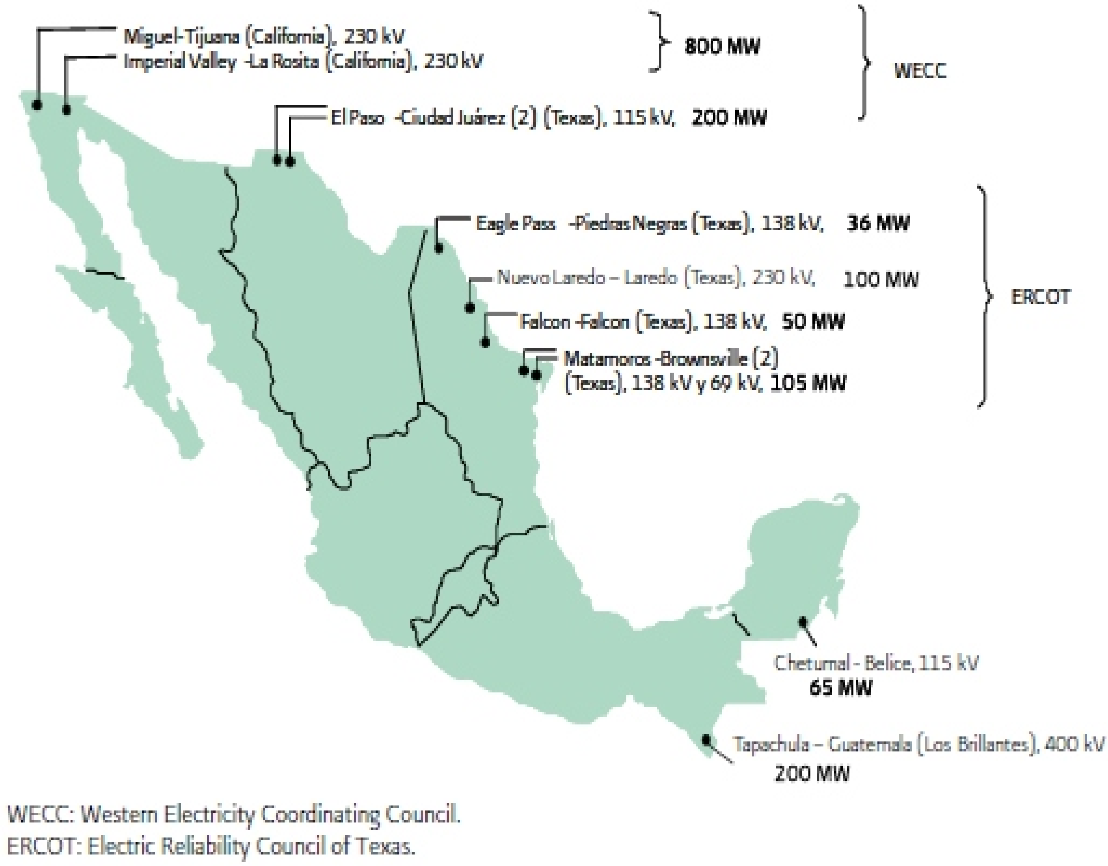
Most of the electricity trade across the US-Mexico border is between the State of California and Baja California, and between Texas and northeast Mexico.

As figure 14 shows, in northwest Mexico, 230 kV alternating current interconnections allow bi-directional commercial transactions of up to 800 MW via the interties between Miguel and Tijuana, and between Imperial Valley and La Rosita. Two 115 kV lines between Ciudad Juarez and El Paso offer a capacity of 200 MW. In the northeast, three 138 kV lines that connect points at Eagle Pass, Falcon, and Brownsville, in Texas, to the Mexican communities of Piedras Negras, Nuevo Laredo, and Matamoros, can accommodate transfers of 191 MW. The interconnections between Eagle Pass and McAllen are both direct current (DC) connections (Puga, 2007; Flores Quiroga, 2007; Secretaría de Energía, 2009).

31 The addition of the Point Lepreau nuclear station appears problematic for two reasons. First, the nuclear reactor business of Atomic Energy of Canada Limited has been put up for sale by the Canadian government and NB Power will find it more difficult to reach an agreement for a second unit with an owner that is not moved by claims that another unit would contribute to economic development in the Maritimes. Second, the availability of low-cost natural gas as the result of shale gas development will make it more difficult for nuclear power to compete in the Maritimes and New England markets.

32 An estimate finalized in the fall of 2010 places combined net imports from Canada and Mexico in 2009 slightly lower at 34,033 GW-h (Energy Information Administration, 2010d).

Figure 14: United States-Mexico international electric power lines



Source: Secretaría de Energía, 2009; Flores Quiroga, 2007. Reprinted with permission.

Trade volumes across the US-Mexico border, similar to those between Canada and the US, will generally be a function of price differences and capacity. For example, favorable spreads between relatively low electricity power prices in Texas and higher industrial on-peak prices in Mexico make it attractive for northeast Mexican industrial consumers to import electricity. On the other hand, excess electric generation capacity on the Mexican side of the border that drives prices lower there makes imports attractive to US consumers (Puga, 2007).

Mexico exported 1,082 GW-h of electricity to the US in 2009, while importing 647 GW-h, for net exports of approximately 434 GW-h. During the preceding five years, Mexican net exports to the US averaged close to that amount, although there was considerable fluctuation from one year to the next. Mexico became a net exporter of electricity to the United States in 2003, with a peak in net exports of over 1,100

GW-h in 2005. Since then, net exports have been in the 200 to 700 GW-h range (Energy Information Administration, 2010d).

Because the US Energy Information Administration's *Annual Energy Outlook* projects US electricity imports and exports on an aggregate basis (from Canada and Mexico combined), there is no indication of the portion of net US imports attributable specifically to either Canada or Mexico. However, given the anticipated rapid growth rate in Mexican electricity consumption, Mexican net exports to the US are unlikely to increase in the long term.

Required electricity infrastructure investment in North America

Investment in generation capacity

As indicated earlier in table 2, the National Energy Board, the US Energy Information Administration, and the Comisión Federal de Electricidad, along with Mexico's energy secretariat, are projecting that 102,291 MW of new electric generation capacity will be added in North America from 2010 to 2020 (National Energy Board, 2009a, Energy Information Administration, 2010a; Comisión Federal de Electricidad, 2009; Secretaria de Energía, 2009). An estimate for the investment requirements for these additions is developed in this section.

In November 2010, the Energy Information Administration released updated estimates of the overnight capital cost of new electric power plants in the United States (Energy Information Administration, 2010i). These costs are indicative of those faced by investors in new power plants, including turnkey (engineering, procurement, and construction) costs, as well as land, infrastructure, site works, licenses, administration, and related costs (but excluding the costs of financing and possible cost escalation because of increases in labor, capital, or material costs during construction). The estimates are provided on a dollar per MW basis and for power plants using various technologies and fuels.[33]

Based on the Energy Information Administration's breakdown of capacity additions by technology type and cost estimates, it is estimated that the weighted average cost of the projected additions to electric generation capacity, based on median costs by fuel type, will be approximately US$3.2 million per MW (2010 dollars)[34] (Energy Information Administration, 2010a and 2010i).[35] This compares with the general rule that had been used for many years for estimating the capital cost of new capacity at

33 The same information was used in the modeling process employed to estimate additions to US electric generation capacity in the Energy Information Administration's *2011 Annual Energy Outlook*.

34 Unless otherwise stated, all estimates in this section are provided in 2010 US dollars.

35 We used median costs by fuel type for these calculations. For a particular kind of fuel, such as natural gas, the cost estimate used is the median of the costs provided by the EIA across different types of plants such as, in the case of natural gas, gas turbines, combined cycle, and steam turbines. Types of power plants that were not identified as contributing to the addition of generation capacity from 2010 to 2020, such as natural gas fuel cells or hydroelectric pumped storage, were excluded.

about $1 million per MW and reflects the ever-increasing costs that investors face in electric power generation.

Given the projected capacity additions and their weighted average cost per megawatt, we estimate that the investment required for new generation facilities in the United States from 2010 to 2020 will total around US$169 billion (2010 dollars).[36] Assuming an average annual inflation rate of 2.5 percent, this translates into an electric generation facility investment requirement of approximately US$189 billion nominal or "as spent" dollars.

The overnight capital cost (OCC) estimates developed by the Energy Information Administration are very similar to estimates the International Energy Agency has developed for new power plants in North America (International Energy Agency, 2010c). For this reason, we also relied on the EIA's OCC information to estimate Canadian and Mexican electric generation facility investment requirements during the period from 2010 to 2020.

