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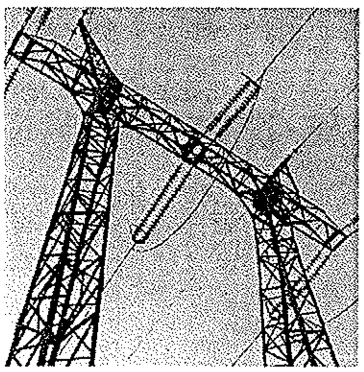
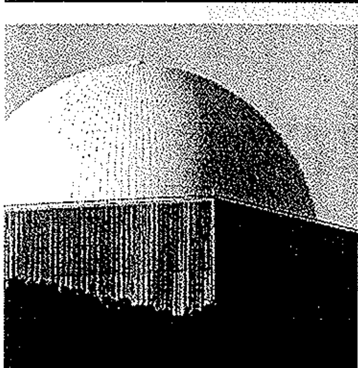
FRASER INSTITUTE

April 2012

A Sensible Strategy for Renewable Electrical Energy in North America

by Gerry Angevine, Carlos A. Murillo, and Nevena Pencheva





Key findings

- Recent studies by the International Energy Agency and others indicate that the cost of electricity from renewable energy technologies is generally greater than that from fossil-fuel combustion or nuclear power.
- Official forecasts suggest that at least 80% of the net increase in electric generation capacity in North America during the present decade will involve renewable energy technologies as a result of so-called portfolio standards, "feed-in tariffs" (FITs) that guarantee electricity producers attractive prices, and other incentives and subsidies that are being pursued by governments without regard to cost.
- Consequently, electricity consumers in North America face much higher electricity costs in the future. The impact will be especially large in Ontario, where the government is promoting renewable energy development with an exceedingly generous FIT program.
- Ontario's energy users could be burdened with an extra cost of at least \$18 billion over the next 20 years and many, if not most, of the jobs that the Ontario government claims will be created by its "Green Energy Initiative" will likely be offset.
- A number of policy reforms are needed including abandonment of renewable energy portfolio targets and of subsidies and incentives for all types of electric generation. Further, a market-based approach is required to determine the most efficient mix of technologies used for electric generation.

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Summary

Renewable energy has come to be one of the most popular topics in the public debates over energy policy and climate change. Despite significant technological advances, renewable, inexhaustible, sources of energy in North America are more useful at this time for generating electric power than for space heating or transportation and it is important to have a clear understanding of the challenges and opportunities faced by the various renewable energy technologies used for this purpose. Renewable sources of energy also need to be compared to other sources of energy, like fossil fuels and nuclear technologies, used to generate electricity.

A Sensible Strategy for Renewable Electrical Energy in North America is the fourth in a series published by the Fraser Institute on developing a continental energy strategy. It analyzes the economics of technologies used to generate electricity, technical issues, and, using Ontario's Feed-in-tariff (FIT) program as a case study, some of the broader effects that renewable energy policies are likely to have on the North American economy.

The report also reviews the barriers that stand in the way of a sound and sustainable path for developing renewable energy as a significant source of electric power in North America and makes recommendations for an economically efficient electricity policy framework based on competitive-market conditions.

Contents

Overview

This report examines the role of renewable energy policy in the context of continental energy policy, with focus on the electricity (power) sector. It is the fourth in a series of papers produced by the Fraser Institute in the course of developing a Continental Energy Strategy. The goal of this research program is to ensure that policy and institutional frameworks are as conducive as possible to rapid and responsible development of North America's energy resources as dictated by market conditions, legitimate environmental concerns, and global investment opportunities (Klein and Tobin, 2008).

Renewable energy supplies as alternatives to non-renewable fossil fuels for power generation have become an important element of energy policy in recent years largely because elected officials have been caught up in the climate-change debate. According to official forecasts for Canada, the United States, and Mexico, it is anticipated that almost 82% of the increase in North American electric generation capacity over this decade will come from facilities using renewable energy sources. This reflects the expected outcome of policies designed to increase the share of renewable energy in generating electricity rather than a clear examination of the costs and benefits associated with such policies.

The higher cost of electricity produced from renewable energy sources is underscored by a recent International Energy Agency (IEA) study of the "levelized" costs of electricity (i.e. combined capital, fuel, and operating costs over the life of an electric generation plant) (International Energy Agency, 2010b). Geothermal installations, onshore wind power, and some biomass generation configurations are able to compete with coal-fired and gas-fired units but only when mandatory carbon-emission controls are factored into the cost calculations. But wind power is generally not available all day, every day and, if the cost of the back-up facilities is included, wind power is less able to compete with other forms of electric generation. Wind power is further disadvantaged if the electric generation sites are remotely located, requiring incremental, costly investment in transmission systems. Offshore wind power and solar power generally cannot compete with non-renewable energy sources because of their high capital cost.

In spite of their higher cost, renewable energy technologies are being supported to compete with conventional cost-effective and reliable electric generation by preferential government policies at all levels. Two kinds of programs supporting renewable energy are driving much of the investment in renewable energy today in North America: renewable portfolio standards (RPS), which require electric-power utilities to use renewable energy sources such as wind for generating a certain percentage of their overall electricity supplies by specified dates, and feed-in-tariff (FIT) programs, which guarantee investors long-term, attractive, above-market prices for the electricity that they produce.

The RPS approach to pushing investment in renewable energy forward has been mushrooming in the United States in recent years. As of March 2012, 29 US states and the District of Columbia had enacted renewable portfolio standards; others had adopted non-binding renewable energy goals on top of mandatory targets, or just targets. In Canada, three provinces had explicit RPS programs while others had RPS targets. Generally, RPS initiatives are supported by special incentives or subsidies.

Ontario established a generous FIT program in late 2009. When the research for this report was begun, that was the only initiative of its kind in Canada. However, Nova Scotia implemented a limited "Community" FIT program and a Feed-In-Tariff for Developmental Tidal Arrays in September 2011 and British Columbia is reportedly pursuing a program similar to Ontario's, although less aggressively. It is estimated that, at the time of writing, contracts for over 140 terawatt hours (TW-hs) of electricity from renewable energy sources had been agreed to under the Ontario program, at a total cost of $28.4 billion (nominal dollars)—implying a weighted average electricity price of 20.31 ¢/kW-h. If the same amount of electricity had been contracted for at a rate of 7.3 ¢/kW-h (the average competitive residential rate as of December 2010), the price tag for the 140 TW-hs of electricity would have been approximately $10.2 billion. This implies that Ontario energy users could be burdened with an extra cost of at least $18 billion over the next 20 years.

We estimate that residential electricity customers alone will be faced with an average annual increase in their electricity bill of $285 million (nominal dollars). Results from a Statistics Canada Input-Output (I/O) Model simulation indicate that a drop in discretionary personal spending of that magnitude could lead to a loss of close to 41,000 full time equivalent (FTE) jobs across the country over a 20-year period. In addition, the FIT program will have a negative impact on employment in the commercial and industrial sectors of the economy as companies adjust to competitive pressures.

In general, Input-Output Models can overstate the multiplier effects, especially when considering a long period for consumer adjustment to higher electricity prices as in this case. However, in the industrial sector, part of this adjustment involves moving facilities to other jurisdictions, with a corresponding negative impact on employment. Our overall conclusion is that many, if not most, of the jobs that the Ontario government claims will be created by its green energy initiative will be offset through the negative impacts of higher electricity prices. This is on top of other negative economic impacts including losses in employee compensation, provincial gross domestic product, and taxation revenue.

In the United States, feed-in-tariffs are not yet being widely used to foster the application of renewable power generation technologies. To some extent, this reflects an aversion on the part of policy makers to what amounts to mandating electricity prices. It is also a consequence of constraints that certain federal legislation imposes on the ability of states to put Ontario-style FIT programs in place. As a result, only a handful of US states and a few municipalities have adopted limited FIT-type subsidies. In other states, some elected representatives have been attempting to have FIT programs legislated.

Although replacing fossil-fueled electric generation with renewable energy sources may at first glance appear to constitute an efficient and appropriate means for reducing greenhouse-gas emissions that some believe contribute to global warming, there are numerous barriers and challenges to the widespread penetration and application of renewable energy. These include, but are not limited to: public opposition; uncompetitive capital costs relative to most non-renewable energy sources; the inability to rely on electricity supplies from some forms of renewable energy all day, every day (especially true of wind and solar); and access to the transmission system and related cost issues. While the possibility of stringent environmental policies directed at reducing carbon emissions (such as carbon capture and storage requirements) could make the high capital costs associated with some renewable energy technologies attractive relative to conventional, non-renewable sources, there is considerable uncertainty as to if, when, and to what degree, governments will take such actions.

Instead of mandating the deployment of renewable power generation technologies, a market-based approach is required to determine the most efficient mix of technologies for electric generation. This will help to ensure that electricity consumers are able to enjoy electricity prices that are generally as low as possible and foster innovation, economic growth, and prosperity. We recommend that governments:

1 abandon renewable energy portfolio targets;

2 level the playing field by stopping the promotion of any source of electricity via incentives or subsidies of any kind;

3 foster the development of long-term plans for transmission systems capable of accommodating those electric-generation-capacity expansion paths and portfolios that appear most likely to evolve from informed, market-based, investment decisions;

4 simplify and streamline regulatory approval processes and procedures for investment in transmission facilities and electric-generation capacity;

5 remove uncertainty about limits on carbon emissions;

6 establish clear, stable energy policies and regulations.

Together, these reforms can be expected to lead to lower electricity costs throughout North America in the years ahead than would otherwise be the case. This will help to improve the standard of living of electricity consumers and enhance the ability of North American manufacturers to compete with producers in other countries.

About the Continental Energy Strategy

The purpose of the Fraser Institute's Continental Energy Strategy research program is to lay out policy recommendations that will help ensure that North America's energy resources, such as natural gas, coal, uranium, and hydro-electric, 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 responsible production of the continent's energy resources within competitive markets, along with free trade in energy with the rest of the world, would generate extensive employment, labour income, and the benefits of economic growth and, thereby, contribute to improvements in the quality of life of North Americans. Further, increased development of the continent's energy resources would also bolster the security of energy supply by increasing the range of energy-supply options that are available to North American consumers.

Because market forces are the most efficient means of allocating North America's energy resources, development of a continental energy strategy does not include identifying energy investment, production, or 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; as such they will lead to optimal market conditions. Government intervention in decisions about energy investment must be avoided as the allocation of resources is best left to those who are motivated by opportunities for investment in competitive markets, have in-depth knowledge of the advantages and disadvantages of competing energy production technologies and market conditions and are, therefore, prepared to take risks based on their understanding of how energy requirements are likely to evolve.

Policy frameworks must support competition and innovation in the energy market and, subject to appropriate environmental and safety restrictions, allow investors freedom of choice in determining which energy resources to develop 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 labour pools required for the financing and construction of new energy production and transportation facilities is not constrained by market barriers.

Introduction

Renewable energy policy is presently the focus of considerable discussion, mainly because much of the public and many elected officials have been caught up in the climate change debate. Further, convinced by the argument put forward by the United Nations' Intergovernmental Panel on Climate Change (IPCC) and environmentalist organizations that global warming is occurring and that greenhouse gases (GHG) such as carbon dioxide emitted during the combustion of fossil fuels for the purposes of power generation, transportation, or space heating, are a major contributing factor, many governments have been seeking to promote renewable energy alternatives to so-called "dirty" hydrocarbon fuels. This paper examines the role that renewable energy sources such as biomass, geothermal, hydroelectric power generation, solar energy, and wind power can play in an energy strategy for the North American continent.

Most of the new emphasis on the renewable energy sources is focused on the generation of electrical power rather than their other applications. This is because, for the most part, renewable energy options cannot be readily and economically adapted for direct use in transportation and space heating. The economics of renewable energy sources for transportation and heating are clearly separate and distinct topics from that of power generation, which is the focus of this paper. Further, geothermal space heating is not being actively pursued by many jurisdictions. Also, although passive solar energy is increasingly being used as a heat source, the technology is different from that of solar power (whether concentrated or photovoltaic). Because of the need for sails, which are space-encroaching, wind is generally not regarded as a viable source of transportation except over water. In Canada, the United States, and Mexico, the main outcome of this attention on renewable energy sources of electricity has been the setting of targets for increasing the share of renewable energy sources used to generate electric power. To facilitate achievement of such targets, governments are offering investors incentives and providing subsidies through various programs.

The first section of this report provides a brief overview of the outlook for additions to the capacity for generating electricity (supply potential) using renewable energy sources and technologies relative to projected capacity additions using all available technologies in the three countries during the period from 2010 to 2020. It also provides official forecasts for electricity production in Canada, the United States, and Mexico and estimates of the implied capacity utilization rates for the various technologies. This informs the reader of the extent to which Canadian and American federal, provincial, and state governments and the government of Mexico are promoting renewable energy sources for power generation in spite of the fact that they are generally less reliable and more costly than electric generation from combustion of fossil fuels and nuclear power plants.

The second section provides estimates of the levelized and capital costs of electricity generation from non-renewable energy sources—thermal (coal, oil, and natural gas) and nuclear—and renewable energy sources. In the third section, we discuss two important policy tools—renewable portfolio standards and feed-in-tariff programs—that are being used to channel investment from new electric generation facilities towards projects that rely on renewable energy sources. This section also delves into FIT initiatives in the province of Ontario and provides an economic analysis of the policies being pursued in that jurisdiction. The fourth section examines barriers and obstacles to the development of renewable energy resources according to the economic merits of the available technologies. The report concludes with a discussion of recommended reforms to renewable energy policy.

1 Outlook for renewable energy sources of electric-generation capacity in North America

Table 1 indicates the additions to electric-generation capacity in North America from 2010 to 2020 projected by leading government agencies in Canada, Mexico and the United States. Overall, generation capacity is expected to increase at a compound annual growth rate of 0.4%, from 1,201,807 MW in 2010 to 1,254,574 MW in 2020 (a 4.4% increase). Affordable, reliable, non-renewable electric-generation capacity is likely to account for only 18% (9,653 MW) of the overall increase, mainly driven by increases in Mexico, as policy-makers in Canada and the United States increasingly turn towards policies aimed at reducing these sources' share of generation capacity, based largely on their assumption that this is necessary in order to reduce greenhouse gas emissions. As a consequence, capacity for non-renewable power generation will decrease from 82% of total capacity in 2010 to 80% in 2020. This is mainly driven by large decreases in coal-fired generation capacity in Canada and in oil and natural gas simple-cycle steam turbine applications in the United States, as well as some reductions in conventional thermal generation capacity in Mexico.

Capacity for generating electricity from renewable energy sources accounts for almost 82% (43,114 MW) of the projected increase in North American generation capacity. Consequently, renewable-source generation capacity increases by 20% by 2020 from 2010 levels, a 1.8% compound annual growth rate. Wind-energy generation capacity is expected to increase the most among the renewable-energy technologies and accounts for 63% of the projected increase in renewable-energy source capacity and 51% of the increase in total North American generation from 2010 to 2020. As a result of these projected increases, wind-energy capacity in North America would increase by 27,156 MW and its share of generating capacity from renewable energy sources from 20% to 27%, and of total generation capacity from 4% to 6%. The projected increases in wind capacity are greatest in the United States (14,450 MW) and in Canada (10,716 MW).

Hydroelectric generation capacity is projected to increase by 11,864 MW (7%), equivalent to 22% of the overall increase in electric-generation capacity from 2010 to 2020, but its share of North American renewable generation capacity is indicated to fall by 8 percentage points, from 75% in 2010 to 67% in 2020. Hydroelectric's share of North American overall electric-generation capacity is expected to remain unchanged at 14%. The growth

Table 1: Expected net additions (decommissions) to electric power generation capacity (MW), 2010–2020, in North America, by source

	Canada	United States	Mexico	North America
Wind	10,716	14,450	1,992	27,158
Hydroelectric	9,323	735	1,806	11,864
Geothermal	812	640	245	1,697
Solar	598	820	5	1,423
Biomass	972	—	—	972
Subtotal: renewables	22,421	16,645	4,048	43,114
Subtotal: all other sources (fossil fuels & nuclear)	(328)	897	9,084	9,653
Total: all sources	22,093	17,542	13,132	52,767

Sources: National Energy Board, 2011; US Energy Information Administration, 2011; Comisión Federal de Electricidad, 2009, 2010, 2011; Secretaría de Energía, 2009; authors' calculations.

in hydroelectric generation capacity is mainly expected to occur in Canada (9,323 MW), where there are large hydroelectric power projects in British Columbia, Quebec, and Newfoundland & Labrador, as well as in Mexico (1,806 MW). Geothermal and solar electric generation capacity, together, account for only about 7% of the increases in renewable electric-generation capacity in North America. Geothermal capacity is expected to increase by 1,697 MW (51%) from 2010 to 2020, while solar generation capacity is expected to increase by 1,423 MW (an almost threefold increase from 2010 levels). Biomass electric-power generation capacity is forecast to increase by 972 MW (13%) over the 2010 to 2020 period, reflecting a compound annual growth rate of less than 1%. Biomass as a share of renewable-energy generation capacity is expected to remain relatively unchanged at around 3%, less than 1% of overall generation capacity. Increases in biomass electric-generation capacity are projected to occur mainly in Canada (972 MW).

The outlook for increased capacity in North American electric generation reflects the degree to which policy makers in the United States and Canada are hastening to support the deployment and development of renewable energy technologies through subsidies, incentives, and other measures (see section 3). However, policy makers typically fail to acknowledge the burden that their decisions will place on tomorrow's consumers of electricity (section 2).

Table 2 summarizes the North American outlook for generation of electric power by country. While a 374 terawatt hour (TW-h) (or 8%) increase is projected overall, the largest (186 TW-h) increase is expected to occur in the United States, followed by Canada and Mexico. However, in percentage

Table 2: Outlook for generation of electricity (TW-h), 2010–2020, in North America, by country

	2010	2020	Increase (TW-h)	Increase (%)
Canada	585	680	95	16%
United States	3,963	4,149	186	5%
Mexico	241	334	93	39%
North America	4,789	5,163	374	8%

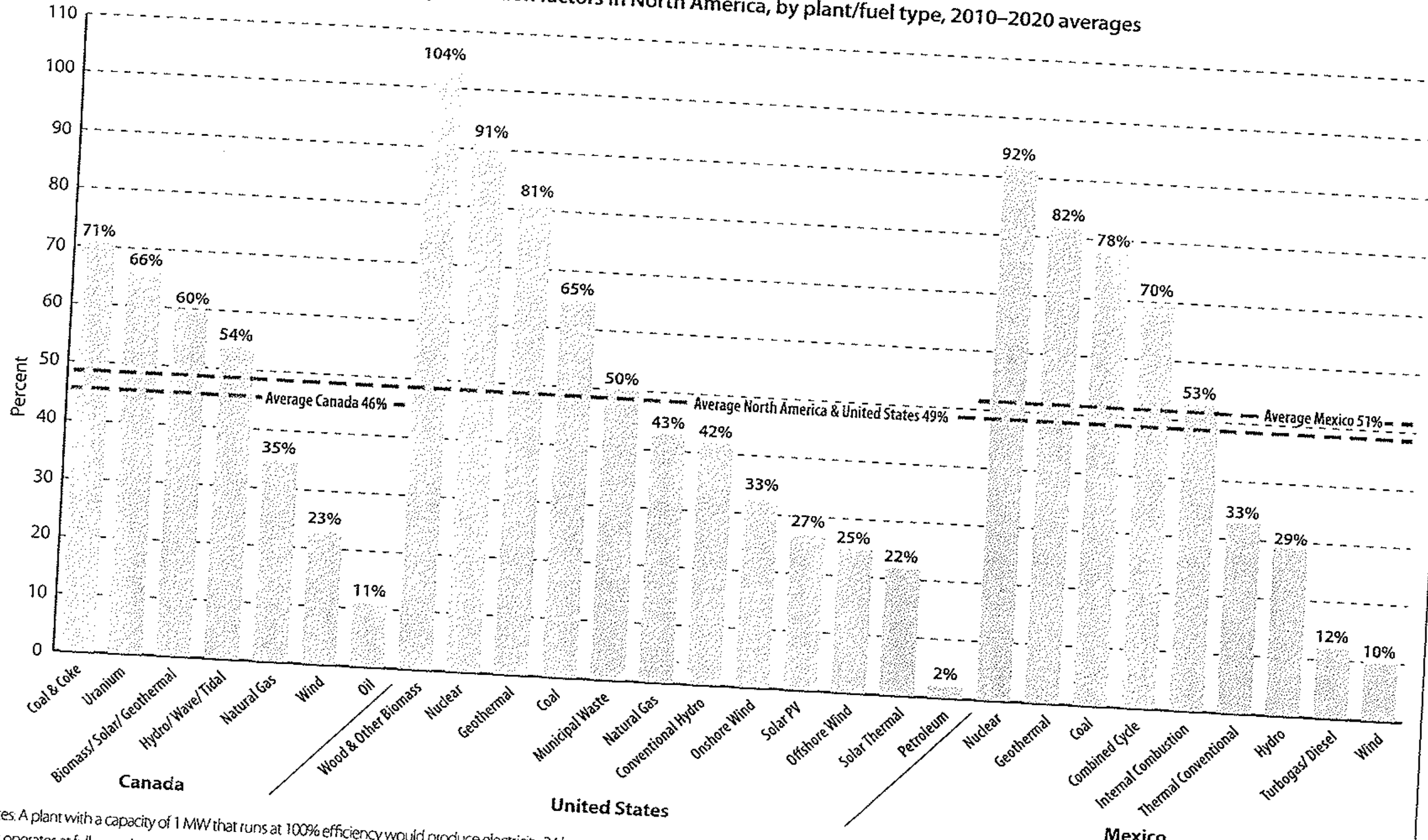
Sources: National Energy Board, 2011; US Energy Information Administration, 2011; Comisión Federal de Electricidad, 2009, 2010, 2011; Secretaría de Energía, 2009; authors' calculations.

terms the largest increase is projected to occur in Mexico, followed by Canada and the United States. This pattern is consistent with expectations for macroeconomic and population growth in the three countries.

Figure 1 summarizes the average capacity utilization factors for power plant technologies in North America from 2010 to 2020, derived from the projections by the respective government agencies for electric-generation capacity and production of electricity. A capacity utilization factor indicates the portion of time (usually measured on an annual basis) that an electric-generation facility can generally be relied upon to produce electricity. Wind and solar-power generation facilities have relatively low capacity utilization factors because wind is not always available at the required optimal velocity and the sun does not shine every day, every hour of the day. Hydroelectric facilities often have low capacity utilization factors due to seasonal rainfall patterns and limited or no reservoir capacity. On the other hand, nuclear and thermal power plants have high capacity utilization factors since they only need to shut down for maintenance purposes and the fuels used have a relatively high heat content.

In a given year, 1 MW of electric generation capacity could theoretically (with zero downtime) produce 8,760 megawatt-hours of electrical energy (1 MW × 24 hours × 365 days) or 8.76 GW-h. This, then, serves as the benchmark for measuring the capacity utilization factor. Due to technological and physical limitations (energy losses) and differences, along with maintenance requirements, different technologies and fuels produce different amounts of electricity relative to the amount of installed capacity and power plants generally never achieve 100% efficiency. In order to calculate the overall usage efficiencies or average capacity utilization factors implied by the most recent projections by Canada's National Energy Board, the amount of electricity projected to be generated by each category of electric-generation capacity in a given year was divided by the assumed generation capacity for the same year according to each type of plant or fuel. This was done for each of the 10 years in the forecast period and the results were averaged and expressed in percentage terms.

Figure 1: Implied electric generation capacity utilization factors in North America, by plant/fuel type, 2010–2020 averages



Notes: A plant with a capacity of 1 MW that runs at 100% efficiency would produce electricity 24 hours a day, 365 days a year or 365 × 24 = 8,760 MW-h. The actual generation (invariably less than 8,760 MW-h since no electric generation unit operates at full capacity continuously because of technological limitations and the need for maintenance) is divided by the generation capacity and that number is divided by 8,760 yielding a percentage or efficiency for that source. This is done on an annual basis from 2010 to 2020 and averaged across the 20 years. These are the numbers provided above. Wood & Other Biomass = 104%: In situations such as co-firing where biomass is used together with other sources, as in coal plants, the level of output (electricity generated) effectively increases although the capacity of the power plant does not necessarily do so; this is why, in this example, the capacity utilization factor edges above 100%.

Sources: National Energy Board, 2011; US Energy Information Administration, 2011; Comisión Federal de Electricidad, 2009, 2010, 2011; Secretaría de Energía, 2009; authors' calculations.

The same approach was used to derive capacity utilization factors for Mexico and the United States. The data for Mexico and the United States are divided into more categories than for Canada. This provides a more accurate picture of the individual technologies. However, the overall results are very much in line with those for Canada and highlight the fact that certain technologies are depended on to a greater extent than others. In the case of non-renewable energy sources in general, this reflects the fact that they are more reliable.

Clearly, some technologies and types of plants can be relied upon to operate at higher usage levels than others. This is a function both of physical attributes such as the availability of energy sources—whether natural gas, coal, wind, or solar energy—and frequency and duration of required maintenance, and of the costs of the available technologies relative to market requirements. Where the electric generation is deregulated, as in Alberta, facilities with relatively high production costs tend to be called on less frequently than more efficient base-load units. This is because electric-generation units are called on in the order of the prices at which their respective owners offer electricity to the market. In a competitive market, producers with lowest costs will be able to offer the lowest prices.

