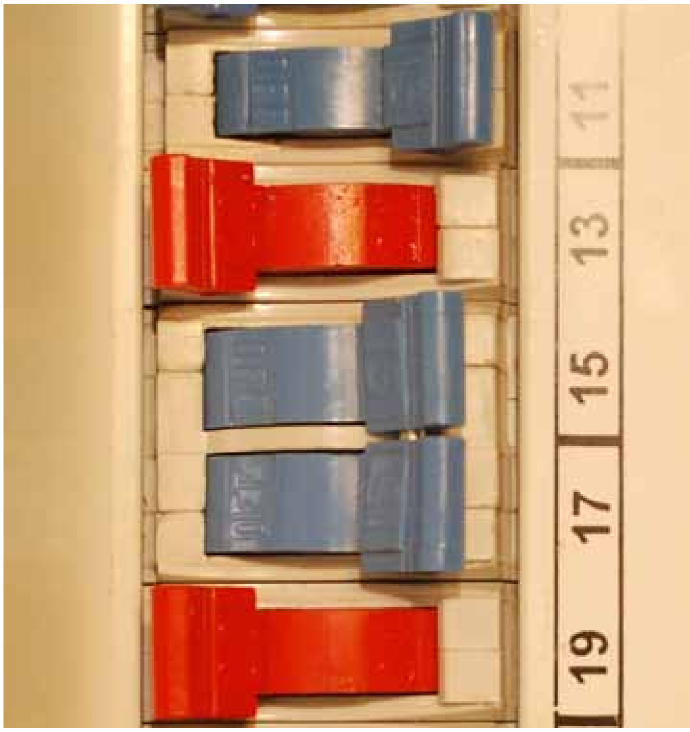
Behind the Switch

PRICING ONTARIO ELECTRICITY OPTIONS

the PEMBINA institute
Sustainable Energy Solutions

Tim Weis • P.J. Partington

July 2011

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The Pembina Institute is a national non-profit think tank that advances sustainable energy solutions through research, education, consulting and advocacy. It promotes environmental, social and economic sustainability in the public interest by developing practical solutions for communities, individuals, governments and businesses. The Pembina Institute provides policy research leadership and education on climate change, energy issues, green economics, energy efficiency and conservation, renewable energy, and environmental governance. For more information about the Pembina Institute, visit www.pembina.org or contact info@pembina.org. The Pembina Institute's engaging monthly newsletter offers insights into its projects and activities, and highlights recent news and publications. Subscribe to Pembina eNews at www.pembina.org/enews/subscribe.

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Executive Summary

Across Canada, our electricity infrastructure will demand significant investment over the coming decades. Ontario, accounting for roughly a quarter of Canada's national electricity system, is no exception, and will require investments to maintain, update and renew its infrastructure. New investments invariably result in new costs for consumers of electricity.

As the National Energy Board has noted, "Ontario has one of the oldest electricity systems in the world and, as such, the cost of maintaining reliability on the system is increasing with the system's age."

Ontario is also delivering significant health and climate change benefits by phasing out its entire coal fleet. While these old coal plants are capable of producing electricity at a low price, their continued operation does result in significant costs, notably to the health care system, which are paid by Ontario's taxpayers. New forms of generation to replace coal and other old infrastructure will more realistically reflect the full costs of generating and delivering the power we consume.

In recent decades, Ontario has generated almost half of its electricity from its fleet of nuclear power plants. Every nuclear reactor in Ontario has either begun or is in need of refurbishment, or is scheduled to be retired within the next 10 years. A decision to reduce reliance on nuclear energy has the potential to increase the long-term sustainability of the province's electricity system, particularly in the context of the Fukishima disaster in Japan and the announced sale of Atomic Energy of Canada, but is beyond the scope of the analysis presented here. Rather, the focus of this study is on the impact of the 2009 Green Energy and Economy Act, and the potential consequences of a decision to repeal the Act.

Even with the continued use of nuclear as 50 per cent of the generation capacity in Ontario, significant decisions about Ontario's electricity system remain to be made, particularly in light of how the system will cope when nuclear reactors are offline for refurbishment for years at a time. It is important therefore to understand how choices about these investments will impact prices and what value Ontarians can expect from these decisions. To do this, we set out to compare two plausible scenarios of Ontario's electricity future over the coming decades.

Scenarios considered for Ontario's electricity future

The 2003 blackout underscored a need for greater planning and investment in Ontario's electricity system, and long-term planning processes have been a core feature of Ontario's approach ever since. This has most recently been expressed in the province's Long-Term Energy Plan and consultation documents for the Ontario Power Authority's second Integrated Power System Plan. In addition to the continued dominant role for nuclear power in Ontario's electricity mix, these plans also forecast strong growth in renewable energy and conservation, enabled by the Green Energy and Economy Act (GEA).

The Act, and its feed-in tariff which is used to procure renewable energy, has drawn criticism in some circles and there have even been propositions to dismantle the legislation in favor of diverting resources back toward expanding more traditional generation technologies. Such a pathway would likely maintain the province's current support of nuclear power, but sharply curtail growth in wind and solar power in favour of increased gas-fired generation and some additional large hydro. These therefore represent the two scenarios examined in this study: Scenario 1 based on the current planning framework (including the Green Energy and Economy Act), and Scenario 2 which assumes the dismantling of that legislation and consequently greater reliance on fossil fuels (especially natural gas). Comparing and contrasting these scenarios allows for a better understanding of the incremental impact on cost and other key economic variables of the Act

The system cost impacts of these two scenarios were evaluated over the next 20 years using a dynamic model of Ontario's energy system within the Canadian Energy System Simulator (CanESS). Using CanESS enabled a comparative simulation of sectoral electricity demands, infrastructure costs and generator dispatch in the two different generation scenarios, while running sensitivities for key parameters such as natural gas prices, electricity demand and nuclear capital costs. The simulation enables a comprehensive modelling of how these factors integrate to result in differing potential electricity prices for the different scenarios considered.

Ontario's electricity system is very complex, and many contracts and system costs are confidential in nature, or are highly speculative, notably the costs of nuclear energy or future natural gas prices. The approach that was taken with this simulation was to ensure that key cost assumptions were based on publicly available third-party data. Key data sources included the United States Energy Information Administration's 2011 Annual Energy Outlook, the Ontario Power Authority, Ontario's Independent Electricity System Operator, the United States Environmental Protection Agency, Natural Resources Canada, and publicly available consulting reports published by Black and Veatch Engineering and Navigant Consulting. While there have been significant differences in actual costs compared to costs that had been forecast in the past in Ontario, particularly with respect to nuclear, costs were taken from these data sources as reported and sensitivities were run for nuclear capital costs and natural gas prices.

What we found

We examined overall system electricity prices in Ontario, including industrial, commercial and residential consumers. The results therefore reflect the trend of the overall system in Ontario, but are not meant to be interpreted at being specific to any individual consumer.

Simulation results show that electricity prices in Ontario are set to continue to rise sharply in the future in both scenarios, peaking around 2022 when Ontario's nuclear fleet is in the midst of significant rebuilding. As can be seen below, there would be virtually no change in electricity prices in the immediate future if future contracts for renewable energy were ended in 2011. Replacing the commitment to renewable energy largely with natural gas is likely to result in only a slightly slower increase in electricity rates from the years 2015-2025. However, within the next 15 years, as natural gas prices begin to rise and increased action (including some form of price on carbon emissions) is likely to be taken to combat climate change, the simulation found that investing in renewable generation today will keep consumer prices slightly lower in the long term.

If natural gas prices begin to rise faster than they are current forecast by the United States Department of Energy, or if more aggressive action is taken to combat climate change, these savings will be larger, and will begin to occur sooner in the future.

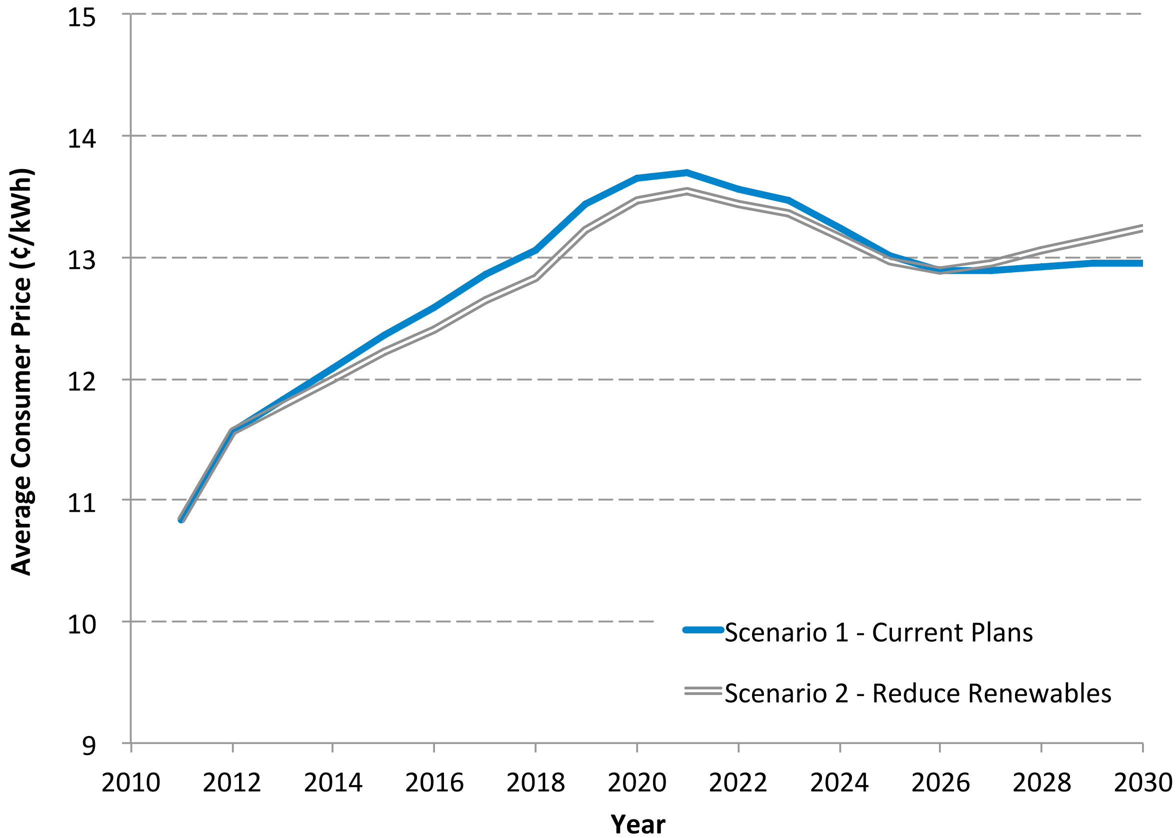

Figure A: Simulation results of average Ontario electricity prices (2010 constant dollars)

Consumer prices are virtually identical between the two scenarios. While prices in the more gas-focused Scenario 2 are slightly lower in the early years, the biggest gap between the two scenarios is only 1 to 2 per cent, an almost negligible difference. In later years, consumers would likely end up paying even higher electricity prices as a result of the elimination of the GEA, as renewable energy would hedge against natural gas price increases.

According to these results, the elimination of the Green Energy Act would have very little impact on electricity prices. Scenario 2, a trajectory of reduced renewables, would, however, pose both economic and environmental risks to Ontario from further increased dependence on natural gas for electricity generation.

While gas burns cleaner than coal, natural gas is still a fossil fuel and has much higher emissions of greenhouse gases, smog precursors and other pollutants than renewable energy technologies (which are mostly non-emitting). Upstream emissions from gas production and distribution are also a major source of greenhouse gas emissions in Canada. Building additional gas-fired infrastructure now will increase the cost of taking more ambitious action on emissions in the future.

In the current plan scenario, average emissions fall from current rates of 20 million tonnes of CO_2 per year to below 10 million tonnes over the next 20 years due to the phase-out of coal power. By reducing the use of renewable energy that is generated in Ontario, Scenario 2 and its heavier reliance on natural gas would produce as much as 3 million additional tonnes of CO_2 annually, as well as over 260 tonnes of nitrogen oxides, 21 tonnes of sulphur dioxide and 75 tonnes of volatile organic compounds.

Finding appropriate sites to build additional gas plants may prove challenging, given the recent strong opposition to proposed projects in Oakville and Mississauga. The previous Integrated Power System Plan working documents for Ontario had already identified the densely populated Greater Golden Horseshoe area as well as Kitchener-Waterloo as potential sites for proposed additional natural gas plants. Air quality problems in this region were a major motive for the phase-out of coal-fired electricity.

While prices for natural gas are currently lower than they have been in recent years, they are expected to rise again over the coming two decades even with the increased use of shale gas, bringing higher costs for gas-fired generation. Significant uncertainty exists as to the future of the natural gas market in North America and higher prices are possible, particularly if there is a large-scale shift from coal to gas in U.S. power generation or a large penetration of natural gas vehicles into the market, or unforeseen complications in the development of shale gas resources.

Unconventional gas (particularly shale gas from the northeastern U.S.) produced using hydraulic fracturing is anticipated to account for a growing portion of Ontario's supply. The environmental and health impacts of this type of gas production are a cause for concern, and future production moratoriums or stricter regulation may reduce supply and/or impact prices.

Finally, it is worth noting that while electricity prices may rise slightly less quickly in the short term with a heavier focus on natural gas compared to renewable energy, an increasing proportion of renewable energy technologies are being manufactured in Ontario, while the bulk of natural gas purchases come from outside the province.

Value for money

Like those of the rest of Canada, Ontario's electricity prices are poised to continue increasing in the short term as old infrastructure is updated and replaced, regardless of the choice of electricity generation mix. The outcome of the current debate over the GEA will have no meaningful impact on these future price increases, which reflect the inevitable costs of modernizing Ontario's aging electricity infrastructure. However, the choices facing Ontarians today will have an impact on air quality, greenhouse gas pollution, economic diversity and employment.

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1. Introduction

1.1. Ontario at a crossroad

Electricity systems all across Canada require major re-investments in the coming years. Work must be done to rebuild transmission lines, modernize the distribution system and replace aging and polluting sources of electricity generation. The Conference Board of Canada recently reported that across Canada, "the pace of investment must accelerate to accommodate a changing generation mix and changing market requirements, and to replace or update aging assets. The sector is expected to invest $293.8 billion from 2010 to 2030 to maintain existing assets and meet market growth."[1] The electricity system in Ontario faces many of the same fundamental challenges as in the rest of Canada.

Investments in electricity infrastructure inevitably result in price changes for electricity consumers. As provinces make these investments, electricity prices are rising all across Canada. Electricity rates have increased as much as 40 per cent in Saskatchewan[2] and Nova Scotia[3] over the past decade, while BC Hydro rates rose 6 per cent in 2010 and 8 per cent in 2011[4] and could rise by as much as 33 per cent between 2010 and 2013[5].

In Ontario, electricity consumer prices have been kept artificially low for years, and have not reflected the higher costs of building new sources of electricity generation, environmental impacts, or periods of high strain on the generation system.[6] Decisions such as the phase out of coal plants, investments in transmission infrastructure and the adoption of preferential pricing systems for renewable energy generation all mean that the cost of generating electricity in Ontario will increase. Equally important, Ontario's entire fleet of nuclear reactors reach the end of their operational lives over the next 20 years and will need to be replaced, refurbished or retired. As nuclear energy currently supplies approximately half the province's electricity, decisions about the future of these reactors will have major implications for electricity prices in Ontario.

As a result of these changes, consumer electricity costs are becoming an increasingly important issue in Ontario. Over the coming years, the cost of electricity in Ontario will increase. To best manage these costs and make effective policy decisions, it is important to understand the role different factors play in price increases and what realistic alternatives are possible.