Using the EIA's median cost by fuel type estimates, the 26,793 MW of new electric generating capacity that is projected to be built in Canada from 2010 to 2020 has a weighted average cost of about $3.5 million per MW. This implies that approximately US$93 billion (2010 dollars) of electric generation facility investment will be required, or US$104 billion ("as spent" dollars) by 2020, assuming an average inflation rate of 2.5 percent over the forecast period.

In Mexico, the 23,323 MW of generation capacity that is projected to be added over the 10-year period has an estimated weighted average cost of close to $1.8 million per MW. The lower unit cost than in the US or Canada reflects the fact that a larger proportion of thermal power capacity is projected to be added in Mexico and a smaller proportion of renewable energy than in Canada and the United States. On this basis, the required investment in new electric generation capacity in Mexico during the period is estimated to be about US$42 billion (in constant 2010 dollars), or close to US$49 billion nominal dollars by 2020, assuming an average inflation rate in Mexico of 3.5 percent.[37]

36 This estimate is simply the product of the indicated 52,175 MW of new capacity and the indicated cost per MW of $3.2 million.

37 With a higher inflation rate in Mexico than in the US, one might argue that the Mexican peso will depreciate and a different exchange rate should be used to convert estimated Mexican investment to US currency. However, the US dollar is likely to be under considerable downward pressure because of mounting US foreign debt. Further, forecasting the Mexican peso-US dollar exchange rate is beyond the scope of this study.

Table 3: Private investment in electric generation capacity in Mexico, 1994-2010

Category	Number of Permits	Authorized Generation Capacity (MW)	Investment ($ Billions)
IPPs	27	13,760	$12.9
Self-Supply	507	6,453	$9.2
Co-generation	60	3,321	$3.3
Exports	6	2,780	$2.8
Imports	36	228	$0.0
Small scale	3	19	$0.0
Total	639	26,562	$28.3

Source: Comisión Reguladora de Energía, 2010.

As indicated earlier, the opportunities for private investment in electricity generation in Mexico are very limited.[38] In fact, private investment in independent power production is generally not feasible unless the investor can succeed in obtaining a long-term sales contract with the CFE for the energy that is produced.

Table 3 indicates the electric generation capacity that was added in Mexico from 1994 to 2010 through private investment, by type, according to information from the Comisión Reguladora de Energía (CRE), Mexico's energy regulatory agency.

Self-supply and independent power production (IPP) projects in response to bid calls issued by the Comision Federal de Electricidad accounted for over half of the increase (52 percent). Much of that investment was undertaken by foreign companies.

According to data for permits issued by the CRE, all of the IPP projects have been built and placed in service since 2000 (Comisión Reguladora de Energía, 2010a). Foreign companies account for $11.4 billion of the investment in generation capacity over the past 11 years, or about $1.04 billion per year. If that pace were to continue, the amount of private investment in IPP generation projects from 2010 to 2020 would be approximately $12 billion ("as spent" dollars). By way of comparison, the Comisión Federal de Electricidad's 15-year plan contains only $7.8 billion in IPP investment from 2010 to 2024, or the equivalent of $5.7 billion from 2010 to 2020 (Comisión Federal de Electricidad, 2010).

38 Transmission and distribution facilities in Mexico are controlled by the Comisión Federal de Electricidad (CFE). Private investment in generation is only allowed under certain arrangements dictated by the law.

Clearly, private investment could provide much of the capital needed to expand Mexico's electric sector, including transmission and distribution facilities as well as electric generation capacity. However, greater private sector participation in electricity generation and private investor involvement in expansion of the transmission and distribution system would require significant legal reforms.

Our estimate of the North American investment required for the additions to the electric generation capacity projected by official sources in the three countries from 2010 to 2020 is US$343 billion (current or "as spent" dollars). However, the required investment will, among other factors, be determined by the technological composition of the capacity that is added. This, of course, is because of the marked differences in the median OCC estimates across the electric generation technologies. Clearly, changes in the composition of projected generation capacity would change the amount of investment required. For example, if the proportion of renewable energy capacity were lower, the total investment needed would also be lower since the cost per MW of non-renewable capacity is generally much lower than that for renewable energy electric generation facilities.[39]

Transmission investment

Based on projections by the North American Electric Reliability Corporation (NERC) to 2019 for Canada and the United States, and projections to 2024 developed by Mexico's CFE, it is estimated that between 2010 and 2020, an additional 52,864 miles of high voltage (>200 kV) transmission lines will be required in North America (North American Electric Reliability Corporation, 2010b; Comisión Federal de Electricidad, 2009). This corresponds to an average of about half a mile (0.51 miles) of transmission line capacity per MW of added electric generation capacity.

A study undertaken by the Brattle Group (a consultancy) for the Edison Foundation estimates that for every GW of renewable energy added to the United States electric system, an additional 10 miles per year of transmission lines will be required to connect such projects to the transmission grid. The new transmission lines will be necessary because renewable energy projects are site-specific and, increasingly, will be located at further distances from existing transmission facilities (Brattle Group, 2008).

39 For North America as a whole, we estimate that the weighted average cost for the projected new non-renewable electric generation capacity is $2.3 million per MW. This compares to $3.9 million per MW for the renewable component of total new-generation capacity.

For the purpose of this report, this means that for every MW of additional generation capacity arising from renewable energy projects, an additional 0.1 miles[40] of new transmission lines will be required to connect renewable energy projects introduced from 2010 to 2020. Thus, overall, on top of the estimated 52,864 miles of transmission lines required (as mentioned above), renewable energy projects (42,227 MW) will require an additional 4,223 miles of transmission lines. This suggests that a total of 57,087 miles of new transmission line capacity will be required over the 2010-2020 period.

The Brattle Group estimates that required investment in US transmission lines from 2010 to 2030 will cost about US$298 billion ("as spent" dollars) (Brattle Group, 2008). Using the group's assumed 1.9 percent inflation rate over the period, the total investment in transmission assets in the United States in constant 2010 dollars will be about US$200 billion. Since this estimate is calculated for a 20-year period (2010 to 2030), the average annual investment in transmission in the United States is equivalent to about $10 billion. On this basis, over the 10-year period (2010 to 2020), the estimated investment required is US$100 billion in 2010 dollars, or about US$112 billion (current or "as spent" dollars), assuming a 2.5 percent average inflation rate during the 2010 to 2020 period.

Based on the NERC's projections, we estimate that 34,862 miles of new transmission lines will need to be added in the United States from 2010 to 2020 inclusive, before adjusting for the fact that many of the renewable generation facilities that will need to be connected to load centers will be located further from them than conventional generation facilities. Using the Brattle Group's assumption that 0.1 extra transmission miles will be required for every megawatt of new renewable energy capacity that is installed increases the estimated new transmission line requirement to 36,533 miles (Brattle Group, 2008). Given that the weighted average cost per mile of added transmission capacity is approximately US$3 million (constant 2010 dollars), the investment requirement would therefore be about US$105 billion (constant 2010 dollars).[41] Assuming an inflation rate of 2.5 percent, this would be the equivalent of US$118 billion (current or "as spent" dollars).

Canada will also require considerable investment in new and improved transmission and distribution facilities during the 2010 to 2020 period. Because of the scope of some of the proposed new projects, such as the 1,200 kilometer Labrador-Island Transmission Link, the Quebec-Ontario Interconnection Project, the Bipole III Transmission Project in Manitoba, and plans for new transmission construction in

40 Ten miles per year for 10 years = 100 miles divided by 1,000 in order to convert to MW from GW.

41 This estimate is likely a bit conservative given that the median cost per mile for high voltage power lines (230 kV, 345 kV, 500 kV, and 765 kV) is about US$3.4 million (2010 dollars). (Estimated using information from NERC data presented in the Brattle Group study, 2008).

Alberta, British Columbia, and other provinces, required investment in transmission system expansion and upgrading in this period will be substantial.

The $3 million weighted average cost per mile estimate developed from NERC and Brattle Group data, and the estimated requirement for an additional 4,586 transmission line miles between 2010 and 2020 inclusive (see North American Electric Reliability Corporation, 2010b: Transmission section) were used to develop an estimate of Canadian transmission investment requirements. First, though, the estimated transmission mile requirement was increased to reflect the projected 20,583 MW of renewable generation capacity that would need to be connected (National Energy Board, 2009a). Using the same adjustment factor as for the US (0.1 miles per MW of added renewables capacity), we estimated the additional amount of transmission mile requirements on this account to be 2,058 miles. This raised estimated transmission mile requirements during the 10-year period to a total of 6,644 miles. On this basis, we estimate that about US$19 billion (constant 2010 dollars) of investment in electric transmission facility assets will be required in Canada from 2010 to 2020, or the equivalent of US$21 billion ("as spent" dollars), assuming a 2.5 percent inflation rate.