Technologies such as nuclear, geothermal, biomass, and coal-fired power plants have above-average implied capacity utilization factors (both at the country and continent-wide level), followed by technologies such as natural gas combustion and hydroelectric generation, which fall near the average. Wind turbines, solar power technologies, and diesel and oil generators generally have the lowest implied capacity utilization factors. These observations, together with projected generation capacity, are important to keep in mind as we examine the economics of each generation technology in section 2 as well as for understanding and assessing the implications of current energy policies on renewable energy technologies (section 3).

2 Comparing the costs of conventional and renewable sources of electricity

Electricity is vital to modern society and our quality of life. For this reason, investment in electric power and the cost of electricity are of importance to a broad spectrum of parties, including investors, government officials, and end-users (International Energy Agency, 2010b). This section provides a comparison of the costs of various methods of generating electricity based on recent information from the International Energy Agency (IEA) and similar sources. The objective is to clarify for policy makers and the general public how the cost of generating electricity using renewable energy sources compares with conventional, non-renewable, sources of electricity.

The section examines two metrics that help in understanding of both the costs of electric generation to the producer and the prices of electricity faced by the end-users or consumers. The first is the levelized cost of electricity (LCOE), which estimates the price at which the producer must generate (and thus, sell) its output in order to recover the costs of the investment over the economic life of the type of power plant in question. The LCOE also represents the price that end-users are likely to face for electricity generated by the technology being reviewed; this price does not include delivery costs such as transmission and distribution costs (Angevine and Murillo, 2011). We discuss this concept and the advantages of using it as well as its underlying assumptions and limitations and provide LCOE estimates for various electric-generation technologies in relation to North American electricity prices.

The second metric is the overnight capital cost (OCC) of electric power plants, a metric that provides another perspective on the costs of building power plants. Overnight capital costs are defined as the bare plant costs or engineering, procurement, and construction (EPC) costs together with costs to the plant's owner such as the cost of land, cooling infrastructure (when applicable), administration, site works, project management, and licences. Overnight capital costs do not include financing, cost escalation due to project delays, increases in the cost of labor or material, or inflation. They are an initial estimate (World Nuclear Association, 2011).

Levelized cost of electricity (LCOE)

Concepts and advantages

The levelized-cost approach is frequently used for financial analyses of generation costs. The concept of an average levelized cost of electricity (LCOE) is based on the assumption that the present value (PV) of the revenue stream generated by an electric-generation facility (from sales of the output generated) over its economic lifetime is equal to the present value of the sum of the construction, operations and maintenance (O&M), fuel, and decommissioning costs. In addition, also included, when applicable, are the costs of carbon capture and storage technologies (CCS) to capture the carbon dioxide (CO_2) and other greenhouse gases (GHG) that are emitted when electricity is generated by fossil-fuel combustion; and the costs of either piping those gases to underground storage locations or injecting them into oil reservoirs in order to improve production. LCOE, then, is that price of electricity that equates the present value of the sum of discounted revenues from the sale of the electric power generated to the present value of the sum of total discounted costs over the plant's lifetime. In other words, the levelized cost is the discounted all-in cost, divided by the amount of electricity that is produced, adjusted for its economic time value, or the break-even cost to the investor (International Energy Agency, 2010b).

This approach makes use of a discount rate that allows for the costs and cash flows to be discounted back to the present (or the date of commissioning). The discount rate is determined by the opportunity cost of capital and other factors such as the time required to recover the investment fully (required capital recovery time). For example, a high discount rate may be used to reflect relatively short time frames for the recovery of investment capital, and a lower discount rate where the required capital recovery time is longer. The discount rate also reflects the return on investment expected by prospective project proponents and investors and, thus, the risk associated with a particular investment as well as the cost of capital.

The discount rate is also affected by the track record of a particular technology or type of power plant. Those with established track records generate certainty about stable costs and performance during both the construction and operation phases and are usually regarded as less risky; they are, therefore, able to attract capital with less difficulty. A new electric-generation technology, for which no track record for construction and operation has yet been established, is generally regarded as more risky and, therefore, requires higher rates of return on investment (and a higher discount rate when calculating net present values).

Investment (or capital) costs are the most important cost factor to be considered in deciding to invest in a power plant and more so for technologies that have high capital costs per unit of output. Such costs vary considerably amongst the various technologies and from one region to another. They are sensitive to fluctuations in the prices of materials used to manufacture equipment components (such as steel prices) and are also exposed to labour and other construction-related costs. Plant equipment costs are also dependent on global manufacturing capacity (or supply chain) constraints, as high demand for certain equipment can create worldwide bottlenecks and drive up prices.

Cost comparisons for electric-generation capacity and electricity generation or production based solely on either the capital cost or the operating, maintenance, and fuel costs, while useful, can be incomplete as they do not take into account all of the necessary information. Some technologies, such as nuclear power and wind energy, require large up-front investment yet have relatively low operating costs. As a result, over the lifetime of the plant, they could be competitive with technologies with much lower initial capital requirements (costs) but higher operating, maintenance, and fuel costs. For this reason, comparisons of the costs of generating electricity with different technologies are frequently based on estimated "levelized" costs.

The levelized cost of electricity concept aids comparison of the unit costs (¢/kW-h is used here) of power plants using different technologies over their expected economic lives, providing useful benchmarks of costs for policy makers, consumers, and investors alike. Other advantages of using the LCOE approach include the flexibility of the method for sensitivity analysis of how changes in particular cost components such as fuel prices, assumptions about contingency and decommissioning costs, and discount rates affect the relative attractiveness for investment of particular technologies.

LCOE analyses, therefore, provide important insights into the main cost factors of alternative technologies for generating electricity. Since various cost components can vary considerably from location to location and from project to project, sensitivity analysis is key in determining the impacts of changes in costs on the costs of generating electricity. In general, uses of the LCOE approach include:

- estimating the all-in costs of producing electricity from a proposed power plant using a specified technology;
- analysing the various options available to investors in a specific market (thus allowing them to adjust proposals or plans according to local conditions);
- identifying the least-cost options among competing power projects;
- evaluating impacts of changing market conditions on generation costs (for example, changes in fuel prices or costs for operation and maintenance);
- comparing cost structures of competing generation technologies;
- assessing the impacts of changes in key policy parameters such as emission controls on the relative attractiveness of competing generation technologies.

Assumptions and limitations

The levelized-cost approach to comparing the cost of electricity produced using specified technologies requires that the assumptions about fuel costs, the applicable discount rate, and other factors be comparable across the technologies being examined. Calculations of this sort are particularly sensitive to the discount rate, or the cost of capital. For example, nuclear power plants, wind turbines and other electric generation facilities that have high capital cost components become much less competitive, the higher the discount rate. Knowing the assumptions used in the International Energy Agency's study, *Projected Costs of Generating Electricity* (2010b), is necessary for understanding the Agency's estimates of the levelized costs of electricity (LCOE). For this reason, the main assumptions about the lead-time for construction and economic life time of different types of power plants as well as the different assumed costs for fuel, control of carbon emissions, and decommissioning that the Agency used are presented in table 3.

Two important inputs are held constant during the plant lifetimes used in the LCOE calculations. One is the interest rate that is used for discounting both costs and revenues. While this assumption may be regarded as unrealistic since interest rates typically fluctuate with economic conditions, the LCOE approach does allow one to choose different discount rates and then compare the results. The second constant is the price of electricity. The LCOE approach assumes that the price does not change during a power plant's lifetime and that all output produced by the plant is immediately sold at that price. The estimated LCOEs provided in the study by the International Energy Agency (IEA) are for plants that it assumes will be commissioned in 2015 and reflect the costs of producing electricity over the medium- to long-term, at current prices.

The estimates provided in the IEA's study are "busbar" or plant-site costs for base-load generation and do not take into account additional required costs like those for delivery. This is important to note because such extra costs affect the overall price of generation from all technologies, especially for some of renewable-energy technologies since they are often constrained by natural conditions or limited to specific sites. Renewable energy technologies also often have low capacity factors and/or are only capable of generating power intermittently. These kinds of limitations add to costs because of required additional investments in transmission, backup facilities, and balancing activities (added system costs or ancilliary services). For this reason, the costs attributed to some of the technologies in the IEA's study may be underestimated.

The IEA's approach to comparing generation technologies via LCOE also includes assumptions about the costs of carbon capture and storage technologies (CCS). The cost estimates in the IEA's study include the costs of capturing emissions at the plant level but not the costs of transportation and storage, which could add substantial costs to the estimated LCOE. This means that the IEA's analysis may be somewhat biased toward technologies where CCS is required.

Table 3: Levelized costs of energy (LCOE) International Energy Agency, study assumptions

	Plant Construction (Lead) Times (years)	
Technology		Years
Non-hydro renewables		1
Gas-fired power plants		2
Coal-fired power plants		4
Nuclear power plants		7
	Harmonized Expected Plant Lifetimes (years)	
Technology		Years
Wave and tidal plants		20
Wind and solar plants		25
Gas-fired power plants		30
Coal-fired power & geothermal plants		40
Nuclear power plants		60
Hydropower		80
	Fuel Costs (US$ 2008)	
Location		Price
OECD	Hard Coal	$90.00/tonne
Mexico	Hard Coal	$87.50/tonne
	Natural Gas	$7.72/mcf
US	Hard Coal	$47.60/tonne
	Natural Gas	$7.62/mcf
OECD	Uranium (U_3O_8)	$50.00/pound
	Nuclear Front End Fuel-Cycle Costs (uranium mining, milling, conversion, enrichment, & fuel fabrication)	$7.00/MW-h
	Nuclear Back End Fuel-Cycle Costs (spent fuel transport, storage, reprocessing, and disposal)	$2.33/MW-h
	Other Costs (US$ 2008)	
		Price
Carbon Emissions Price		$30/tonne of CO_2
	Costs of Decomissions (% of Construction Costs)	
Plant type		
Nuclear		15%
All other		5%

Source: International Energy Agency, 2010b; compilation and table by authors.

Another important assumption made by the IEA is that support by government for particular technologies can be ignored. As a result, the costs provided are net of all forms of government intervention (so-called social resource costs) and do not take into consideration policies such as taxes and subsidies that encourage some types of technologies and discourage others. It is important to keep this in mind given that in the past few years (as we will see in the following section) governments have effectively promoted technologies such as wind power and other renewables, and subsidies, tax credits, and accelerated rates of depreciation can have considerable impact on the profitability of a project, expecially capital-intensive projects such as power plants. Similarly, the effects that taxes, such as capital and income taxes, would have on the decisions of investors are ignored.

Finally, the discount rates used in the IEA's study are the equivalent of risk-free interest rates. In reality, private investors have higher financing costs (interest rates) because capital markets demand a risk premium due to the added risk of default. Risk-free discount rates would be more appropriate to situations where electricity prices are regulated, as a more predictable stream of income is available, or where the generators are publicly-owned crown corporations and the risk is spread over a large base of capital. In restructured electricity markets, the discount rate will need to account for the risk resulting from price volatility. Other inherent risk elements (such as political or regulatory risks) can be factored in by using a higher discount rate. The problem of risk being different under different market structures and conditions can, therefore, be mitigated to some extent by making use of sensitivity analysis of the assumptions about discount rates.

By way of summary, limitations of the LCOE approach to comparing the cost effectiveness of competing electric-generation technologies include:

- their inability to capture the impacts of market dynamics on both prices and costs;
- their inadequacy for analyzing the implications for total electric-system costs since the LCOE estimates are limited to generation-site costs;
- incompleteness (as employed by the IEA) as carbon emission storage and transmission costs are ignored;
- overestimation and underestimation of unit costs because the ability to capture risk elements accurately is limited through the use of a single, subjectively determined, variable, the discount rate.

While the LCOE methodology and results are by no means perfect, if interpreted and used properly together with other analytical tools, they can provide a useful analytical framework for assessing investment in alternative sources of power generation and energy (electricity) policy propositions for innovative energy technologies, non-renewable and renewable alike.

Competitive electricity prices in North America

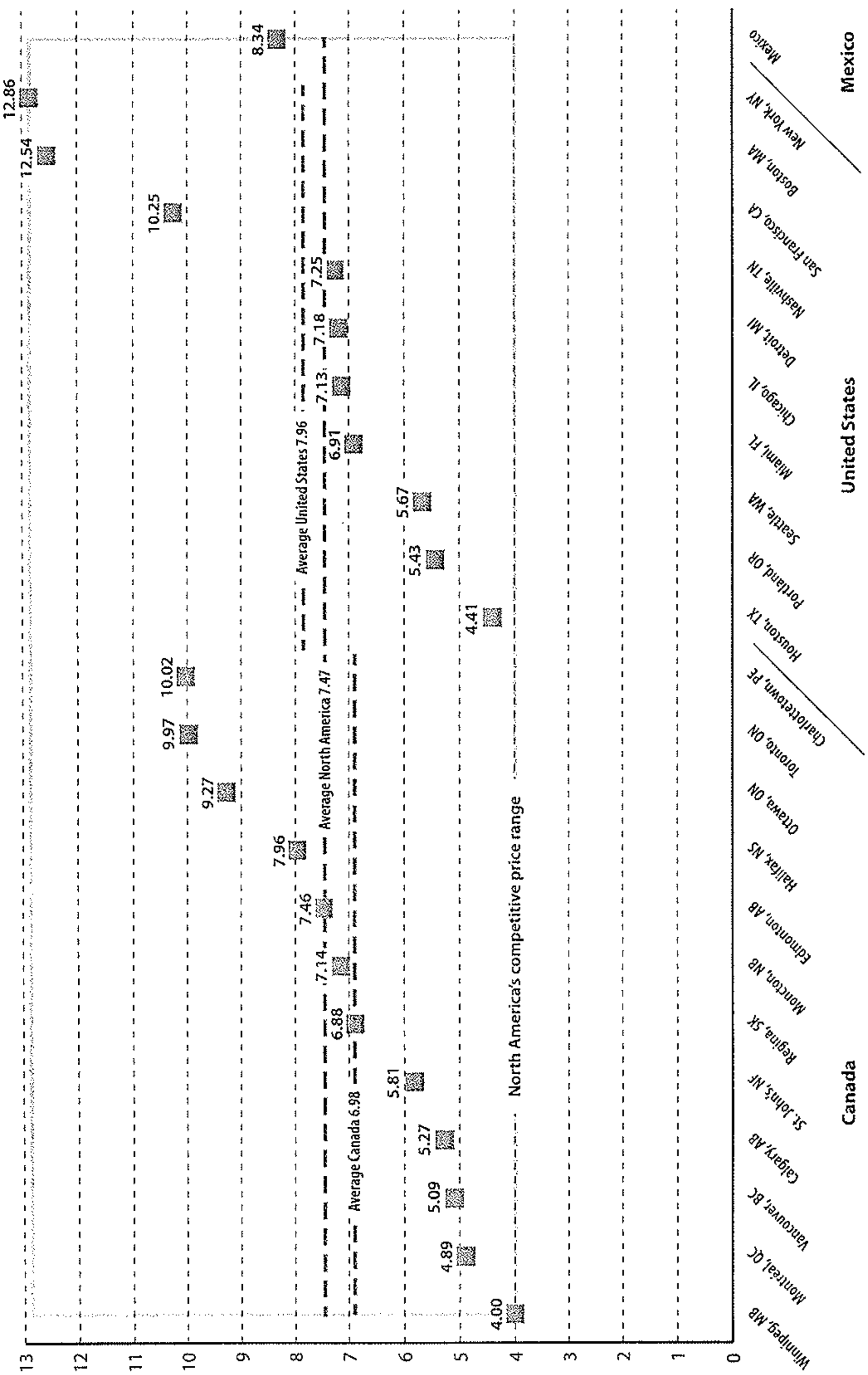
Before examining and comparing LCOEs for different technologies and regions, it is important to establish the range of electricity prices that one may consider competitive in North America as it will be useful to compare the LCOEs against the estimated prices that plant operators may reasonably expect to realize per unit of electricity produced over the lifetimes of the various kinds of projects. If the estimated LCOE for a particular technology is above the competitive price range, then the technology will not likely be able to compete on its own merits

The price of electricity put forward for comparison against the estimated all-in generation cost or LCOE in each region is the average price at which large industrial users in North America have access to electrical power. These users tend to be located closer to generation sources, therefore incurring lower or no transmission and distribution charges and their power rates are, therefore, more likely to reflect the spot price in deregulated markets and the regulated rates (before transmission and distribution charges) in regulated markets (Angevine and Murillo, 2011).

Hydro-Québec publishes an annual study that compares electricity rates across North America (including twelve cities in Canada, and ten cities in the United States) for various types of users while the International Energy Agency (IEA) publishes annual statistics on average electricity rates for various types of end users across the members of the Organisation for Economic Co-operation and Development (OECD). Hydro-Quebéc's study was used to obtain rates for large industrial users in Canada and the United States. We used the IEA statistics to obtain the price of power for large industrial users in Mexico (Hydro-Québec, 2010a; International Energy Agency, 2011). The results are presented in figure 2.

The data indicate that, on average, electricity prices for large industrial end-users in North America range from as low as 4¢/kW-h in Winnipeg to close to 13¢/kW-h in Boston and New York City. In Mexico, the average price for large industrial users is close to 8.5¢/kW-h. The average electricity rate for large industrial users in Canada is about 7¢/kW-h, in the United States about 8¢/kW-h, and close to 7.5¢/ kW-h across North America. Therefore, the benchmark range of competitive prices in North America that is used for comparison with the LCOE data is from 4¢/kW-h to 13¢/kW-h. While it seems logical to assume that this range will not hold constant and will increase over time as power prices for large industrial users increases over the long term, projections both from the National Energy Board's Reference Case and the US Energy Information Administration point to both stable and declining trends in average (real) power prices for industrial users in Canada and the United States (National Energy Board, 2011; US Energy Information Administration, 2011). Keeping this in mind, comparing the suggested price range against the estimated LCOEs for power plants to be commissioned in North America by 2015 appeared appropriate.

Figure 2: Average electricity costs (¢/kW-h) for large industrial consumers in North America, 2010



Sources: Hydro-Québec, 2010a; International Energy Agency, 2011; figure by authors.

The following section analyses the data provided in the IEA's study of LCOEs for power plants in North America (International Energy Agency, 2010b). The subset of power plants for North America was compiled by the authors and includes all technologies expected to be used in the country outlooks presented in section 1. It includes 32 power plants: six in Canada, 21 in the United States, and three in Mexico. Data is included for one power plant in the Czech Republic and one plant in Sweden to illustrate technologies for which data was not reported to the IEA by North American power producers.

General LCOE analysis

Table 4 (pp. 24–25) shows the data used for the LCOE analysis in this section. It provides a comparison of LCOEs by electric-generation technology in North America, as well as their different cost components. Data is shown for the following technologies using non-renewable energy sources: nuclear, pulverized coal combustion (PCC), coal with integrated gasification combined cycle (IGCC) technology, IGCC with carbon capture but without storage (CC[S]), heavy fuel oil, natural gas combined heat and power (CHP), natural gas combined cycle gas turbine applications (CCGT), and natural gas CCGT with carbon capture but not storage (CC[S]).

Figures 3 to 5 present the results of various analyses of the LCOE data assuming a 5% discount rate. Since results are available for two discount rates, a brief overview of the changes implied by increasing the assumed discount rate to 10% discount is presented on pages 45 to 50 following the technology-by-technology discussion. The information presented in these figures is drawn from the most recent version of *Projected Costs of Generating Electricity* from the International Energy Agency (IEA), which is based on estimates submitted by various member-country representatives as well as industry associations such as the US Electric Power Research Institute (EPRI) (International Energy Agency, 2010b).

Figures 6 to 8 present the results of a similar LCOE analysis conducted by the US Energy Information Administration (EIA) for power plants in the United States. These results support the general findings and trends exhibited in the IEA's analysis (US Energy Information Administration, 2011).

Figure 3 presents the LCOE data by country and by power plant or project from the one with the lowest overall unit costs (¢/kW-h) to the highest, broken down by key LCOE cost components such as investment costs, decommissioning costs, fuel costs, costs of carbon capture and storage, operations and maintenance costs, as well as credits for marketable heat such as steam or hot air produced in the electricity-generation process (at co-generation, heat and power, plants only). The range of what we defined earlier as

Table 4: Levelized cost of electricity (LCOE) for generating technologies in North America (¢/kW-h)

	Type of plant	Technology	Net capacity (MW)	Load factors (%)	Overnight Capital Costs (US$ millions/ MW)
Canada					
Renewable Energy Technologies	Onshore Wind	33 × 3MWe	99	30%	$2.75
	Offshore Wind	200 × 2MWe	400	37%	$4.50
	Solar PV	10MWe (Park)	10	13%	$3.37
	Solar PV	1MWe (Indus.)	1	13%	$4.36
	Solar PV	0.1MWe (Com)	0	13%	$6.34
	Solar PV	0.005MWe (Res)	0	13%	$7.31
United States					
Non-renewable Energy Technologies	Nuclear	Adv Gen III+	1,350	91%	$3.38
	Coal	Blk PCC	600	39%	$2.11
	Coal	Blk IGCC	550	39%	$2.43
	Coal	Blk IGCC w/ CC(S)	380	32%	$3.57
	Natural Gas	CCGT	400	54%	$0.97
	Natural Gas	AGT	230	40%	$0.65
	Natural Gas	CCGT w/ CC(S)	400	40%	$1.93
	CHP	CHP Simple Gas T.	40	n/a	$0.80
Renewable Energy Technologies	Onshore Wind	100 × 1.5MWe	150	41%	$1.97
	Offshore Wind	150 × 2MWe	300	43%	$3.95
	Solar PV	5MWe	5	24%	$6.18
	Solar Thermal	n/a	100	24%	$5.14
	Solid Biomass	n/a	80	87%	$3.83
	Biogas	n/a	30	90%	$2.60
	Geothermal	n/a	50	87%	$1.75
[Data below supplied by US Electric Power Research Institute]					
Non-renewable Energy Technologies	Nuclear	APWR, ABWR	1,400	91%	$2.97
	Coal	Blk SC PCC	750	41%	$2.09
	Natural Gas	CCGT	798	48%	$0.73
Renewable Energy Technologies	Onshore Wind	50 × 3MWe	100	33%	$1.85
	Solar Thermal	n/a	80	34%	$4.35
	CHP	CHP Biomass	75	n/a	$2.96
Mexico					
Non-renewable Energy Technologies	Heavy Fuel Oil	Oil Engine	83	85%	$1.82
	Coal	Blk PCC	1,312	40%	$1.96
	Natural Gas	CCGT	446	49%	$0.98
Sweden					
	Large Hydro	70MWe	70	40%	$3.41
Czech Republic					
	Small Hydro	5MWe	5	60%	$11.60

Note: "MWe" denotes megawatts of electric output.

Source: International Energy Agency, 2010b; compilation and table by authors.

Investment costs (¢/ kW-h)		Decomissioning costs (¢/ kW-h)		Fuel costs (¢/kW-h)	Heat credit (¢/kW-h)	Carbon costs (¢/kW-h)	Operations & maintenance costs (¢/kW-h)	LCOE (¢/kW-h)	
5%	10%	5%	10%					5%	10%
7.49	11.54	0.077	0.030	—	—	—	2.42	9.99	13.99
10.18	16.04	0.102	0.039	—	—	—	3.50	13.78	19.58
21.24	32.72	0.218	0.084	—	—	—	1.47	22.93	34.28
27.43	42.27	0.281	0.109	—	—	—	1.35	29.06	43.73
39.88	61.45	0.409	0.158	—	—	—	1.10	41.39	62.70
46.02	70.90	0.472	0.182	—	—	—	1.00	47.49	72.08
2.65	5.52	0.013	0.001	0.93	—	—	1.29	4.89	7.74
1.77	3.31	0.008	0.002	1.96	—	2.64	0.88	7.26	8.79
2.05	3.82	0.010	0.002	1.96	—	2.64	0.84	7.50	9.26
3.00	5.59	0.014	0.003	2.42	—	0.26	1.13	6.82	9.40
0.89	1.51	0.007	0.002	4.93	—	1.47	0.36	7.66	8.28
0.58	0.94	0.005	0.002	6.65	—	1.47	0.45	9.15	9.51
1.77	3.00	0.013	0.004	6.70	—	0.15	0.57	9.20	10.42
0.72	1.17	0.006	0.002	6.90	(5.06)	1.40	0.11	4.06	4.51
3.98	6.18	0.042	0.016	—	—	—	0.86	4.88	7.06
7.74	12.28	0.075	0.029	—	—	—	2.36	10.18	14.67
20.97	32.71	0.011	0.004	—	—	—	0.57	21.56	33.28
18.36	29.61	0.185	0.071	—	—	—	2.76	21.30	32.44
3.14	5.84	0.014	0.003	0.67	—	—	1.57	5.39	8.09
2.27	3.85	0.018	0.006	—	—	—	2.48	4.77	6.34
1.43	2.62	0.015	0.006	—	—	—	1.82	3.26	4.44
2.31	4.77	0.012	0.001	0.93	—	—	1.58	4.84	7.29
1.79	3.41	0.008	0.002	1.80	—	2.59	0.97	7.16	8.77
0.68	1.14	0.004	0.001	5.58	—	1.27	0.34	7.88	8.33
4.85	7.80	0.049	0.019	—	—	—	1.34	6.24	9.15
10.93	17.56	0.111	0.043	—	—	—	2.69	13.73	20.29
2.79	4.70	0.021	0.007	1.60	(2.25)	0.31	1.21	3.68	5.57
1.76	3.12	0.014	0.004	5.04	—	1.68	2.03	10.52	11.87
1.78	3.57	0.008	0.002	2.67	—	2.34	0.65	7.45	9.23
0.93	1.69	0.007	0.002	5.80	—	1.22	0.46	8.42	9.18
5.47	11.80	0.004	—	—	—	—	1.52	6.99	13.32
14.91	29.21	0.008	—	—	—	—	0.70	15.61	29.91

competitive power prices in North America is included for illustrative purposes. Certain trends are visible at first glance: technologies with the highest proportions of investment cost in their respective LCOE costs tend to have the highest overall unit costs.