In recent months, Ontario's Green Energy Act (GEA) has been portrayed as being either a present or a future source of consumer electricity price increases in Ontario. In particular, its feed-in tariff (FIT) program, which pays renewable energy producers a price for feeding energy onto the electricity grid, has received criticism. However, a number of other significant changes in the electricity system also have direct consumer prices, notably investments in transmission infrastructure, closing coal power plants, new natural gas development, costs associated with refurbishing Bruce A nuclear units, the fulfillment of contracts for renewable power awarded prior to the GEA, as well as the introduction of the Harmonized Sales Tax (HST). These factors, as well as the decisions on how Ontario will deal with its aging nuclear fleet, will all impact electricity rates, regardless of the success or failure of the GEA.

Currently, there is little or no public information available on what the long-term price impacts will be in Ontario as a direct result of the GEA, taking into account the decrease in FIT prices over time and the relative cost of other power sources. Additionally, no comprehensive quantitative analysis has examined the relative impacts of various other factors on price increases over time, nor compared the costs of the current energy plan in Ontario to a scenario that reduces the projected role of green energy or the GEA.

Given the major electricity infrastructure investment that needs to happen in Ontario, it is almost certain that electricity prices will rise regardless of any individual policy direction; the question is, by how much? What is particularly lacking in the current discussion is a comparative basis for examining what Ontario's costs would/could have been had the GEA not been implemented, as well as what consumer prices would be if other development paths rather than the GEA are pursued in the future.

1.2. Limitations of scope of current work

The Green Energy Act has become the focus of much controversy as a major source of future rate increases in Ontario. The research contained herein seeks to examine the relative price impacts of continuing this policy compared to a likely alternative scenario if this policy were brought to an immediate end. This research does not seek to optimize Ontario's system, either for price or for environmental performance.

This effort examines two plausible scenarios for electricity generation over the next 20 years assuming the current commitments to generating approximately 50 per cent of Ontario's electricity supply from nuclear power are retained. These two scenarios include the current plans put forth by Ontario's Ministry of Energy in its Long-Term Energy Plan, compared to a scenario where contracts for new renewable energy development are halted almost immediately and largely replaced with natural gas.

This research is limited to examining these two alternatives as they are currently part of the public discussion, but it is not necessarily an endorsement of either approach. This research does not examine a deeper move to a more sustainable electricity system with a decreasing emphasis on nuclear energy and increasing roles for conservation and renewable sources — a move several countries in Europe are currently pursuing in the wake of the March 2011 Fukushima nuclear accident in Japan.

1.3. Important decisions in Ontario's electricity system

The Electricity Conservation and Supply Task Force Report (June 2003)

A task force was commissioned in June 2003, with a final report recommending how best to fill a looming electricity gap resulting from the end of much of the nuclear fleet's working lives:

> *"Ontario faces a looming electricity supply shortfall as coal-fired generation is taken out of service and existing nuclear plants approach the end of their planned operating lives. Early action is needed to ensure that Ontarians continue to enjoy an affordable and reliable supply of power and that electricity prices in the province remain competitive with prices in jurisdictions with which Ontario competes for investment and jobs."*[7]

Recommendations from the task force included the creation of "a conservation culture" in Ontario such that peak demand could be reduced from its average growth of 1.7 per cent annually to 0.5 per cent per year. Furthermore, demand reduction should be given the opportunity to compete with supply side alternatives, and be evaluated on a level playing field.

The Task Force also called for quick action to implement a Renewable Portfolio Standard, as it felt renewable generation will play a key role in Ontario's future supply mix.

Electricity Restructuring Act (passed in December 2004)

Government amended the Electricity Act to give the Ontario Power Authority (OPA) accountability for preparing an integrated power system plan intended to guide the development of Ontario's entire power system, including transmission networks, and charged the Ontario Energy Board (OEB) with the mandate to approve it, as was largely recommended in the Electricity Conservation and Supply Task Force.

OPA Supply Mix Advice Report (December 2005)

The OPA prepared an advice report to the government on the best way to meet the province's electricity needs by 2015, 2020 and 2025.[8] The supply mix advice became the first step in preparing an Integrated Power System Plan (IPSP) for Ontario. The first IPSP was to be developed and submitted to the Ontario Energy Board in 2006.

Based on a projection of continued demand growth, the advice report recommended maintaining existing nuclear capacity, thereby requiring the refurbishment of existing facilities as well as new plants, while coal generating capacity would be replaced with renewable energy sources (principally wind) and gas-fired generation.

Ontario's Renewable Energy Standard Offer Program (2007)

Ontario's Renewable Energy Standard Offer Program (RESOP) was the first feed-in tariff introduced in North America in 20 years. The program offered standard rates of 11¢/kWh for wind, biomass and hydro projects that were less than 10 MW in capacity and 44¢/kWh for solar projects. The program received applications for over 1,000 MW of renewable energy within two years after it was launched. It was suspended in 2008 in anticipation of the Green Energy Act.

Supply Mix Directive (June 2006)

The Minister of Energy directed the OPA to create an IPSP based on the advice from the OPA's 2005 report. The directive sought to increase total available nuclear generating capacity, including the construction of at least two new reactors and the refurbishment of units at the Bruce, Pickering and Darlington nuclear facilities, exempting them from the Environmental Assessment Act.

The OPA was also directed to meet increased demand reduction targets from conservation programs totaling 6,300 MW by 2025. The plan was required to reduce projected peak demand by 1,350 MW by 2010, and by another 3,600 MW by 2025. The reductions of 1,350 MW and 3,600 MW are to be in addition to the 1,350 MW reduction set by the government as a target for 2007.

IPSP I (August 2007)

On August 29, 2007 the Board received from the OPA applications for review and approval of the IPSP and for the electricity procurement processes of the OPA. The IPSP incorporated the recommendations of the supply mix directives, and was to be reviewed every three years. The IPSP was never formally passed by the OEB as it was withdrawn by the the OPA in light of a new directive from then-energy minister George Smitherman to place more emphasis on renewables and conservation.

Green Energy and Green Economy Act (May 2009)

The Green Energy and Green Economy Act (GEA), and related amendments to other legislation, received royal assent on May 14, 2009. Regulations required to implement the legislation were introduced in September 2009. A cornerstone of the Green Energy and Economy Act (often referred to as simply the Green Energy Act) was the creation of a feed-in tariff program that guarantees specific rates for energy generated from renewable sources and establishes the right to connect to the electricity grid for renewable energy projects that meet technical, economic and other regulatory requirements. The Act also establishes a streamlined approvals process; provides service guarantees for renewable energy projects that meet regulatory requirements; implements a 21st-century "smart" power grid to support the development of new renewable energy projects; and prepares Ontario for new technologies like electric cars.

Nuclear bids rejected (June 2009)

The government of Ontario rejected all three bids submitted for the construction of up to four new nuclear units at Darlington. No costs were officially released, although the Toronto Star reported total cost estimates to be as high as $26 billion[9] for the construction of two 1,200 MW

Advanced Candu Reactors, or $10,800 per installed kilowatt.

Long Term Energy Plan (November 2010)

The Ministry of Energy released an update of the IPSP I, to guide the development of a new IPSP. The Long Term Energy Plan (LTEP) explicitly calls for 50 per cent of Ontario's demand to be met by nuclear power, thus retaining the previously sought refurbishments and new build plans for Ontario's nuclear fleet. The plan will see coal power phased out by the end of 2014. Ontario will continue to pursue conservation, with the government encouraging exceeding and accelerating its conservation targets. The targets for wind, solar and bio-energy have been raised to about 13 per cent of generation by 2018, up from the previous target of 10 per cent by 2030. Currently, these sources contribute just three per cent of Ontario's electricity supply.

Darlington Joint Review Panel Hearings (November 2009-May 2011)

On November 16, 2009, the joint review panel announced the start of a public and technical review period for the environmental impact statement application for new nuclear facilities at Darlington.

Emissions commitments (2007 and onward)

Ontario's Action Plan on Climate Change, published in 2007 states:

- *"we will reduce Ontario's greenhouse gas emissions to 6 per cent below 1990 levels by 2014 – a reduction of 61 megatonnes relative to business-as-usual.*
- *By 2020 Ontario will reduce greenhouse gas emissions to 15 per cent below 1990 levels – a reduction of 99 megatonnes relative to business-as-usual.*
- *By 2050 we will reduce greenhouse gas emissions to 80 per cent below 1990 levels".*

The plan also includes commitment to shut down coal and increase clean renewable electricity capacity by 50% by 2015.

Ontario is one of five partner jurisdictions moving ahead with the Western Climate Initiative (WCI) in the short term. California, British Columbia and Quebec intend to launch the regional cap-and-trade system in 2012, with Ontario and Manitoba joining shortly thereafter.[10] The WCI establishes a carbon market that, when fully implemented, will cover nearly 90% of emissions in partner jurisdictions.[11]

Part I: Model and Assumptions

2. Electricity Simulation

2.1. Approach

Modelling an electricity system is a complex and challenging task. It requires an ability to simulate the ebbs and flows of generation availability and consumer demand, and to make assumptions about provincial infrastructure needs and future construction and fuel costs for numerous technologies. It is impossible to predict exactly how the future will unfold, particularly as there are major uncertainties right now with respect to the long-term price of natural gas, the costs of rebuilding nuclear plants and how seriously governments and industry will react to the threat of climate change in trying to curb emissions.

The approach taken in this study is to use publicly available data for capital costs, long-term fuel prices and infrastructure lead-times for known and likely electricity infrastructure projects in Ontario in order to simulate future electricity costs. Individual projects may deviate from these costs. For the purpose of the current study, data was compiled from the following sources where possible: the Ontario Ministry of Energy's Long Term Energy Plan, the United States Energy Information Administration's Annual Energy Outlook 2011[12] and the Ontario Power Authority's IPSP Planning and Consultation Overview.[13] System balancing, electricity distribution and producer profits are also incorporated.

We view this as a conservative approach, as overruns and price escalations have been common in Ontario's experience, particularly with respect to nuclear energy, while forecast natural gas prices are subject to widespread development of unconventional gas resources such as shale gas, the public acceptance of which remains unclear.

We also assume that there will be some action taken to address climate change through a carbon price reaching \$32 per tonne of equivalent carbon dioxide (CO_2e) by 2020, and rising to \$58 per tonne CO_2e. These prices are the minimum that would be required for Ontario to meet the provincial commitments it has made as a member of the Western Climate Initiative,[14] although they are below what most studies suggest would be adequate to meet Canada's national climate change targets — including the National Roundtable on the Environment and the Economy which suggested a price close to a \$75 per tonne CO_2 by the year 2020.[15] This approach to carbon pricing was taken in this study in order to err on the side of disadvantaging renewable energy costs, to ensure that projections are not perceived as biased in favour of renewable energy sources.

While it remains uncertain exactly how policies to address carbon emissions may unfold, it is likely that some action to combat emissions will take place over the next 20 years. While this action may not take the form of a formal price on carbon, the assumed price on carbon in this analysis can serve as a proxy for such policy action, whether it ends up being market based or regulatory in nature.

Given the complexities of the market and the potentially significant impact that some of these uncertain variables will have on the Ontario context, the results of this study should not be interpreted as being a definitive projection of actual future electricity costs. However, the model does provide a reasonable framework for comparing the effects of alternative policies on future electricity prices in Ontario.

Unless otherwise stated, all modeled prices are listed in 2010 constant Canadian dollars.

2.2. Canadian Energy Systems Simulator (CanESS)

The Canadian Energy Systems Simulator (CanESS) was used for this analysis. CanESS is a proprietary model built by whatIf? Technologies to dynamically simulate the entire Canadian energy system. The CanESS model simulates energy system scenarios in the context of the Canadian economy and the demand and supply of fuels for Canada. While CanESS simulates all of Canada's energy systems including international and interprovincial trade, provinces, in this case Ontario, can be extracted and examined in detail.

A high-level overview of CanESS is shown in Figure 1. Population via households and the size of the economy drive energy end-use breakdown. Within each end-use sector, CanESS tracks energy-consuming stocks (e.g. vehicles, dwellings, and appliances) over time and associates conversion efficiencies with the vintages of the stocks.

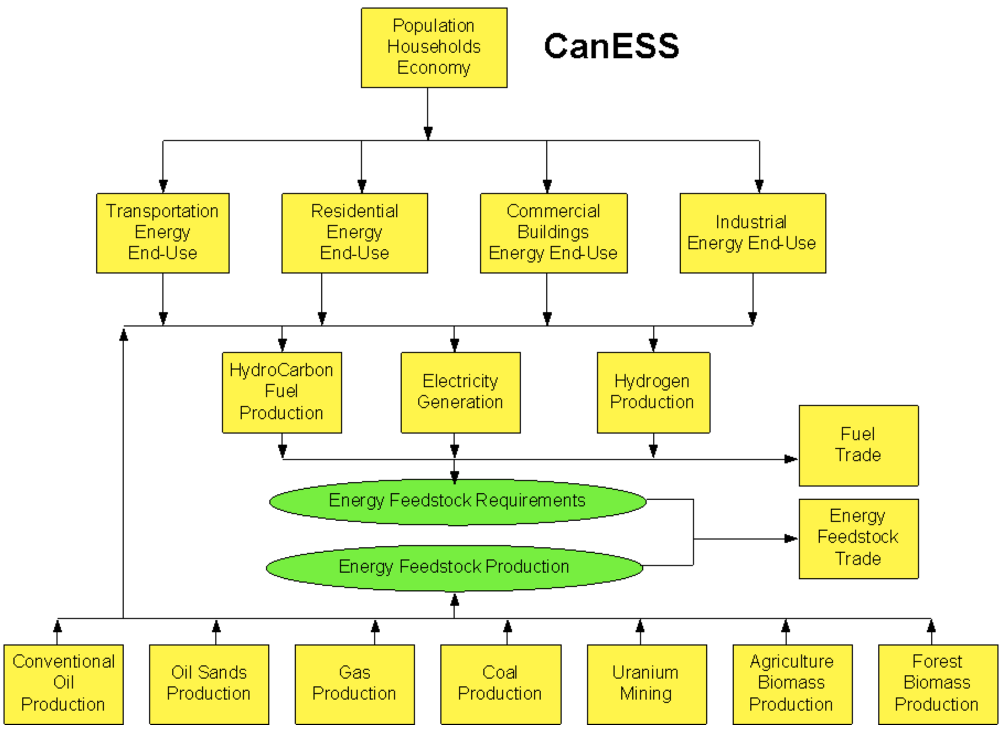

Figure 1: CanESS model high-level view

SOURCE: WHATIF? TECHNOLOGIES

Key variables including population, households, buildings, vehicles, appliances, productive capacity, resources and reserves fuel have been collected from data sources including:

- CanSIM (Demographics, GDP, Agriculture, Land Use)
- Statistics Canada Report on Energy Supply and Demand
- Natural Resources Canada, Office of Energy Efficiency, Demand Policy and
- Analysis Division
- GHG Inventory
- EPA Mobile 6 Model and Database
- Electric Power Statistics
- CanPlan (National Energy Board)
- Life Cycle Analysis Models (GREET, GHGenius)
- Scientific Reports (Sandia Labs, Battelle, USDA, etc.)

CanESS is back-calibrated over historical time to 1978 in one-year steps, so that CanESS has a complete historical data base of all of the variables in the model that are adjusted to be consistent with the current stock and rates of turnover and incremental changes in characteristics.

Data is input into CanESS through a graphic interface that allows users to see how variables are interrelated and interdependent as shown in Figure 2 below.