In Mexico, an estimated 13,415 miles of required transmission line additions will cost US$39 billion (2010 dollars) of investment, without adjusting for the 494 "extra" miles on account of the projected 4,941 MW of generation capacity additions from renewable energy projects. With that adjustment, the price tag comes close to US$40 billion (2010 dollars), or US$47 billion ("as spent" dollars), assuming a 3.5 percent inflation rate.

In North America overall, 57,086 miles of transmission assets will be required over the 2010 to 2020 period, including 4,223 miles needed to accommodate 42,227 MW of renewable energy projects. The required investment will be close to US$164 billion (2010 dollars), or about US$186 billion ("as spent" dollars).

Distribution investment

Investment requirements in the distribution segment of the electricity sector will be substantial during the current decade as local distribution companies increase the capacity to deliver electricity to end users in response to population and economic growth and demand springing from new technologies, such as cellular communication devices and electric vehicles. In addition, requirements will be buoyed by spending on new technologies such as "smart" (time of use) meters, aimed at improving energy efficiency and reducing energy use. The Brattle Group estimates, based on a 0.8 percent average annual growth of real US investment in distribution facilities during the 1998 to 2007 period, suggest that between 2010 and 2030, close to US$400 billion (constant dollars) of investment in distribution lines and related facilities (about US$20 billion a year) will be required (Brattle Group, 2008). At that rate, during the 2010 to 2020 period, distribution sector investment totaling US$200 billion (2010 dollars) will be required in the United States. This is equivalent to close to US$224 billion "as spent" dollars, assuming a 2.5 percent inflation rate.

For the United States, the estimated US$200 billion (constant dollars) of electric distribution facility investment required during the 2010 to 2020 period relative to the projected 52,175 MW in electric generation capacity additions implies a weighted average cost of distribution additions per MW of added generation capacity of about $3.8 million per MW. We used this relationship to estimate the amount of distribution investment that will be required during this period in Canada and Mexico.[42]

For Canada, this approach yielded an estimate of US$102 billion (constant dollars) of distribution facility investment from 2010 to 2020 inclusive, or about US$114 billion ("as spent" dollars). For Mexico, the equivalent amounts are US$89 billion (constant dollars), and close to US$104 billion ("as spent" dollars). Overall, investment in distribution lines and facilities in North America during the 10-year period is estimated to total about US$391 billion (constant 2010 dollars), or about US 443 billion "as spent" dollars.[43]

Overall electricity infrastructure investment requirements

Table 4 summarizes our estimate of the electricity infrastructure investment that will be required in North America during the 10 years from 2010 to 2020.The total investment required is close to US$858 billion (in 2010 constant dollars). Assuming a 2.5 percent annual inflation rate in the US and Canada, and a 3.5 percent rate in Mexico, this amount is equivalent to nearly a trillion current or as spent dollars. By way of comparison, in its 2010 *World Energy Outlook,* the International Energy Agency projects that investment in electricity infrastructure in North America (including generation,

42 The authors recognize that this approach could, in fact, overestimate the required investment in distribution. A more precise approach would have been to review all of the local distribution companies' investment plans, but that was beyond the scope of the study. Distribution investment will be driven by population growth, construction of new housing, and the need to replace and upgrade distribution networks as distribution companies introduce smart grid technologies in their operations.

43 Note that these estimates were derived on the assumption that distribution investment is not sensitive to the proportion of new electric generation capacity that will involve renewable energy projects (i.e., that no adjustment is required to account for the renewable energy component).

Table 4: Required North American electricity infrastructure investment (billions of 2010 $US) from 2010 to 2020

	Canada	United States	Mexico	North America
Generation	$93	$169	$42	$303
Transmission	$19	$105	$40	$164
Distribution	$102	$200	$89	$391
Total	$214	$473	$171	$858

Sources: National Energy Board, 2009; Energy Information Administration, 2010a and 2010i; Comisión Federal de Electricidad, 2009; Secretaria de Energía, 2009; The Brattle Group, 2008; North American Electric Reliability Corporation, 2010b; table and calculations by authors.

transmission, and distribution) from 2010 to 2020 inclusive will be in the order of US$1.1 trillion (2010 constant dollars) (International Energy Agency, 2010d).

In North America overall, the estimated cost of the 102,291 MW of generation capacity that is projected to be added by 2020 is about US$303 billion (2010 dollars).

According to the estimates summarized in table 4, investment in additional generation capacity comprises about 35 percent of total North American electricity infrastructure investment from 2010 to 2020 inclusive. Generation capacity investment requirements are affected by the high proportion of projected projects with high overnight capital costs. Most noteworthy is the magnitude of investment in renewable energy projects, which constitute 41 percent of projected electric generation capacity additions, yet represent 55 percent of the investment required in generation capacity of all types. Wind power projects, in particular, account for a greater share of the generation investment requirements (at 36 percent) than their share of projected capacity additions (at 25 percent).

Next to wind, nuclear energy projects represent the second largest component of the electric generation investment requirement at about 21 percent of the total, although their contribution to the added generation capacity is projected to be only about 12 percent.

Natural gas and oil powered projects (the vast majority being gas) will contribute about 37 percent of the total additions to generation capacity over the 10-year period, yet only require approximately 12 percent of generation investment. This underscores the fact that the capital cost of gas-fired power plants is much lower and more efficient, on a per-unit of capacity basis, than that of wind, nuclear, and a number of other alternatives, including coal.

Coal-fired power plants are projected to account for 10 percent of total generation capacity additions in North America (mostly in Mexico), but represent close to 12 percent of generation investment, about the same as hydroelectric power projects and nuclear power plants.

Investment in transmission assets is estimated to account for about 19 percent (more than US$164 billion) of the total electricity infrastructure investment requirement in North America from 2010 to 2020. This includes an adjustment for the extra transmission miles estimated to be required for connections to anticipated renewable energy projects.

Required investment in electric distribution facilities in North America from 2010 through 2020 is estimated to be about US$391 billion, constituting about 46 percent of required electricity infrastructure investment.

The estimated $858 billion of investment in electricity infrastructure that will be required from 2010 to 2020 is based on specific projections of new-generation capacity additions and on the estimated investment requirements for transmission and distribution facility upgrades, extensions, and additions. For the United States and Canada, the renewable energy share of the projected additions to generation capacity is substantial. If the renewables share of added generation capacity in North America were lowered from 42 percent to 25 percent, we estimate that the total required investment could be lowered by about $56 billion (or 7 percent), assuming that the non-renewables share is increased accordingly and the non-renewables mix is the same as in the projections examined earlier in this report. Similarly, if governments extend and/or increase their commitment to renewable energy beyond the programs that are presently in place, the overall investment requirement could be larger than estimated because of the higher capital cost of renewables.

Regardless of the composition of increased generation capacity, the electricity infrastructure investment that will be needed from 2010 through 2020 is very large. It is important, therefore, that non-market barriers, such as those discussed in the following section, which threaten to prevent the required investment from being realized in a timely and efficient manner, be removed or lowered. Constraints that prevent the capacity to generate and deliver electricity from growing in step with increasing demand will push electricity prices higher, threaten the reliability of the electric system, and increase the risk of electricity supply shortages.

Barriers to investment

As indicated, considerable electricity infrastructure investment will be required in Canada, the US, and Mexico in coming years. Generation capacity will need to be added not just to meet growing electricity consumption, but also to replace aging, inefficient generation facilities. Moreover, electricity production and consumption growth will require expanded, more efficient transmission and distribution networks. Failure to build new facilities as they are needed will lead to unplanned generation outages, service interruptions, and congestion, and prevent the full benefits of electricity trade from being achieved. The end result will be higher than necessary electricity costs and slower employment, labor income, and economic growth.

Unfortunately, a number of non-market barriers threaten to slow the required pace of electric generation, transmission, and distribution investment. Such obstacles include but are not limited to the following factors:[44]

a. Energy policy risk

Prospective investors in particular generation types, such as coal combustion and nuclear power, will not move ahead if applications to construct new-generation facilities are likely to be denied for political reasons. A case in point is Ontario, where coal-fired power generation is being phased out, a limit has been established on the permissible amount of nuclear power electric generation capacity, and a hold has been placed on the approval of any new nuclear power plants.