In Canada, all of the reported projects are renewable energy projects. The onshore wind project is seen to generate power at competitive prices (at the 5% discount rate) while the offshore wind project's unit costs is slightly above the competitive range. Solar Photovoltaic (PV) projects are, in general, not competitive but they seem to benefit from economies of scale as the larger the installation, the lower the overall unit costs (¢/kW-h).

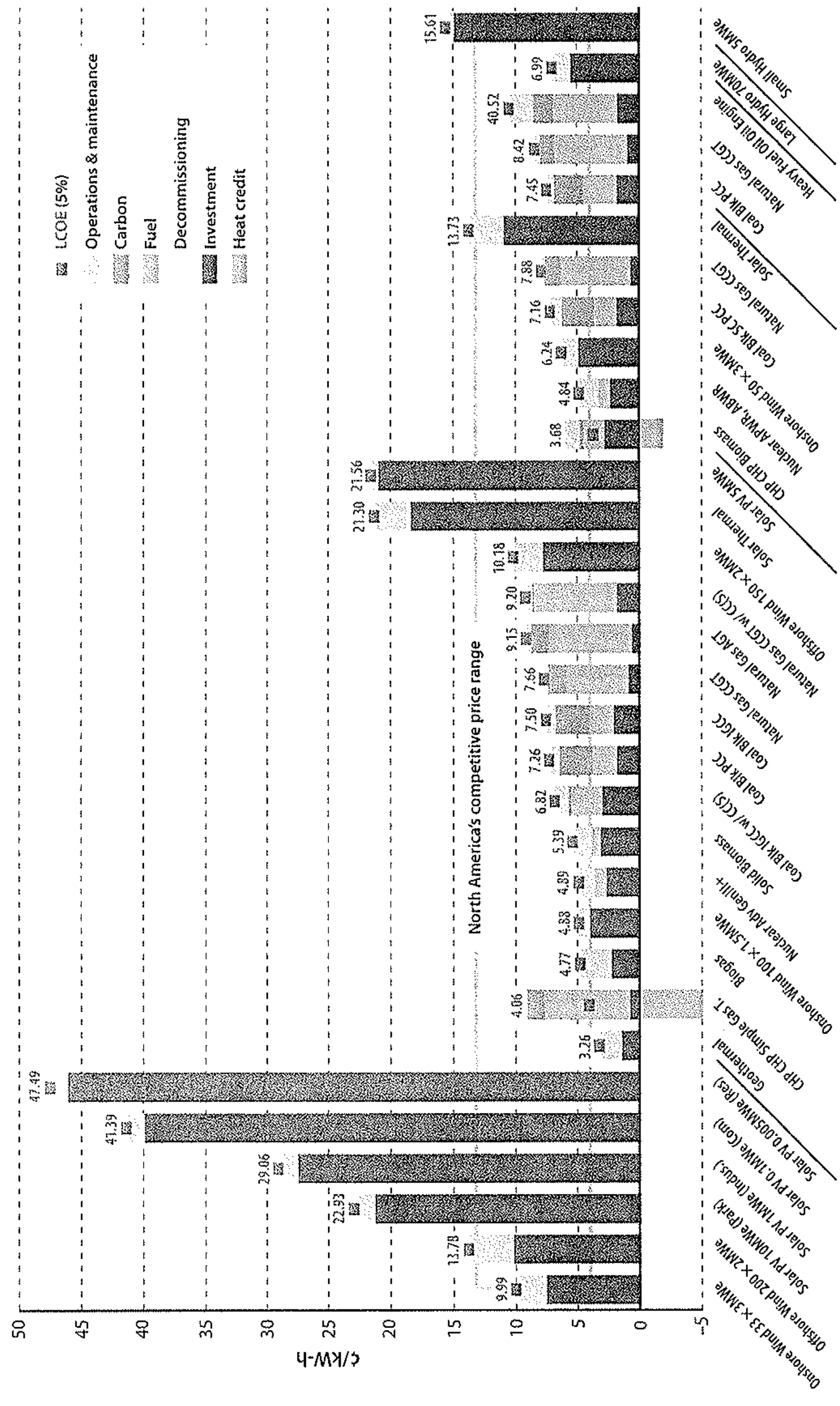
In the United States, most technologies are able to generate power at competitive prices except for certain solar PV and solar thermal projects. In Mexico, all of the plants in the dataset are from non-renewable technologies and are able to produce power in the competitive range. Of the Swedish (SWD) and Czech (CZR) proxies for hydroelectric power projects, large hydro is competitive while small hydro is above the North American competitive price range.

Figure 4 presents the LCOE data by power plant or project, organized from lowest to highest percentage of capital requirement (investment), together with the rest of the LCOE components as a percentage of the overall unit costs (¢/kW-h). Overall, with the assumed 5% discount rate, the average percentage of investment costs as a portion of overall unit costs across all plants in the dataset (¢/kW-h) is about 55%. Natural gas, fuel oil, coal, geothermal, biogas, and nuclear power projects (in that order) have investment costs lower than average but some of these technologies have large exposure to fuel price volatility (natural gas and coal) as well as to carbon-emission control costs. Nuclear power plants have relatively low operations and maintenance (O&M) costs. Biomass, wind, hydroelectric, and solar projects (both PV and thermal) exhibit above-average investment (capital) cost requirements but no exposure to volatility in fuel prices (except for biomass projects); on the other hand, they are exposed to relatively high operations and maintenance (O&M) costs.

Figure 5 shows LCOEs for projects in the dataset grouped by fuel source or technology, giving an average measure as well as a range that represents the maximum and minimum unit costs for the technology when a 5% discount rate is used. These ranges illustrate the cost variability by project type across geographic regions as well as according to project size. The results are consistent with those observed in figure 3.

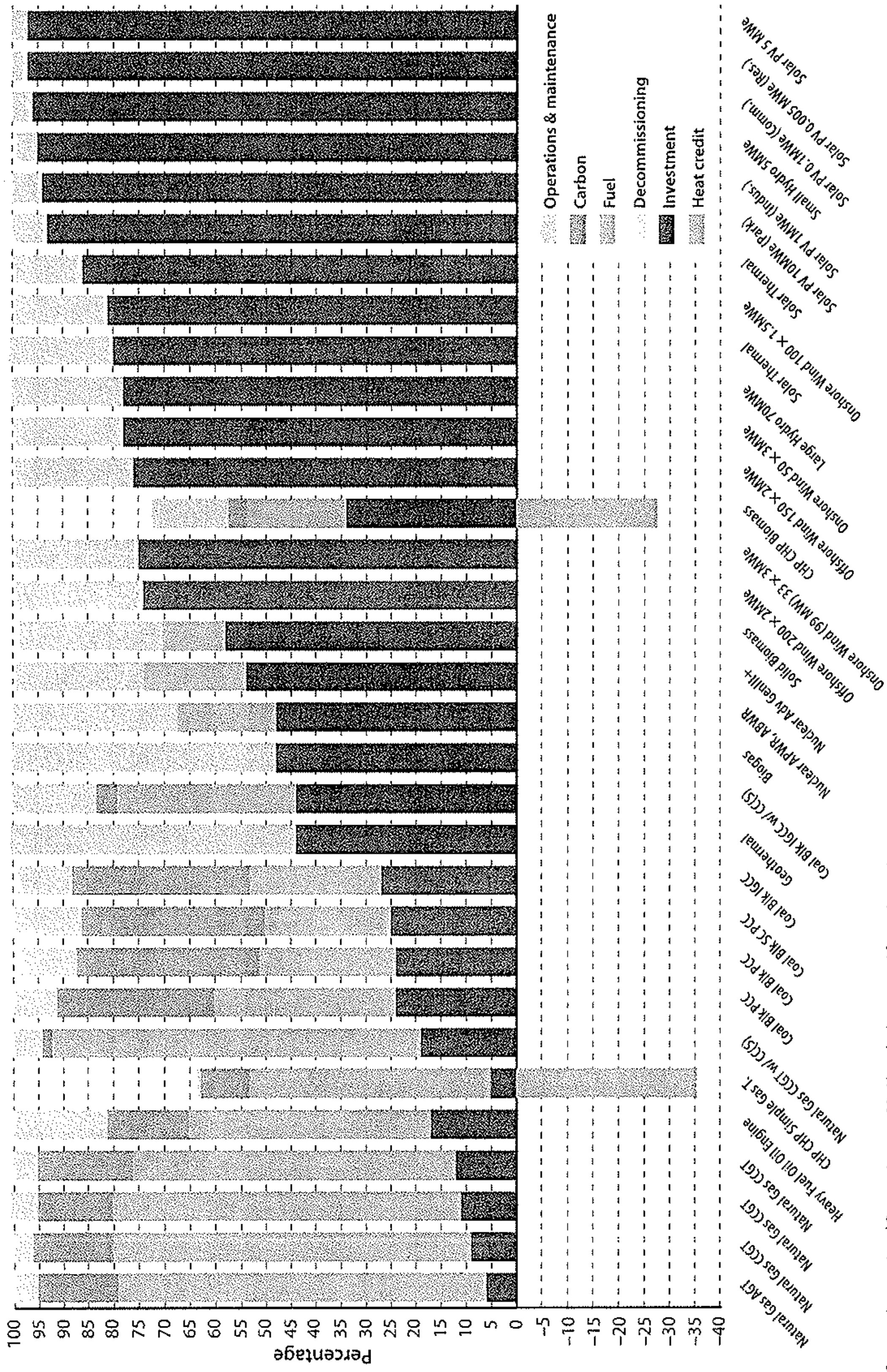
Figure 6 presents the data obtained from a recent analysis performed by the US Energy Information Administration (2011). The analysis corresponds to LCOEs for power plants in the United States to be commissioned by 2016, and does not include the effects of subsidies, tax credits, or related government incentives. Costs are calculated for utility-scale (commercial)

Figure 3: Levelized Costs (¢/kW-h) of Electricity (LCOE) generation in North America, by type of plant, at 5% discount rate—International Energy Agency



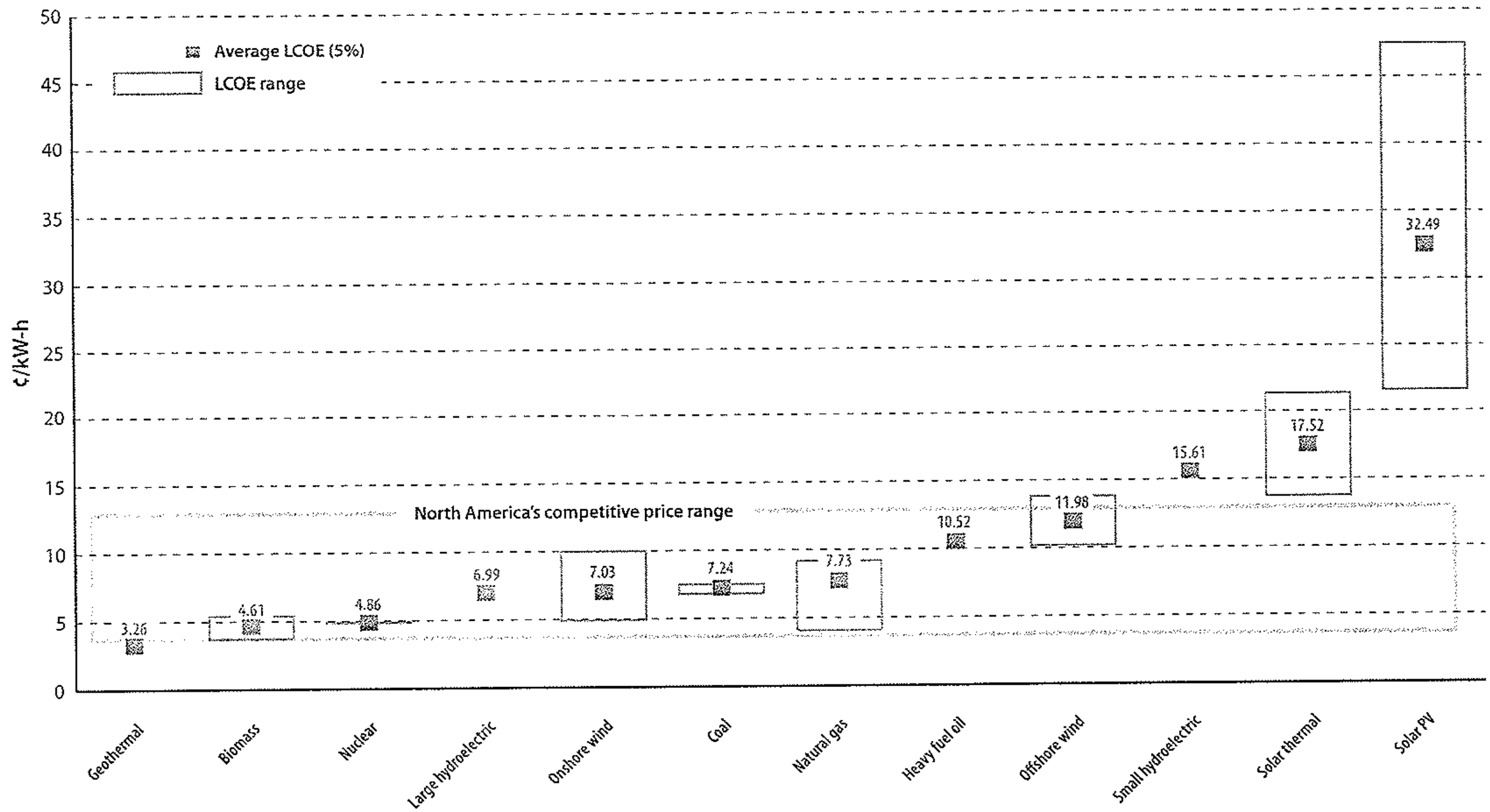
Sources: International Energy Agency, 2010b; calculations and figure by authors.

Figure 4: Percentage of LCOE component, by type of plant, at 5% discount rate—International Energy Agency



Sources: International Energy Agency, 2010b; calculations and figure by authors.

Figure 5: Average Levelized Costs (¢/kW-h) of Electricity (LCOE) generation, power plants in North America, at 5% discount rate—International Energy Agency



Sources: International Energy Agency, 2010b; calculations and figure by authors.

operations, based on a 30-year cost-recovery period, using a real, after-tax, weighted average cost of capital (WACC) of 7.4% (used as the discount rate). A penalty of $15/tonne is applied to technologies that are carbon-intensive to account for the costs of carbon capture and storage (CCS) components. The results presented in figure 6 are national averages though, in fact, costs will vary across regions because of differences in labour markets and in the cost and availability of fuel. The regional variation in unit costs (¢/kW-h) across the different power plants is displayed in figure 8. Figure 7 displays the proportion of each cost component as a percentage of the national average unit costs (¢/kW-h) arranged from the lowest percentage of capital cost to the highest.

Consistent with the IEA's analysis, figure 6 indicates that, on average, most electric-generation technologies can produce power at unit costs (¢/kW-h) that are consistent with the "competitive" North American power price range of between 4¢/kW-h and 13¢/kW-h that we identified earlier. This includes some natural-gas combined-cycle power plants with CCS components. However, technologies such as advanced coal with CCS, solar PV, offshore wind power, and solar thermal projects are not competitive according to this analysis.

Figure 7 supports the general findings about capital intensity, volatility of fuel prices, and fixed O&M costs in relation to overall unit costs (¢/kW-h). The average capital or investment cost as a percentage of unit costs in this sample is 65%. All of the types of plant powered by natural gas and the biomass plants are below this level and also have relatively low O&M shares. However, these technologies exhibit relatively high exposure to fuel-price volatility. Coal plants in this sample are, on average, more capital intensive, with smaller portions of exposre to variable fuel costs and smaller portions of fixed O&M costs. Nuclear power plants have similar characteristics. Solar thermal and solar PV, geothermal, wind (both onshore and offshore), and hydroelectric projects have the highest capital-cost proportions.

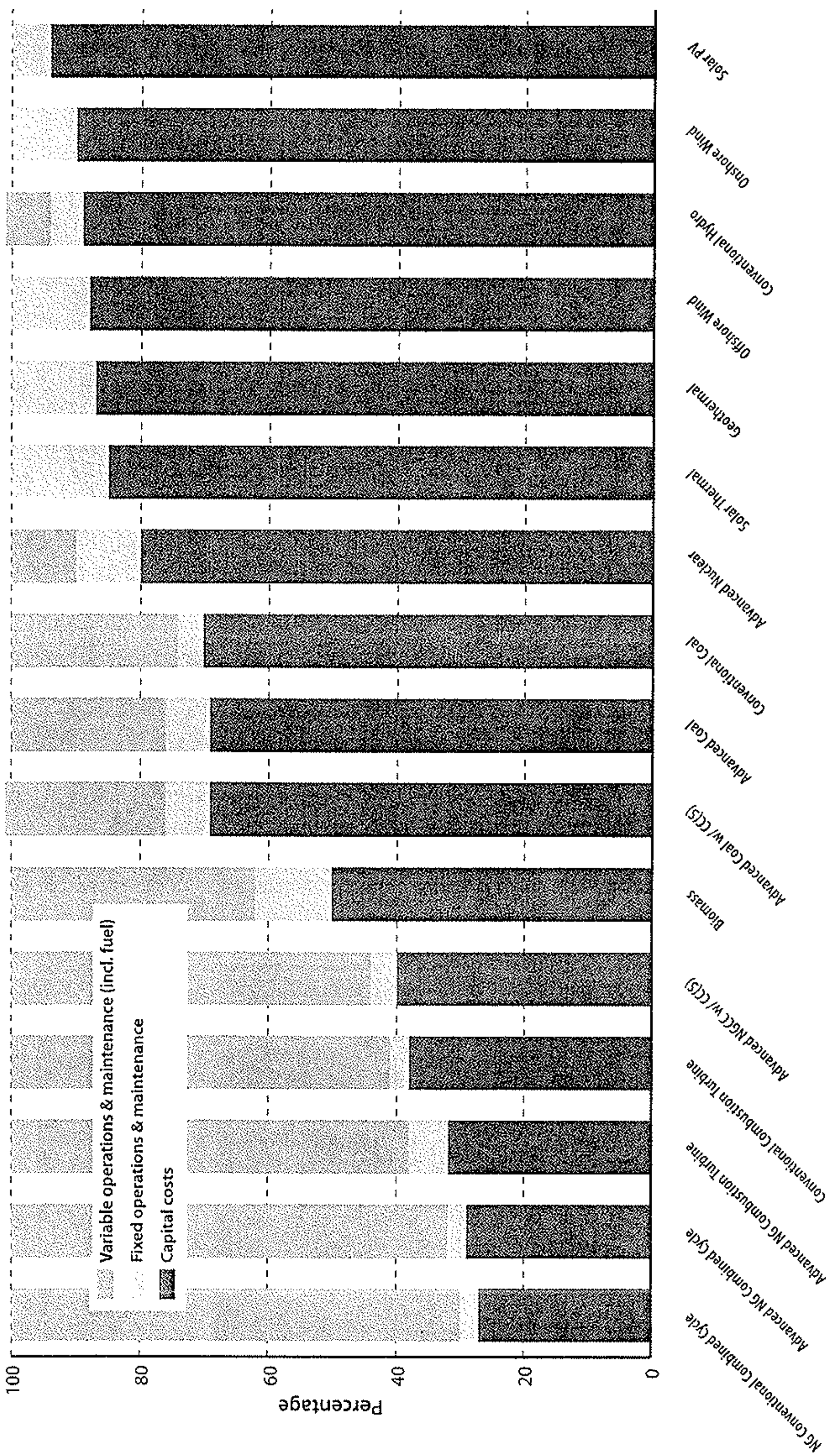
Figure 8 illustrates that, in the United States, most technologies have unit costs that are competitive. Hydroelectric projects, depending on location and size, have unit costs as low as 6¢/kW-h and as high as 15¢/kW-h. Advanced coal projects with CCS components are not competitive and have little regional variation, while solar PV, offshore wind, and solar thermal projects exhibit both large regional variability and unit costs that, in general, are not competitive with the indicated price range for electric power in North America.

A short technology-by-technology discussion is presented below, followed by a sensitivity analysis in relation to the discount rate in the IEA study. Finally, a comparison based on power plant overnight capital costs (OCC) is presented.

Figure 6: Estimated Average Levelized Costs (¢/kW-h) of Electricity (LCOE) generation, new power plants, United States, by type of plant—US Energy Information Administration

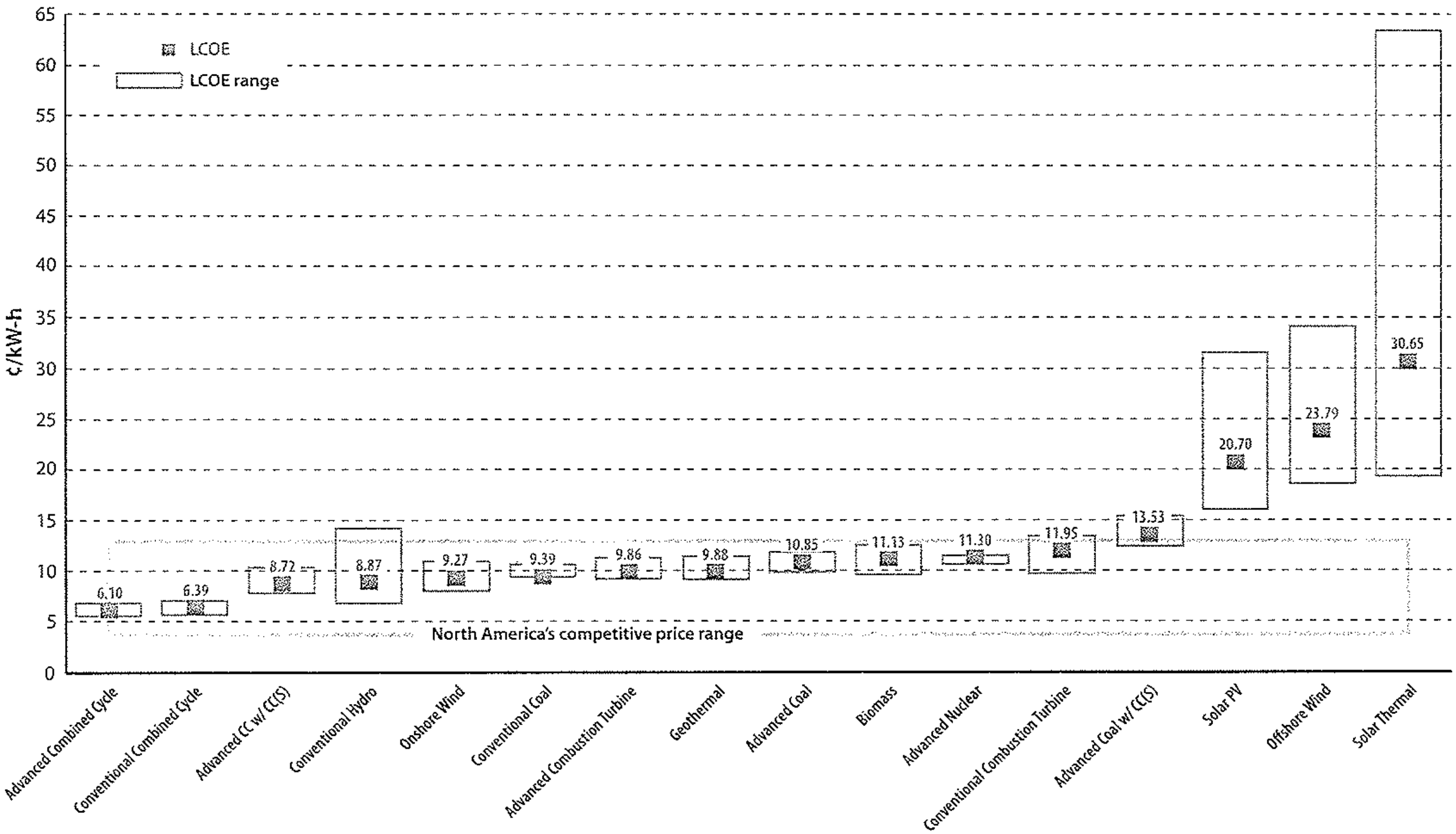
Sources: US Energy Information Administration, 2011; calculations and figure by authors.