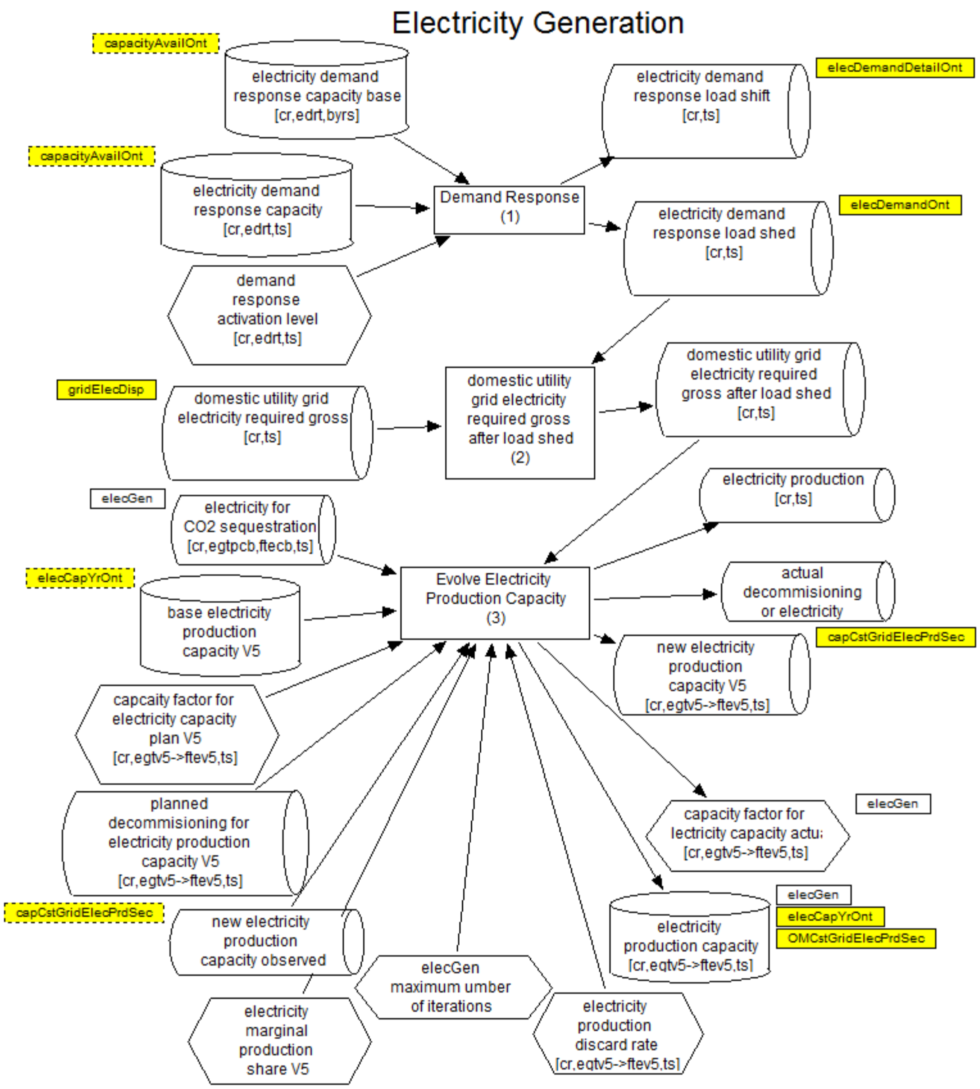

Figure 2: CanESS electricity generation calculator

SOURCE: WHATIF? TECHNOLOGIES

Variables, flows and parameters can be examined down to their primary data and assumptions. Figure 3 illustrates an example of how parameters in CanESS are built up of their underlying components.

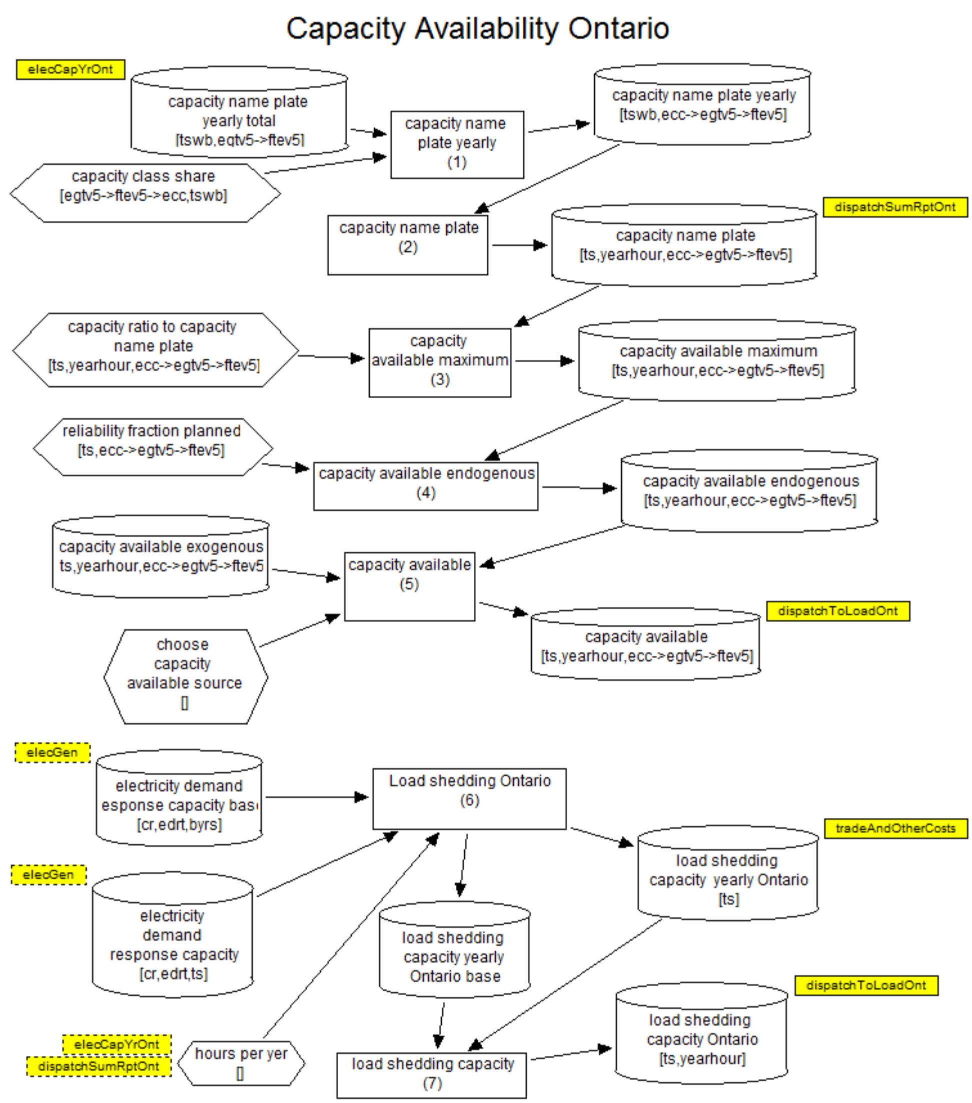

Figure 3: Sub-layer of CanESS electricity model

SOURCE: WHATIF? TECHNOLOGIES

The model tracks the stocks of energy consumption including vehicles, houses, buildings, power plants and transmission lines in the context of energy consumption, and associates conversion efficiencies with the vintages of the stocks. New technologies are introduced and retired annually as new capacity is required for expansion and/or replacement of the stock.

For the current model, CanESS compiles the complete national energy flows for each iteration, including natural gas and transportation fuels, with the changing interprovincial and international levels of trade. Stock turnover and fuel switching interact with the electricity system and will impact the overall provincial demand profile over time.

The emissions of greenhouse gases and criteria air contaminant are calculated at point of source and in the year in which they are released.

Having examined models that could handle the scope of work required for this study, we feel CanESS offers a sufficiently robust and transparent model that is also flexible enough to run iterations and sensitivities, which ensures consistency between scenarios.

2.3. Modelling Ontario's electricity system

The CanESS model has 31 different generation technology archetype plants available. Nine of these types — namely nuclear, coal, combustion natural gas, combined cycle natural gas, solar photovoltaic, on-shore wind turbines, bioenergy, large hydro, and run-of-river hydro — were used to represent the bulk of electricity generation in Ontario between the years 2010 and 2030. Power plant retirement, new generation capacity, infrastructure build and demand changes are simulated in one-year time steps.

In this study, the type and amount of generation available is based on currently installed capacity in the province and is modified annually based on projections included in the Long Term Energy Plan, as is discussed in Chapter 3. Using the annual demand projection, electricity generation was simulated by dispatching available technologies to match an 8,760-hour load shape that reflects electricity demand from electricity-consuming devices each model year. The hourly load shape pattern is built up from a detailed end-use representation of electricity use across all sectors of the economy. Load shapes are associated with individual residential end uses or specific commercial and industrial sector electricity use.

"Must run" generation, wind and solar are assumed to be dispatched when available. Average hourly resources and output patterns were calibrated based on historical output for wind and solar. Baseload generation technologies are then dispatched, followed by intermediate and peaking technologies. In each case, generation is dispatched according to a parameterized distributed merit order method reflecting historic levels of dispatch.

This approach takes a realistic rather than an optimization approach to dispatch, recognizing that other non-price factors (such as voltage support) are also considered in the dispatch process. The parameters of the distributed merit order method can be set to reflect the economics of dispatch as well as other factors.

In this dispatch method, baseload generation in excess of demand in any hour is reported. This study assumes this excess generation is exported. Intermediate and peaking capacity is only run up to the level required to meet demand. Electricity demand that is not dispatched is interpreted as requiring imports.

Electricity costs are calculated based on the actual generation dispatched in a given scenario and represent the cost of the types of generation dispatched and contracts associated with that generation, such as FIT contract prices.

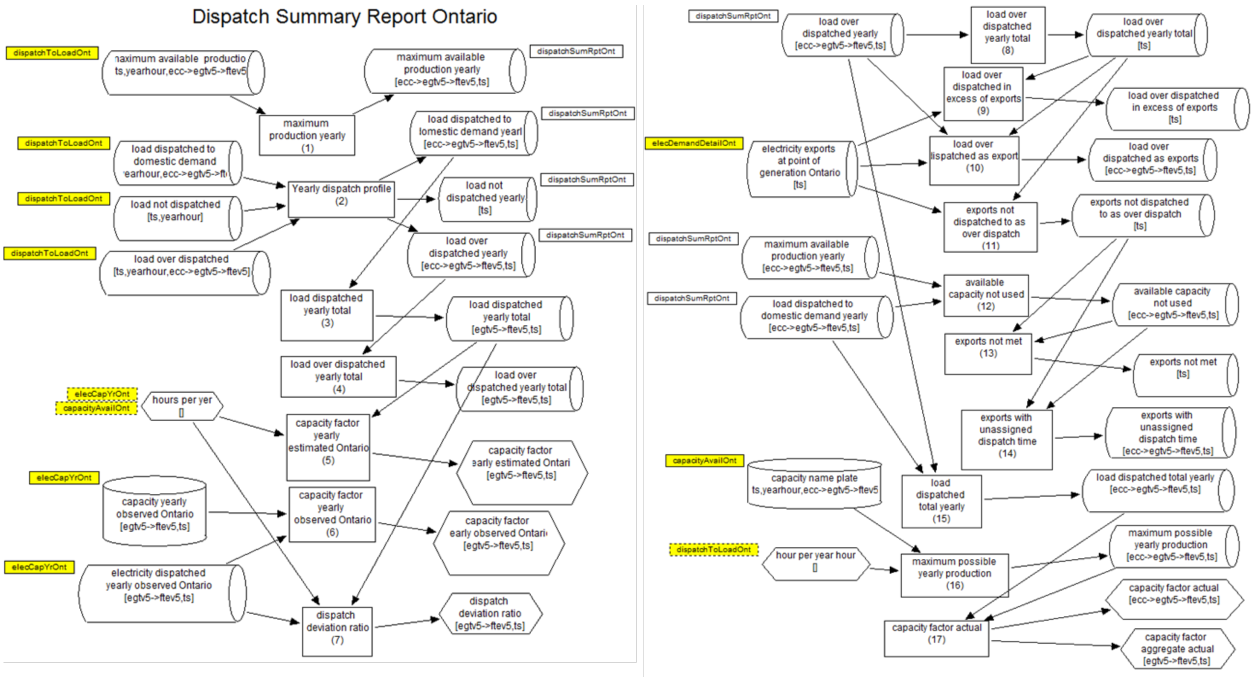

Figure 4: Structure of CanESS Ontario electricity dispatch model

SOURCE: WHATIF? TECHNOLOGIES

2.4. Cost modelling

Ontario's electricity system is a hybrid of contracted power and a competitive market. The contracted market dominates the overall system prices. Except for the FIT and RESOP programs, the exact nature of contracted power is seldom fully publicly disclosed, although the OPA publishes price ranges of these contracts as illustrated in Figure 5 .

In the absence of these contract details, we assume that the OPA prices are based on the producer cost of generation, plus a profit. While individual generating stations were not represented in the model, typical power plant costs can be surmised based on publicly available literature. For this study, cost and performance data were based on Black and Veatch and the Annual Energy Outlook 2011. Adjustments were made where necessary, particularly in the case of nuclear power, to ensure the producer costs were calibrated to published OPA prices.[16]

Producer costs are dependent on the technology and are divided into capital cost, fixed operating cost, variable operating cost, fuel cost and other specialized costs. These are assigned to each technology specifically. Capital costs are specified as overnight capital cost while interest changes are accumulated over the construction duration of each technology. This cumulated capital change is amortized over the expected life of the technology.

System-wide costs are transmission capital cost, transmission maintenance cost, debt retirement cost, distribution and transmission operations cost and wholesale market service cost. These are prorated over generation. Incremental transmission requirements for new generation capacity are also assigned an additional system cost as estimated by the EIA's 2010 AEO.

The price of electricity generated by feed-in tariff technologies is determined by the feed-in tariff and the time pattern of new feed-in tariff capacity. Feed-in tariffs are set as 20-year contacts and so none of these contracts would expire by the end of the current study period.

The price of electricity generated by non-feed-in tariff technologies is determined by the levelized unit cost structure of producer costs. Producer cost assumptions are outlined in Appendix A. Three prices are then calculated. First the producer cost price is calculated. Second, an assumed profit margin of 9.8 per cent is applied and an average price including profit margin is calculated. This approach does not explicitly simulate contract prices, but assumes that cost of production plus a reasonable profit is a reasonable proxy for how private generators would negotiate contracts. Existing nuclear stock was assumed to operate at current prices paid to OPG and Bruce Power, and the stranded nuclear debt charge is explicitly added, while refurbished and new build production costs are based on published cost estimates for refurbishments and for new reactors.

Finally, for each of the base, intermediate and peak generation types, an hourly demand marginal price, including as a minimum the same profit margin as in the average price method, is determined and all generation in that hour are paid that price. The marginal price is then set by the highest-cost "last-in" generator.