Investors will also turn away from any situation where there is a likelihood of re-regulating an already deregulated electricity market.[45] Prospective policy changes that would require generators to assume responsibility for a greater portion of the cost

44 Regulators are likely aware of the barriers to investment discussed here, and may strive to factor into their decisions the impacts of regulatory and other obstacles on the time that it takes to have new electric generation or transmission facilities built and commissioned. However, the fact remains that such barriers tend to delay the development of electricity supply infrastructure and cause investors in new projects to gravitate to jurisdictions with fewer obstacles and lower risks. Reduction in investment barriers of the kind discussed here often require changes in government policy or legislation. However, in some situations, as with unnecessarily complex regulatory processes and procedures, a regulatory tribunal or commission may have room to introduce reforms under existing legislation.

45 In deregulated electricity markets, the transmission and distribution functions generally remain regulated, but the amount, types, and size of generation facilities, and the prices of electricity are determined by free market forces. (See the short and informative exploration of electricity deregulation issues by Mark Mullins, 2004.)

of transmission system upgrades and expansions could also serve to discourage investment in electric generation projects if the return on investment is unattractive relative to other opportunities when the additional cost is factored in.

Where electricity generation is regulated and there is uncertainty about key determinants of investment decisions, investors may delay or cut back investment plans. For example:

- Uncertainty about the allowable rate of return on equity because of a pending or likely review by the public utility commission;
- Anticipated changes in applicable laws or regulations; or
- An announcement by the regulator that a formula, methodology, or procedure will be changed at some future date with no indication as to precisely how or when.

b. Uncertain impacts of likely environmental policy change

Potential investors in new electric generation facilities are likely to hesitate, scale back, or postpone their investment plans due to anticipated but as yet unknown increases in the cost of regulatory compliance from pending changes to air pollutant emission standards, greenhouse gas emissions, and other environmental policies, including but not limited to carbon capture and storage requirements. Environmental policy changes that materially add to project costs also increase project risk, and drive up required rates of return and hurdle rates. Therefore, the pace of development will likely be slowed until the timing, nature, and extent of anticipated environmental policy changes are known with certainty, and their impacts on the relative economics of competing electricity generation technologies can be estimated with some degree of accuracy.

c. Land access and landowner compensation obstacles

Local residents often oppose the location of wind, nuclear, and other power plants close to their properties, even if the environmental hazards and risks are relatively small. Similarly, farmers and other landowners may oppose the erection of transmission towers on their lands either because of the amount of compensation being offered or for some other reason.

Proponents of new electricity generation or transmission infrastructure must overcome "not in my backyard" attitudes, which can be costly since delays generally translate into higher capital costs. In the case of delays in transmission investment the additional costs ultimately lead to higher electricity costs because of increased delivery charges.[46]

d. Native land claims

Demands from native groups for compensation for allowing land access and use can also delay the time required to obtain the approvals for electricity generation, transmission, and distribution projects from the responsible agencies. If such delays elevate project costs, the would-be developers may decide to abandon the project in question, or even to postpone it indefinitely. If they do eventually proceed, the costs to consumers will probably be greater than planned because of inflation during the intervening period and costs incurred because of the need for additional consultation and negotiation.

e. Need for transmission system connections

If undeveloped hydro, wind power, or other renewable resources are located at considerable distance from electricity consumption or "load" centers, the higher cost of connecting proposed generation facilities to the transmission grid (because of the distance and, in some cases, the terrain that must be crossed) can be a deal breaker. In fact, the developer(s) may have second thoughts about proceeding if the regulator determines that it would be inappropriate to saddle consumers in the state, province, or region in question with the cost of expanding or upgrading the transmission system to accommodate generation capacity addition in remote areas. Investors in proposed generation developments will be unwilling, at the very least, to commit to moving ahead until they know when the required transmission facilities will be in place and whether they will have to bear a portion of the cost, and if so, how much.[47]

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46 Cost overruns might occur due to inflation during longer than planned project approval and construction periods. This likely event will have little impact on the owner-operators of new regulated generation and transmission facilities since their revenues will be adjusted through application of the approved rates of return to the larger, inflation-adjusted rate base. However, electricity consumers will not be so fortunate, as the regulated prices will need to be higher to meet the expanded revenue requirements from generation or transmission utilities. Where electricity generation is deregulated, the increased costs incurred because of project delays may lead the facility owners to increase the prices at which they prepared to offer supply to the market. Whether and to what extent electricity prices are pushed upwards as a result will depend on market conditions, especially the extent of competition.

47 In relation to this issue, in its 2008 *Long-term Reliability Assessment*, the North American Electric Reliability Corporation recommended that regulators and policy makers support the development of guidelines for the allocation of the costs of expanding electric transmission systems in order to accommodate delivery of energy from renewable energy generation sources to consuming centers (where such resources or services are deemed necessary and beneficial) (NERC, 2008).

While some may believe that it doesn't matter whether electricity generators or consumers pay for transmission system expansion in the first instance since consumers must always pay for such costs in the end, it does matter. If generators have to pay for the cost of the incremental transmission facilities, and are unable (as in a deregulated, competitive market) to influence the price of the electricity, they may look for generation projects in other jurisdictions that are located closer to the transmission grid or where the regulator does not require that they contribute to the transmission costs. If this decision results in less generation capacity being added in the affected jurisdiction, higher electric *energy* costs will be the result. Hence, it may be preferable to have consumers pay for the cost of the incremental transmission facilities directly so that the additional generation gets built and consumers have greater and more diverse supplies to draw on, improved system reliability, and other associated benefits.

Whether or not the required transmission expansion is undertaken, the end result will likely be higher electricity costs. If the expansion is carried out, consumers will face higher delivery charges. If it is not, consumers may be confronted with increased electricity prices due to market pressures caused by limited local power supplies or the need to import more expensive power from other provinces, states, or regions.

f. Nuclear plant approval issues

Complex, overlapping, and lengthy regulatory procedures and processes are required to obtain permission to construct new nuclear power plants and are a barrier to such investment in all three countries. While special, detailed processes are necessary to ensure the safety and wellbeing of personnel working at nuclear power plants during the construction, testing, and operations phases, overlapping national and state or provincial regulations often result in long and costly approval processes. In Canada, approvals must be obtained from the Canadian Nuclear Safety Commission and various other federal and provincial government agencies. In the United States, the Nuclear Regulatory Commission has primary responsibility for issuing construction approvals on behalf of the federal government, but numerous other federal and state agencies are also involved.

Cumbersome, lengthy, and overlapping approval procedures for new nuclear power facilities will ultimately lead to higher power rates for electricity consumers. The main reason for this will usually be an increase in project capital costs due to price inflation during the "extra" time required to comply with complex regulatory processes as well as additional regulatory compliance costs.

g. Inadequate returns on equity

Allowable rates of return on proposed regulated electricity transmission and distribution projects will not attract required investment unless the projects are competitive in relation to similar or competing projects in other provinces, states, or industries. Certainly, if regulated cost-of-service based rates in a given jurisdiction fail to reflect the economic value of the proposed facilities, development is unlikely to proceed.

There is indication that rates of return on electricity transmission and similar utility investments (e.g., oil and gas pipelines) have become more attractive in the United States than in Canada during the past 10 to 15 years (Concentric Energy Advisors, 2009). This is mainly because, in an effort to streamline the ROE determination process, the National Energy Board, the Alberta Utilities Commission (formerly part of the Alberta Energy and Utilities Board), the Ontario Energy Board, the British Columbia Utilities Commission, and other Canadian regulatory bodies began to adopt a formula approach based on the yields expected on long-term government bonds. However, in the United States, ROEs continued to be determined on a case-by-case basis using the yield plus growth, and the equity premium methodologies outlined above. As a consequence of Canada's simplified blanket approach, and the drop in government bond yields, allowable rates of return on the equity of Canadian investor-owned utilities suffered.

Other things being equal, uncompetitive ROEs for Canadian-regulated utilities relative to similar utilities in the US make it more difficult to attract investment in this country. Further, attempts to privatize government-owned utilities in Canada will presumably suffer because there will likely be fewer potential buyers interested if more attractive ROEs can be secured elsewhere. At the very least, proceeds from sales of government-owned utilities in Canada can be expected to be lower than otherwise since pre-sale valuations will be lower. In addition, the extent of re-investment by the regulated companies here will be affected by lower earnings as a result of lower ROEs. Finally, with lower earnings, government-owned utilities wanting to expand will have to look to other sources for the required funding and taxpayers may be faced with higher property or income taxes as a result (Concentric Energy Advisers, 2008).