Figure 7: Percentage of LCOE component, by type of plant, at 5% discount rate—US Energy Information Administration



Sources: US Energy Information Administration, 2011; calculations and figure by authors.

Figure 8: Average Levelized Costs (¢/kW-h) of Electricity (LCOE) generation from power plants in the United States —US Energy Information Administration



Sources: US Energy Information Administration, 2011; calculations and figure by authors

Costs of generating electricity from non-renewable sources

Nuclear

The most common nuclear reactor in the United States is the pressurized water reactor (PWR), which uses enriched uranium and light water as both coolant and moderator. The most common reactor in Canada is the CANDU (Canadian Deuterium-Uranium) design, which uses heavy water used as moderator and coolant, and uranium as a fuel. The cost estimates for nuclear power are based on information provided by the US Department of Energy, assuming advanced generation-III technology, as well as information provided by the Electric Power Research Institute (EPRI), which assumes the use of both advanced pressurized water reactors (APWRs) and advanced boiling water reactors (ABWRs) (International Energy Agency, 2010b).

The advantages of nuclear power include reliability—it is the most reliable of all generating technologies—because of high capacity factors (that is, the ability of the technology to transform the fuel into useful energy consistently and efficiently during relatively long periods of time without much interruption); long-term cost stability because of long plant lifetimes (60 years, as assumed in the 2010 IEA study); a relatively low fuel cost component (about 20%, figure 4), which is the lowest amongst the non-renewable energy technologies and second lowest overall (after biomass); as well as the absence of greenhouse-gas emissions and, therefore, of costs of carbon capture and storage, which were assumed by the IEA to be about $30 per ton of CO_2 equivalent.

Challenges include high investment costs (the highest amongst all non-renewable energy technologies) and, therefore, sensitivity to the costs of financing (as will be seen in the following sensitivity analysis section); long waits for regulatory approval; long construction periods (lead times—the IEA assumes seven years for nuclear plants); as well as high costs for decommissioning, safety, and waste disposal. And, following the recent incidents at the Fukushima Daiichi power plant in Japan, prospective nuclear power projects are certain to face difficulty in being accepted by the public. One last challenge that is not apparent when looking at the LCOE for nuclear power, yet is brought up in the IEA's study, is security and the threat of nuclear proliferation. This is part of a broad set of geopolitical risks that should be taken into consideration.

Some of the challenges related to nuclear technology can be met through the promotion of a stable and clear energy and environmental policy framework and an economic environment that allows investors to make better decisions based on knowledge of clear rules, regulations, and conditions. Streamlining the regulatory processes for obtaining permits would help to minimize cost escalation by shortening the time required to obtain approvals.

And, plant model standardization would help speed up the overall commissioning process and help to retard the escalation of costs (International Energy Agency, 2010b).

Coal

Coal-fired plants burn coals of various qualities such as lignite, brown, and black or "hard" coal. It is assumed that hard coal is used in the cost estimates for the coal technologies for which cost information is reported in table 4. Integrated gasification combined cycle (IGCC) technology, which is a combination of steam and gas turbine applications, is a cleaner and more efficient technology than conventional and pulverized coal combustion (PCC) but IGCC has higher overnight, investment, decommissioning, and fuel costs, and, thus, a higher LCOE compared to PCC.

The analysis above indicates that, when carbon capture and storage (CCS) requirements are combined with IGCC, the total levelized unit costs of electricity generated from coal combustion drops below that of IGCC without CCS and PCC in the 5% discount-rate case. This is because the higher combined investment, overnight, fuel, operating, and maintenance costs are more than offset by a substantial reduction in carbon costs since the carbon emissions problem is met by the investment in CCS technology. In the 5% discount rate case, all of the coal-fired power plants in the dataset can generate power at rates consistent with competitive power prices in North America.

Coal-fired power plants in the dataset generally have higher investment costs than natural-gas power plants (because of long lead times, around four years, according to the IEA [2010b]), yet most coal-fired power plants have capital-to-unit-cost percentages that are below the average 55% for the dataset, and coal also benefits from plants with a long life (40 years). Fuel costs are moderate, usually lower than those for natural gas and heavy fuel oil, thus making coal-fired power plants less exposed to fuel price volatility. Operation and maintenance costs are low in comparison to overall unit costs, which means that coal-fired power plants have more stable fixed costs over their operating lifetimes. Overall, coal's advantages include moderate LCOEs, as well as low fuel and O&M costs and long plant lives. Further, coal-fired power plants located near coal mines benefit from lower fuel costs, as transaction and transportation costs are significantly reduced. On the downside, costs of carbon capture and storage for coal plants are amongst the highest across all of the fossil-fuel technologies because of high emissions intensity (i.e., more carbon molecules) and can constitute as much as 35% of the overall LCOE unit costs for plants without CCS technologies.

These advantages and challenges are important given the significant extent of coal resources available in North America (table 5). According to

Table 5: Coal resources in North America (million tons of hard coal), year end 2009

	Reserves	Production	Consumption	Exportable surplus	Reserve/ Production
Canada	6,578	63	40	23	105
United States	238,308	973	747	226	245
Mexico	1,211	11	10	1	109
North America	246,097	1,047	797	250	235
World	826,001	6,941	4,917	2,023	119

Source: British Petroleum, 2010; calculations and table by authors.

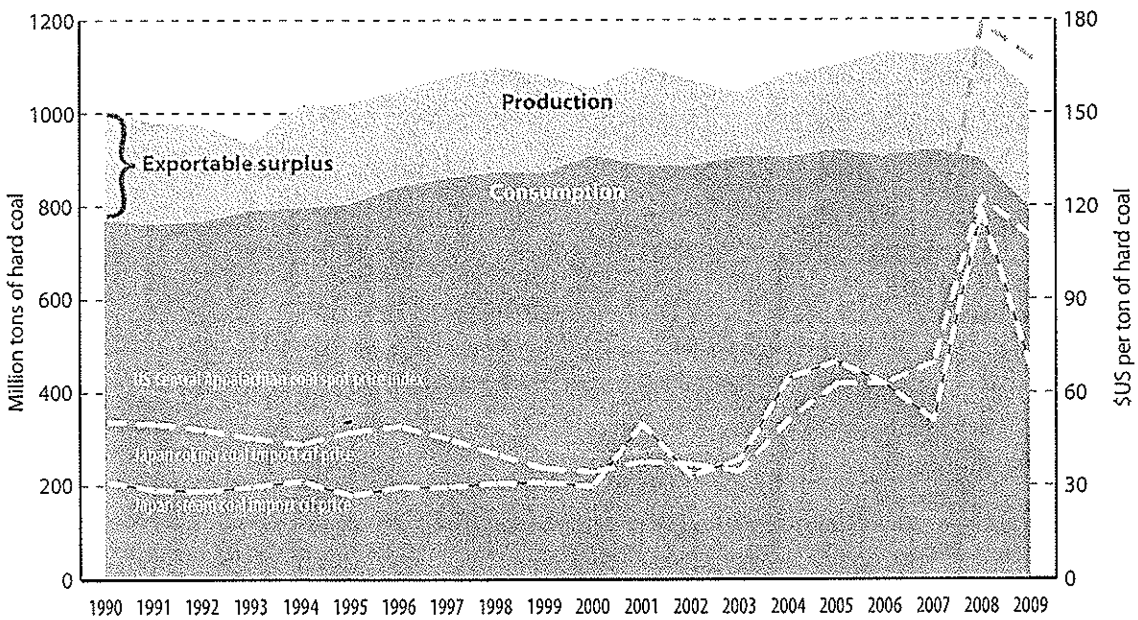
data from the *BP Statistical Review of World Energy*, as of year-end 2009 about 246.1 billion tonnes (30% of the world's total) of coal reserves were located in North America, mainly in the United States (about 97% of North America's reserves) but with significant reserves also available in western Canada (close to 3%), and some in Mexico (less than 1%) (British Petroleum, 2010). As of year-end 2009, coal production in North America represented only 15% (1,047 million tons) of the world's total in 2009, with 93% of this produced in the United States, 6% in Canada, and 1% in Mexico. Production of coal at the end of 2009 was very close to 1990 levels (1,009 million tons) and just below the average for the period from 1990 to 2009 (1,058 million tons, close to year 2000 levels) (figure 9). The highest production in the 20-year period was in 2008, when 1,142 million tons of coal were produced in North America.

Coal consumption in North America in 2009 was 797 million tons, or 16% of the world's total. This level of consumption was close to the lowest in the 20-year period (762 million in 1991), 7% lower than the 20-year average (855 million tons, close to 1997 levels), and 16% lower than the highest levels in the period from 1990 to 2009 (922 million tons in 2007). Exportable surplus levels in North America have remained fairly stable over the 1990s and 2000s, averaging 203 million tons, with a high of 250 million tons in 2009 and a low of 137 million tons in 2003.

The reserve to production ratio (R/P) in table 5 indicates that, assuming a constant rate of production at the 2009 level and given the reserves available, North America has enough coal to meet requirements for 235 years. This compares to an R/P ratio of 119 for the world as a whole and indicates the potential importance of the North American coal industry.

While not all coal is used for electricity generation in North America, a significant proportion of it is. And, while coal prices have increased over the past 20 years and have been volatile, they are low per unit of energy content compared to other non-renewable sources.

Figure 9: Production, consumption and selected prices of coal, North America, 1990–2009



Sources: British Petroleum, 2010; calculations and figure by authors.

Oil

Use of oil as a fuel for generating electricity has declined over time because of high fuel costs and concerns about emissions of greenhouse gases. However, oil is still used in areas of North America where it makes economic sense to do so, either because of proximity to ports and refineries or because other sources of power for electricity generation are not readily available, as in remote locations like Hawaii and northern communities in Canada. Fuel oil provides 5% of Canada's electric generation capacity (mainly in the Atlantic Provinces and Quebec), about 6% of the US generation capacity (Hawaii, Eastern and Southern states), and a considerably greater amount in Mexico. The types of oil being used for electricity generation include fuel oil, petroleum coke, and diesel fuel in Canada; distillate fuel oil, residual fuel oil, petroleum liquids and coke, jet fuel, kerosene, and waste oil in the United States; and heavy fuel oil and diesel in Mexico.

Fuel-oil plants have the highest LCOE of all of the non-renewable electric generation technologies (table 4). The advantages of oil-fired plants include moderate overnight and investment costs, as well as high capacity factors; and, while the size of the generators is usually small, they are ideally suited for the remote locations where they are often used. However, oil-fuelled plants have high decommissioning costs compared to most other non-renewable generating technologies, the third-highest costs for fuel and carbon capture and storage amongst this group, and the highest operating and maintenance costs of the non-renewable energy technologies.

Natural gas

Natural gas burns cleaner than coal because sulphur and other by-products are generally removed in processing plants before the gas enters the transmission system. In a combined-cycle gas turbine (CCGT), the gas generator is coupled with a steam turbine. The hot gases flowing from the gas turbine are used to generate steam in a heat-recovery unit and the steam is then used to produce additional electricity, improving the overall efficiency. Advantages of CCGTs include low capital cost, short lead times, high efficiency, operational flexibility, and low carbon intensity (International Energy Agency, 2010b). The technology listed under natural gas plants as "AGT" denotes advanced combined-cycle gas-turbine generation (a newer and improved version of IGCC), while CCGTs with CCS use carbon capture and storage (CCS) facilities as discussed earlier.

The LCOEs (or unit costs) of electricity generated using natural gas technologies (table 4) are generally higher than those for coal. However, gas-fired plants are less costly to build than coal-fired plants, they have some of the lowest overnight and investment costs amongst the non-renewable technologies (except for natural gas plants with CCS components), and overnight and investment costs are also well below those for all other technologies. They also can be built more quickly (with average lead times of two years, according to the IEA's study), and have long plant lives (30 years). Natural-gas-fired plants also benefit from some of the lowest costs for carbon capture and storage across the non-renewable technologies because of lower emissions intensities, as well as some of the lowest operation and maintenance costs across all technologies.

As with the case for coal, natural gas plants with CCS components have higher investment costs, lower costs for carbon capture and storage, and higher operations and maintenance costs, and generally have higher overall unit costs (¢/kW-h). This reflects on the effects that CCS requirements or restrictions on carbon emissions can have on the economics of both coal-fired and natural-gas-fuelled power plants.

The main draw-back to natural gas as a source of electricity is the high proportion of fuel costs in overall unit costs (¢/kW-h), higher than in the case of coal-fired, nuclear, and oil-fired plants. Also, the price of gas tends to be more volatile than the price of coal or uranium, introducing greater uncertainty. Because coal plants are more capital intensive, natural gas becomes more competitive compared to coal as the cost of capital increases.

Natural-gas combined heat and power (CHP)

Combined heat and power (CHP), or co-generation, plants are becoming increasingly popular as they generate electricity and the heat generated during that process can be used to heat water or living and working space. The LCOE for the one natural-gas CHP plant for which information was provided in the IEA's study (2010b) is the lowest for all of the non-renewable energy technologies. Advantages of natural-gas CHP plants include low overnight and investment costs (the lowest amongst all technologies), some of the lowest decommissioning costs amongst the non-renewable energy technologies, the lowest operation and maintenance costs across all generating technologies.

Moreover, natural-gas CHP is the only type of non-renewable electric generation technology for which the economic analysis benefits from the value of the heat that is provided to industrial or commercial customers. The heat-value "credit" that is realized helps to offset operating costs and to ensure viability where the co-generator is faced with the costs of controlling emissions of CO_2 by carbon capture and storage or similar costs of complying with environmental regulations. Their low capital costs mean that the LCOE for natural-gas CHP plants is not as sensitive to changes in the discount rate as the LCOEs of high-capital-cost technologies such as nuclear and coal-fired generating plants.

The disadvantages of natural-gas CHP plants include their generally having higher fuel costs than some non-renewable technologies as well as carbon emissions comparable to other generation technologies using natural gas.

Summary

According to our analysis of the IEA's data, the lowest cost non-renewable energy source option for electricity generation is natural-gas combined heat and power (CHP) (or co-generation), followed by nuclear technology, and coal-fired plants. Although natural gas CHP plants have low overnight, investment, operation and maintenance costs, fuel costs for natural gas CHP plants are the greatest of all the non-renewable energy technologies. Natural-gas CHP plants, therefore, have considerable exposure to the volatility of the price of natural gas.

Other types of natural-gas power plants also benefit from low capital intensity, low costs for carbon capture and storage compared to those for coal-fired plants, and low to moderate decommissioning, and operations and maintenance costs. On the other hand, natural-gas power plants have a high level of exposure to volatile fuel prices. However, we believe (consistent with the estimates produced by various energy agencies including the International Energy Agency, the National Energy Board, and the US Energy Information Administration) that, due to recent developments in natural-gas markets in North America, including the large supply of shale gas, over the medium to long term, natural gas prices in North America will remain stable and will increase only moderately. Overall, natural-gas power plants can generate power at competitive rates, though it is important to keep in mind that CCS components can affect the economics of a natural-gas-powered plant.

While lead times for construction of nuclear plants are the longest (thus increasing the sensitivity to changes in costs of financing) and the capital and decommissioning costs of nuclear power are relatively high, median operation and maintenance costs are moderate. According to our analysis of the IEA's data, nuclear power also has lower fuel costs relative to generation using coal, oil, and natural gas, zero carbon emissions, the highest load factor and reliability, and the longest plant lifetimes. Whether these advantages will attract much investment in nuclear power generation over the next decade will largely depend on regulations, public acceptance of the technology, and local market conditions.

Coal plants face challenges similar to nuclear technologies as they also have high capital and operations and maintenance costs, as well as long lead times. But, in the case of coal, costs for carbon capture and storage are of increasing concern in light of current environmental concerns. When carbon capture and storage requirements are imposed on coal and natural-gas generation plants, the case for nuclear power becomes more compelling. However, the long lead times and high capital costs of nuclear plants and the prospects of low and stable gas prices suggest that generating electricity with natural gas, which has relatively low carbon emissions compared to coal, will increasingly be seen by investors as more advantageous than either nuclear or coal, a trend that is confirmed by additions to North American electric generation capacity over the last decade, especially the increased reliance on natural-gas combined-cycle turbines (International Energy Agency, 2010b: figure 6.31).

Costs of generating electricity from renewable sources

The main advantages of renewable energy sources for generating electricity are their relatively short lead times for construction (assumed by the IEA to be about one year for non-hydro renewables) and relatively low (biomass) or no fuel costs (all other). Also, except with biomass combustion, there are no greenhouse-gas emissions to control. On the other hand, all renewable energy technologies other than hydroelectric plants generally have shorter plant lifetimes than non-renewable technologies, and most renewable energy sources (except for geothermal and biogas) have considerably higher capital costs than those of non-renewable energy sources. Also, most renewable energy-generating technologies have high operating and maintenance costs compared to various non-renewable energy technologies. Technologies using renewable energy sources are seriously disadvantaged if the cost of capital is high (sensitivity to financing costs). This explains why the levelized unit cost of electricity from most renewable energy-generating technologies is so high compared with the non-renewable energy sources, particularly in the 10% discount rate case, as will be seen in the sensitivity analysis section.

Hydroelectric

LCOE analysis for hydroelctric facilities in North America was not available in the IEA's study, as neither Canada, the United States, nor Mexico contributed information on hydroelectric power projects. Sweden reported an LCOE of close to 7¢/kW-h for a 70 MW hydroelectric facility on the assumption of a 5% discount rate. Brazil reported an LCOE as low as 1.7¢/kW-h for a 300 MW hydroelectric facility with a 5% discount rate. The Swedish estimate is in line with a levelized-cost estimate by the California Energy Commission of 6.7¢/kW-h (using a discount rate of approximately 8.45%) for an 80 MW hydroelectric facility in California (California Energy Commission, 2010). If that estimate, which is in 2009 US dollars, were adjusted to 2008 dollars in order to conform to the IEA's recent estimates, the estimated levelized cost would lie in the vicinity of 6.6¢/kW-h. Of course, the actual cost of a new hydroelectric facility would be heavily affected by both size and location, as the cost of the land required, including area for a reservoir, is an important factor.

For small hydroelectric facilities, the LCOE per ¢/kW-h is generally higher than in the case of large facilities, which benefit from economies of scale. For the IEA's 2010 report, the Czech Republic indicated a levelized unit cost of 15.6¢/kW-h for a 5 MW hydroelectric facility at a 5% discount rate. A 2010 study by the California Energy Commission placed the estimated all-in cost of a small (15 MW) hydro facility in California at 8.6¢/kW-h in 2009 US dollars, assuming a cost of capital (discount rate) of approximately 12.1% (California Energy Commission, 2010). In 2008 dollars, that would translate into an approximate cost of 8.5¢/kW-h.

As a means of comparison, the US Energy Information Administration estimates the national average LCOE for all hydroelectric projects to be about 8.87¢/kW-h with prices ranging from as low as 5.7¢/kW-h to as high as 14.7¢/kW-h (2008 US$) for plants to be operational by 2016, using a discount rate equal to 7.4% (US Energy Information Administration, 2011). Further, a recent US Department of Energy report (US Department of Energy, Office of Energy Efficiency & Renewable Energy, 2010) estimates that large hydroelectric projects in the United States can generate electricity based on levelized unit costs in the range from 4¢/kW-h to 13¢/kW-h. These estimates are in a range close to the average of the LCOE estimates for the large Swedish hydroelectric project and the small Czech hydroelectric facility, which is equivalent to 11.3¢/kW-h at the 5% discount rate.

Overall, because hydroelectric projects—especially those that are small—have large overnight and unit investment costs, they tend to be very sensitive to increases in the cost of capital. Hydroelectric projects (as with wind and solar projects) are also limited by the availablility of suitable locations and resources. On the other hand, hydroelectric projects benefit from low exposure to other factors such as decommissioning costs, no costs for fuel or carbon capture and storage, and low and modest operations and maintenance costs. Large hydroelectric projects can generate power at competitive prices while the unit costs of small hydroelectric power projects are above the competitive boundary.

Wind

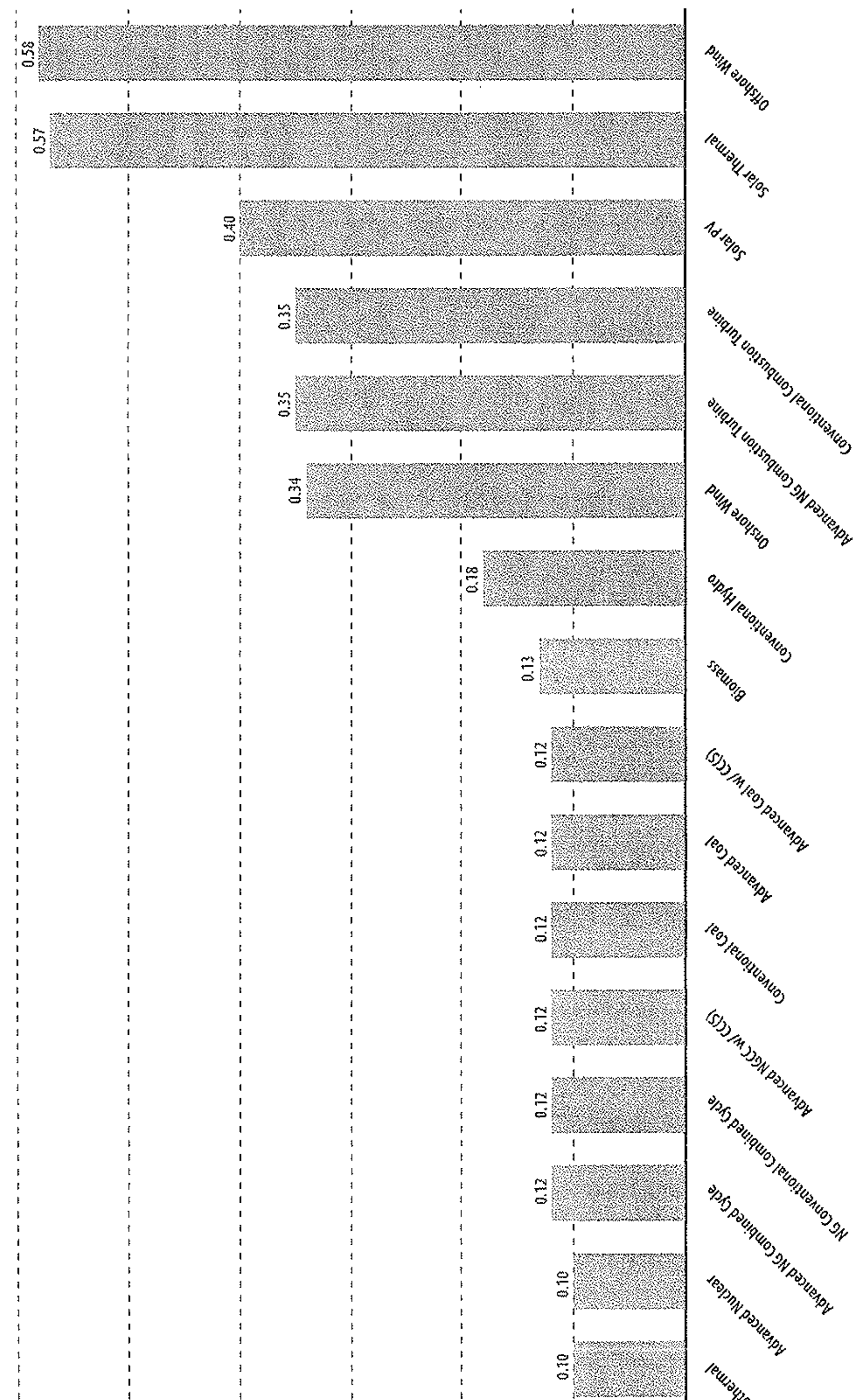
In North America, as elsewhere in the world, there is increasing interest in generating electricity using wind power. This is occurring for a number of reasons. First, since they have no fuel requirements, wind-power facilities are not subject to the risks associated with fuel price uncertainty and volatility that investors in fossil-fuel combustion plants face. Second, the cost of wind generation units has been declining (in part because of larger-scale applications). Third, and most important, there has been a proliferation of government incentive programs aimed at increasing electricity generation from renewable energy sources that many investors in wind power facilities have been able to take advantage of.

Capital costs account for between 75% and 90% of the total cost of electricity in the case of wind power. According to the Canadian Wind Energy Association (CanWEA), one megawatt of installed capacity requires between $1.8 million and $2.2 million in investment (Canadian Wind Energy Association, 2009). Lowering capital costs is therefore critical if generating electricity with wind technology is to be feasible.

A major drawback with wind-power installations is that sufficient wind is generally not available to allow wind turbines to operate on a consistent hourly, daily, weekly, and seasonal basis. In fact, on many occasions, installed wind-power capacity may not be available because the wind velocity is not high enough. Because of this, capacity utilization rates for wind turbines frequently average as low as 30%—much lower than for any of the non-renewable technologies. On the other hand, the turbine will shut down for safety reasons if the wind speeds velocity exceeds the design limit.