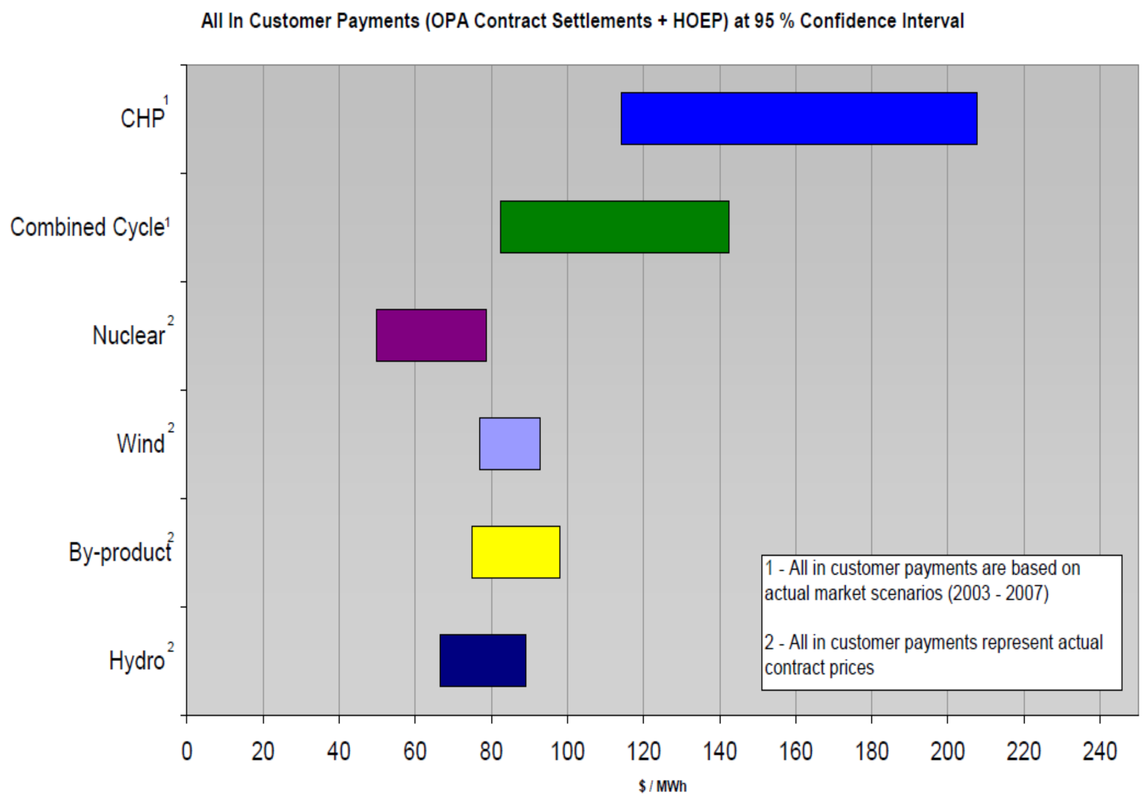

Figure 5: Pre-2009 contracted OPA electricity prices

SOURCE: ONTARIO POWER AUTHORITY[17]

3. System scenarios

3.1. Demand forecast

The OPA is responsible for forecasting long-term electricity demand in Ontario. The Ministry of Energy's Long-Term Energy Plan presented an updated forecast based on their analysis. The forecast includes three scenarios ranging from low growth to high growth and are listed in Table 1 below.

All three demand forecasts represent a net growth of electricity demand in Ontario over the next 20 years. It is worth pointing out that since 2006 (before the onset of the recession) electricity consumption has in fact been falling in Ontario, as illustrated in Figure 6 below. Nonetheless, the current research takes the demand forecasts at face value and uses their predictions for the various supply scenarios.

Table 1: Ontario projected electricity demand

Growth Scenario	Electricity Demand (TWh)				
	2010	2015	2020	2025	2030
Low[18]	143	140	142	144	150
Medium[19]	142	146	148	157	168
High[20]	143	150	160	175	200

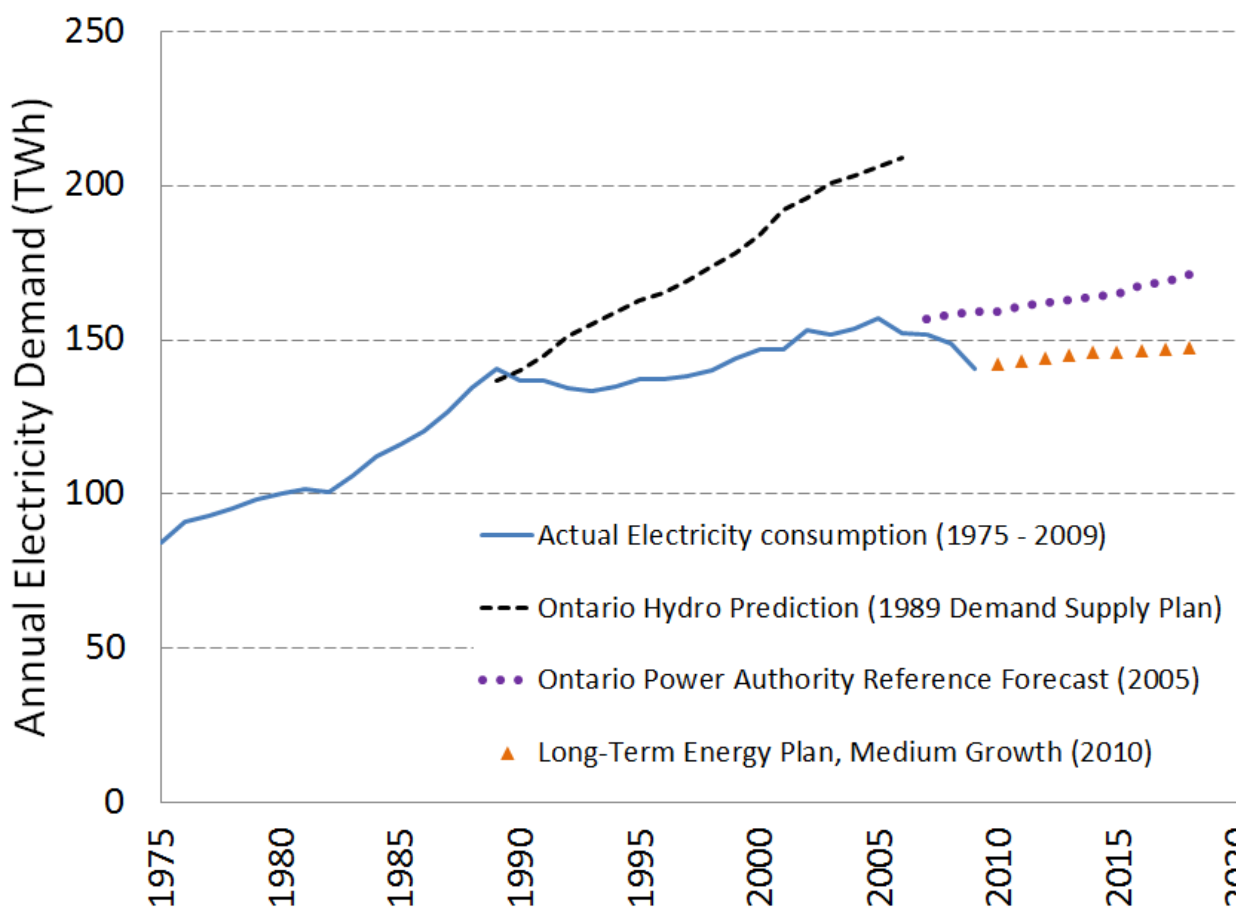

Figure 6: Recent Ontario electricity demand

SOURCE: OPA DATA COMPILED BY KEITH STEWART, GREENPEACE CANADA

The low, medium and high growth demand forecasts all assume that the government's conservation and demand management targets are achieved, and the figures are net of these demand reduction measures.

Supply planning in the LTEP and IPSP II is based on the medium growth forecast, which is described as follows:

> *"The medium-growth scenario assumes modest recovery in the industrial sector, as well as continued growth in the residential, commercial and transportation sectors. This scenario can be described as a status quo scenario with growth rates and trends returning to levels observed before the recent economic slowdown."*[21]

The medium growth scenario also assumes that five per cent of light-duty vehicles on Ontario roads are electric by 2020 (consistent with the current government target).[22]

Many factors influence demand, including population and economic growth, industrial structure, fuel prices, and consumer behaviour. Each scenario represents a different combination of these complex factors. As OPA notes, the high growth scenario is one based on aggressive climate action:

> *"A high-growth scenario assumes the application of aggressive North American greenhouse gas regulation, prompting consumers to switch from higher carbon sources of energy to lower ones. This would drive the electrification of heating and water heating in the residential and commercial markets, and lead to the faster adoption of electric vehicles, as well as the electrification of mass transit."* [23]

The low growth scenario[24] foresees a continued modest growth of industrial demand, in line with current trends. This is driven by a continued shift away from energy-intensive industries and a subsequent reduction in the growth rate of the residential and commercial sectors due to reduced manufacturing employment.

For consistency, we apply the OPA's demand forecast for both supply scenarios. As in the LTEP and IPSP II, we use the medium growth scenario as the primary demand forecast.

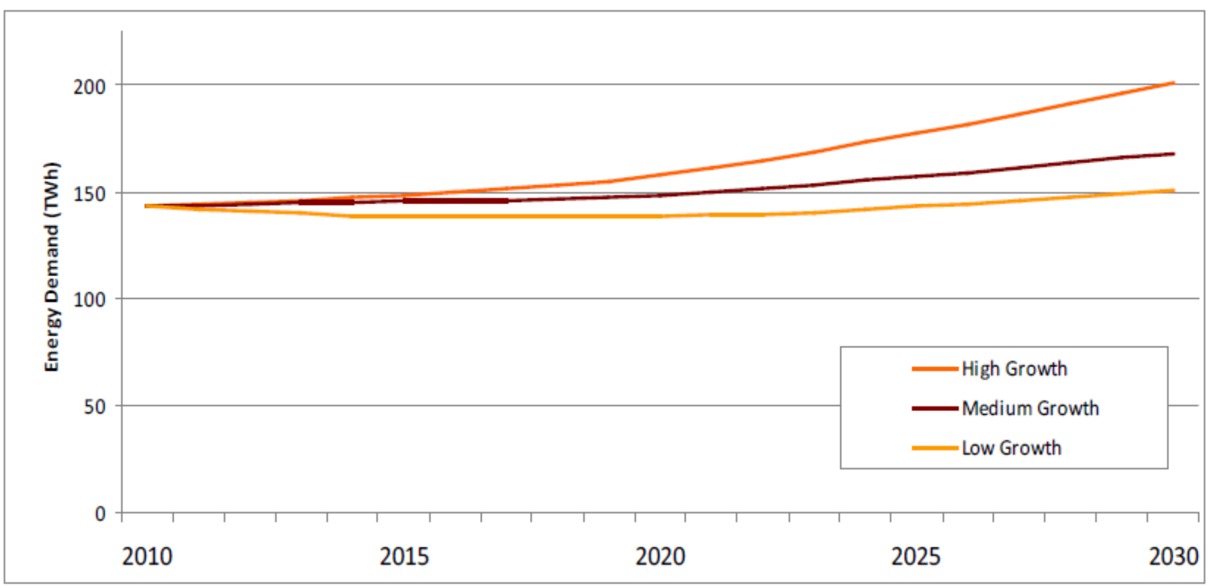

Figure 7: Long-Term Energy Plan demand forecasts
SOURCE: ONTARIO MINISTRY OF ENERGY

The low growth and high growth forecasts, illustrated in Figure 7, are run as sensitivity tests.

Planning for long-term energy demand is one component of managing an electricity system, but meeting peak loads and ensuring the system can follow hour to hour and day to day variations is equally important. Ontario's electricity system has a wide variation in daily demand, as shown in Figure 8 below.

Furthermore, Ontario's system has a broad variation in its annual maximum and minimum demands. In 2009, these ranged from low of 10,000 MW to a peak of close to 25,000 MW. Nuclear and hydroelectricity make up the bulk of the baseloading capacity, while the other technologies supply electricity in the intermediate and peak times. While Ontario buys and sells electricity with its neighbouring provinces and states, its system is designed to be able to meet its domestic peak load with generation capacity inside the province. This assumption was used for the development of the generation scenarios.

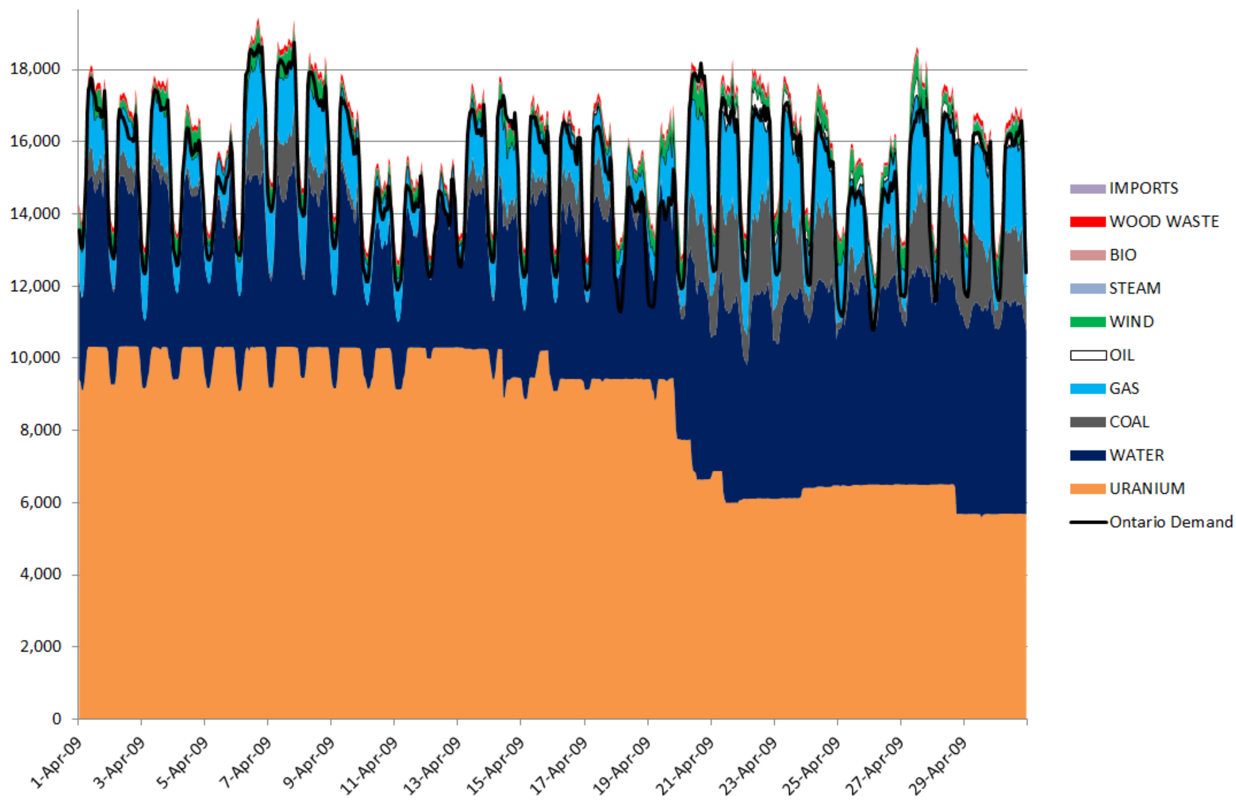

Figure 8: Hourly production data from April 2009

SOURCE: DATA FROM IESO

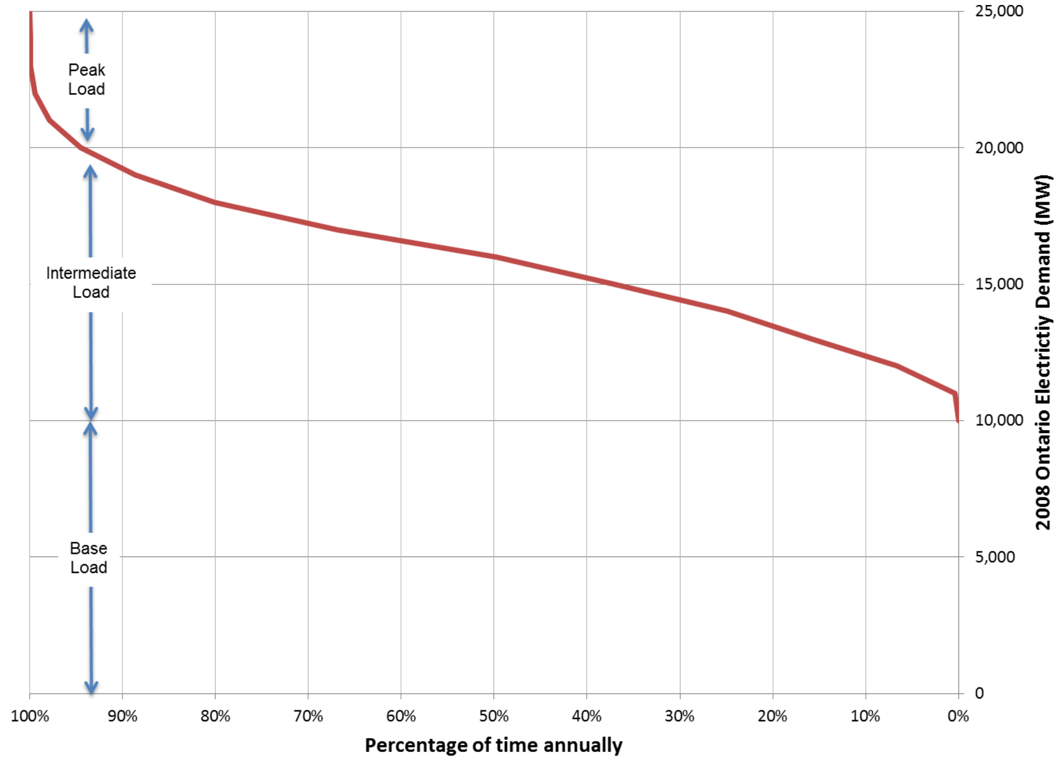

Figure 9: 2008 Ontario load duration curve

SOURCE: DATA FROM IESO

3.2. Scenario 1: Current plans

In order to simulate future costs in Ontario's electricity system, we have created two scenarios. These are built on unique assumptions reflecting possible approaches to Ontario's electricity future.