If rates of return on investment in Canada are lower than in the US, fewer companies are likely to submit bids to construct regulated transmission facilities here. Without much or any competition, there is a risk that the capital costs of new transmission facilities built in Canada will be greater than otherwise. Ultimately, Canadian electricity consumers will be penalized by having to pay higher electric transmission tariffs.

h. The time, cost, and uncertainty of regulatory processes

Prospective investors in electricity generation and transmission facilities are reluctant to undertake electric generation capacity and transmission projects in jurisdictions where approval processes are more protracted and expensive than in other locations. In fact, the length and uncertainty of regulatory processes may lead power plant investors to plan for multiple projects in their planning and development budgets even though, ultimately, they intend to proceed with only one or a small number of projects. As more information comes to hand, the less attractive projects are dropped sequentially until only those that will be completed remain in the budget (Walls, Rusco, and Ludwigson, 2007). In other words, uncertainty about regulatory outcomes may increase the cost of projects that are actually developed when the soft development costs of projects that are considered only up to a certain point, and then dropped, are added in.

Segmented chains of regulatory responsibility along proposed transmission path routes can create costly and time-consuming duplication of effort by a project proponent as well as by the various government departments and agencies involved.

Responsibility for transmission in the US has become a patchwork requiring, in some cases, local, state, and federal government involvement. Generally the states have exclusive jurisdiction over the planning for and location of proposed transmission lines in their jurisdictions, and for the allocation of costs. Would-be developers of interstate transmission lines have to apply to different regulatory bodies and stickhandle through different regulatory hurdles in each state, which is a major deterrent to such investment. Undoubtedly this is one reason why only 14 interstate transmission lines with a total of only 668 miles of 230 kV capacity or higher have been built in the US since 2000 (Democratic Policy Committee, 2009).

The US is making an effort to overcome the obstacle to transmission line investment that arises when investors must seek approval from regulators in a number of states, each of which may hold views as to where a new line should be located. For example, S. 368 of the *Energy Policy Act of 2005* requires US federal agencies to coordinate transmission siting decisions into their plans for land use and resource management. Further, S. 1221(a) requires the energy secretary to study electricity transmission congestion at three-year intervals.[48]

More importantly, it gives the secretary of energy the authority to designate geographic areas experiencing electric energy transmission capacity constraints or congestion as "national interest electricity transmission corridors." This gives the Federal Energy Regulatory Commission the authority to override state decisions on the place-

48 And due to provisions in the *American Reinvestment and Recovery Act of 2009*, the secretary of energy has included, in the 2009 version of the study, an analysis of significant potential sources of renewable energy that are constrained by lack of adequate transmission capacity. This initiative emphasizes the willingness of the US Federal government to focus on renewable energy development.

ment of transmission lines and, in certain cases, issue siting permits for new transmission lines.

In Canada, the National Energy Board must approve the Canadian portion of any transmission line that crosses the Canada-US boundary. The federal and provincial environment and related departments or ministries are also typically involved, as well as any municipalities through which a new facility will pass. The NEB also has jurisdiction over transmission lines that pass from one province to an adjacent one, if the provinces involved agree to have the Board assume regulatory responsibility. (Otherwise, each province regulates the portion of the line that falls within its own jurisdiction.)

Where electricity production is to come from a renewable energy source, the potential supplier may have to get over a number of hurdles in the "recipient" jurisdiction in order to gain certification as a supplier of energy under a renewable energy program (e.g., Renewable Portfolio Standards (RPS) certification, as in California). The level of "regulatory risk" is greater in such cases since would-be developers face possible changes to laws and regulations in more than a single state or province. Also, the supplier may need to "re-qualify" as an eligible supplier on a regular basis.

In short, the presence of multiple authorities with responsibilities for approving and providing oversight to the siting and construction of new and expanded facilities is a major barrier to transmission investment. Because a proposed electric generation facility will be located in single state or province, approval to construct and operate a new facility is generally the responsibility of the government of the state or province in which the facility will be located. However, the multiple jurisdictional responsibilities involved (e.g., municipal, county, state or provincial, and federal) can greatly increase the cost and time required to gain approval of a proposed new or expanded generation facility. Similarly, there frequently are overlapping responsibilities among and between state or provincial and federal officials, since the responsible government departments in each jurisdiction must be satisfied that the regulations that they oversee are met. In Canada, for example, both the provincial and federal environmental departments are typically involved with applications to construct new facilities, as is the federal department of fisheries and oceans where rivers, lakes, or oceans are involved.

The time for and costs of regulatory compliance often mean that it takes many months for electricity generation and transmission project proponents to receive the necessary approvals to begin construction. In some cases, disputes between overlapping jurisdictions with regard to siting may prevent a project from ever going ahead. Such delays and disputes are not without costs to electricity consumers. Transmission projects that are approved months or years after the need has been identified may mean the transmission system remains congested for a long period of time, resulting in much higher electricity market prices than would otherwise have been the case.

Further, delays getting projects approved may lead to higher capital costs than otherwise on account of inflation, and, ultimately this leads to higher transmission tariffs.

The uncertain duration of approvals procedures, and the possibility that any one of a number of regulatory agencies could create unexpected and even insurmountable roadblocks, create the risk that even well structured applications may be rejected or have to be abandoned. Since many millions of dollars are required to prepare proposals for major transmission and other electricity infrastructure projects, including engineering and design costs, and to shepherd them through the approval process, it is likely that applications for some projects are never made and that applications often are only filed for the potentially most profitable ventures. This suggests that because of regulation, the amount of electric system infrastructure in place at any one time will tend to be somewhat less than it would otherwise be.[49]

i. Additional hurdles in the case of international power lines

Where a proposed transmission facility is to be built across international boundaries, the facility developer will have an even more difficult task than that described above. This, of course, is because of the need to clear somewhat different regulatory requirements not only between the Canadian province(s) and the US state(s) involved, but also the need to satisfy the several layers of federal regulations on both sides of the international border. As evidenced by the protracted approvals process that the first merchant transmission line between Canada and the United States, the Montana-Alberta Tie Line, required, this can be a lengthy, costly and frustrating experience. From the project's inception in 2004, it took 5 years to get the necessary regulatory approvals in place.

Permits obtained in Alberta expired while issues were still being thrashed out with landowners in Montana. This required the developer to re-file every application that it had filed with the Alberta Surface Rights Board. Four renewals had to be filed with the National Energy Board, and the developer had to file twice with the US Department of Energy for the required permit. The lengthy period required for the approvals process meant that materials had to be re-priced, the project capital costs re-estimated, and the financing renegotiated. As a result of the frustrations he experienced, Johan Van't Hof, the CEO of project owner Tonbridge Power Inc., stated, "I will never build a trans-border line again" (O'Meara, 2010).

49 In spite of the fact that some regulated entities may seek to overbuild in order to expand their rate base.

j. Regulated electricity generation

Where electricity generation is regulated, the regulated rates of return may not be sufficient, compared with other jurisdictions and industries, to attract potential investors. Electricity prices emanating from free, wholesale markets must be allowed to determine the type and quantity of electric generation units that are added, instead of regulated rates of return on investment, or government decree.

That is, competing investors with intimate knowledge of the attributes of competing technologies who are prepared to take risks on behalf of their shareholders should determine the path of electricity supply expansion, including the composition of electric generation capacity that is added. Only in this way are long-run supply costs likely to be minimized. For this reason, deregulating electricity markets and adopting free-market principles is clearly desirable.

Deregulating (or restructuring) electricity generation will enable wholesale electricity prices to be determined through the interaction of the forces of supply and demand in competitive markets. It will also let investors determine the type and location of added (and retired) electric generation capacity. There are strong theoretical arguments to support this. With regulation, there is a tendency for generators to add to capacity to a greater extent than necessary (i.e., to overbuild) since their revenue is based on the amount of their invested capital or rate base. In turn, this leads to operational inefficiencies and power rates that are generally higher than in a competitive market (Averch and Johnston, 1962). When deregulation occurs, competition among the existing generators, new entrants, and importers forces electricity producers to shed inefficiencies and to seek innovations in order to increase productivity (Clifford, 1998). Further, competitive markets give price signals that lead investors to determine the mix of electric generation capacity based on their knowledge of the relative efficiencies of competing technologies and market conditions—something that regulators cannot do. In the long run, the efficiencies resulting from competition will lead to better price results for consumers (Stoft, 2002).