Further, because of the variable and unreliable nature of wind, alternate sources of supply such as gas-fired generation must be available as backup to wind-power capacity for system reliability. Moreover, because wind-power plants are restricted to sites with certain characteristics, considerable investment in new or extended transmission facilities may be required. Figure 10 provides a representation of recent estimates developed by the Energy Information Administration of the average levelized unit costs of transmission investment required for new power plants (2016 commission date) in the United States (US Energy Information Administration, 2011). In general, renewable energy technologies (except for geothermal and biomass) require some of the highest investment costs for transmission. There are also added costs for balancing the electric system once wind-power technologies been connected to the grid. Costs of this kind are not included in the estimates provided in table 4.

Figure 10: Estimated levelized transmission investment costs (¢/kW-h), new power plants, United States, by type of plant—US Energy Information Administration



Sources: US Energy Information Administration, 2011; calculations and figure by authors.

As the IEA study points out, the variability of wind-power output can be reduced to a degree by increasing the area over which wind power applications are installed. This may be achieved by installing clusters of wind turbines in different areas of a region ("geo-spread") in order to smooth the combined output of all of the wind turbines and farms in the region. This may reduce the variation in electricity generation, but at a cost, because of the need for multiple units with high capital, operation, maintenance, and decommissioning costs and the need for multiple points of connection to the transmission grid.

Because of these issues, one cannot conclude that onshore wind generation, which is indicated by one of the sources that contributed information to the IEA study as having a levelized electricity cost of only 4.9¢/kW-h at the 5% discount, will actually be able to compete with non-renewable energy technologies. Barring subsidies or incentives of some kind, the answer will largely be determined by site-specific conditions including the cost of connection to the grid and wind variability, as well as the fuel costs faced by competing non-renewable electric generators in the area.

According to the IEA, offshore wind plants have LCOEs ranging from 10.2¢/kW-h to 13.8¢/kW-h in the 5% discount rate case. Although wind variability may be less of a problem than with onshore locations, offshore locations face higher costs for operations and maintenance, decommissioning, and connection. Moreover, offshore facilities have higher capital costs than onshore wind facilities. The likelihood of offshore wind facilities being able to compete with onshore non-renewable electric generation facilities is therefore less likely, in general, than that of onshore wind facilities.

Biomass and biogas

The least costly source of renewable electricity after geothermal is combined heat and power (CHP) using biomass. Compared with most non-renewable-source power plants, biomass (and biogas) power generation facilities can have relatively high overnight, investment, and operation and maintenance costs. Solid biomass and CHP biomass power plants have percentages of fuel costs in relation to overall unit costs similar to those of nuclear power plants and, thus, have similar costs structures and overall unit costs (¢/kW-h). These biomass plants are also subject to costs for carbon capture and storage, while CHP biomass plants can offset a cost through heat credits. Biogas plants, which use gases produced as a by-product of anaerobic digestion or fermentation, have no fuel costs and therefore investment and operations and maintenance components make up a bigger share of the costs. All of the biomass plants included in the dataset can produce power at competitive levels. Also, depending on location and the source of the fuel that is used, biomass may benefit from low fuel costs compared to oil, natural gas, and coal. Biomass plants also typically have very high capacity factors, which make the technology ideal for base-load power.

Solar

The average LCOE of photovoltaic (PV) solar power is considerably greater than that for a typical biomass plant, ranging from 21.6¢/kW-h to 47.5¢/kW-h at the 5% discount rate. Solar PV has both some of highest decommissioning costs and the highest LCOEs of all technologies. Like wind power, the capacity factor of the technology is low (around 30% or less) and projects improve their overall competitiveness through economies of scale. Solar PV projects have large capital-cost components (generally above 90% of total costs) and are, therefore, sensitive to changes in the costs of capital (discount rate).

Solar thermal has characteristics similar to solar PV as a generating technology and in terms of cost structure. However, LCOEs for solar thermal are significantly lower than those for solar PV.

Geothermal

Geothermal energy is reliable, can be used as a source of base-load power, and generally has a high efficiency factor. Depending on the site, geothermal energy may require a relatively large capital investment as well-drilling costs can account for as much as one third or one half of the total costs of a project (International Energy Agency, 2010b). For the example provided in table 4, the investment cost is lower than for all of the other renewable technologies. On the other hand, operating and maintenance costs are comparable to those of nuclear power plants. Overall levelized unit costs for the geothermal plant in the sample are the lowest, at less than 4¢/kW-h. The difficulty, of course, is that economic geothermal resources are limited and site specific.

Summary

Comparing the renewable technologies for which data are provided in table 4 and figures 3, 4, 5, 6, 7, 8, and 10 indicates that geothermal and biomass electric-generation facilities have the lowest levelized unit electricity costs of the renewable energy technologies. Whether onshore wind installations can compete with other sources of electricity in a given situation will depend on the backup and transmission system requirements. The cost of solar power is much too high for it to compete with other renewable energy sources though it may be advantageous in remote locations.

Sensitivity of technologies with high capital requirements to changes in the cost of capital

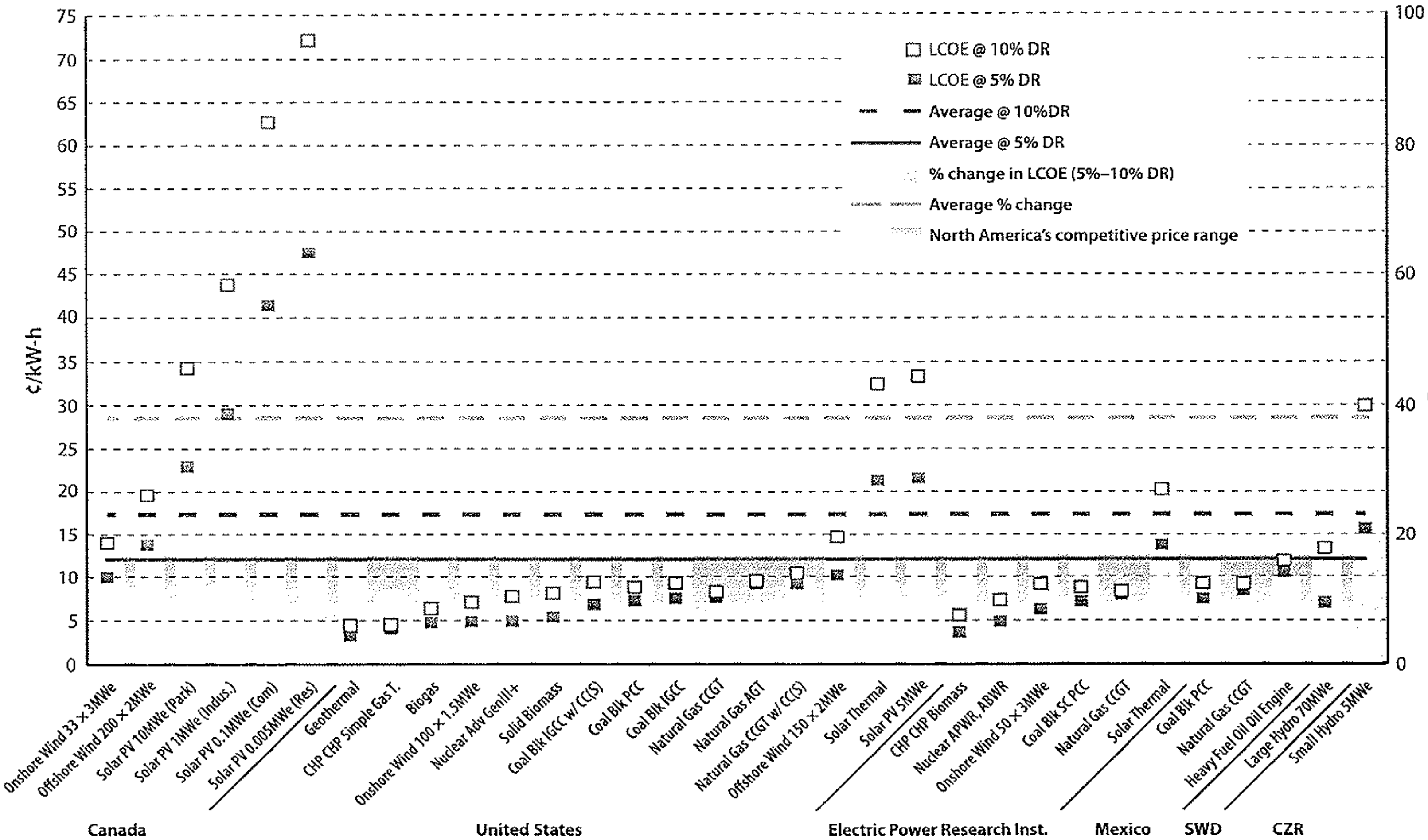
Generation of electricity is highly capital-intensive because large capital resources are required to construct an electric generation facility (Angevine and Murillo, 2011). It is also evident from the foregoing analysis that, although the different electric-generation technologies have very distinct cost structures, the capital (investment) components usually constitute most of the overall cost. In general, technologies that have the longest lead (construction) times or have the largest capital requirements are the most vulnerable to changes in the costs of capital. In order to illustrate this sensitivity, in this section we examine the implications of using a 10% discount rate in the LCOE analysis instead of a 5% discount rate.

Under current macroeconomic conditions in North America, with low inflation rates and very modest economic growth, it is reasonable to assume that yields on long-term government bonds, which can used as a proxy for the discount rate, will remain low and that a discount rate in the vicinity of 5% is more appropriate than a significantly higher rate. However, a higher discount rate may be appropriate if one assumes that investors in power-generation facilities demand a risk premium. The fact is that returns on investment even in generation-asset portfolios diversified in technological types, fuels, and locations are subject to risk because of the inherently unpredictable nature of technological change and the possibility of changes in energy policy occurring at any time. Further, investors in North American power projects not only compare the expected rates of return with other opportunities on this continent (for example, in other industries such as mining and oil and gas) but also with potential industrial projects overseas, including the emerging markets of Asia where higher discount rates generally apply both because of the greater geopolitical risk and the possibility of higher returns. Since North American power projects compete for capital in the global market, it is important to understand how the LCOEs of the competing technologies compare when a higher discount rate is assumed.

Figures 11 to 13 are for the most part equivalent to figures 3 to 5: the essential difference is that the estimates in this case were generated using a discount rate of 10% rather than 5%. This allows for ready comparison of the impact on the estimated LCOEs for the various technologies from moving to a significantly higher discount rate. Figure 11 serves as a benchmark for the sensitivity analysis since it not only shows the LCOEs for the power plants at the two different discount rates but also the percentage changes in the LCOEs from moving from the lower to the higher discount rate. Moving from a 5% to a 10% discount rate generally increases the estimated LCOEs significantly in the case of technologies that have large portions of capital as part of their overall unit cost. It also increases their investment costs (figures 12 and 13).

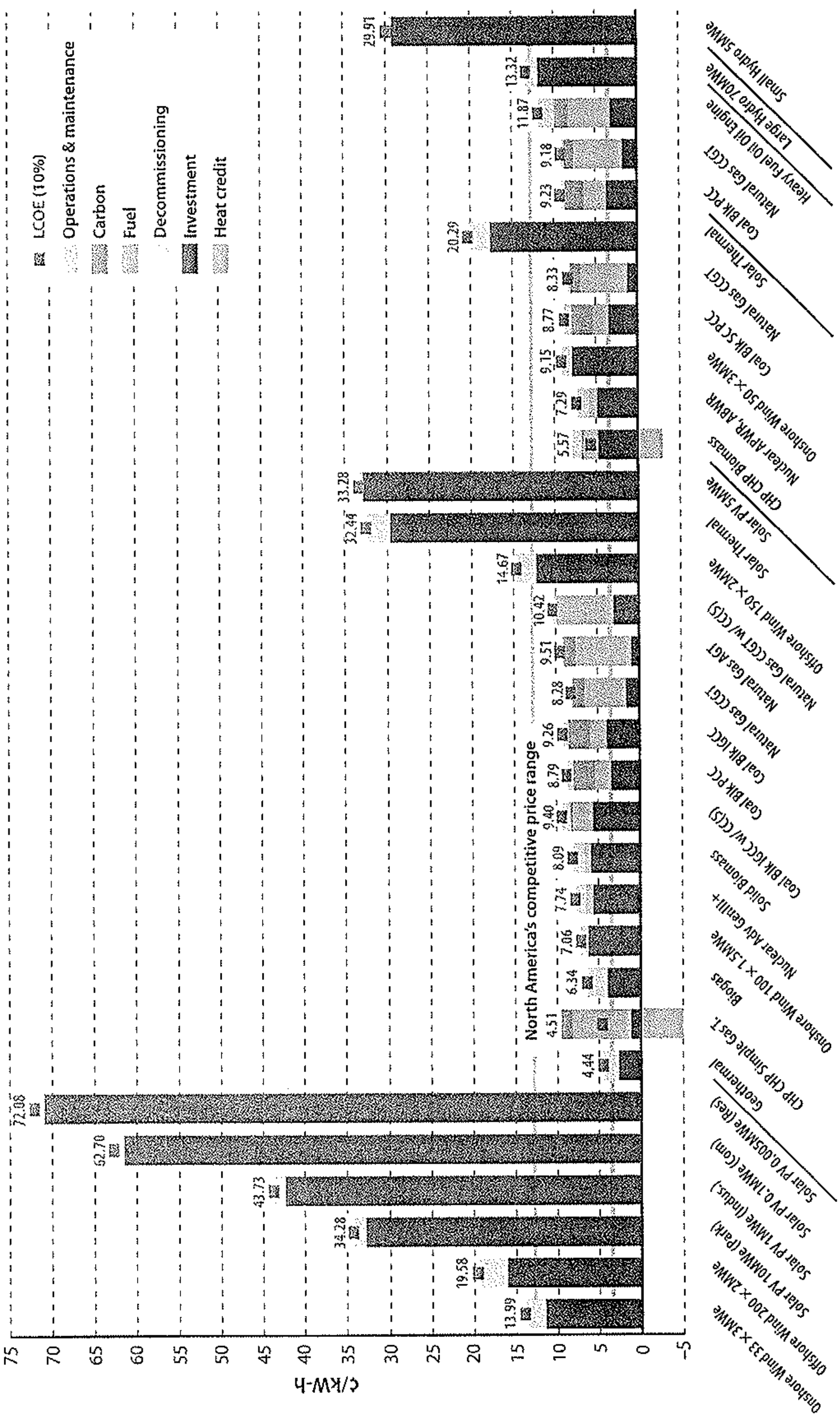
The average LCOE across all technologies in the data set increases by 5.3¢/kW-h (or 44%) from 12¢/kW-h at a 5% discount rate to 17.3¢/kW-h at the 10% discount rate. The average percentage increase in the LCOEs from moving to the 10% discount rate across all technologies in the dataset is 38%, with technologies such as onshore wind, offshore wind, solar PV, nuclear, solid biomass, coal with CCS, and a pulverized-coal combustion project exhibiting percentage changes above the 38% average. The lowest percentage increase (4%) corresponds to the geothermal plant in the dataset, while the highest percentage increase (92%) corresponds to the small hydroelectric power project.

Figure 11: Levelized Costs (¢/kW-h) of Electricity (LCOE) generation in North America, by type of plant, and sensitivity analysis (% change) of discount rate—International Energy Agency, 2010b



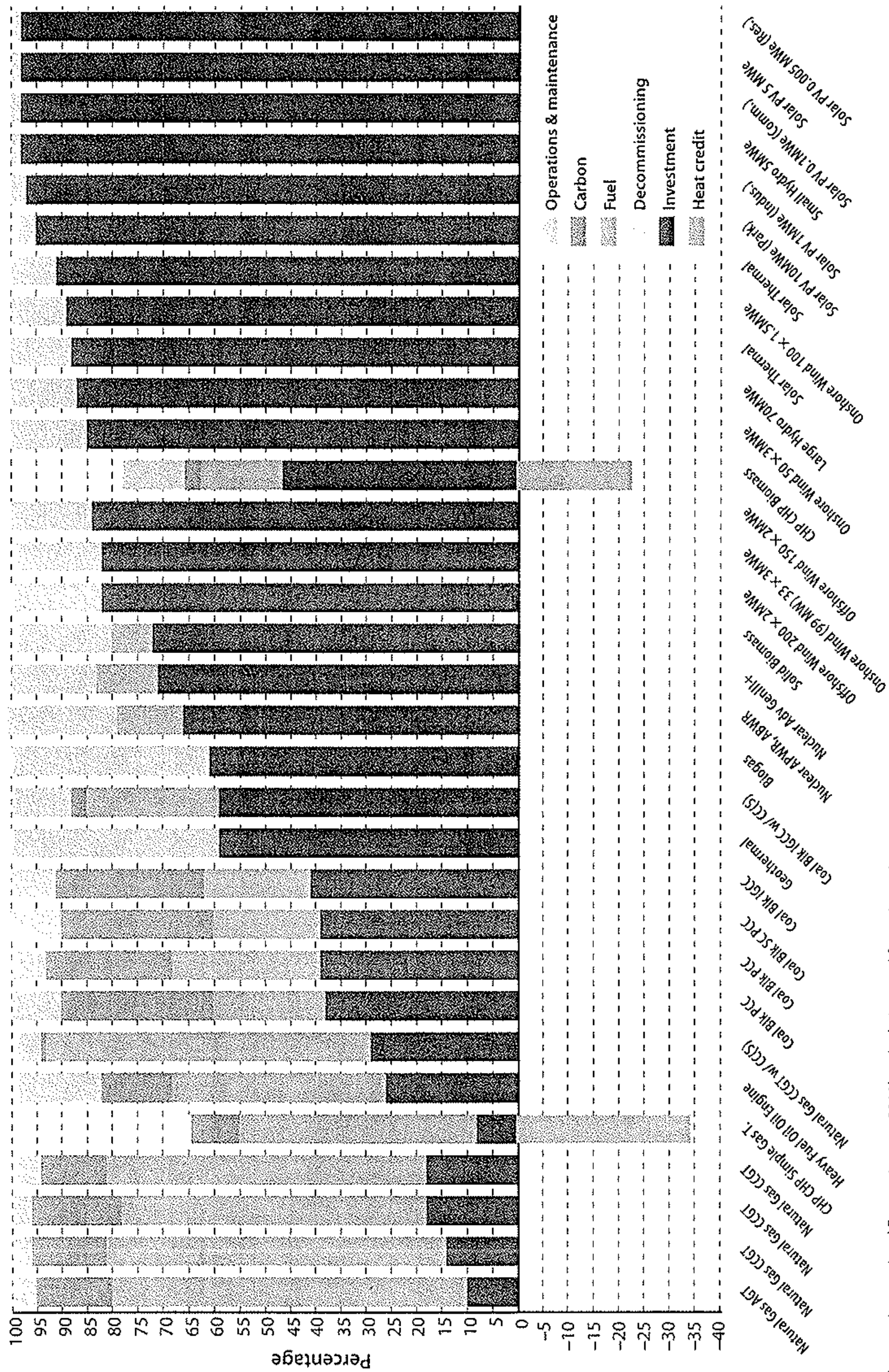
Sources: International Energy Agency, 2010b; calculations and figure by authors.

Figure 12: Levelized Costs (¢/kW-h) of Electricity (LCOE) generation in North America, by type of plant, at 10% discount rate—International Energy Agency



Sources: International Energy Agency, 2010b; calculations and figure by authors.

Figure 13: Percentage of LCOE component, by type of plant, at 10% discount rate—International Energy Agency



Sources: International Energy Agency, 2010b; calculations and figure by authors.

We find, when comparing competitiveness by technology and fuel source (figure 14), that technologies such as geothermal, biomass, and nuclear remain the most competitive, followed by natural gas and coal-fired power plants. Some onshore wind projects are placed outside the competitive boundary, large hydroelectric projects are slightly above the upper bound, while technologies such as offshore wind, solar thermal, small hydroelectric projets, and solar PV (in that order) are largely uncompetitive in relation to North American power rates for industrial users.

Overnight capital cost comparison

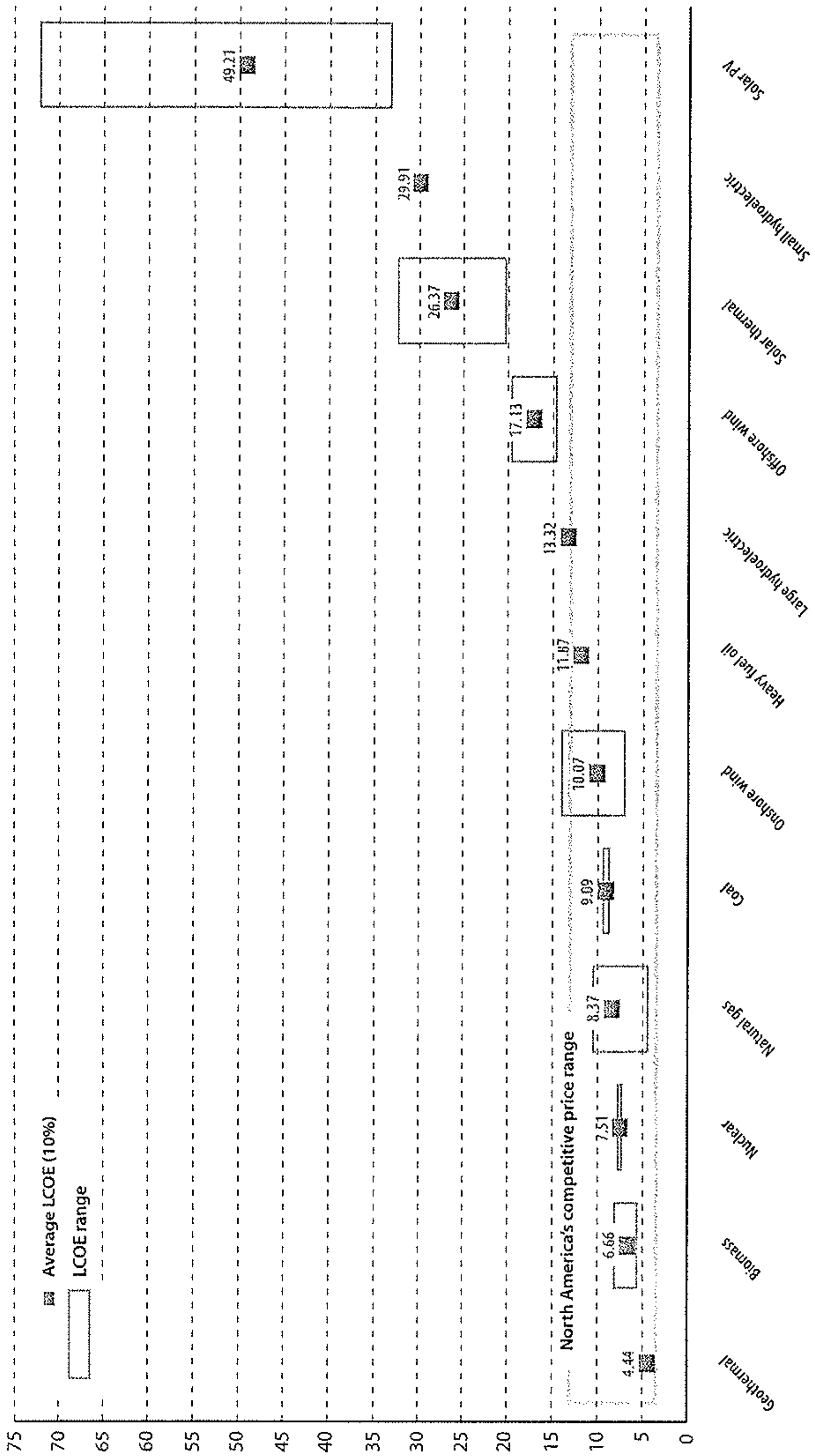
Comparisons based on levelized costs of energy (LCOE) are very useful as they help both investors and policy makers to evaluate the merits of the various options for generating electricity. The foregoing analysis demonstrates that most non-renewable energy technologies have a clear lead over the renewable energy alternatives both in cost-effectiveness and performance. Onshore wind power and hydro technologies can be viable if they are located in regions where the price of electricity is sufficiently high.

LCOE analysis measures the costs of electric generation at the site of power generation or production. Therefore, even if the all-in cost of generation over the life of a plant is covered by the industrial power rate, a technology may not be able to compete if the plant location requires considerable incremental cost for a transmission system such that the delivered cost of energy to the end users would be greater than the market price of power or the regulated rate, as the case may be. Moreover, losses during transmission will add to the delivered cost and further disadvantage the proposed facility.

Because there are differences across North America in the costs and prices of various components used in the LCOE calculations—costs of financing, operations, maintenance, decommissioning, fuel (and, if applicable, emission controls) as well as prices for electricity—estimates of the overnight capital cost (OCC) alone are also used to compare electric-generation technologies to assist in making investment decisions. Information on the OCC for power plants in the United States was available from a recent study by the US Energy Information Administration that included most of the technologies reviewed in the IEA's study (as well as others); this provided a basis for comparison with the estimates presented in the previous section (US Energy Information Administration, 2010).