The first scenario represents current planning with regards to Ontario's electricity system, namely the Long-Term Energy Plan and the likely approach to the OPA's 2011 Integrated Power System Planning and Consultation Overview (IPSP II).

Under this scenario, nuclear power continues to generate roughly half of Ontario's electricity, following a period of major refurbishments. Renewable energy and conservation grow sharply, but new capacity from renewables is capped at 13 percent in 2018, in line with the LTEP targets.

Here we outline the assumptions by technology in greater detail:

Nuclear power continues to constitute 45 to 50 per cent of Ontario's generation mix[25] in 2030, as individual units transition in and out of service. Nuclear capacity follows the path laid out in the IPSP II consultation document, including the extended operation of units at Pickering GS.[26] Following a period of retirements, significant refurbishments and new build — during which capacity falls as low as 6,445 MW — capacity reaches 12,051 MW in 2024 and remains constant thereafter.

Hydropower grows to generate roughly 24 per cent of Ontario's electricity in 2030.[27] Hydro capacity follows the path laid out in the IPSP II consultation document, increasing to 9,000 MW by 2015 and remaining at that level through 2030.[28]This reflects several large new projects coming on-stream, as well as smaller developments under the FIT program. We have assumed the FIT portion of hydroelectric generation to be 188 MW, reflecting the current amount contracted by OPA (as of April 15, 2011).[29]

Natural gas has grown significantly in Ontario since 2004 with the commissioning of over 4,150 MW of capacity since 2004, as illustrated in Table 2 below. These facilities have assisted in the province's move to phase out coal-power generation.

Table 2: New natural gas plants since 2004

Facility	Location	MW	In-Service
Brighton Beach Power Station	Windsor	541	2004
Greenfield Energy Centre	Sarnia	1005	2008
Goreway Station	Brampton	839	2009
Portland Energy Centre	Toronto	550	2009
St. Clair Energy Centre	Sarnia	577	2009
Halton Hills Generating Station	Halton Hills	642	2010

The long-term energy plan foresees that this capacity will continue to grow from the current 9,631 MW to 10,107 MW by 2030. However, as additional renewable supply comes on line and demand grows, the gas share of the generation mix decline from roughly 15 per cent in 2010 to 8 per cent by 2030.[30] This reflects an increasing use of gas-fired generation for peaking and balancing, rather than baseload generation, as well as a need for increased generation from gas-fired units between 2014-2023 while nuclear capacity undergoes refurbishment. For this scenario, annual gas-fired capacity follows the path laid out in the IPSP II consultation document.[31] It was assumed that new additions were built proportional to the current mix of combined-cycle and simple-cycle peaking plants until 2030.

Wind power substantially increases its share of generation, growing to almost 20 per cent of total system installed capacity by 2030. It reaches an installed capacity of 7,576 MW by 2018 and remains level thereafter.[32] We have assumed that all of this is onshore wind, given the recent moratorium placed on offshore wind development.[33] This is a very conservative assumption. There is an exceptional offshore resource potential in Ontario, with significant potential for economic benefit to the province.[34] For these reasons, it seems likely that there will be some offshore wind development in Ontario before 2030, although none is assumed in either scenario.

Wind capacity was divided between programs based on existing and contracted non-FIT capacity at the end of 2010 (including RES III and RESOP),[35] and an analysis of FIT contracts as of mid-April, 2011.[36]

Solar PV grows to generate 2 per cent of Ontario's power by 2030, with solar capacity expanding to 2,498 MW.[37] The timing of solar capacity additions is guided by the LTEP.[38]

Bioenergy includes waste wood, biomass, biogas and wood pellet conversions of coal plants. Bioenergy generation capacity doubles between 2010 and 2018, as capacity grows steadily to 619 MW and remains stable thereafter. The timing of biomass capacity additions is guided by the LTEP.

Bioenergy capacity is divided between programs based on existing non-FIT capacity at the end of 2010 and the anticipated repowering of Atikokan GS with biomass, beginning in 2013. Biogas and biomass additions from the FIT provide the balance of projected capacity additions.

Coal-fired generation continues to decline in advance of a full phase-out. Two units are retired at Nanticoke GS in late 2011, bringing capacity to roughly 3,500 MW. This capacity is phased out to reach zero by the beginning of 2015.

Demand response for peaking follows the path laid out in the IPSP II consultation document, growing to 1,362 MW by 2030.

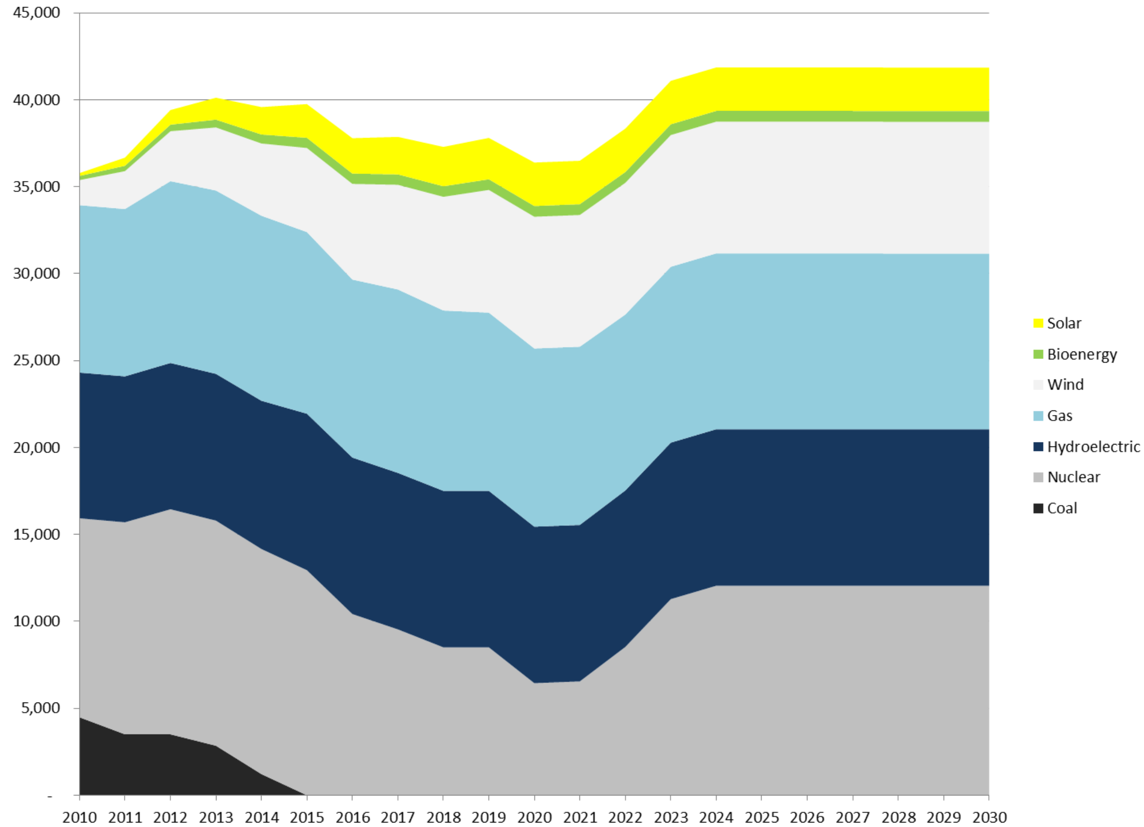

Figure 10: Generation capacity projected under current plans scenario

3.3. Scenario 2: Reduced renewables

This scenario represents a future in which non-hydro renewable energy development is largely halted and capacity additions are dominated by natural gas and some large hydro.

In this scenario, the FIT and microFIT programs do not contract additional capacity beyond the end of 2011. It is assumed that existing contracts at that time are respected. Additionally, the Green Energy Investment Agreement is revoked and none of the 2,500 MW of wind or solar capacity it contracted is built. No penalty is assumed for breaking this contract, which is unrealistic and favours this scenario.

Nuclear generation is assumed to follow the same course as in Scenario 1. Due to Ontario's significant variations in daily electricity consumption, the province is currently facing periods of time when the output from baseload facilities exceed provincial demand (a situation known as surplus baseload[39]). Given the modest electricity demand growth forecasts, it seems unlikely that additional baseload facilities such as nuclear would be built. However, both hydropower and — to a much larger extent — natural gas increase their installed capacity as well as their output relative to Scenario 1 as they largely replace wind and solar. Installed gas-fired capacity increases by roughly 47 per cent between 2009 and 2030, reflecting an increased prominence in the generation mix.

Below we outline in greater detail the assumptions for each generation technology:

Nuclear power follows the same pathway as Scenario 1. This includes the extended operation of several units at Pickering.

Hydropower grows relative to Scenario 1, adding an additional 500 MW of capacity to reach a total of 9,500 MW by 2030. Capacity follows the path laid out in the IPSP II consultation document[40] until 2015, after which it grows incrementally to 2030. All additions are in the non-FIT category, and represent the development of several larger-scale hydro projects. If these projects are developed in more remote locations, such as the Albany or Moose River basins, additional transmission capacity to northern Ontario will be required.[41]

FIT capacity for hydro remains at the same level as Scenario 1, as this amount has already been contracted.[42]

Natural gas capacity grows significantly relative to Scenario 1, reflecting its increased importance in the generation mix if growth in wind and solar capacity is sharply curtailed. Gas capacity approximately follows the path laid out in the IPSP II consultation document[43] until 2015, when a period of major capacity additions begins. Growth continues until 2020, when installed capacity reaches 14,200 MW — nearly 50 per cent above 2009 capacity. Added capacity is likely to include conversion of some or all units at Nanticoke and Lambton to gas — a possibility highlighted in the LTEP.[44]

Wind power continues to expand from current levels. However, capacity additions are significantly slowed relative to Scenario 1, particularly due to the removal of the FIT program and cancellation of the Green Energy Investment Agreement.

To determine the level of FIT capacity installed, we have assumed that no new projects enter the contract stage after mid-April 2011. We have estimated the capacity contracted as of that point, as well as those projects in the contract stage that are likely to proceed, giving a total of approximately 1,816 MW. (See Appendix A for a detailed discussion). This level is reached by 2015 and maintained thereafter.

Existing and contracted non-FIT capacity totals approximately 1,840 MW. This level is reached in 2012. From 2015 onwards, non-FIT capacity grows modestly, adding 30 MW per year until 2030. This reflects the likelihood of continued interest in wind power, despite a severe reduction in incentives for development.

Solar PV capacity grows rapidly from current levels until 2014, as large numbers of projects contracted under RESOP (328 MW), FIT (1,076 MW) and microFIT (225 MW) enter commercial operation. The total capacity of "committed" solar as of mid-April 2011 is 1,629 MW. This figure is calculated in the same method as wind, above, and is discussed in Appendix A. As there is a two-year requirement between final contract signing and commissioning, these level are reached by the end of 2013, after which no further development occurs.

Table 3: Contracted solar PV in Ontario

Contracted Solar PV	MW installed by 2014
Non-FIT Solar	164
MicroFIT roof	50
MicroFIT ground	175
Rooftop >10 kW	196
Ground-Mount >10 kW	881
Total	1,466

Bioenergy generation follows largely the same path as in Scenario 1, although new FIT contracts are no longer issued after 2011. The total capacity plateaus at 586 MW in 2015 instead of 619 MW as forecast in the IPSP II.

Coal-fired generation follows the same path as Scenario 1, above.

Demand response programs follow the same path as Scenario 1, above.

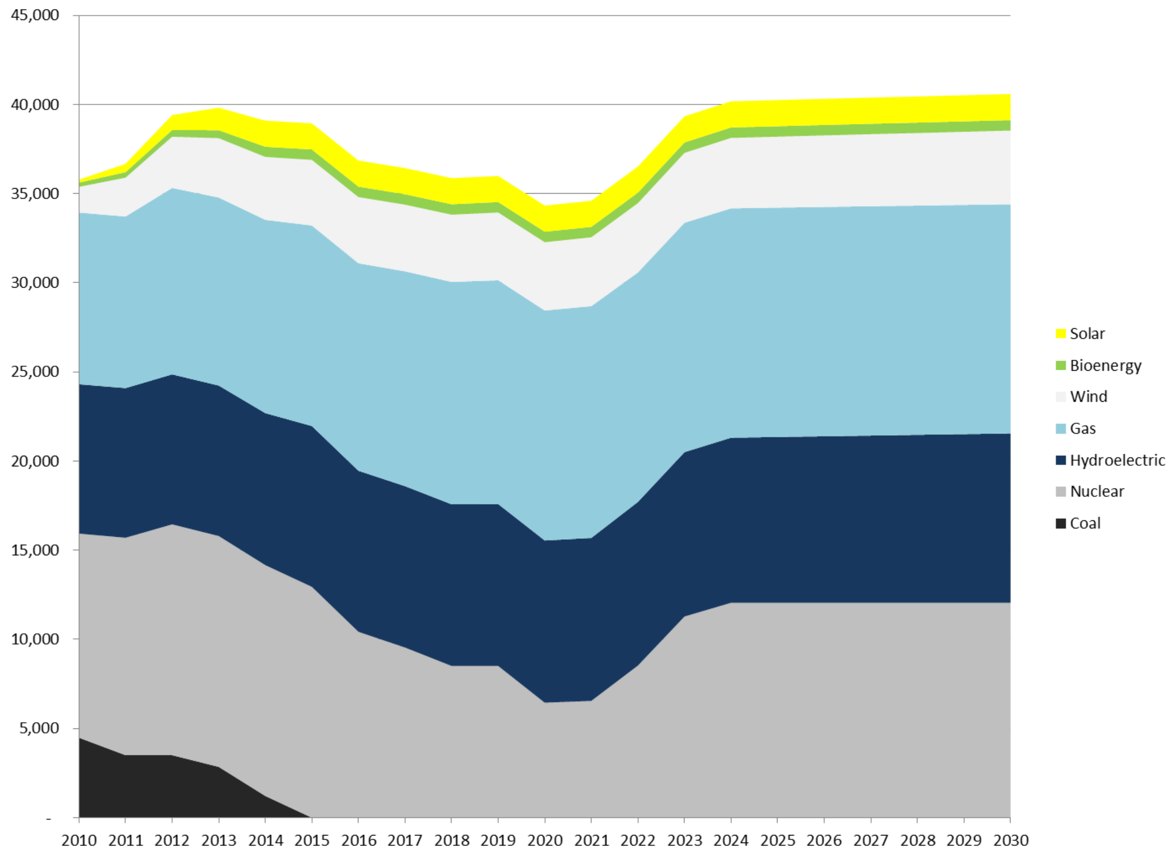

Figure 11: Generation capacity projected under reduced renewables scenario

3.4. Anticipated changes in feed-in tariff rates

In 2009 the government passed the Green Energy and Green Economy Act, which introduced fixed rates for renewable energy generation projects that are built in Ontario. Once signed, these rates or tariffs are guaranteed for a 20-year period for any electricity that the particular project feeds into the grid, and are commonly referred to as feed-in tariffs (FITs). The OPA was also tasked with establishing a two-year review of the program to examine the tariffs. This practice is common in Europe, as it reflects the falling prices for renewable energy, and encourages innovation.