Empirical analysis of experience in the United States with respect to deregulation provides evidence that restructuring in the electricity sector to allow market competition has, in fact, led to lower residential and industrial electricity prices (Joskow, 2006). However, without sufficient competition, the full benefits of deregulation (i.e., lower prices) are unlikely to be realized since one or more of the larger suppliers may frequently be able to cause the market to clear at higher price levels than would be the case with a truly competitive market environment. For this reason, it is important that jurisdictions that have or are about to deregulate their electricity market ensure that institutional arrangements are in place to monitor market conditions and to adjust the rules that govern how electricity is offered to and bid for by market participants, as appropriate, in order to foster competition.[50]

Empirical evidence further supports the theoretical arguments for deregulation summarized above. For example, a 2005 study by the International Energy Agency concluded that deregulation triggered timely, adequate investment and competition in the United Kingdom, the Nordic electricity market, Australia, and the Pennsylvania, New Jersey, Maryland (PJM) market (International Energy Agency, 2005). Another report by a former executive director of the Fraser Institute found that deregulation of electricity markets led to both greater, more diversified generation capacity and lower electricity prices (Mullins, 2004).

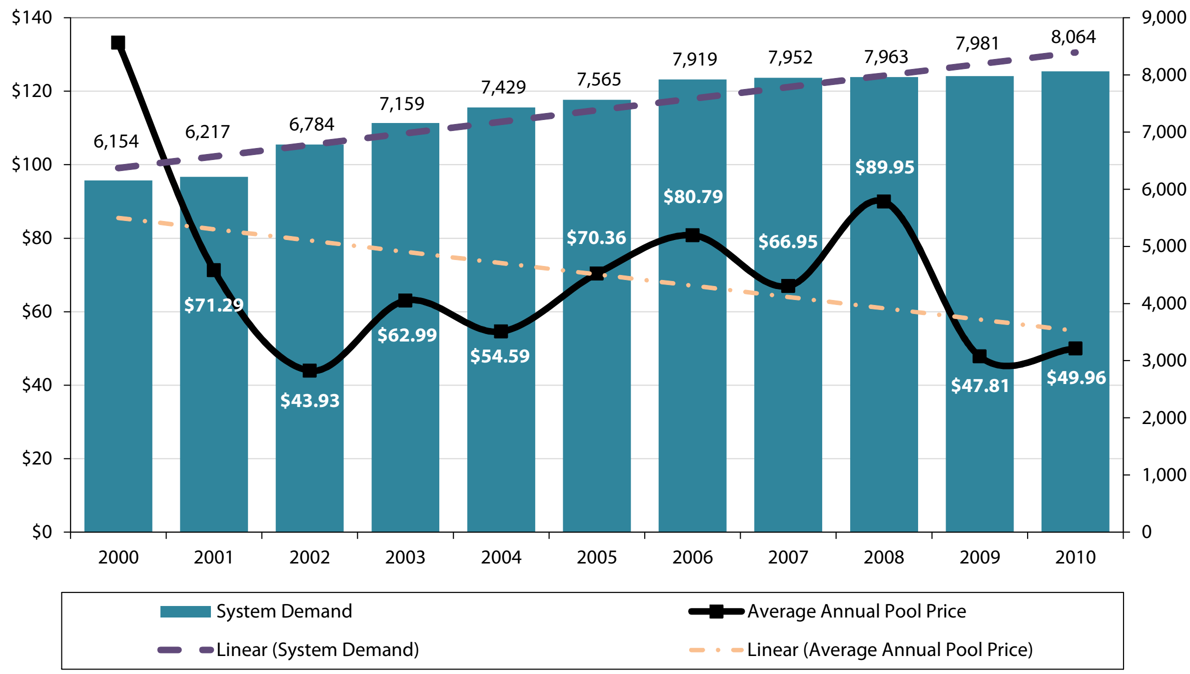
The Alberta evidence, where deregulation of the electricity generation sector was completed at the beginning of January 2001, also indicates that deregulation can bring forth more market participants, increase overall capacity, and lead to competitive prices.[51] Electric generation capacity has grown from 9,580 MW at the end of 2000 to approximately 12,834 MW at time of writing. The 3,254 MW net gain has occurred in spite of the retirement of 1,424 MW of capacity. In other words, new units with a combined capacity of 4,678 MW have been put in place since 2000. The new facilities have mainly been gas-fired plants, especially cogeneration facilities built in conjunction with oil sands projects requiring both process heat and electricity. However, significant amounts of new coal-fired generation capacity and wind power capacity have also been built in the province.[52]

50 Before the Alberta wholesale electricity market was opened to competition in 2001, rights to offer electricity produced by the three formerly regulated generators into the market with terms of up to 20 years were packaged in the form of "power purchase arrangements" and sold at auctions in order to increase the number of market participants and help ensure that competitive conditions would exist. Since then, additional electric generators have entered the market, generally improving competitive conditions.

51 Although the Alberta wholesale market began to operate in 1996, the power purchase arrangements that transferred responsibility for marketing most of the electricity produced by the three formerly regulated generators to new market participants did not take effect until January 1, 2001. From then on, the number of market participants has steadily increased.

52 The extent of investment in wind generation in Alberta during the past decade, in spite of the fact that wind facilities are not completely dependable because of fluctuating wind velocities, is the result of number of factors. These include federal tax incentives, anticipation that coal-fired and gas-fired electricity would become less competitive as a result of carbon capture and storage (CCS) requirements and high natural gas prices, and the desire by greenhouse gas emitters to position themselves to have ready access to carbon "credits" in anticipation that Canada would impose carbon emissions limits that would foster the development of carbon emissions trading. Further, construction of the Montana-Alberta Tie Line is expected to increase electricity trade with northern Montana and the hydro facilities there are seen as compatible with the development of wind capacity in southern Alberta for two reasons. First, the presence of hydro capacity provides needed back up to wind capacity. Second, during the fall and early winter months when average wind velocities are greatest, hydro capacity tends to be lower than during the summer, which provides seasonal opportunities for Alberta-Montana electricity interchange.

Figure 15: Alberta electric system average annual power pool price ($/MW-h) and system demand (MW), 2001 to 2010



Sources: Alberta Electric System Operator, 2010; Alberta Energy, 2010; figure by authors.

As Figure 15 illustrates, wholesale electricity prices have not risen dramatically during the past 10 years as predicted by deregulation naysayers. In fact, in spite of a 31 percent increase in average annual electricity consumption since 2000 (shown as "system demand" in figure 15), Alberta electricity prices are significantly lower today than they were prior to deregulation.

Regulated electricity generation is of particular concern in Mexico where the government, through the Comisión Federal de Electricidad (CFE), owns most of the country's electricity generation facilities and for the most part arbitrarily determines what generation facilities to add in order to meet electricity demand growth. But this is also a significant problem where there is considerable private ownership of generation facilities, yet the provincial or state government sees fit to decree how electricity supply growth is to be met instead of leaving the composition of generation capacity to investors' decisions based on their knowledge of the relative advantages of competing technologies and market requirements.

To dictate the future composition of electric generation capacity according to the type of fuel, as the Ontario government is doing (e.g. zero coal, ceiling on nuclear; natural gas only for peaking; and increased dependence on renewables), would saddle electricity consumers with higher power costs for generations. As in Ontario, the penalty that consumers will ultimately have to pay will not be limited to higher power production costs. For example, if some of the “chosen” electrical generation units are in remote locations, large investments in transmission system expansion will be required, the costs of which will ultimately show up on consumers’ bills (Angevine, 2008).

k. Low fidelity price signals

Where electricity generation has been deregulated but the wholesale electricity market is not competitive because of certain conditions, such as too few market participants, prices may be greater than what investors in new-generation capacity could reasonably expect to realize. Also, an uncertain or highly volatile price outlook based on recent price performance may keep wary investors out of the market.