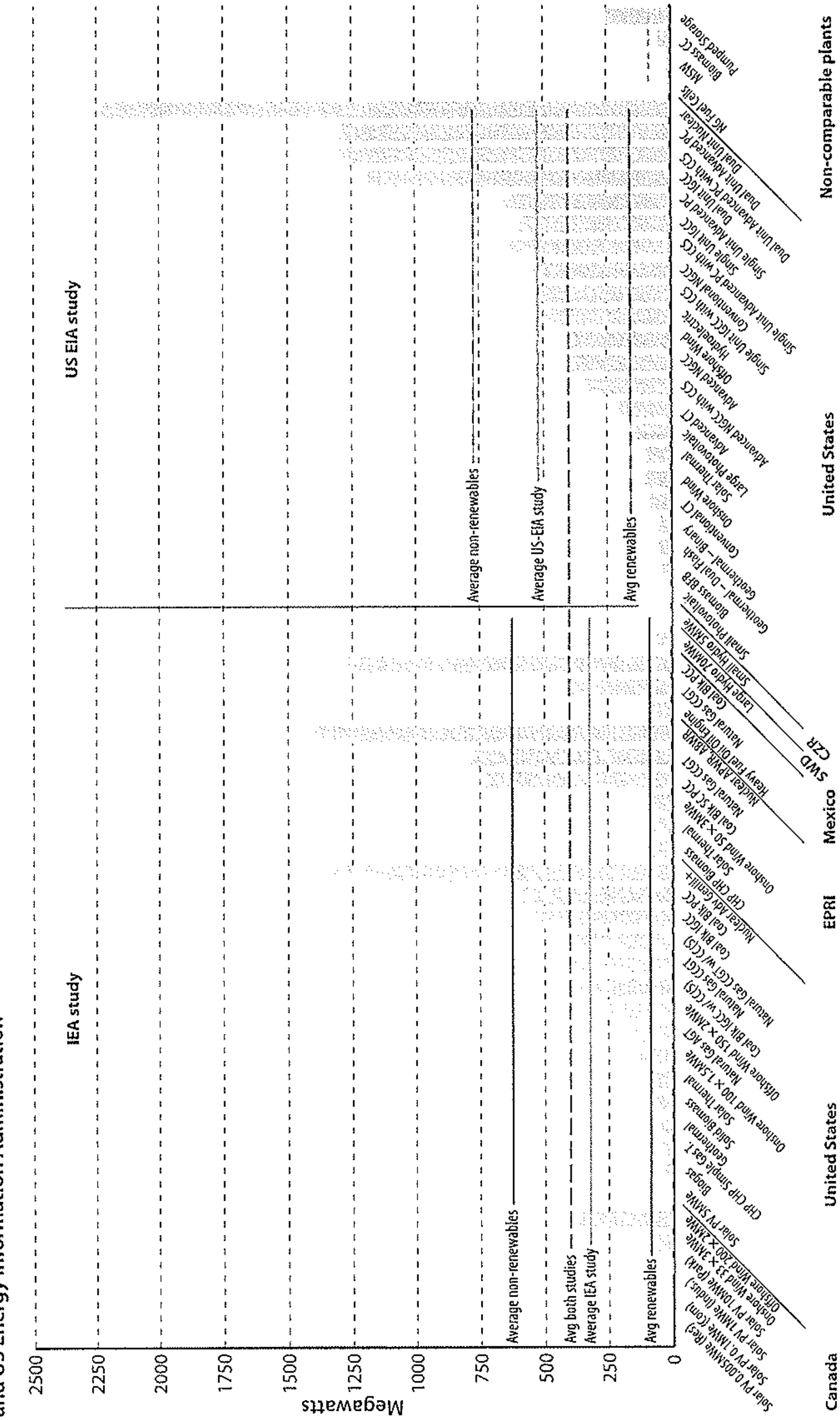
Figure 15 compares the assumptions about power-plant sizes (capacity in MW) used in the studies by the International Energy Agency (2010b) and the US Energy Information Administration (2010). In the US-EIA's study the average non-renewable project is about 150 MW larger than in those in the IEA's study, with the exception of nuclear where the plant capacity in the

Figure 14: Average Levelized Costs (¢/kW-h) of Electricity (LCOE) generation, power plants in North America, at 10% discount rate—International Energy Agency



Sources: International Energy Agency, 2010b; calculations and figure by authors.

Figure 15: Power plant capacity (MW) used for calculation of Overnight Capital Costs (OCC) in studies by International Energy Agency and US Energy Information Administration



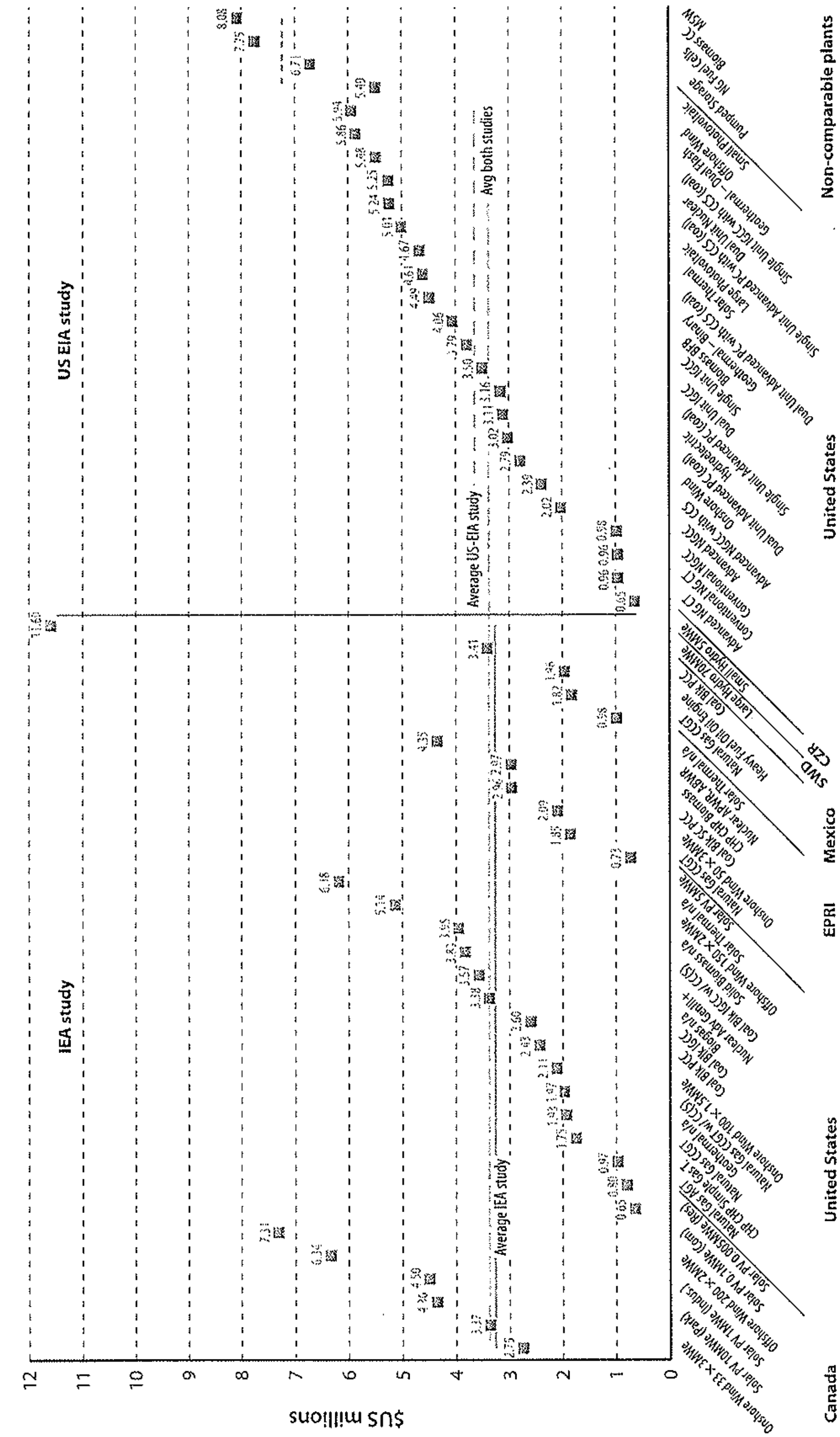
Sources: International Energy Agency, 2010b; US Energy Information Administration, 2010; figure by authors

US-EIA study is almost double that in the IEA study. Also, on average, renewable power projects in the US-EIA's study are 70 MW larger than in the IEA's study and the average power plant in the US-EIA's study is close to 200 MW larger than those in the IEA's study. The cost information in the US-EIA's study was converted to 2008 constant dollars in order to be consistent with the data in the IEA's study.

Figure 16 summarizes OCC estimates from the IEA and the EIA studies. The average OCC for power plants in the IEA's study is $3.27 million/MW of capacity, whereas the average OCC for the comparable group of plants in the EIA study is $3.6 million/MW of capacity. The average OCC for the group of non-comparable plants from the EIA study (including pumped storage, natural-gas fuel cells, combined cycle biomass, and municipal solid waste plants (MSW)) is $7.23 million/MW of capacity. The average OCC across the plants in both studies is $3.4 million/MW of capacity. In general, most of these technologies have high capital burdens: these include nuclear power plants, coal plants with CCS components, offshore wind-power projects as well as both solar PV and thermal power projects.

The conclusion from the review and comparison of the overnight capital costs (OCC) in both studies—that most non-renewable energy-generating technologies generally enjoy a cost advantage over renewable energy technologies—supports the conclusion arrived at from examination of the LCOE information about both groups of technologies contained in the IEA study. Further, the data show that estimates of overnight capital costs for the United States are in general consistent with those across North America, and therefore provide a useful benchmark for analysis.

Figure 16: Overnight Capital Costs (US$ millions/MW) of North American electric power plants, in studies by International Energy Agency and US Energy Information Administration



Sources: International Energy Agency, 2010b; US Energy Information Administration, 2010; figure by authors.

3 Policies promoting renewable energy

For more than a decade, North American governments have been aggressively pursuing policies aimed at promoting renewable forms of energy. While politicians supporting such policies have usually argued that such policies are necessary to control greenhouse-gas emissions, they have generally failed to communicate the impacts that such policies will have on the cost of electricity or, for that matter, upon the overall economy.

Various measures are being used to implement renewable energy policies. Policies that channel public finances in a particular direction or allow governments to determine which types of electric generation are to be permitted are of particular concern because they interfere with the free-market principles that, through time, have proven to be the principal drivers of innovation and economic growth. As explained in the section two, the main obstacle to investment in electric generation from renewable energy sources is the fact that the unit costs are generally higher compared with generation from conventional sources. For this reason, renewable energy is being heavily subsidized in some states and provinces, and often by federal, and even municipal, governments in order to allow such projects to compete with conventional cost-effective and reliable electric generation.

Such subsidies and incentives come in many forms, including guaranteed preferential rates for renewable energy output, special provisions in the tax codes (e.g., tax credits, tax deductions, and special tax rates), as well as special provisions for loans to investors or customers, and energy or related services contracts. This section provides an overview of the two kinds of renewable energy support programs that are driving much of the investment in renewable energy today: renewable portfolio standards (in conjunction with tax incentives and other means) and feed-in tariffs.

Renewable portfolio standards and related policy initiatives

Renewable Portfolio Standards (RPS), also sometimes known as Renewable Energy Standards (RES), require utilities to use renewable energy to reach a certain percentage of their overall electricity sales (or a certain amount of generating capacity) by specified dates (North Carolina Solar Centre, 2012). RPS programs have been imposed by many Canadian and American jurisdictions. In addition, some jurisdictions have designed comprehensive long-term energy strategies that include support for renewable energy development by various means regardless of whether they have adopted specific RPS targets.

In some instances, as in British Columbia, this involves imposing greenhouse gas (GHG) emission intensity targets or carbon taxes that make investment in conventional thermal-powered generation of electricity less attractive.

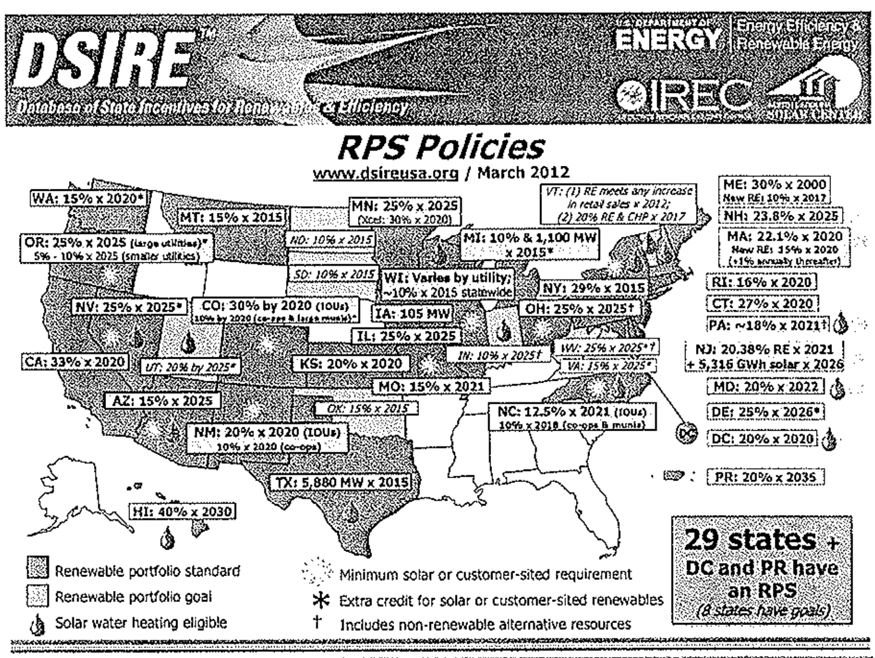
United States

In the United States, 29 states and the District of Columbia had enacted renewable portfolio standards as of March 2012, while eight states had renewable portfolio standard targets (figure 17). The RPS policy approach to increasing renewable investment has been mushrooming in recent years. Of the 26 such programs in place at the end of 2007, half had been created since the beginning of 2004. Several states have adopted non-binding renewable energy goals. Other states, such as Texas, have introduced more aggressive non-binding goals on top of mandatory RPS targets.

The setting of RPS by the state governments combined with federal tax incentives for renewable energy projects has become the key driver of investment in renewable energy projects. When all the mandatory RPS programs have been implemented, it is estimated that renewable sources will supply 46% of US electricity (Wiser and Barbose, 2008).

Renewable portfolio standards are mainly supporting the development of wind power capacity. In states with RPS, more than 8,900 MW of non-hydroelectric renewable energy capacity was added between 1998 and 2007,

Figure 17: Renewable Portfolio Standards (RPS) across the United States



Source: North Carolina Solar Centre, 2012: <http://www.dsireusa.org/documents/summarymaps/RPS_map.pdf>.

of which roughly 93% is wind power. Biomass (4%), solar(2%), and geothermal (1%) power sources have played less significant roles. California is an example of this: of the renewable energy projects approved between 2002 and 2007, 58% of the total capacity was wind, 23% solar, 12% geothermal, 7% biomass, and less than 1% small-hydroelectric and ocean energy (Wiser and Barbose, 2008).

Canada

Table 6 summarizes the renewable portfolio standards (RPS) and related policy targets that the Canadian provinces have put in place to fast-track investments in renewable energy electric generation. Nova Scotia, New Brunswick, and Prince Edward Island are the only Canadian provinces to have established renewable power standards (RPS) or targets for the share of total electricity generated in their jurisdiction to be generated from renewable energy projects. Nova Scotia made a committment to having 40% of its electricity generated from renewable energy sources by 2020 (Nova Scotia Department of Energy, 2010). New Brunswick's government has undertaken to increase the amount of electricity from new renewable sources to 10% of total use by 2016 (New Brunswick Department of Energy, 2010). Even though Prince Edward Island presently imports the majority of its electricity from New Brunswick, the provincial government plans to meet its renewable energy objective by investing heavily in wind energy. The province has adopted an RPS of 30% by 2013 (Prince Edward Island, Department of Environment, Energy and Forestry, 2008).

Public utilities in Quebec, Manitoba, Saskatchewan, and British Columbia are seeking to increase the role for independent power producers in renewable energy development through programs by which the government-owned utilities will contract to purchase specified volumes of electricity produced from renewable energy sources. As outlined in its Provincial Energy Strategy, the Quebec government will accelerate the pace of development of the province's large hydroelectric potential over the next few years (without including small-hydroelectric projects) in order to increase electricity exports (Québec, Ministry of Natural Resources and Wildlife, 2006). It is also committed to add 100 MW of wind power for every 1,000 MW of hydroelectric power added. As noted in table 6, the province has a target for wind power capacity of 4,000 MW by 2015. To date, contracts have been signed with investors to put over 3,000 MW of wind power capacity in place (Hydro-Quebec, 2010b, 2010c).

BC Hydro has initiated a net metering schedule for residential and commercial customers who wish to connect small electric generation units to the provincial grid. This means that, if consumers produce more than they consume, they will receive a credit to their account that can be applied against future consumption charges (BC Hydro, 2012). BC Hydro acquires power from independent power producers (IPP) in the province, based on system need, via different arrangements such as a Clean Power Call for firm energy

Table 6: Summary of Provincial Renewable Energy and Related Policies

Policy tool	Policy Objective or Mandate
British Columbia	
Energy Strategy Targets (EST)/Carbon Tax	90% of new generation from renewables, all new projects-zero GHG emissions, replacing 1.7 million residential metres with smart meters, replace the Burrard thermal station, zero GHG emissions in existing thermal plants, energy self-sufficiency, development of biomass projects/revenue-neutral carbon tax introduced in 2008
Alberta	
GHG Regulations &Targets/ EST & Objectives/ CCS Project Funding	GHG emissions intensity regulations and long-term reduction targets: 20 mega-tonnes (Mt) by 2010, 50 Mt by 2020, and 200 Mt by 2050/promotion of renewable energy technologies and clean fossil fuels; technology-neutral approach for generation technologies, focus on industry-led technological innovation and clean fossil fuel production; free-market approach; energy conservation and efficiency/funding for three to five commercial- scale CCS projects to be operational by 2015
Saskatchewan	
Future Power Plan	Pursuing new generation technologies; greater IPP participation for development of renewables
Manitoba	
Goals/Targets	Coal-free generation (long-term)/1,000 MW of renewable energy projects by 2020; increased IPP participation, wind in particular.
Ontario	
EST/Energy Plan	A total of 2,700 MW in additions of renewable energy projects by 2010 and 15,700 MW by 2025; 10,700 MW (excluding hydro) by 2018; additional 9,000 MW in hydro additions by 2030/ reduce projected electric generation capacity by 2500 MW through energy conservation measures by 2010, 6,300 MW by 2025; Reduce electricity consumption by 10% by 2012
Quebec	
EST/Large Project Development/ Carbon Tax	3,500 MW of wind power by 2013; 4,000 MW by 2015/ construction of various large scale hydro projects by 2020; additional 3,500 MW of renewable energy power by 2035 from both wind energy and emerging technologies/carbon tax introduced in 2007
New Brunswick	
Renewable Portfolio Standard (RPS)/EST	10% from new renewable sources by 2016/energy self-sufficiency by 2016
Prince Edward Island	
RPS/EST	30% from renewable sources by 2013, opportunity to have 100% by 2015/500 MW of wind energy by 2013; 10 MW of new biomass electric generation capacity by 2013
Nova Scotia	
RPS/EST	5% from renewable sources by 2010, 10% by 2013, 25% by 2015, 40% by 2020/ develop bio-resource strategy by 2011; demonstration facilities for energy efficiency and sustainability to be built by 2015; 20% increase in energy efficiency by 2020; carbon-neutrality of all government buildings by 2020
Newfoundland & Labrador	
EST/Large Project Development	To use revenues from non-renewable sources to fund renewable energy development; limited integration of small hydro and wind projects/development of the Lower Churchill project by 2015, expiration of Upper Churchill contract

Sources: Alberta Dep't of Energy, 2008; British Columbia, Ministry of Energy, Mines, and Petroleum Resources, 2009; Manitoba, Dep't of Conservation, 2010; Prince Edward Island, Dep't of Environment, Energy and Forestry, 2008; New Brunswick, Dep't of Energy, 2010; Newfoundland & Labrador, Dep't of Natural Resources, 2007; Nova Scotia Dep't of Energy, 2010; Ontario, Ministry of Energy and Infrastructure, 2010; Ontario Power Authority, 2008; Québec, Ministry of Natural Resources and Wildlife, 2006; SaskPower, 2010; table by authors.

(via a competitive bid process), bioenergy initiatives to acquire power from projects that use wood fibre and biomass fuel sources, as well as a standing offer program (SOP) for projects of 10 MW or smaller (BC Hydro, 2010). As of October 2010, there were 65 IPP projects that had electricity purchase agreements with BC Hydro, totalling 2,842 MW of generation capacity. The standing-offer program involves purchasing output from small generators based on rates that are adjusted according to location, inflation, load-time, and environmental charges (BC Hydro, 2010).

SaskPower is expanding its Small Power Producers Program (similar to BC Hydro's standing offer program), increasing acquisition of output from large-scale producers of wind-power, and expanding its Green Options Partners Program, which is designed to streamline the process for mid-size (around 10 MW) producers of renewable energy to sell electricity to the utility. Projects under the program are selected by a lottery process and the developers must assume the costs of feasibility studies and system connections. The price paid per unit of output does not differ by on- or off-peak load periods or technology types but the rates are guaranteed even if the program is cancelled (SaskPower, 2010).

Alberta has focused on reducing emissions from fossil fuels through regulation of GHG intensity as well as investments in clean fossil-fuel technologies while maintaining a technology-neutral approach—it does not dictate specific types of plants or projects—to competitive generation technologies. Meanwhile, the province has also introduced a $15/tonne charge on GHG emissions for large emitters (>100,000 tonnes per year).

Ontario has taken a related but more aggressive approach by heavily subsidizing renewable energy projects via feed-in-tariff rates that make such investment highly-attractive. The pitfalls of that approach are examined next.

Feed-in tariff programs

Ontario

In 2009, Ontario introduced a broad renewable energy-subsidy initiative in the form of a feed-in tariff (FIT) program. This program allows all sizes of electric generation facilities using renewable energy sources to sell their output to the grid, based on a defined fixed tariff. The program is part of the Green Energy and Green Economy Act (GEA) that became law in May 2009 (Ontario Power Authority, 2010a).

The Ontario Power Authority (OPA) arranges the contracts with the FIT participants. The contracted electricity producers sell their output to a local distribution company (LDC) for the agreed-upon rate for a set period of time and the LDC then sells the output to the end-users, effectively passing on the cost. The tariffs offered under the FIT program are intended to cover total project costs and provide a reasonable rate of return on investment over a 20-year contract (40 years for hydroelectric power), and the arrangement provides an easy way for the power authority to contract for renewable energy generation from various technologies such as biogas, biomass, landfill gas, solar PV, wind, and hydroelectric (figure 18; Ontario Power Authority, 2010c). The program sets different rates for different technologies and project sizes.

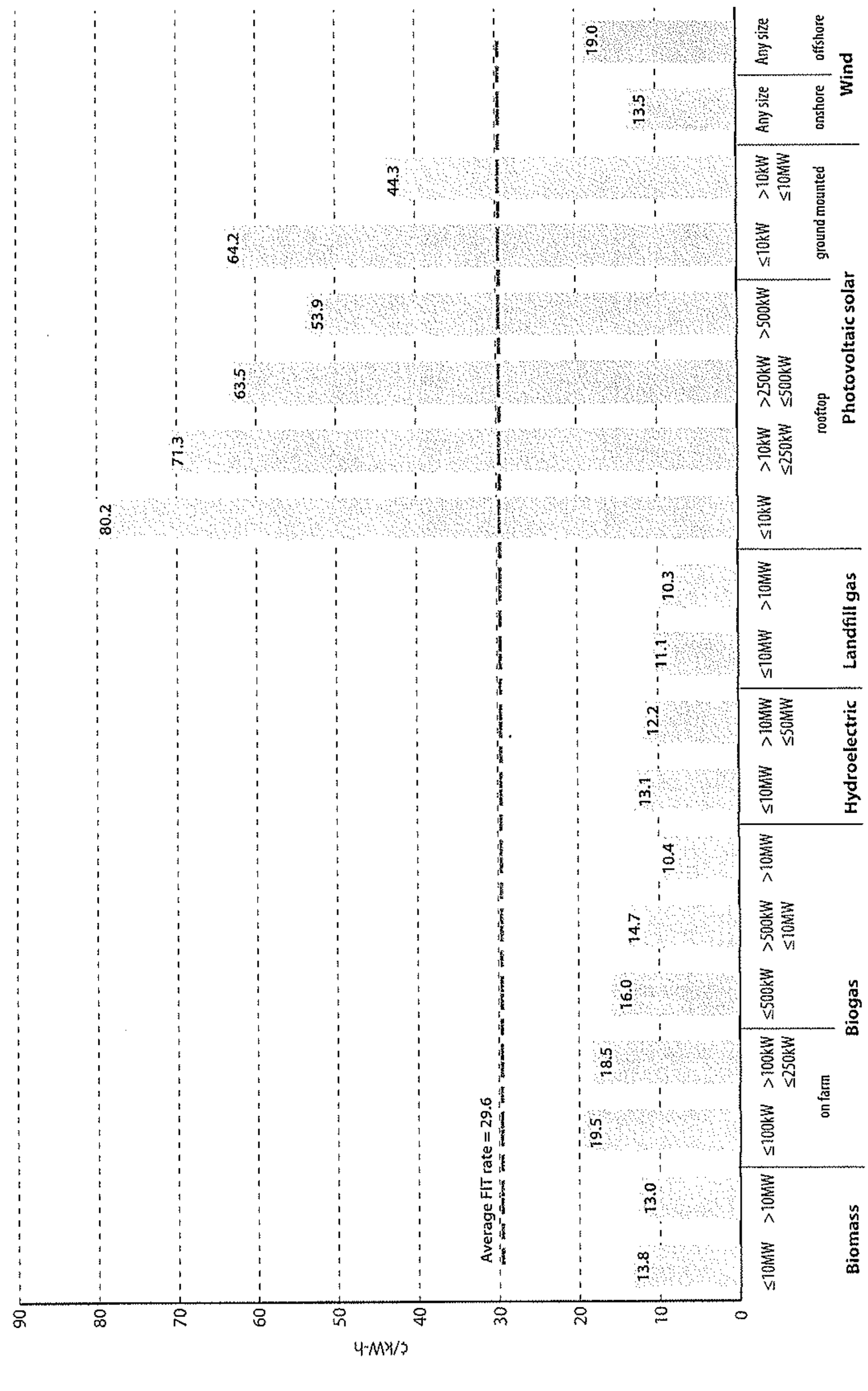
The FIT program also has eligibility requirements stipulating domestic content: for example, a certain percentage of a project's capital costs must be incurred in acquiring goods and services from Ontario sources. The domestic-content requirement for wind energy projects was 25% (increasing to 50% in 2012); for microsolar PV projects, 40% (increasing to 60% by 2011); and for large solar projects, 50% (increasing to 60% by 2011). The domestic-content requirements are the subject of a dispute raised before the World Trade Organization (WTO) by the government of Japan, which considers them to be a form of subsidy and a protectionist policy, inconsistent with international trade agreements. The United States and the European Union have also joined the consultation process on this issue (World Trade Organization, 2010).