Current FIT rates are differentiated by technology and have further sub-categories based on project type. For example, a community-owned wind energy project receives an additional 1¢/kWh compared to non-community owned projects, while roof-mounted solar systems receive a higher tariff than ground-mounted ones. The table below reflects the average price of FIT contracts signed to date.

Table 4: Current average feed-in tariff rates

Technology	¢/kWh
Wind	13.5
Solar	52.5
Run of River Hydro	13.0
Bioenergy (also includes biogas and landfill gas)	14.1

The first FIT review is due in the last quarter of 2011. As has been consistently the case for FIT programs in Europe, it is expected that rates offered for new contracts will be decreased to reflect the declining costs of renewable energy technology. Solar PV modules have dropped in price by almost 50 per cent in the past five years[45] as shown in Figure 12 below.

Figure 12: Normalized price of solar PV modules
SOURCE: RENEWABLE ENRGY POLICY NETWORK (REN21)

In addition to the global technology improvements that are driving costs down, the fact that local manufacturing capacity and project development capacity has had two years to establish itself in Ontario will also likely result in reduced costs. In order to approximate what new prices might be offered, the assumed price declination rates was based on new technology generation "learning rates" outlined in the American Energy Information Administration's 2011 Annual Energy Outlook's Electricity Market Module (table 8.3).[46] It lists technology-specific cost declinations based on double periods of installed capacity. Ontario's doubling of installed capacity for FIT technologies used a metric for price declinations.

3.5. Nuclear scheduling and costs

3.5.1. Costs of new nuclear

Both generation scenarios in this analysis use the same capacity and schedule for nuclear power in Ontario; therefore, the prices used here have no impact on the relative differences between the two scenarios. However, given the dominant role nuclear energy has in Ontario's electricity system, it is important to account for its expected costs. The development of nuclear reactors in Canada has a track record of cost overruns. Furthermore, no new nuclear facilities have been built in North America in several decades and so the actual costs for these facilities are highly uncertain. As the costs will be the same in both generation scenarios, for the purpose of this research we have assumed the overnight capital cost of new build nuclear to be $5,600/kW[47]. This is based on the U.S. Energy Information Administration (EIA)'s latest plant costs, as reflected in the Annual Energy Outlook (AEO) 2011 report. AEO 2011 presents updated costs for a range of new build utility-scale generation facilities, including a dual-unit nuclear plant, based on an EIA-commissioned study by R.W. Beck Inc and SAIC.[48]

The nuclear project reflected in the Beck study[49] is similar to that proposed for Ontario, making it a working basis for an overnight capital cost estimate in the absence of publicly disclosed bid prices. Both the model project and the proposed new build for Darlington are dual-reactor facilities with approximately 2,000 MW total capacity built on existing nuclear sites.

When adjusted for inflation, several other studies support a similar range of overnight capital cost for new built nuclear.[50,51]

Additional costs, including the cost of capital and escalation, are calculated internally by CanESS to generate the final cost. This does not take into account the potential for large-scale overruns, which have marked every nuclear project in Ontario to date. Historically, nuclear projects in Ontario have exceeded their original cost estimates by an average of 2.5 times.[52] Future cost overruns would increase prices equally in both scenarios, as they have the same nuclear capacity and construction schedule. Therefore the assumption of no future cost overruns, while very conservative, causes no bias between the scenarios.

As the LTEP notes, the construction of new nuclear infrastructure requires at least eight to ten years of lead time to commercial operation.[53] Based on the capacity figures presented in the IPSP II consultation document, we have assumed both new reactors will commence operation in 2023.

3.5.2. Costs of refurbished nuclear

For this report we have assumed an overnight capital cost of $3,000/kW for refurbished nuclear. This is based on the upper range of preliminary OPG estimates for the cost of the Darlington Refurbishment Project (DRP)[54] and final costs, as currently estimated, for the two CANDU refurbishment projects underway at Point Lepreau (NB)[55] and Bruce A (units 1 and 2).[56]

As with new build, cost overruns are typical for refurbishments. Noting this, the OEB has questioned whether the costs estimated for the DRP are realistic. "Quite apart from whether OPG has improved its performance, the Board has concerns because no CANDU plant has yet been refurbished on budget."[57] Given current evidence, they warn that "[i]f there are cost overruns with the DRP, the Board does not expect OPG to suggest that they could not have been foreseen at this stage."[58]

The costs of planned nuclear refurbishment in Ontario may also rise due to construction bottlenecks. It appears that there will be as many as four reactors, across two facilities, being refurbished at any given time — all during construction of two new reactors at Darlington (see below).

For these reasons, we have applied a sensitivity test of $4,000/kW for refurbished nuclear.

Based on the total capacity numbers presented for nuclear in the IPSP II consultation document (including extended operation at Pickering NGS),[59] OPG's preliminary schedule for the DRP,[60] and reported timing for refurbishment of Bruce B units,[61] nuclear refurbishments were assumed to occur for an average of three years, with currently operating units starting to come off line in 2015 and refurbishments completed by 2024. As the Bruce A units 3 and 4 have undergone refurbishment already, for the consideration of this study they are treated as "existing".

Table 5: Assumed Ontario nuclear capacity schedule

Year	Existing (MW)	Refurb'd (MW)	New (MW)	Life ext'n (MW)
2010	11,446	-	-	-
2011	11,446	750	-	-
2012	11,446	1,500	-	-
2013	11,446	1,500	-	-
2014	10,414	1,500	-	1,032
2015	8,867	1,500	-	2,579
2016	5,837	1,500	-	3,094
2017	4,956	1,500	-	3,094
2018	4,956	1,500	-	2,062
2019	2,471	4,015	-	2,062
2020	1,590	4,896	-	-
2021	1,590	4,896	-	-
2022	1,590	6,500	-	-
2023	1,590	7,381	2,200	-

Year	Existing (MW)	Refurb'd (MW)	New (MW)	Life ext'n (MW)
2024	1,590	8,262	2,200	-
2025	1,590	8,262	2,200	-
2026	1,590	8,262	2,200	-
2027	1,590	8,262	2,200	-
2028	1,590	8,262	2,200	-
2029	1,590	8,262	2,200	-
2030	1,590	8,262	2,200	-

Given uncertainties about project timing, this schedule should be treated as an approximation of OPA's current schedule, not a firm unit-by-unit plan. For example, Bruce units 1 and 2 are expected to return to service in Q1 and Q3 of 2012, respectively[62] — not one each in 2011 and 2012, as shown here. Other adjustments are likely as more detailed assessments are undertaken, but this schedule provides a guideline for investment timing and projected capacity.

3.6. Natural gas fuel prices

The so-called "unconventional gas revolution" has raised expectations that natural gas will play an even greater role in our energy future. In the past few years, producers have developed technology capable of producing large volumes of gas from shale and other low-permeability rock formations at relatively low cost. This has "completely transformed the North American gas supply and price picture,"[63] to the point where Canada's natural gas resource has expanded to well over 100 years of supply at current rates, and North America has about 40 years of profitable supply at mid-2010 prices.[64]

New sources of unconventional gas — particularly shale gas — could therefore more than compensate for the steady decline in production of conventional natural gas. The most recent business-as-usual projections by Canada's National Energy Board and the U.S. Department of Energy anticipate, respectively, a three per cent decline in Canada's total natural gas production between 2008 and 2020,[65,66] but a 15 per cent increase in U.S. total production over the same period.[67] The U.S. projection foresees production increasing much more slowly after 2020, giving an overall 24 per cent increase from 2008 to 2030[68] (the Canadian forecast ends in 2020). The two projections agree that with Canadian consumption increasing while production falls slightly, Canadian natural gas exports to the U.S. will decline by about one-third between 2008 and 2020.[69]

Natural gas in North America is essentially a continental, not a global market. Exports of liquified natural gas (LNG) to other continents would face many hurdles, including competition from other suppliers and uncertainty about the future prices in destination countries needed to support the high capital costs of LNG infrastructure.[70] The U.S. Department of Energy continues to foresee no new U.S. LNG export capacity between now and 2035.[71] LNG trade does not therefore seem likely to significantly affect North American natural gas prices.

Natural gas prices are currently low compared to recent years, but they are expected to rise over the next two decades. Figure 13 below depicts the U.S. Department of Energy's price projections published in April 2011.[72] It shows how prices might vary depending on the pace of economic growth and the evolution of natural gas production technology.

In addition, concerns over the economic viability at current gas prices of many shale gas projects have been raised within industry.[73] Production may slow, as drillers shift their focus towards more valuable liquids-rich gas plays and oil production until prices increase.[74] Large shifts in demand may also have significant impacts on gas prices and production. The U.S. power sector may shift heavily towards gas as aging coal plants become a growing liability under new air pollution and GHG regulations.[75] Dow Chemical, a large industrial user of natural gas, has recently warned that an increase in the use of natural gas vehicles at the same time as a shift towards gas in the power sector would lead to large price spikes.[76]

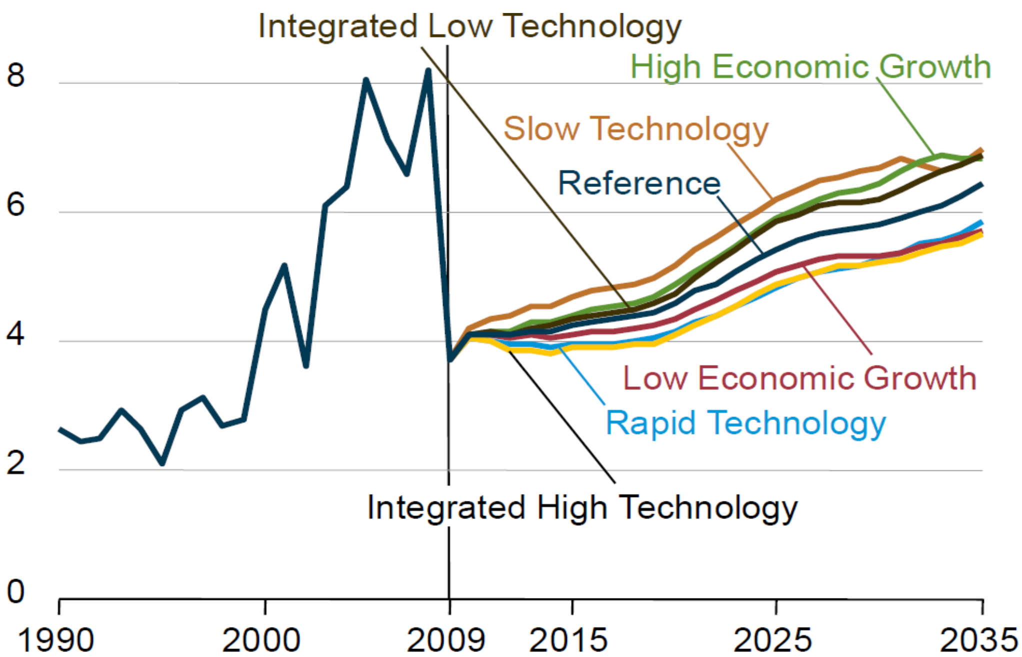

Figure 13: U.S. natural gas wellhead prices (*2009 $US per thousand cubic feet)

SOURCE: US DEPARTMENT OF ENERGY

Specific details of gas generation contracts are confidential, however, their structure illustrates how they would respond to changes in natural gas market prices as well as any potential future carbon price. Under the 20-year Clean Energy Supply and Early Mover contracts, generators are guaranteed a set net revenue requirement.[77] The Ontario Energy Board assumes an average of $7,900/MW-month (up to 20% of which may be indexed to inflation[78]) for these contracts, which cover the most recent natural gas plants.[79] The OPA is responsible for contingent support payments to cover any gap between the net revenue requirement and the market revenues deemed to have been earned in a given month based on dispatch parameters in the contract. Deemed production is based on the market price of electricity and variable energy cost for the generator, one component of which is the gas price at the Dawn hub.[80] Therefore, an increase in gas prices will have the effect of raising the variable energy cost and reducing deemed revenues, unless the HOEP also increases. This would increase the value of payments from the OPA. Carbon pricing would have a similar effect.

For the current research, natural gas prices were assumed to follow the reference case projection of the 2011 Annual Energy Outlook, and are illustrated in Figure 14 below. Increased fuel prices are reflected in the overall cost of electricity production from natural gas technologies. Combustion turbine peaking plants are particularly sensitive to the natural gas market price.

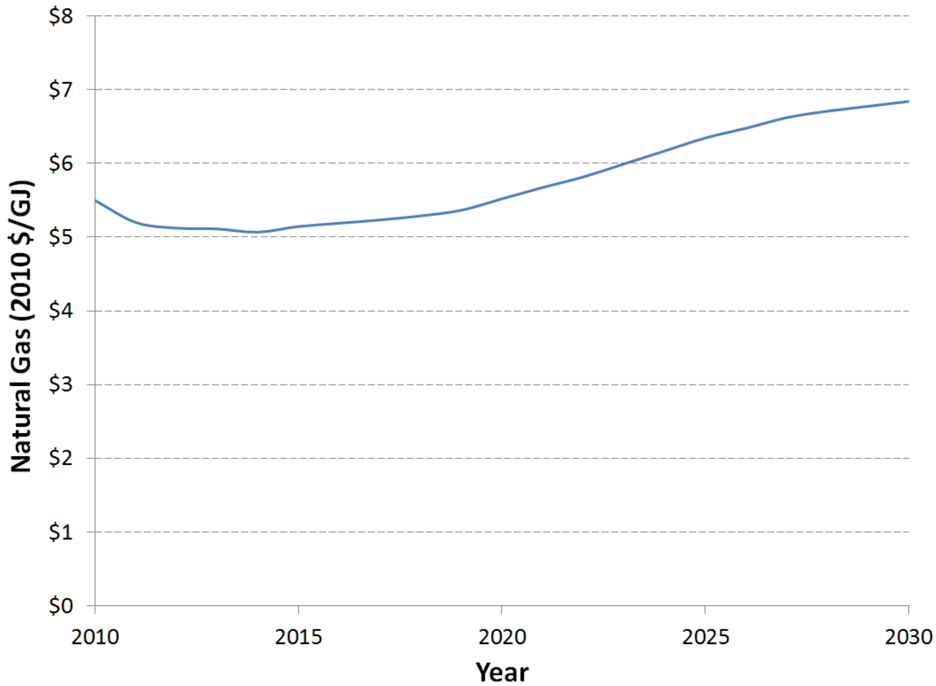

Figure 14: Reference case delivered natural gas prices

SOURCE: DATA FROM UNITED STATES ENERGY INFORMATION ADMINISTRATION[81]

3.7. Carbon pricing

As noted earlier, Ontario is one of five partner jurisdictions moving ahead with the Western Climate Initiative (WCI) in the short term. Beginning in 2012, WCI establish will establish a carbon market that will cover emissions from electricity generation and industrial combustion[82]. Collectively, the WCI jurisdictions aim to reduce GHGs 15% below the 2007 level by 2020 using the cap-and-trade system and complementary policies.