In a competitive market, the clearing price (or market price) should generally reflect the market participants’ expectations about electricity price fundamentals, such as demand, natural gas prices or other fuel costs, conditions in neighboring markets, and expected outages of generation facilities for maintenance. Under such conditions, the resulting “high fidelity” competitive price signals will guide investors in new-generation infrastructure and consumers to make rational choices. Alternately, where market prices have only a weak connection to the underlying determinants of prices and price expectations, but yet a strong connection to the delivery or pricing strategies of particular participants (or even worse, the strategy of a single participant), then the prices will send inaccurate, “low fidelity” price signals to investors and consumers. “Low fidelity” price outcomes of this kind, where the price appeared to be disconnected from the fundamental drivers, were of apparent concern to former Alberta Market Surveillance Administrator Martin Merritt, as when he made a presentation on the state of competition in the Alberta wholesale market to the Van Horne Institute in 2006 (Merritt, 2006).

l. Obstacles to wider application of the merchant transmission model

Regulated transmission companies may object to merchant lines being located in their franchise areas. However, if investors are willing to put capital at risk by putting a market interconnector in place to satisfy a perceived need, political lobbying by incumbents should not be allowed to stand in the way.

Neither is refusing to allow a merchant line from being built justified on the grounds that the end-user beneficiaries cannot be identified clearly enough to determine an appropriate means for allocating the capital and operating costs. If marketers or distributors indicate in response to a call for indications of expressions of interest (i.e., a so-called "open season") that they are willing to pay for reserve capacity on a proposed merchant transmission facility, and to use the facility, that indicates that there is a real market need. The negotiated tariffs on the merchant line would end up being passed on to consumers as part of their distribution service charges.

Nor should the traditional view that all transmission lines should be regulated because they are natural monopolies be used to prevent the authorities from at least carefully considering the benefits and costs of merchant transmission proposals. If it is clear from market conditions and signals (e.g., transmission congestion, the need for an alternative transmission path such as across a sound or bay, and willingness of investors to risk capital) that additional transmission capacity is required, and a merchant facility would allow that need to be met more efficiently, then a merchant line may be the appropriate solution.

Policy recommendations

The policy recommendations outlined below are predicated on the need to reduce barriers to timely investment in required electricity infrastructure, such as those identified in the preceding section. For the most part, the recommendations are described in general terms and do not provide implementation guidelines or blueprints. This is because the specific measures, actions, and steps that would need to be undertaken in a particular jurisdiction would depend on the specific legal and institutional framework there as well as the composition and structure of its electricity sector, which is beyond the scope of this study.

1. Reduce energy policy uncertainties and risks

Investors require both clarity and stability about the legal and regulatory framework within which they will operate. For this reason, federal, state, and provincial authorities need to provide clear and transparent policy positions and rules. They must also commit not to introduce changes to laws and regulations unless they are needed to improve electricity market and transmission system efficiencies.

2. Reduce environmental policy uncertainties

The protracted delay and uncertainty regarding whether and to what extent carbon emissions will be restricted needs to be settled as soon as possible. If carbon emissions are to be curbed, specific carbon emission limits and carbon capture and storage requirements must be introduced with sufficient lead time and in sufficient detail to ensure that the affected stakeholders have adequate time to adjust their business plans.

3. Establish consultative processes and mechanisms

Consultative processes and mechanisms should be established to ensure that policy makers clearly understand how any proposed changes on energy policies will affect the different parties. Specifically, electricity industry advisory councils should be established (as was the case in Alberta when deregulation was being implemented) to ensure that government officials and investors discuss energy policy matters.

When policy uncertainties and risks are gone, investors who have been "on the fence" can make commitments. This will help to ensure that new-generation facilities and new or upgraded transmission systems are built in a timely manner. Electricity consumers should benefit from lower capital costs than if construction projects are delayed and, consequently, lower power costs and transmission and distribution charges.

4. Defuse land access issues

Where electric system operators and landowners find it difficult to reach an agreement about land access, as in Alberta where the effort to win approval for a new north-south line has met with considerable resistance; planners and developers must consult, inform, and educate the public and other affected parties.

Where required access cannot be negotiated with landowners, appropriate institutional arrangements must be available that will allow opponents' arguments to be heard and discussed and fair and appropriate settlements to be awarded without undue delay (although subject to appeal). Similar processes must be in place in situations where native land claims threaten to prevent access to land required for electricity infrastructure. In other words, project planners and developers must implement conflict and dispute prevention and resolution initiatives.

Preventing land access disputes and, when they do occur, resolving them more quickly, will help to ensure that transmission and generation facilities are built in a timely fashion, thereby keeping capital costs lower than would otherwise be the case. In turn, this will give electricity consumers the benefit of lower prices, whether or not the electricity market has have been opened to competition.

5. Streamline regulatory approval processes for nuclear plants

Quicker, more efficient approvals processes for new nuclear power plants are necessary, and federal and state or provincial agencies must work together closely to achieve this goal. Clearly, joint one-window approvals processes (whereby a project proponent can deal with one agency rather than many for all the necessary permits, approvals, filings, etc.) would eliminate unnecessary duplication, create organizational efficiencies, and speed up decisions. Cost savings will be the direct result of speedier regulatory processes because project developers can procure the goods and services needed for major construction much sooner than otherwise. Again, the ultimate beneficiaries will be electricity consumers. Regulators must, of course, continue to abide by the high standards that are required in permitting and regulatory processes.[53]

53 The authors are not calling for cost and resource cutting at the regulatory agency level, but rather are emphasizing the benefits to consumers and industry from regulatory operational efficiency improvements and streamlining.

6. Improve efficiency of approvals for multi-jurisdictional, international cross-border projects

Because transmission lines will likely be needed in the future that, for economic reasons, cross international boundaries, joint international approval processes and procedures should be established before the need arises to facilitate the approvals process. As the recent Montana-Alberta Tie line experience illustrates, policies need to be in place to ensure more efficient handling of multi-national applications as through a single-window (possibly joint panel) approach.

Electricity consumers on both sides of the border will be the beneficiaries, as will those who are employed, directly or indirectly, to build and operate the transmission lines and to develop and operate the electric generation facilities served by the new transmission lines.

7. Streamline regulatory processes for electricity transmission and distribution

More generally, federal and state or provincial governments need to streamline their regulatory processes and procedures for applications for approval to construct, operate, and maintain electricity transmission and distribution systems.[54] Essentially, the time and cost of the regulatory process needs to be reduced as much as possible to help ensure that approvals are not delayed unnecessarily and that the cost of regulation is not excessive. This will benefit taxpayers, ratepayers, and shareholders.

8. Deregulate the electricity generation sector

Mexico, where the Comisión Federal de Electricidad owns most of the electric generation facilities and the government determines electricity prices, as well US states and Canadian provinces that have not deregulated electricity generation, should do so. Deregulation will ensure that the wholesale price of electricity is determined through offers by generators and importers to supply energy and bids by domestic marketers and exporters to purchase it. This process will help make certain that meaningful and clear market price signals are available to potential investors in electric generation facilities, helping them to make better decisions as to the size and type of electric generation facilities to consider.

54 A similar recommendation was made in the NERC's *2008 Long Term Reliability Assessment*, which highlights the need for expedited licensing processes for transmission infrastructure projects (NERC, 2008).

To achieve meaningful price signals, governments will need to do two things. First, by studying the experiences of other "open" markets and by relying on their own experiences during the initial months of operation, they must make sure that the market functions effectively and that sufficient competition is available to prevent one or only a few companies from determining prices on a frequent basis. Second, they must establish an independent market surveillance agency with the power to take appropriate corrective action if the performance of the market appears to be inefficient because of insufficient competition, collusion, or other reasons.

9. Privatize government-owned electricity generation and transmission facilities

Where governments still own electricity generation units and electric power transmission and distribution systems, as is the case in most Canadian provinces (e.g., Hydro-Quebec and Manitoba Hydro) and Mexico (the Comisión Federal de Electricidad), they must ask themselves why. Such businesses should be privatized, even if they are regulated. Performance and operational incentives in a privately-owned business environment are clearly different than at the bureaucratic level. Management on behalf of shareholders will be more effective than management by government-appointed directors of a state-owned corporation. Simply put, this is because the business then operates to economic imperatives rather than political ones and shareholders with a direct interest in private firms are more likely to dismiss management teams that are ineffective, than are governments. More efficient electricity generation, and transmission operation and maintenance will reduce costs and, ultimately, benefit electricity consumers via lower energy prices, and lower transmission and distribution tariffs.[55]

10. Ensure that investment in regulated transportation infrastructure is attractive

As discussed, Canadian regulated electricity transmission companies are at a disadvantage compared to their US counterparts, which generally enjoy higher rates of return. The same applies to electricity distribution companies. Regulators overseeing transmission and distribution companies in all jurisdictions need to ensure that timely investment in such activities is sufficiently attractive compared to competing opportunities at home and abroad.