Contract payments under the FIT program range from 10.3¢/kW-h for landfill-gas projects larger than 10 MW to 80.2¢/kW-h for residential solar rooftop projects 10 kW or smaller, and have a median price of 29.6¢/kW-h (figure 18). To encourage further participation, the program also includes "price adders" for Aboriginal projects ranging from 0.6¢/kW-h for biogas, biomass, and landfill-gas projects to 1.5¢/kW-h for wind and solar PV projects; and for community projects ranging from from 0.4¢/kW-h for biogas, biomass, and landfill-gas projects to 1¢/kW-h for wind and solar PV projects (Ontario Power Authority, 2010b).

As of the second week of December 2010, the FIT program had resulted in 3,854 applications for a total of 16,050 MW of generation capacity (table 7). Of those applications, as of that date, 1,270 projects (33%) had resulted in contracts under the FIT program, for a total generation capacity of 2,632 MW. Of those, 89% (1,126 projects) were for solar PV generation while the remaining 10% were distributed among bioenergy (41 projects), hydroelectric (48 projects), and wind (55 projects). Contracts for wind power projects accounted for 58% (1,531 MW) of generation capacity from all contracts, followed by solar PV (33%, 857 MW), hydroelectric (7%, 188 MW), and bioenergy (2%, 56 MW) (Ontario Power Authority, 2010b).

Solar energy is embraced by Ontario's Green Energy legislation and qualifies for special incentives under the FIT program. However, Hydro One, the provincially owned transmission facility, is having difficulty keeping up with requests to connect solar and other renewable energy facilities that investors—in many cases farmers or small land owners—have put in place to take advantage of the FIT program. Reportedly some owners have been waiting for more than a year to be connected (D'Aliesio, 2011, August 12).

Figure 18: Feed-in-tariff (FIT) prices (¢/kW-h) for renewable energy projects in Ontario, August 2010



Source: Ontario Power Authority, 2010c; figure by authors.

Table 7: Ontario Power Authority's (OPA) FIT Contracts as of December 6, 2010

	Applications		Contracts executed	
Energy Goup *Source Type*	Number of applications	Sum of applications (MW)	Number of contracts	MW contracted
Bioenergy				
Biogas	39	48	19	20
Biogas (on Farm)	28	8	15	3
Biomass	16	173	3	18
Landfill	8	32	4	15
Subtotal Bioenergy	91	261	41	56
Solar PV				
PV Groundmount	606	4,154	104	654
PV Rooftop	2,807	568	1,022	203
Subtotal Solar PV	3,413	4,722	1,126	857
Hydroelectric				
Hydroelectric	94	356	48	188
Subtotal Hydroelectric	94	356	48	188
Wind				
Wind On-Shore	248	10,350	54	1,231
Wind Off-Shore	8	361	1	300
Subtotal Wind	256	10,711	55	1,531
Total All	3,854	16,050	1,270	2,632

Source: Ontario Power Authority, 2010b; table by authors.

While the FIT program is very attractive to developers and investors, the long-term implications of the program for the province's electricity consumers are unfavourable, both because the average cost of production will be greater than if investment decisions were made under free-market conditions and because large investment in transmission facilities will be required to accommodate the new policy, much of which could have been avoided. In order to understand how generous the rates offered through the FIT program are, we compare them to electricity prices in Ontario as of December 2010. The following three rate options are available to Ontario's residential electricity consumers (Ontario Energy Board, 2010).

1 *Regulated Price Plan (RPP) with Tiered Prices (TP)* These are regulated rates for volumes below two threshold levels. The threshold level for the winter months is 1,000kW-h and, for the summer months, 600kW-h. As of December 2010, the regulated prices were 6.4¢/kW-h for the lower tier and 7.4¢/kW-h for the higher tier (figure 19).

2 *Regulated Price Plan (RPP) with Time-of-Use (TOU) prices* This is a regulated rate (revised every six months) that changes according to the level of demand for electricity, defined by three different time periods during the day: off-peak (9 pm to 7 am during the winter and summer months); mid-peak (11 am to 5 pm during the winter; 7 am to 11 am and 5 pm to 9 pm during the summer); and on-peak (7 am to 11 am and 5 pm to 9 pm during the winter; 11 am to 5 pm during the summer).

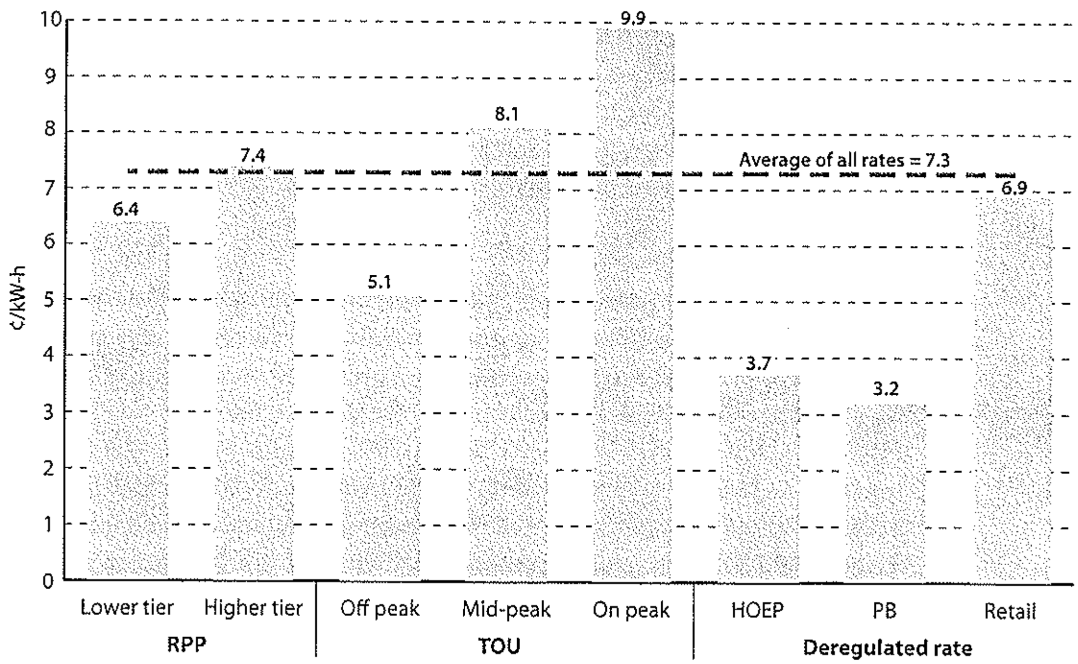
3 *Retail contracts (deregulated rates)* These offer different rates and different types of contracts for different contract periods. The rate is usually determined by the monthly, weighted, average spot price of electricity in the open market—the wholesale price—also known as the Hourly Ontario Energy Price (HOEP). On top of that, a Provincial Benefit (PB) or Global Adjustment component is included, which is equal to the difference between the spot price (HOEP) and the rates per kW-h that have been guaranteed by the Ontario Energy Board (OEB) to regulated generators (RPP rates). The PB also captures the difference between the spot price and the contract rates guaranteed by the Ontario Power Authority under the FIT program (Independent Electricity System Operator, 2010a; Direct Energy, 2009). Thus, going forward, both the regulated and deregulated rates will increasingly reflect the higher costs of the OPA's obligations under FIT contracts.

As of December 2010 (figure 19), the average across all generation rates available to residential consumers was 7.3¢/kW-h. The average rate of 26.9¢/kW-h (figure 18) that the Ontario Power Authority was offering through its FIT contracts was 2.7 times that amount.

The rates illustrated in figure 19 reflect the cost that the local distribution companies (LDCs) must pay for the electrical energy that they deliver to consumers (essentially, the cost of generation). The full price that the consumer will pay will include the costs of transmission and distribution (delivery costs), taxes, and other charges (Hydro One, 2010a). According to Hydro One, one of Ontario's largest distribution companies, these additional costs combined account for 56% of the final retail price. Therefore, in the case of a 7.3¢/kW-h cost of generation, the final all-in cost to the consumer is closer to 16.6¢/kW-h.

As LDCs increase the number of contracts under the FIT program in their electricity acquisition programs, not only will they continue to acquire power at costs that are higher than necessary but they will also pass on the incremental cost of the transmission capacity required to accommodate the generation capacity added under the FIT program, adding more costs to the final price for the end user. In fact, Hydro One expects to incur $1.2 billion in capital expenditures during 2011 and 2012 explicitly targeted at supporting the Green Energy Act's objective for renewable energy generation under the FIT program (Hydro One, 2010b).

Figure 19: Ontario's residential electricity rates (¢/kW-h), December 2010



Sources: Independent Electricity System Operator, 2010a, 2010b; Ontario Energy Board, 2010; figure by authors.

Based on the information presented above and technical information provided by a recent study by the International Energy Agency (IEA), we estimated the cost of the FIT program as well as a weighted average price (WAP) for electricity under the FIT contracts as of December 2010 (International Energy Agency, 2010b). To that point, the OPA had executed contracts totalling close to \$28.5 billion in nominal dollars for the provision of 1.40 TW-h of additional renewable electricity over the next 20 years, or \$17.3 billion in real (2010) dollars. By way of comparison, if the same amount of electricity were provided at the average estimated rate on December 2010 of 7.3¢/kW-h (figure 19), the cost would be \$10.2 billion. This suggests that the FIT contracts will burden electricity customers with approximately \$18.2 billion in additional costs over the next 20 years (\$11.1 billion in real 2010 dollars). According to our estimate, the weighted average price (WAP) of electricity under the FIT contracts is equivalent to 20.3¢/kW-h. Essentially, this is 178% (almost three times) higher than if the same volume of electricity were to be provided under competitive conditions, assuming the mix of power generation supply and costs of electricity generation as of December 2010.

The FIT program and its repercussions have been very controversial. In fact, a recent report from the Ontario government's Task Force on Competitiveness, Productivity, and Economic Progress argued that the consumer will end up bearing the costs of this policy through an increase in the so-called provincial benefit (PB) that, as more renewable energy is bought into the grid, will increasingly reflect the widening difference between the (HOEP) spot price and FIT rates (Ontario, Task Force on Competitiveness, Productivity, and Economic Progress, 2010). The same report cites various studies that discuss various consequences that the FIT program will likely have on the Ontario economy and its residents. These include the potential for an additional increase of between $247 and $631 in electricity bills per household per year and estimated cumulative costs for implementation of between $18 and $46 billion between 2010 and 2025 (London Economics International, 2009); and expected increases in electricity rates of from 6.7% to 8% per year over the next five years for residential consumers, and 8% to 10% for non-residential (e.g., industrial, commercial) users of electricity over the same time period (Aegent Energy Advisers Inc., 2010). In addition, the government's prediction that the Green Energy Act could generate 50,000 jobs did not consider empirical evidence from a recent study on FIT–type policies in Germany where the effect on job creation was found to be negligible because of the increased cost of electricity and the crowding out of conventional energy generation (Rheinisch-Westfälisches Institut für Wirtschaftsforschung, 2009).

Ontario's Auditor General has heavily criticized the initiatives undertaken by the provincial government under the Green Energy Act and, especially, the FIT program. The *2011 Annual Report of the Office of the Auditor General of Ontario* says that, given the extent of ministerial direction and the government's eagerness to implement the Green Energy Act as quickly as possible, no comprehensive business-case evaluation was undertaken to evaluate objectively the impacts of what amount to multi-billion dollar commitments; this includes a failure to analyze the economic impact of higher electricity prices resulting from the FIT program (Office of the Auditor General of Ontario, 2011: § 3.03).

The FIT program and other initiatives under the Green Energy Act will undoubtedly create some new jobs throughout the province in coming years. However, there are likely to be substantial offsets and it is questionable whether a net gain in employment will be achieved. There are at least two reasons for this. First, the huge loss that consumers will take on account of higher electricity costs resulting from the FIT program means that less of their income will be available for spending on other goods and services. This direct loss of income available for discretionary spending will have a substantial impact on employment throughout Ontario. Second, higher electricity costs will impinge on the ability of Ontario manufacturers to compete and some, whose energy costs represent a large portion of production costs, may be forced to shut-down or to relocate to regions such as Quebec and Manitoba, where there are appreciably lower electricity costs.

We have noted that the additional electricity bill faced by Ontario consumers over the next 20 years on account of the impact that the FIT program will have on electricity prices will tally $18.2 billion. This works out to an average increase of approximately $910 million per year, of which an estimated $285 million per year is the extra cost that residential customers will face. Statistics Canada, in response to a special request by the Fraser Institute, used the Interprovincial Input-Output Model to analyze the "shock" from a sudden drop in Ontario personal expenditure. According to our assessment of the results of this analysis, a drop in consumer spending of $285 million in a given year would lower Ontario's gross domestic product (GDP) by $207 million (at basic prices) and, at the same time, result in a loss of 2,197 full-time-equivalent (FTE) jobs in Ontario (Statistics Canada, 2011). Further, the loss of employment in Ontario and the reduction in spending that it produces will have a negative impact on employment in other parts of the country that produce goods and services (including tourism) that Ontarians typically purchase. Consequently, as many as 2,556 full-time-equivalent job positions could be lost in Canada as a whole in a given year.

Simply multiplying these results by a factor of 20 would indicate that more than 51,000 full-time-equivalent positions could be lost in Canada during the full 20-year period. However, this overstates the impact because it ignores the effect that inflation would have on the real value (in 2010 dollars) of the reduction in available discretionary consumer spending during the period and on the number of jobs that would be affected. After accounting for inflation, we estimate that the loss in employment in Ontario could range from 26,811 to 35,100 full-time-equivalent jobs. In Canada as a whole, close to 41,000 full-time-equivalent positions could be lost over the 20-year period because of the increase in the cost of electricity to residential electricity customers brought about by the FIT program.

Because this analysis is based on the results of a Statistics Canada Input-Output Model simulation designed to assess the likely consequences for employment and income from a major reduction in discretionary consumer spending in a single year, it does not recognize that residential demand for electricity is bound to shrink somewhat as consumers adjust their power consumption when they face the higher prices imposed by the FIT program. If electricity consumption in the residential sector is reduced by the higher prices then, while the increase in the annual bill faced by that sector might be as great as $285 million in the first year, the effect will be less in the ensuing years. Consequently, the impact on employment will be somewhat less than suggested above. Further, the static nature of the Input-Output analysis does not recognize that workers displaced because of weaker consumer spending could eventually find work in another industry or province. Notwithstanding these qualifications, the analysis underscores the fact that, by substantially raising residential electricity costs, the FIT program will have serious negative implications for employment.

The estimates of the negative impact of the FIT subsidies on employment described above completely ignore the consequences of the $625 million increase in the annual cost of electricity to commercial and industrial consumers (based on those two sectors' combined 69% share of Ontario electricity demand). In a "best case" scenario, the increased bill to the commercial and industrial sector would lower Ontario's GDP by $625 million. No impact upon employment would be felt in the near term if one assumes that the commercial and industrial consumers are "price-takers" and unable to make price or cost adjustments to offset the consequences of higher electricity costs on "surplus" (i.e., their return on investment). But, over time, the negative impact on commercial and industrial employment in Ontario could be quite significant. Other things equal, the ratios provided in Statistics Canada's Input-Output analysis summarized above suggest that a reduction of $625 million in Ontario's GDP (comparable to the increase in commercial and industrial sectors' electricity costs) could be accompanied by a loss of 6,647 full-time-equivalent jobs in the province. This is corroborated by the fact that the ratio of GDP to employment for Ontario in 2010 (Ontario, Ministry of Finance, 2012) suggests that a $625 million drop in GDP would correspond to a loss of about 6,740 jobs.

Assuming that their demand for electricity is price elastic to some extent, one can anticipate that some enterprises in the commercial sector will attempt to reduce their electricity requirements in order to offset the impact of higher electricity prices on their power bills. They may also, depending on location and the degree of competition that they face, decide to pass some or all of the cost increase on to consumers in the form of higher prices. This, however, will simply exacerbate the plight of residential electricity consumers.

In Germany, where a FIT-like program was introduced a number of years ago, it has been demonstrated that the higher electricity costs pushed industrial costs up to such an extent that industrial employment contracted (Hillebrand et al., 2006). However, if competition from other jurisdictions largely prevents large industrial consumers of electricity in Ontario from offsetting the cost increases that they face, the impact of higher electricity prices in the industrial sector is likely to be manifested in decisions about the location of plants and, where companies have plants in a number of different provinces, states, or countries, reallocation of production. Future investment decisions both by industry incumbents and possible new entrants are also likely to be affected. If users of industrial electricity respond to the higher electricity prices resulting from the FIT program by downsizing, relocating, and reallocating production that normally would have been done in Ontario to other jurisdictions, Ontario employment, labour income, GDP, and tax revenues will all suffer. The consequences of the income redistribution caused by the FIT program point to further job losses because nearly $1 billion in annual spending by households, commercial enterprises, and large industrial users of electricity, which would typically be spread across a broad array of good and services, is being transferred to the much narrower and more capital-intensive sector—the construction of renewable energy facilites.

It can be argued that Input-Output Model analysis tends to overstate multiplier effects, especially given the long period for consumer adjustment to higher electricity prices in this case. Because demand responses in all sectors of the economy to higher electricity prices could partially offset the impacts of higher electricity costs triggered by the FIT subsidies, the estimates of the negative impacts on employment provided here likely overstate the harm that could be done to the provincial and Canadian economies. However, in the industrial sector, part of the adjustment process is to move production elsewhere, with a corresponding negative impact upon employment. Our overall conclusion is that many—or even most—of the jobs created are likely to be offset by jobs lost as a consequence of the higher electricity prices resulting from the FIT program. This suggests that, when the provincial government proclaimed that its green energy initiative would create as many as 50,000 jobs, the public was not fully informed.

The report by Ontario's Task Force on Competitiveness, Productivity and Economic Progress (2010) estimates that the cost per new job created in Ontario though the Green Energy Act will come with a price tag of $42,000 per worker. The report also calls on the Ontario government to stop subsidizing these technologies because the FIT program discourages innovation and cost-efficient generation of electricity. Industry participants and experts agree that guaranteeing a fixed price to generators (either through a FIT or a guaranteed regulated rate) does not guarantee operating efficiency, or that least-cost generators will be dispatched before high-cost generators. It has been suggested where market price signals are distorted as a consequence of FIT-type subsidies consumers' incentive to conserve energy, which is one of the main objectives of the Green Energy Act, may be weakened (Conference Board of Canada, 2010; Direct Energy, 2009). However, to the extent that FIT initiatives result in higher electricity prices, some consumers, especially those with low incomes, may become more aware of energy-conservation options such as those available under time-of-use pricing.

While the Ontario government has set ambitious renewable-energy targets with the goal of creating a clean-energy manufacturing cluster and bringing more investment in renewable energy to the province, the instability of Ontario's energy-policy environment, its short-term focus, coupled with lack of coordination between government-related bodies have been cited as factors that are likely to create a climate of long-term instability and uncertainty that is both unfavourable and unattractive for prospective investors

(Holburn, Lui, and Morand, 2009). As Jan Carr, former CEO of the Ontario Power Authority, has argued, these types of policies might be publicly popular as constituents voice concerns over climate change and environmental issues but are economically unsound and jeopardize the prosperity of the province (Carr, 2010).

Nova Scotia

Nova Scotia is in the midst of implementing a rather limited FIT program composed of a "community" feed-in tariff and a "tidal arrays" feed-in tariff (Nova Scotia Department of Energy, 2011). In order to be eligible for the community feed-in tariff program, projects must be owned by a local community and connected at the local distribution level, which is indicated as typically under 6 MW. Projects must also use one of the following technologies:

- small wind, equal to, or less than, 50 kilowatt capacity;
- large wind, greater than 50 kilowatt capacity;
- small-scale in-stream tidal projects;
- combined heat and power biomass projects;
- run-of-the-river hydroelectric.

No economic test is required for eligibility and the community in question only has to obtain "ministerial approval" (Nova Scotia, Department of Energy, 2011). Not surprisingly, the province's summary of the economic benefits does not explain that the cost of the electricity produced under the program is apt to be considerably higher than the cost for electricity generated by conventional thermal technologies.

The FIT program for "tidal arrays" applies to developmental in-stream tidal generation devices in units greater than 0.5 MW or in groups that are connected to the transmission system. There are no limitations on ownership in this case and applications will be accepted once the Utility and Review Board establishes a rate for electricity from developmental power projects.

British Columbia

British Columbia's Ministry of Energy, Mines, and Petroleum Resources is in the process of developing a feed-in-tariff (FIT) specifically targeted at supporting emerging (immature) renewable energy technologies such as gasified biomass, biogas from anaerobic digesters, geothermal, in-stream hydrokinetic (water powered) turbines, and ocean-current energy to aid their transition to commercial viability. The FIT rates would be set by BC Hydro (upon approval by the British Columbia Utilities Commission), most likely providing a 5% to 10% rate of return for projects with a maximum capacity of 5 MW of nameplate capacity for a period of five years (British Columbia, Ministry of Energy, Mines, and Petroleum Resources, 2010).

There are important differences between British Columbia's proposed FIT program and that of Ontario. Because British Columbia already has a large share of generation capacity from renewable energy sources (85% as of year-end 2009), its FIT program will be small in scope and scale and is expected to increase electricity rates by only about 1%.

United States

In the United States, feed-in tariffs are not being widely used to foster the application of renewable power generation technologies. To some extent, this may reflect aversion on the part of policy makers to what amounts to mandating prices received by eligible investors as a means of making investment in renewable energy facilities attractive. In practical terms, however, it is clearly a consequence of constraints that the US Federal Power Act (FPA) and the Public Utility Regulatory Policies Act (PURPA) impose on the states' ability to put Ontario-style FIT programs in place. Although feed-in-tariffs can be lawful under the FPA if they are cost-based, each contract between a small generator and a utility must be reviewed by the US Federal Energy Regulatory Commission (FERC), a process generally seen as too costly, burdensome, and time-consuming. Market-based tariffs (e.g., as established through an "auction") can also be lawful under the FPA but in such cases the sellers must file a report with the FERC every three years which, again, is cumbersome and costly (Gipe, 2010, February 9).

There are, however, exceptions to these FPA constraints: FIT policies can be executed by a municipality and in regions where electric systems are either not connected to the continental grid (e.g., Hawaii and Alaska) or where the connection to the grid is weak (as with most of Texas). Since these jurisdictions and states are not subject to the FPA, FIT contracts do not require FERC approval (Couture et al., 2010).

Projects certified as "qualifying facilities" (QFs) under PURPA are eligible to receive a utility's "avoided cost" for their power. For most renewable technologies in most US locations, payments based on avoided cost would need to be supplemented in order to make a renewable energy project viable. Because the FERC has indicated that specific supplements to avoided cost are beyond its jurisdictions, in some cases supplements of various kinds can be used to establish cost-based FIT programs for qualifying facilities. However, contracts of utilities that applied for exemption from PURPA (under the Energy Policy Act of 2005) still fall under the FPA and are subject to FERC scrutiny (Couture et al., 2010).