A broad-based price on greenhouse gas emissions (commonly referred to as a carbon price) is widely recognized as the most effective policy tool for generating substantial emissions reductions at lowest cost.[83]

This view is widely shared in Canada, including by the National Roundtable on the Environment and the Economy (NRTEE)[84] and virtually all major industry associations.[85] As a recent report from the Senate committee on Energy, the Environment and Natural Resources attests, "the committee found near unanimity among witnesses — from the petroleum industry to environmental organizations — that supported pricing carbon as the most efficient way to reduce emissions."[86]

Given the high level of agreement among experts and industry on the importance of carbon pricing as a policy tool, we assume that it will be implemented. The key questions are when and at what scale.

To this end we developed two distinct 'storylines' to represent plausible scenarios for carbon pricing in Ontario. These are built by averaging projections that share assumptions consistent with the storyline.

Carbon Price 1: Federal leadership

In this scenario, we assume that the federal government takes a leadership role in tackling climate change by establishing a carbon price consistent with achieving major progress towards its 2020 emissions target of 607 Mt CO_2e (with continued reductions beyond 2020). We assume that the majority of reductions are made domestically and not through the purchase of foreign allowances or offsets, and that Ontario participates in the federal system rather than the Western Climate Initiative (WCI).

This scenario combines projections based on the NRTEE,[87,88] MK Jaccard and Associates,[89] and the International Energy Agency.[90]

Carbon Price 2: WCI with limited federal policy

In this scenario we assume that the federal government implements a less ambitious national carbon pricing plan than required to meet its 2020 emissions target. In scenarios where the federal government does not act on carbon pricing, Ontario moves forward with participation in the WCI, beginning in 2013. In these cases, Ontario follows the WCI price path until a federal system is introduced.

This scenario combines projections based on WCI,[91] NRTEE,[92] EPA[93] and IEA.[94]

Likelihood of scenarios

Given the federal government's current position that it will not implement a carbon price without the U.S. doing the same[95] — which they view as unlikely in the short to medium term[96] — it would appear that the Carbon Price 2 scenario is more likely, at least in the next few years. In this, Ontario would move forward with the WCI in 2013, or else the federal government would implement a weak carbon price while it waits for the U.S. to take action. While the current Minister of the Environment, Peter Kent, has said cap-and-trade is off the table for the moment, he notes that "it can always be something to consider in the future."[97]

Indeed, much can change in the next few years. The Intergovernmental Panel on Climate Change (IPCC) is set to publish its landmark Fifth Assessment Report (AR5) in 2013-2014, updating the key international synthesis of climate science to reflect recent research.[98] Much of this work has pointed to increasing risks from climate change, and the AR5 is likely to again focus public attention on the need for urgent action to reduce emissions.

Given the broad support that exists for carbon pricing as a policy tool, it is likely to be adopted at the national level before 2020, particularly as pressure mounts on the federal government to achieve its international emission reduction commitments.

The two scenarios presented here capture the likely range of carbon prices in Ontario over the coming decades. However, more ambitious action is also a possibility, particularly after 2020.

The less ambitious Carbon Price 2 was used as the primary carbon price path for both technology scenarios, reflecting the current federal stance on carbon pricing, while the more ambitious Carbon Price 1 represents a real possibility of where carbon prices may go, and should be prepared for when making fossil fuel policy decisions.

For the purpose of this model, the carbon prices are treated as a carbon tax. This may not be the mechanism that is ultimately used, but it is illustrative of the environmental cost that is associated with continued CO_2 emissions. Given that the most recent data suggest that much stronger action is needed much more urgently,[99] it is entirely possible that a carbon price will affect electricity consumer prices in spite of Ontario's gains by shutting down its coal plants.

While it remains uncertain exactly how a carbon pricing mechanism may unfold, it is unlikely that action to combat emissions will not increase over the next 20 years. However, even if no action were taken, the assumed price on carbon used in this simulation can also serve as a proxy for future regulatory cost of natural gas, including environmental controls or tighter regulations on the upstream effects of exploration and extraction which have already begun in the United States and are expected in Canada.[100] Based on the current government's preference for policy harmonization, it is likely Canada will also propose emissions regulations covering gas-fired generators, as these requirements are already in effect in the United States for new facilities[101] and are currently being developed for existing ones.[102] Federal greenhouse gas regulations are also currently under development for coal-fired generation. Finally, the government is also expected to regulate GHG emissions from the oil and gas sector,[103] which could add to the cost of natural gas delivered from Western Canada.

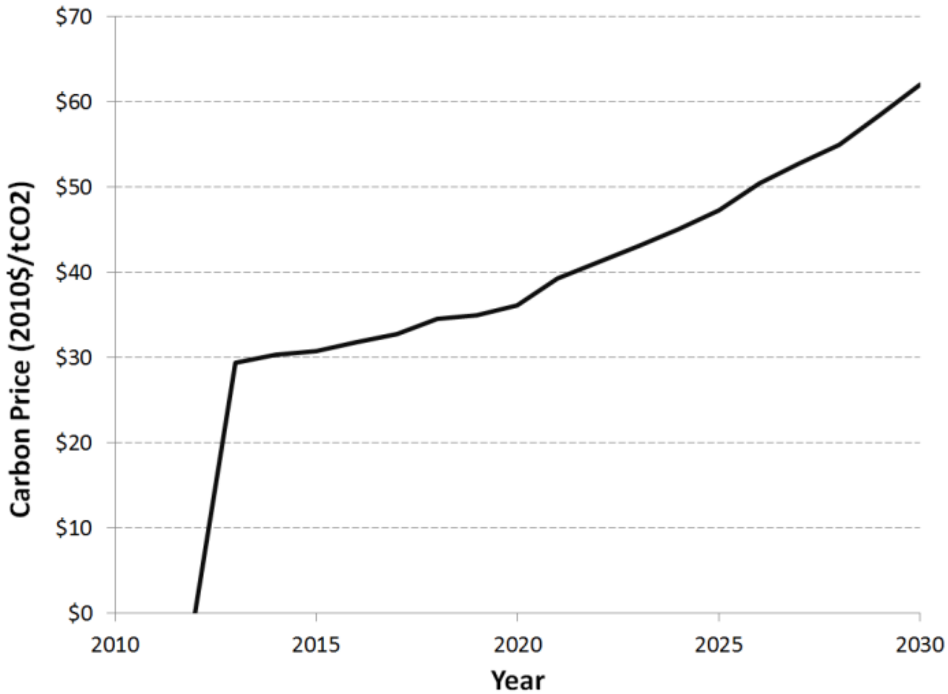

Figure 15: Assumed carbon price under Carbon Price 2 scenario

3.8. Transmission

Hydro One, an Ontario Crown corporation, owns and operates virtually all of Ontario's transmission system, accounting for 96 per cent of transmission capacity in the province.[104] As of 2010, this included 28,438 circuit-kilometres of high voltage overhead transmission line and 270 circuit-kilometres of underground transmission lines in urban areas.[105]

Much of this network is aging and will require increased maintenance expenditure and replacement in the coming decades. Below is demographic breakdown of overhead transmission lines, by circuit-kilometre:

Table 6: Ontario transmission system age

Age class		Age class	
0-10yrs old	3.6%	31-40yrs old	19.7%
11-20yrs old	6.2%	41-50yrs old	11.0%
21-30yrs old	7.3%	>50yrs old	52.3%

SOURCE: HYDRO ONE

Demographic breakdowns for other transmission infrastructure, including station equipment, illustrates an aging system and indicates that significant investment will be required to maintain reliability in the coming decades.[106]

In addition to maintaining the current system, new projects are also required to address increasing demand and changing patterns of generation and load. Five of these are highlighted as priority projects in the LTEP and IPSP II: enhancing transfer capability in southwestern Ontario, upgrading existing lines west of London, adding a new line west of London, enhancing the east-west tie with a new line on the east shore of Lake Superior, and a new line to Pickle Lake.[107]

For this study we have assumed the following unit costs for new transmission:

Table 7: New build transmission cost estimates

Type	2009 $US/km
345kV	894,775
345kV (double circuit)	1,497,505
500kV	1,149,537
500kV (double circuit)	1,913,823
400kV DC	1,516,146
800kV DC	2,392,279

SOURCE: NREL, 2011[108]

While incremental transmission costs for some renewable energy technologies like wind are higher than for other technologies,[109] these costs represent a small fraction of the total levelized electricity cost of a new power plant. For example, the EIA estimates the incremental transmission costs of wind power will account for less than 4 per cent of its total levelized cost in 2020.[110]

Major investments in Ontario's transmission system have begun, and the LTEP outlines $9 billion of investment during the period between 2010-2030 to refurbish and modernize significant parts of Ontario's system.

Table 8: Current transmission projects

Project	Description	Service Date
Barwick TS	New 115-44kV Transfer Station	2012
Lower Mattagami	2nd 230kV circuit, 4km	2013
Commerce Way	New Transfer Station (dual 115-27.6kV)	2011
Tremaine Transfer Station	New Transfer Station (dual 230-28kV)	2012
Midtown Toronto	Infrastructure renewal (incl. new 115kV circuit)	2012
Tor. Lakeshore Renewal	Two new 230kV cables (underground)	2012
Bruce to Milton	180km dual circuit 500kV	2012
Supply to Essex County	Various, including new transfer station	2011
Duart Transfer Station	New 230-27.6kV Station	2011

Table 9: Priority projects identified in IPSP II

Project	Description	Service Date
Enhance transfer capability in SW	Reactive compensation	2014
Existing line upgrade west of London	Upgrading existing lines	2014
New line west of London	Renewable generation and potential Lambton gas conversion	2017
Enhance East-West tie on East Superior shore		2018
New line to Pickle Lake	430km single circuit 230kV	2018

SOURCE: HYDRO ONE[111]

These investments were treated by estimating a price based on the description of the required upgrade, and the unit prices listed above. These investments were calibrated to the Long-Term Energy Plan's anticipated transmission investments.

Part II: Results

4. Results

4.1. Pricing of generation scenarios

The pricing results presented in this section represent average customer pricing, including residential, commercial and industrial consumers. The results are presented in constant 2010 dollars.

We have, to the best of our ability, incorporated system costs, although there will be inevitably be incremental costs, particularly at a local distribution level. Incremental local costs would be consistent to both scenarios. Nonetheless, the results are not intended to model any specific end user's prices, but rather the overall pricing trend across all consumers in the province.

The pricing data are presented as the midpoint of three-year results: i.e., 2012 data is the linear average of the model's 2011, 2012 and 2013 forecasts. The model simulates results in one-year time steps, while actual projects and system expenses occur throughout the calendar year.

To compare consumer price impacts of the two generation scenarios considered, the medium growth demand forecast is considered as in the Long-Term Energy Plan (other demand forecasts are considered in the sensitivity analysis in the following section).

In both generation scenarios, electricity prices in Ontario will rise over the coming two decades, as is the case across the country.[112]

Both scenarios show similar trajectories for electricity prices in Ontario, deviating only slightly from one another over the study period. The maximum difference in average end use pricing projected by the model is less than 2 per cent, which is well within the overall margin of error of the study.

Ontario's electricity prices will steadily increase over the next five years as investments are made in transmission infrastructure and as new generation capacity is added to the grid. Steeper price increases are to be expected once the coal plants are completely retired and the nuclear fleet begins significant refurbishment. During this period (2016–2024) Ontario will need to rely more heavily on natural gas. Although current natural gas prices are lower than average feed-in tariff pricing, it is expected that the gap will narrow between these two as renewable energy prices decline and natural gas prices increase over the next 20 years.

Over the study period, prices are forecast to increase by almost 25 per cent from 2011 levels, peaking in 2022 when the maximum nuclear capacity is off-line, after which modest price reductions[113] can be expected if the nuclear fleet refurbishments and new capacity are completed on time and on budget. As noted above, this is an optimistic assumption, given historical cost overruns averaging 2.5 times.

These results are within the same range as those published in the Ministry of Energy's Long Term Energy Plan, which published estimated residential rates rising from 11¢/kWh and peaking at 17¢/kWh in 2020, and industrial prices range from 10¢/kWh and peaking around 12¢/kWh in roughly the same time period.

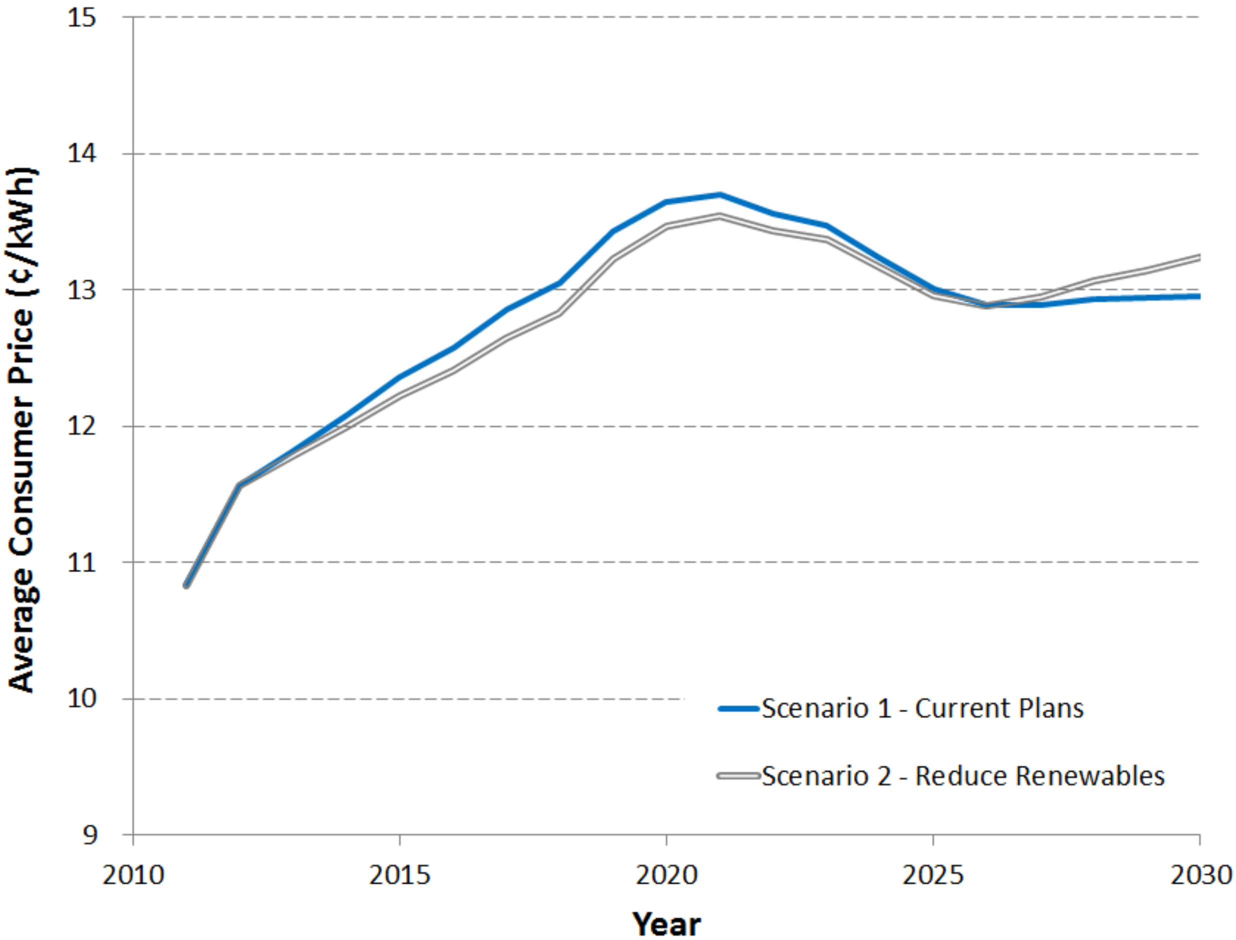

Figure 16: Simulation results of average Ontario electricity prices (2010 constant Canadian dollars)

4.2. Sensitivity analysis

4.2.1. Sensitivity to demand

Figure 17 shows the effect of demand forecasts on the prices in Scenario 1. The electricity prices are insensitive to the three demand forecasts until beyond 2020 — the period when the nuclear fleet is anticipated being back in full service. Around 2020 is also when the three possible demand forecasts begin to diverge more significantly.