55 Clearly, it would be difficult to privatize the Comisión Federal de Electricidad due to the constraints imposed by Mexico's constitution. However, such reform would benefit Mexican electricity consumers.

Wherever required, market regulators should change formulas, rules, and approaches for determining allowable rates of return on equity for regulated transmission and distribution companies to ensure that investment in such projects is competitive both with other industries and with other jurisdictions.[56] This will benefit electricity consumers by ensuring that generation facility investment is not constrained by insufficient transmission capacity. It will also enhance electric system reliability and the ability to supply electricity when and where it is required.

11. Facilitate investment in merchant transmission facilities

"Merchant" transmission lines can help ship power from one market region or jurisdiction to another, and therefore enhance system reliability. As demonstrated by the Montana- Alberta Tie Line, which is currently under construction, merchant lines can also facilitate the expansion and further integration of the continental transmission grid and thereby increase opportunities for cross-border electricity trade.

The benefits to electricity consumers of more merchant transmission arrangements include improved system reliability and greater production diversity. Where electricity markets are deregulated, electricity prices are likely to be less volatile as a result.

12. Establish clear rules for the sharing of transmission system expansion costs

Authorities must be clear about the responsibility for the cost of required transmission system expansion so that potential investors can determine how competitive new electricity generation facilities that are to be sited in remote areas are likely to be. This knowledge will give prospective investors in new-generation facilities a clear picture of their share of the cost of transmission system expansion and pave the way for development. Electricity consumers will benefit from improved system reliability. Further, increased diversification of electricity sources will help to stabilize the prices that consumers ultimately pay for electricity.

56 As an interim, stop-gap solution where rates of return are deemed to be too low, as in Canada, one suggestion is to use "add factors" to increase the rates suggested by the present existing formulas (Concentric Energy Advisers Inc., 2009).

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Appendix: Glossary of terms

Alternating current (AC)/direct current (DC) – under AC, the electric charge continually reverses direction, as opposed to DC in which the electricity flow is in one direction. AC is the more common.

Cap and trade – a market-based approach that some jurisdictions use to reduce airborne emissions of various kinds. A cap is placed on firms' emissions levels. A company may sell (purchase) credits if its emissions are below (above) the limit. This mechanism allows companies with excess emissions to purchase emissions credits if that is a more cost effective means for meeting their emissions limits than purchasing and installing equipment and/or making modifications to their existing plants.

Carbon capture and storage (or sequestration) – the term used to describe the capture and storage of carbon dioxide (CO_2) so it won't be released into the atmosphere. Captured CO_2 is compressed and transported by pipeline or tanker to storage facilities such as underground caverns or depleted petroleum reservoirs. It may also be injected into oil reservoirs to stimulate crude oil production.

Cogeneration – refers to the simultaneous production of electricity and steam.

Combined cycle – the production of electricity using combustion turbine and steam turbine generation units in the same system (see *Combustion turbine* and *Steam turbine).*

Combustion turbine – a rotary engine (similar to a jet engine) that generates electricity from the flow of gases from the combustion of natural gas or low-sulfur fuel oil.

Comisión Federal de Electricidad [CFE] – the federal electricity commission in Mexico. A state-owned electric monopoly established under the constitution to produce and provide electricity.

Comisión Reguladora de Energía [CRE] – Mexico's energy regulatory commission. The commission is charged with the economic regulation of the country's electricity and gas sector.

Deregulated electricity generation **–** when the purchase and sale of electricity is administered through an open market that operates according to established rules. In a deregulated electricity generation environment, private investors are encouraged to build, maintain, own, and operate electric generation facilities.

Electricity distribution **–** also known as low voltage electric transmission, is the last (second) stage in the delivery of electricity to end-users. Distribution facilities transport electricity from the transmission system and deliver it to industrial, business, and residential consumers after it has been transformed down from high transmission voltage levels.

Electric generation capacity – refers to the amount of installed capacity needed to generate electricity at a specific site or in a specific area, province, state or country, generally expressed in kilowatts, megawatts, or gigawatts.

Electricity generation **–** refers to the amount of electricity produced (usually measured in megawatt hours (MW-h), or gigawatt hours (GW-h)), which is then directed and delivered to the transmission system.

Electricity transmission **–** also known as high voltage electric transmission, is the first stage in the delivery of electricity to end users. Electricity transmission involves the transfer of electric energy that is generated from electricity distribution facilities. When connected together, transmission lines comprise the electricity transmission system or grid.

Energy Information Administration (EIA) **–** the statistical and analytical unit within the United States department of energy.

International Energy Agency (IEA) **–** the Paris-based agency within the Organization for Economic Cooperation and Development (OECD) that compiles international energy data and information including energy supply and demand, as well as price studies, forecasts, and energy policy recommendations.

Liquefied natural gas (LNG) **–** natural gas in liquid form achieved by cooling and pressurizing natural gas, thus reducing the gas volume by about 600 times, which allows for transportation by specially equipped tankers.

Merchant transmission line **–** a transmission line that is to be physically independent from a regulated transmission grid, and for which tolls and tariffs (similar to those used in the oil and gas pipeline industry) are negotiated between shippers, merchants, marketers, and the transmission line owner.

National Energy Board (NEB) – the Canadian government agency charged with regulating companies involved in shipping oil, natural gas, electricity, and other energy commodities across interprovincial boundaries, or exporting or importing energy commodities.

Nuclear energy – or nuclear power, produced by controlled nuclear reactions (mainly fission) using uranium to produce energy, which generates steam used to generate electricity.

Pumped storage – the storage of hydroelectric power generation capacity by pumping water to a reservoir from a lower level reservoir.

System reliability – the extent to which an electricity system can be depended upon to deliver electricity to end-users within acceptable standards and in the amount needed. This is often measured by looking at the frequency, duration, or magnitude of possible disruption to the supply of electricity.

Renewable energy resources – are those replaced by natural processes at a rate comparable or faster than their rate of consumption by human beings, and can be used as fuels for electricity generation. For the purpose of this report, renewable energy resources include wind (wind energy), solar radiation (photovoltaic and solar energy), tides (wave and tidal energy), and geothermal heat (for geothermal energy), as well as other resources that should be managed carefully so that they are harvested in a sustainable manner, such as fresh water (for hydroelectricity) and timber (for biomass energy).

Stakeholders –the parties involved in and affected by the development and operation of a specific project or development and production activities in a specific sector or industry. These include landowners, investors, developers, producers, regulatory agencies, and citizens at large.

Steam turbine – a mechanical device that extracts thermal energy from high-pressure steam and converts it into a rotary motion, which in turn is used to generate electricity.

Thermal energy generation – generally, a process of energy conversion in which a fossil fuel such as natural gas, fuel oil, or coal is burned to generate heat energy, which is converted into mechanical energy (e.g., steam), and finally to electrical energy.

Volt **–** a unit of electromotive force or electric pressure. 1 kilovolt (kV) = 1,000 volts. In this report, volts are the measure for the electric pressure in transmission lines.

Watt **–** a derived unit of power (electricity energy flow) that measures the rate of energy conversion. In this report, watts are used in the context of electric generation and transmission capacity, or the potential for producing or transporting given watts of electric power; 1 kilowatt (kW) = 1,000 watts; 1 megawatt (MW) = 1,000 kW; 1 gigawatt (GW) = 1,000 MW; 1 terawatt (TW) = 1,000 GW.

Watt-hour **–** the multiplication of power in watts and time in hours. It is the most common billing unit for consumers by electric utilities. 1 MW-hr is the equivalent of 1,000 kilowatts of power produced or used for one hour. In this report, this unit is used when reporting electricity generation or consumption. (The same conversion rates as above apply.)

Wholesale electricity market **–** a market in which electricity producers and importers offer to sell electricity, and electricity marketers, distributors, exporters, and large electricity consumers offer to purchase electricity.

About the authors

Gerry Angevine is Senior Economist in the Fraser Institute's Global Resources Centre. Since joining the Institute in July 2006, he has written two studies on Ontario electricity policy issues, including a critique of the government's central-planning approach to determining future electricity supplies. He has also written on labor mobility issues affecting Canada's energy sector, the economics of a proposed carbon dioxide "backbone" pipeline in Alberta, issues pertaining to carbon allowance trading, and the merits of "P3s" for relieving municipal infrastructure financing pressures in Alberta's oil sands region. He is presently coordinating a series of studies on the development of a continental energy strategy, and he also manages the Institute's annual Global Petroleum Survey.

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