On October 21, 2010, the FERC issued an order that opens the door for different feed-in tariffs for different renewable energy technologies. The possibility for states to establish multitiered cost-based feed-in tariffs (as in Ontario) without running afoul of the constraints that PURPA places on avoided cost comes from the FERC's ruling that "where a state requires a utility to procure a certain percentage of energy from generators with certain characteristics, generators with those characteristics constitute the sources that are relevant to the determination of the utility's avoided cost for that procurement requirement" (US Federal Energy Regulatory Commission, 2010: 133 FERC ¶ 61,059). In other words, the avoided cost in relation to the least cost (usually fossil-fuel) source of generation overall need not always apply. According to a more detailed explanation provided in the order,

> if a state required a utility to procure 10 percent of its energy needs from renewable energy sources, a natural gas-fired unit would not be a source "able to sell" to that utility for the specified renewable resources segment of the utility's energy needs, and thus would not be relevant to determining avoided costs for that segment of the utility's energy needs. Thus, a state may appropriately recognize procurement segmentation by making separate avoided cost calculations. (US Federal Energy Regulatory Commission, 2010: 133 FERC ¶ 61,059)

It remains to be seen what the impact of this ruling will be. However, the fact that states may establish rates for renewable energy sources that are higher than avoided cost calculations based on fossil fuels is likely to result in more US jurisdictions proceeding with FIT programs.

As of June 2010, Hawaii and Vermont had adopted FIT programs based on the cost of generation. Maine had also adopted a cost-based FIT program, but with a cap on the total payment allowed (Couture et al., 2010). Oregon launched a four-year pilot FIT solar-energy program for small projects in June 2010 but the power prices offered were so high that the program sold out in a manner of minutes. Consequently, the Oregon Public Utility Commission had to lower the payment schedule (Key, 2011, April 6).

Representatives in ten states proposed cost-based FIT legislation at various times from 2008 to 2010: California, Florida, Illinois, Indiana, Michigan, Minnesota, New York, Rhode Island, Washington, and Wisconsin. California introduced a FIT program in 2008 that is based on avoided cost but it has proven to be too low to attract all but a handful of investors. At the municipal level, in 2009 Gainesville Regional Utilities (Florida) and Sacramento Municipal Utility District (California) introduced FIT programs to encourage home owners to invest in solar power generation facilities. San Antonio's City Public Service Energy followed in 2010 (Couture et al., 2010).

Other policies encouraging use of renewable energy

Mexico[1]

Mexico did not seek to actively develop its renewable energy resources until fairly recently, largely because of its extensive reserves of natural gas and oil. Most of the country's renewable energy projects have been focused on rural electrification using wind and solar power as a supplemental power source.

Mexico does not have specific RPS or FIT policies. Rather, Mexican support for renewable energy has been for the most part based on regulatory measures. In the period from 1992 to 1994, the Public Electricity Service Law, which grants the Mexican state the exclusive right to provide electricity through the national electricity companies, was reformed in order to allow private participation in the generation of electricity for purposes other than the provision of public-service electricity. Thus, generators were allowed to produce electricity for the purposes of self-supply, co-generation, small production—less than 30 MW for sale to the Comisión Federal de Electricidad (CFE), Mexico's national public utility—and independent power production (IPP) for exclusive sale to the CFE. Those generating electricity from renewable sources who would not otherwise be able to supply output to the grid on the principle of least-cost generation have found opportunities under the new law, particularly for the purpose of self-supply.

From 1994 to 2000, Sandia Labs managed a renewable energy program in Mexico funded by the US Department of Energy (DOE). The main goal was to provide training and technical assistance, initiate renewable-energy pilot projects, and help pay for a portion of the costs of the pilot projects. The program was focused on rural, off-grid, renewable-energy applications, particularly solar PV, small wind, and solar thermal systems. As a result of the program, more than 300kW of renewable power generation capacity has been installed, in some 400 small systems.

In 2001, the energy regulatory commission (CRE) established special transmission rules that give priority to feeding electricity from renewable energy sources into the grid and provide discounts of 50%–70% for transmission and grid connection for renewable energy projects with capacity over 500 kW. In 2003, CRE established a methodology and rules for transmission service charges for electricity from renewable energy sources, while in 2004 new rules were drafted that required self-suppliers whose generation facilities are located away from their consumption points to sign interconnection (wheeling) contracts with the CFE.

In 2005, legislation that allows accelerated depreciation for investment in environmentally friendly technologies was drafted by the Natural Resources

1 Information about renewable energy policies in Mexico is from the International Energy Agency's renewable energy policies database (International Energy Agency, 2010a).

and Environment Secretariat (SEMARNAT) as well as the Public Finance Secretariat. Investors are allowed 100% deduction in the first year in the case of a renewable energy project, given that the project remains in operation for at least five years and serves a productive purpose. In 2006, the energy secretariat (SENER) allocated close to $97 million for improving access to electricity in rural areas under the Integrated Energy Services Project for Small Localities of Rural Mexico. Approximately US$15 million (nominal) was allocated to renewable energy projects in order to provide electrical power from solar PV, small wind, microhydro, and biomass generation. More recently, the government passed the Renewable Energy Development and Financing for Energy Transition Law, by which rules, mechanisms, and instruments are defined for developing and expanding generation of electricity from renewable sources. The main objective of the law is the regulation of renewable energy sources and "clean" technologies, as well as to establish a national strategy and financing instruments to aid Mexico in increasing its capacity for generating electricity from renewable sources. This law allows SENER to work with states and municipalities to simplify access to areas favourable for developing renewable-energy projects and to streamline the process for acquiring permits. The law also establishes various incentive schemes as well as a fund of US$240 million (nominal) to support renewable energy; it also calls for the Comisión Federal de Electricidad to purchase electricity generated from renewable sources through co-generation, self-supply, or small-scale production.

North America

This section presents a brief overview of the kinds of energy policies that are being used in North America as a whole to promote use of renewable energy sources. The International Energy Agency (IEA) administers a database for information about global policies and measures affecting use of renewable energy (International Energy Agency, 2010a). The policies and measures summarized in the database range in scope from the local, municipal, state, regional, or provincial levels, to the federal, national, and supranational levels. The information encompasses education and outreach initiatives, financial measures, incentives and subsidies, policy processes, public investment, research, development and deployment, regulatory instruments, tradable permits, and voluntary agreements. Financial measures include the distribution of funds to subnational governments as well as taxes and tax incentives, such as tax credits, exemptions, or reductions. Incentives and subsidies include feed-in tariffs, grants, preferential loans, rebates, and third-party financing. Policy processes include the enhancement of existing policies, institution building, project-based programs, and strategic planning. Public investment refers to government procurement programs as well as investment in infrastructure. Research, development, and deployment (RD&D) include demonstration projects, research programs such as technology deployment and diffusion programs, as well as technological development. Regulatory instruments include assessments, audits, benchmarking, mandates, monitoring, quota systems, regulatory reform, and standards.

Review of the International Energy Agency's global database of policies and related measures available from all levels of government in North America covering all technologies except for bio-fuels (which are beyond the scope of this paper), indicated that 77 different policies are either in effect or being planned, in order to encourage the use of renewable sources for energy (International Energy Agency, 2010b). Of those 77 policies and measures, 23 apply to Canada, 45 to the United States, and nine to Mexico (table 8). Note that the number of measures is greater than the number of policies. This is because a given policy may involve more than one type of measure. For example, a policy may involve both a financial measure such as tax credits or tax exemption and some other kind of subsidy. The table provides a useful summary of the number of policies that are in place to encourage renewable energy in each country and in North America as a whole, and of the types of implementation measures that are being used the most frequently.

Canada's 23 renewable-energy policies involve a large number of incentives and subsidies. In fact, 12 out of 39, or 30% of all renewable-energy policy measures currently in use or being planned involve an incentive or subsidy of some kind. Six out of 39 (15%) involve financial measures while five (13%) include either measures related to RD&D or education and research. On the other hand, Canada's policies on renewable energy include no measures on tradable permits, and only about 3% of the measures involve policy processes.

Table 8: Renewable Energy Policies and Measures in North America

	Canada	United States	Mexico	North America
Type of measure in policies				
Education and Outreach	5	8	1	14
Financial	6	15	1	22
Incentives/Subsidies	12	8	3	23
Policy Processes	1	11	3	15
Public Investment	3	4	1	8
RD & D	5	12	—	17
Regulatory Instruments	3	12	5	20
Tradable Permits	—	2	—	2
Voluntary Agreement	4	1	1	6
Number of measures	39	73	15	127
Number of policies*	23	45	9	77

Note: * for reference purposes only.

Source: International Energy Agency, 2010a; table by authors.

The United States has the largest number of renewable energy policies—45. The largest number of the 73 US policy measures are financial measures (20%); as well, there are many in the categories of RD&D and regulatory instruments (16% each). Measures implementing US renewable energy policies tend to involve relatively few voluntary agreement measures (1%), tradable permit measures (4%), or public investment measures (5%).

Mexico's nine renewable-energy policies are focused on regulatory instruments: 33% of the policy measures are of this kind. Incentives and subsidies represent 20% of the measures in place, and policy processes have the same share. Mexico's policies have no RD&D or tradable-permits measures, and all of the other types of measures included in the table, including public investment and voluntary agreements, each appear only once.

Overall, of the 127 measures that the IEA identifies as in place to implement the 77 North American renewable-energy policies, 23 (18%) involve incentives or subsidies; this approach is most prevalent in Canada. Financial measures occur with the second highest frequency (17%); these appeared most frequently in the United States. Measures in North America are also often (16% of the time) regulatory instruments such as assessments, auditing, benchmarking, mandates, monitoring, quota systems, regulatory reform and standards, but this is much more the case in Mexico and, to a lesser degree, in the United States than in Canada.

4 Barriers and challenges

Under the premise of the United Nations Intergovernmental Panel on Climate Change that greenhouse gas (GHG) emissions are a major cause of climate change, the potential for increased use of renewable energy resources is attracting interest among environmentalists, governments, and investors. Although renewable energy may appear at first glance to constitute an attractive alternative to fossil-fuel combustion for electricity generation in much of North America, and the world as a whole, there are numerous obstacles and challenges to the widespread penetration and application of various types of renewable energy. These include—to name but a few—public opposition, conflicts between federal and state jurisdictions, large capital costs, the unreliability of electricity generated with some forms of renewable energy, lack of skilled labour familiar with renewable-energy technologies, limited access to transmission systems, and regulated electricity markets, as well as unclear or uncertain environmental and energy policies.

Public opposition

Even though public support for generating electricity from renewable energy is strong, there is considerable opposition to the construction of certain types of electric-generation plants and the additional transmission facilities that they require. Among the most common complaints are that the proposed facilities will obstruct views, reduce property values, and harm endangered species (Batten and Manlove, 2008). This type of opposition is often referred to as the Not-in-my-Backyard (NIMBY) syndrome, which describes the often observed tendency for people to favour something until it directly affects them and they, personally, have to bear some kind of a cost.

Capital costs

Another barrier to investment in renewable energy projects is their capital cost compared with investment in conventional electric-generation capacity. For example, as indicated by the cost comparisons compiled by the International Energy Agency (IEA) that were presented earlier, a small photovoltaic system may require capital investment (overnight cost) as high as $7,310 per kW of capacity (International Energy Agency, 2010). Again, offshore wind power installations may cost in the vicinity of $4,000 per kW, excluding the sometimes high costs of connecting to the transmission system. Geothermal energy is also very expensive as the cost of drilling a well is from $2 million to $3 million and considerable seismic exploration must first be carried out (National

Energy Board, 2006). Wind power also requires large up-front investment as the generation towers must be built at locations where the wind speed has been carefully measured over a period of time.

Unreliability

Unreliability poses another obstacle to some forms of renewable energy. Wind power, for example, cannot be relied upon to produce electricity all day, every day, because of the variability and intermittency of the resource (National Energy Board, 2006). Because wind power is not always available, backup sources of generation, such as natural gas or diesel-fired generation units, or hydroelectric power facilities must be available. In a jurisdiction such as Quebec that already has a large fleet of hydroelectric power stations, this is generally not a problem. Where sufficient back-up hydro, gas, or other electric-generation capacity is not available, the additional capital cost of installing such capacity in order to ensure reliability of the electric system may be significant. In addition, the intermittent characteristic of wind generally requires adjustments to transmission controls to prevent collapse of the system should wind in a particular area subside rapidly; if wind turbines are scattered over a large geographic region, however, it is less likely that all will lack wind at the same time (National Energy Board, 2006).

Poor access to transmission system

A barrier to the development of some forms of renewable energy rises from poor access to the transmission system. Many of the more attractive sites of renewable energy resources in North America have no access to the existing electric-power grid and the cost of tying them into the transmission system will be high because of their remote locations. Connecting them to the grid will typically be more costly and more difficult than it is for a fossil-fuel or nuclear plant located close to the demand for electricity. In fact, a 2004 workshop organized by the Canadian Wind Energy Association to discuss challenges faced by Ontario's wind-power industry concluded that inadequate transmission capacity was a major barrier to investment in wind power and noted that financial issues, such as who would bear the cost of the new transmission lines, were of considerable concern (Pollution Probe, 2004). Because power generation facilities using renewable sources will not be built unless there are, or will be, adequate connections to the transmission system, transmission infrastructure is an important barrier to the achievement of Renewable Portfolio Standard (RPS) targets. For example, the California Energy Commission announced that the California's three investor-owned utilities could not meet the State's 20% RPS requirement by 2010 mainly because of an inadequate transmission infrastructure (Wiser and Barbose, 2008).

Regulated markets

Regulated electricity markets are also a barrier to successful development and integration of renewable energy resources. While many markets in North America have been liberalized, a large number of jurisdictions in Canada and some in the United States, like Mexico do not have competitive electricity markets. Competitive electricity markets provide the best environment for innovation and adaption of the most efficient electric-generation technologies. Evidence of this has been catalogued in various recent studies. For example, a recent study of three Canadian jurisdictions (Alberta, British Columbia, and Ontario) concludes that, when the generation mix is determined in a competitive, technology-neutral process, both innovation and cost effectiveness are encouraged (Conference Board of Canada, 2010). Also, a study by Navigant Consulting examined changes in competitive electricity markets in North America and found that clear, market-driven price signals lead investors to improve plant heat-rate performance (for coal plants) and capacity factors (for nuclear plants), thus improving outcomes for investors and reducing the environmental footprint of generation (Navigant Consulting, 2009). Further, a recent assessment of competitive electricity markets across North America recommends that public policy goals rely on market forces as much as possible, in order to achieve goals related to renewable energy, energy efficiency, and conservation (Distributed Energy Financial Group LLC, 2010).

Unclear and frequently changing policies and regulations

Uncertainty surrounding the nature and extent of anticipated controls on greenhouse gas emissions poses a considerable barrier to investment in electric generation using either renewable or non-renewable sources of energy. The cost of investing in greenhouse-gas emission controls (as with carbon capture and storage) will affect coal-fired and natural-gas-fired generation. But, until the extent of the limits and their timing are known, would-be investors are unable to gauge accurately the cost and competitiveness of particular technologies—whether they use renewable or non-renewable resources—under the expected policy framework. Alternatively, investors may turn to jurisdictions where environmental policy is of less concern, either because the matter has been resolved or because the existing mix of generation capacity and the available resources makes this kind of uncertainty much less of an issue (in a jurisdiction, for example, where the major source of supply is hydroelectric and there are no local supplies of coal).

Finally, public-policy settings and institutional arrangements need to be conducive to investment in the expansion of the continent's energy supply capacity by establishing rules under which effective, market-based competition can prevail wherever possible. In the electricity sector, non-market barriers to investment in electricity generation, transmission, and distribution—such as unnecessarily complex regulatory approval processes and procedures, as well as incentives and subsidies that favour particular forms of energy or technologies such as renewable energy projects—stand in the way of least-cost electric system expansion. Unclear, and frequently changing policies and regulations increase the level of risk perceived by investors and reduce their willingness to make major commitments.

Recommended policy reforms

Policy makers appear to be convinced by the argument that electricity from renewable energy sources is necessary to reduce greenhouse gas emissions from thermal power plants that the United Nations Intergovernmental Panel on Climate Change and some scientists and interested parties claim are largely responsible for climate change. To this end, federal and many state and provincial governments have been preoccupied with providing direct subsidies and tax breaks for investment in renewable energy and ensuring their connection to transmission systems without regard for the combined cost of generation and transmission which, ultimately, must be borne by electricity consumers. If this approach continues, it will result in the cost of electricity being higher than necessary and this, in turn, will impinge upon the cost of doing business and the competitiveness of North American industry. Instead of mandating the deployment of renewable power-generation technologies, a market-based approach is required to determine the most efficient composition of energy investment. Governments should take the following steps.

1 *Abandon renewable portfolio targets*
The desire to ensure that renewable energy sources have an assured niche in the energy supply mix and the practice of mandating renewable energy portfolio targets or "standards" needs to be abandoned. Instead, governments should let private-sector investors and risk takers with intimate knowledge of the available generation technologies determine the future composition of electric generation capacity consistent with energy and environmental laws and regulations.

2 *Stop promoting any source of electricity by incentives or subsidies of any kind*
Incentives, subsidies, purchase guarantees such as FIT programs, and other measures designed to support particular energy technologies tilt the playing field according to political whims instead of market-based signals. Removal of subsidies and incentives of all kinds, in relation to both renewable and non-renewable electricity sources, will help to ensure that energy resources available for electric generation are allocated most efficiently, according to their economic merit.

3 *Develop long-term plans for transmission systems capable of accommodating those paths to expanded electric-generation capacity that appear most likely to evolve from informed, market-based, investment decisions*
Non-discriminatory long-term transmission development plans need to be developed by the owners of transmission facilities that anticipate how electric generation capacity is most likely to be expanded given the relative advantages of all available technologies. This will allow for an array of new generation plants, including those relying on renewable energy sources if they become feasible, to be tied into the transmission system. In the long run, this should lead to lower transmission charges, and lower delivered-electricity costs, than policies that allow for transmission expansion to accommodate the connection of renewable energy sources without regard to competitive alternatives.

4 *Simplify and streamline regulatory approval processes and procedures for investment in transmission facilities and electric generation capacity*
Regulatory processes that are unnecessarily time-consuming and burdensome can cause would-be investors to turn to other jurisdictions and even other industries for viable investment opportunities. Streamlining regulatory procedures to reduce costs will help ensure that needed additions to generation and transmission facilities are made in a timely manner. This will reduce capital costs of renewable and non-renewable electric-generation projects alike, since input costs will be less subject to inflation if construction is able to commence sooner after the date that an application is filed. The cost of new electric transmission facilities would be less subject to inflation for the same reason. Electricity consumers should ultimately benefit from lower prices.

5 *Remove uncertainty regarding limits on carbon emissions*
The cloud of uncertainty in relation to the competitiveness of the full range of energy sources needs to be removed by determining as soon as possible whether, how, and to what extent greenhouse-gas emitters are to be penalized. Whether or not carbon emissions will be regulated more intensely, removal of the uncertainty surrounding environmental policy in this regard will allow would-be investors in all types of electric generation capacity to know where their respective proposals and plans stand in terms of cost relative to competing technologies.

6 *Establish clear, stable, energy policies and regulations*
The lack of stability and predictability with respect to energy policy that stems from the short-term focus that politicians generally have because of the electoral cycle is in direct conflict with investors in an industry that is capital

intensive, where prudent infrastructure planning and development generally involves years, and where the life spans of capital assets are measured in decades. A clear and stable policy and regulatory environment will remove uncertainty and foster investment and innovation.

Once an environment conducive to investment has been established through recognition of the need for a clear and stable policy and regulatory framework, market forces should be left to determine whether, and to what extent, wind, solar, biomass, hydroelectric, and other renewable energy sources, can compete with electric generation fuelled by the combustion of coal, natural gas, and oil (with and without carbon capture or enhanced combustion technologies) and nuclear power—and what types of generation capacity are put in place. Other things being equal, this will result in electricity costs throughout North America in the years ahead that are lower than would otherwise be the case. This will improve the standard of living of energy consumers and enhance the ability of North American manufacturers to compete with producers in other countries.

Appendix 1 Ontario Power Authority's Feed-in tariff (FIT) contract value and weighted average price (WAP) under FIT contracts

	Average FIT rates (¢/ kW-h)	Generation capacity contracted (kW) as of December 2010	Expected yearly output (kW-h)	Capacity factors	Expected yearly output (kW-h) — subject to capacity factors	Contract term (years)	Expected contract output (kW-h)	OPA's contract value ($ millions 2010)	Weighted average price under FIT contract (¢/ kW-h) ($ 2010)
Bio-energy									
Biogas	14	20,000	175,200,000	1	155,052,000	20	3,101,040,000	$425	13.70
Biogas on farm	19	3,000	26,280,000	1	23,257,800	20	465,156,000	$88	19.00
Biomass	13	18,000	157,680,000	1	139,546,800	20	2,790,936,000	$374	13.40
Landfill	11	15,000	131,400,000	1	116,289,000	20	2,325,780,000	$249	10.70
Solar PV					—		—		
Ground-mount	54	654,000	5,729,040,000	0	744,775,200	20	14,895,504,000	$8,081	54.25
Rooftop	67	203,000	1,778,280,000	0	231,176,400	20	4,623,528,000	$3,108	67.23
Hydroelectric					—		—	$—	
Hydroelectric	13	188,000	1,646,880,000	1	988,128,000	20	19,762,560,000	$2,500	12.65
Wind		—			—		—		
On-shore	14	1,231,000	10,783,560,000	0	3,558,574,800	20	71,171,496,000	$9,608	13.50
Off-shore	19	300,000	2,628,000,000	0	1,051,200,000	20	21,024,000,000	$3,995	19.00
Total	n/a	2,632,000	23,056,320,000	n/a	7,008,000,000	n/a	140,160,000,000	$28,428	20.28
Compare	$7.30						140,160,000,000	$10,227	$7.30
							Premium for FIT ($)	$18,201	$13.0
							(percentage)	178%	178%

Sources: International Energy Agency, 2010b; Ontario Power Authority 2010a, 2010b, 2010c; calculations and table by authors.

Appendix 2 Glossary of terms

Alternating Current (AC)/Direct Current (DC) In AC the electric charge continually reverses direction; in DC in which the electricity flow is in one direction. AC is the more common.

Cap and Trade This is a market-based approach that is used in some jurisdictions to reduce airborne emissions of various kinds. A cap is placed on firms' emissions levels and 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 or making modifications to the existing plant.

Carbon Capture and Storage (CCS) or sequestration CSS is the capture and storage of carbon dioxide (CO_2) before it is 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 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").

Combined Heat and Power (CHP) Also known as cogeneration, CHP is the use of a power plant to generate both electricity and useful heat, whether for industrial processes or space heating.

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 The federal electricity commission in Mexico and a state-owned electric monopoly established under the constitution to produce and provide electricity.

Comisión Reguladora de Energía 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 that is produced 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 Aso known as low-voltage electric transmission, this 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 from high-voltage transmission levels.

Electric Generation Capacity The amount of installed capacity 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 The amount of electricity produced (usually measured in MW-h or GW-h) and 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 electric power to end users. Electricity transmission involves the transfer of electrical energy that is generated from electricity distribution facilities. When connected together, transmission lines make up the electric transmission system or grid.

Energy Information Administration the statistical and analytical unit within the US Department of Energy.

International Energy Agency The Paris-based agency within the Organisation for Economic Co-operation 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 Natural gas in liquid form formed by cooling and pressurizing natural gas, thus reducing the gas volume by about 600 times; this allows for transportation by specially equipped tankers.

National Energy Board The agency of the Canadian government that is charged with regulating companies involved in shipping oil, natural gas, electricity, and other energy commodities across interprovincial boundaries or exporting and importing energy commodities.

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

Pumped Storage The storage of potential for hydroelectric power generation by pumping water up to a higher reservoir from a reservoir at a lower level.

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 adverse events affecting the supply of electricity.

Renewable Energy Resources Resources that are replaced by natural processes at a rate comparable or faster than its 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 in order to maintain harvesting in a sustainable manner such as fresh water (for hydroelectric generation) and timber (for biomass energy).

Run-of-river (ROR) projects Small-scale hydroelectric projects that do not require dams, reservoirs, or flooding to generate electricity; instead, the natural flow and elevation of a river are used to create power.

Solar Photo-voltaic (PV) Solar cells capable of generating electric power by converting solar radiation into direct current electricity via semiconductors that create voltage when exposed to light (photo-voltaic effect).

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 is then used to generate electricity.

Thermal Energy Generation Generally, a process of energy conversion in which combustion of a fossil fuel such as natural gas, fuel oil, or coal generates heat energy that is converted into mechanical energy (e.g., steam) and finally to electrical energy.

Volt A unit of electromotive force or electrical pressure; 1 kilovolt (kv) = 1,000 volts. In this report, volts are used as the measure for the electrical pressure in transmission lines.

Watt A derived unit of power (electrical energy flow) that is used to measure the rate of energy conversion. For this report, watts are used as units of electric generation capacity or the potential for producing given amount of 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. For this report, this unit is used when reporting electricity generation or consumption (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.

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Acknowledgments

The authors would like to thank Mr Fred McMahon, the Institute's Vice President for International Research, and the anonymous external reviewers for their valuable comments and suggestions.

The Fraser Institute wishes to thank our generous donors who have supported this research.

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Date of issue

April 2012

ISSN

1918-8323 Studies in Energy Policy (online version)

Citation

Angevine, Gerry, Carlos A. Murillo, and Nevena Pencheva (2012). *A Sensible Strategy for Renewable Electrical Energy in North America*. Fraser Institute. <http://www.fraserinstitute.org>.

Editing, typesetting, and design
Lindsey Thomas Martin

Cover design
Bill Ray

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