Up until 2020 the dispatched electricity would be similar by technology for each of these demand forecasts, however, beyond 2020, a higher demand will result in increased need for natural gas at a time when gas prices, as well as increased pressure to reduce greenhouse gas emissions, will combine to drive the cost of generation electricity with natural gas up.

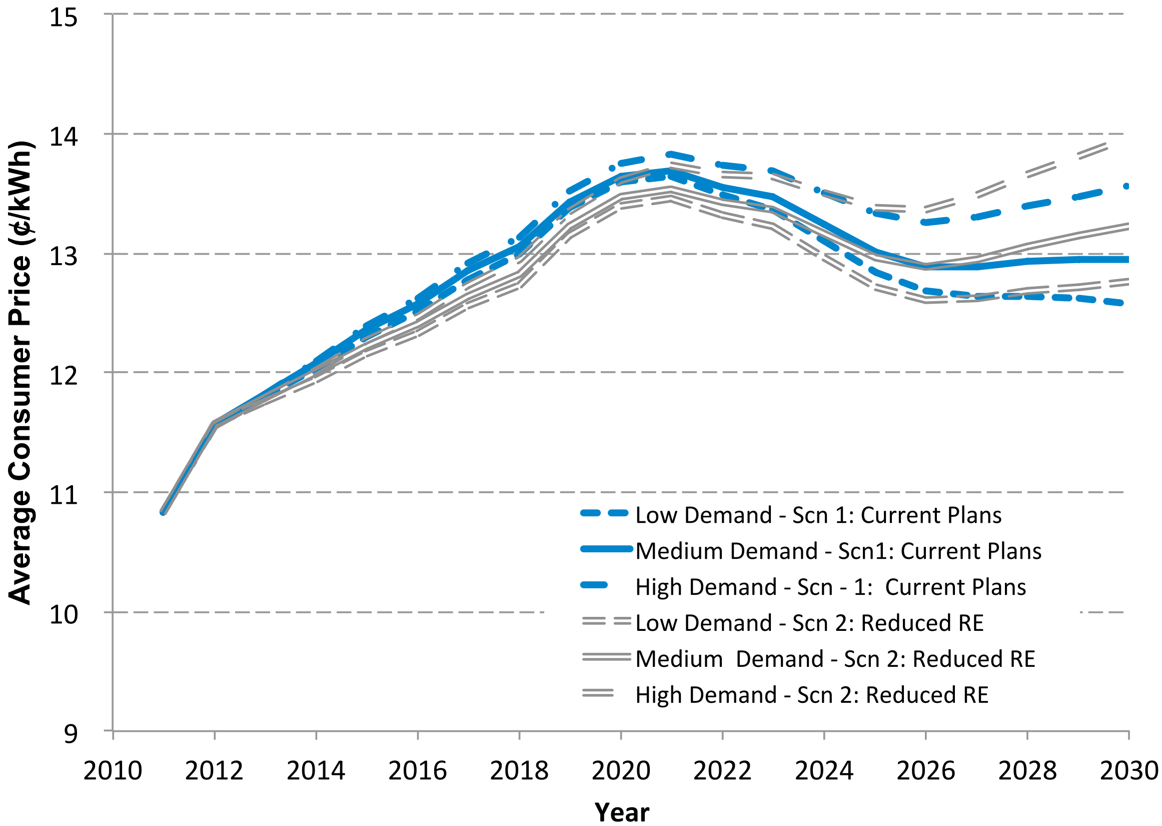

Figure 17: Prices under current plans scenario with varying demand forecasts (2010 constant Canadian dollars)

4.2.2. Sensitivity to gas prices

Under both generation scenarios, as the electricity system becomes more heavily dependent on natural gas, consumer prices become more sensitive to natural gas market prices.

Natural gas prices are forecast to steadily increase over the next 20 years, but are heavily dependent on the pace and technological advances of shale gas, as well as the potential changes in demand for natural gas in the United States.

The sensitivity test used here models gas prices gradually deviating from the reference case forecast by up 29 per cent by 2019 and remaining 29 per cent higher until beyond 2030. This is within the bounds of many natural gas price forecasts.

As shown in Figure 18, both scenarios are sensitive to increased natural gas prices. As natural gas prices increase, their impact on consumer price is felt almost immediately, reaching an increase on average of 1¢/kWh in this model. Final electricity prices are slightly higher in Scenario 2 beyond 2018 as would be expected with a generation portfolio more reliant on natural gas.

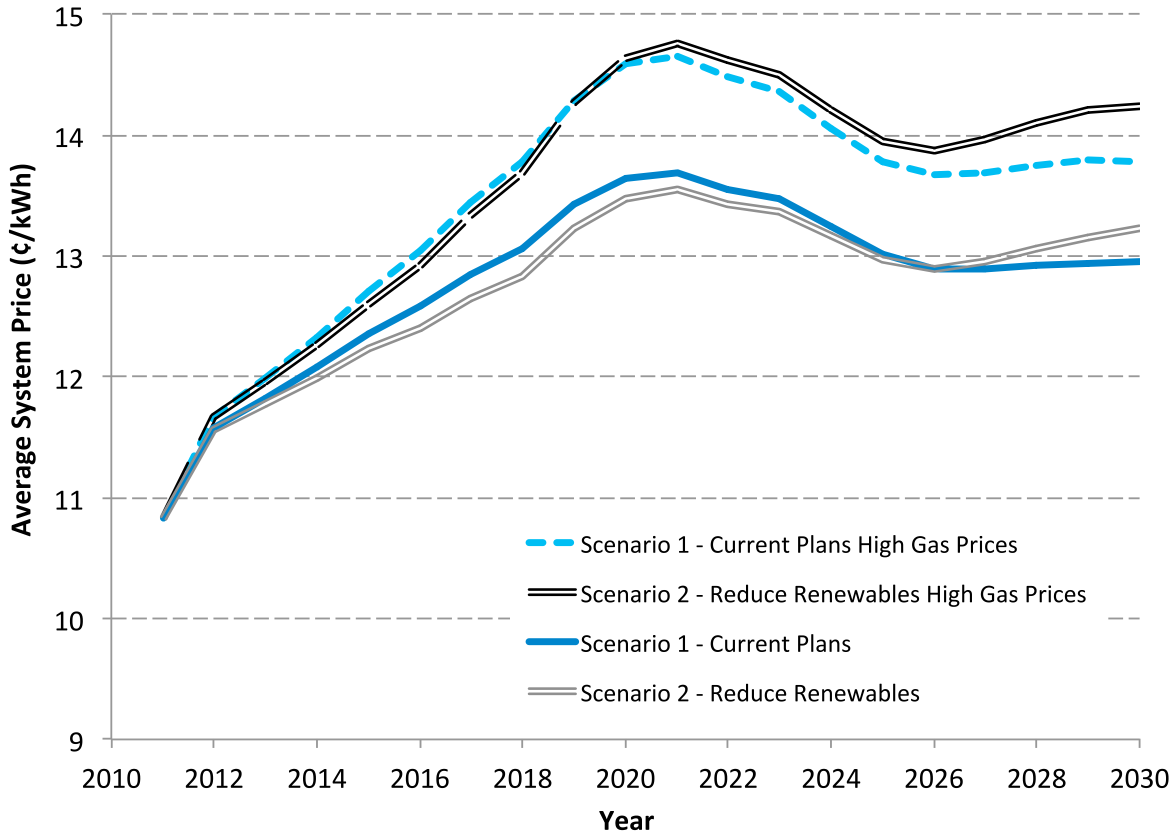

Figure 18: Simulation results with high natural gas prices (2010 constant Canadian dollars)

4.2.3. Sensitivity to nuclear costs

Increases in nuclear costs by 25 per cent from forecast prices would have a similar effect to natural gas price increases, although there would be no change in relative prices between generation in Scenarios 1 and 2, as shown in Figure 19.

In light of the Fukushima nuclear accident, a 25 per cent increase in forecast prices is likely a conservative estimate as safety standards undergo additional scrutiny worldwide.[114] These price changes would be in addition to any cost overruns that have been typical for nuclear plant construction in Ontario. Cost overruns as well as increased financing costs as a result of unanticipated interest accruing on loans due to constructions delays and overruns have resulted in final nuclear projects in Canada costing more than double initial estimates.[115]

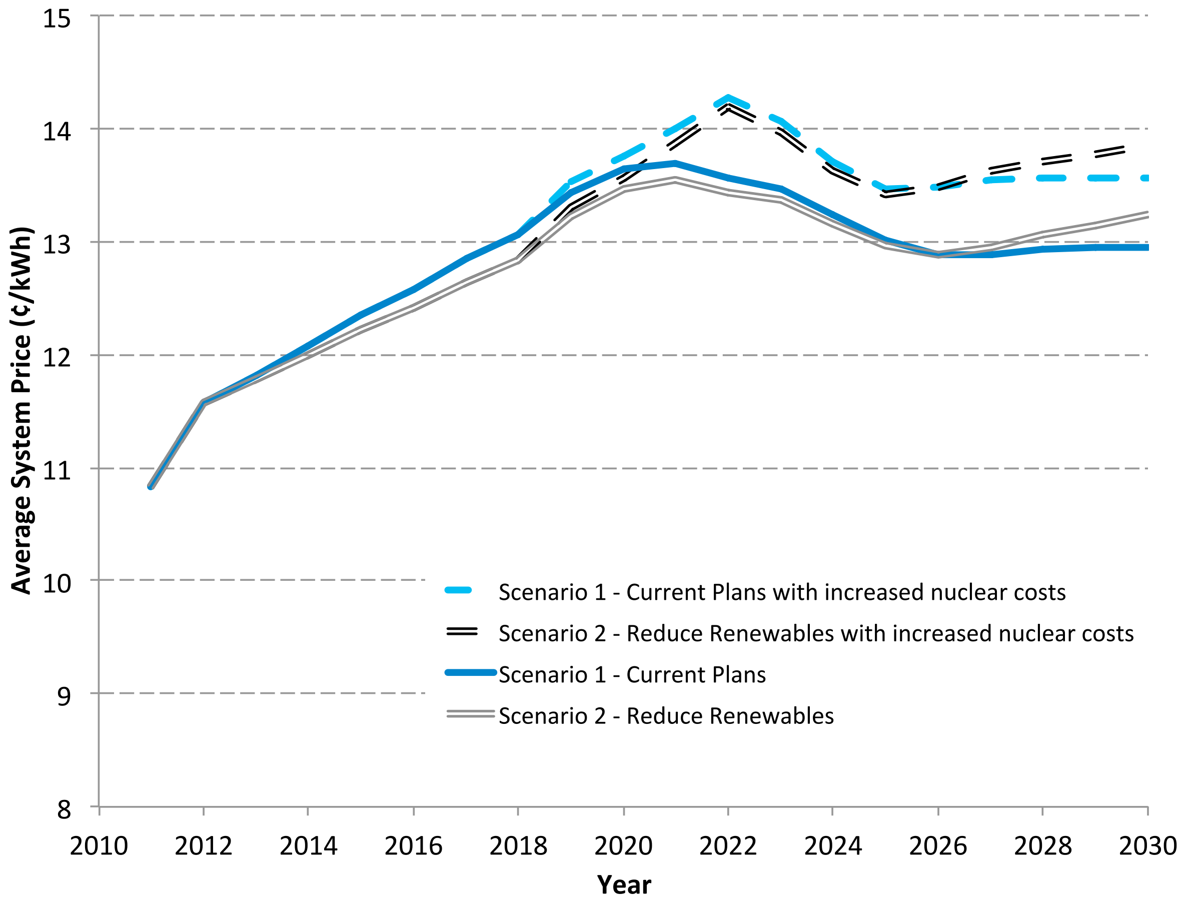

Figure 19: Simulation results with 25 per cent increase in nuclear costs (2010 constant Canadian dollars)

5. Discussion

5.1. Price increases

The simulation found that the elimination of the Green Energy Act would have very little change on electricity prices. Consumer prices are virtually identical between the two scenarios. While prices in the more gas-focused, reduced renewables scenario 2 are slightly lower at times, the biggest gap between the two scenarios is on the order of 1.5 per cent.

Electricity prices in Ontario are set to continue to rise sharply in the future in both scenarios, peaking around 2022 when Ontario's nuclear fleet is in the midst of significant rebuilding. However, in the immediate future there would be virtually no change in electricity prices if future contracts for renewable energy were ended in 2011. Replacing the commitment to renewable energy largely with natural gas is likely to result in only a slightly slower increase in electricity rates from the years 2015-2025. However, within the next 15 years, as natural gas prices begin to increase and there is a likelihood that there will be increased action taken to combat climate change, the simulation found that investing in renewable generation today will keep consumer prices slightly lower in the long-term.

While average emissions fall from current rates of 20 million tonnes of CO2 per year to below 10 million tonnes over the next 20 years due to the phase-out of coal power. By reducing the use of renewable energy that is generated in Ontario, a scenario that relies more heavily on natural gas would produce as much as 3 million additional tonnes of CO2 annually, as well as over 260 tonnes of nitrogen oxides, 21 tonnes of sulphur dioxide and 75 tonnes of volatile organic compounds.

Future electricity prices in Ontario are more sensitive to increased gas prices in addition to additional risks posed from an increased dependence on natural gas.

5.2. Risks with increased reliance on natural gas

5.2.1. Current contract structures for gas-fired generators in Ontario

With the exception of contracts for non-utility generators (NUGs), which are currently held by the Ontario Electricity Financial Corporation (OEFC), contracts for gas-fired generators are held by the OPA.[116]

These contracts are settled through a Deemed Production Model format. This involves "a combination of a monthly fixed component (or revenue requirement) and the monthly variable cost to generate an expected (or deemed) production of electricity, based on a set of contractual parameters."[117] According to a report prepared for the OEB, the average net revenue requirement for projects developed under the Clean Energy Supply RFP[118] (as well as "early mover" projects[119]) is $7,900 per megawatt-month.[120] The OPA is responsible for contingent support payments covering the difference between this amount and the "deemed" energy market revenues (i.e. the market revenues generated based on the dispatch parameters in the contract).[121] Conversely, if deemed revenues ever exceed the revenue requirement, the generator must make a revenue sharing payment to OPA.

As the IESO notes, "in the absence of the ability of the firm to influence HOEP, the OPA payment—whether from or to the OPA—is independent of the firm's actual production choices. …production decisions are not based on the criteria for deeming."[122] The criteria for determining deemed production include variable energy cost — one element of which is the gas price at the Dawn hub.[123]

OPA also holds a contract for the ongoing operation at OPG's Lennox generating station.[124]

The OEFC currently holds contracts with NUGs for about 1,300 MW of gas-fired capacity, much of it self-scheduling CHP. These contracts, developed in the 1990s as 20-year power purchase agreements, will begin to expire in 2012. The Ministry of Energy has directed OPA to enter negotiations for new contracts with NUGs that meet the required criteria.[125] One likely requirement will be enhanced flexibility.[126] Payments to NUGs were $954 million in 2010 and $914 million in 2009.[127]

5.2.2. Greenhouse gas emissions from gas-fired electricity generation

Combustion of natural gas produces considerably less carbon dioxide per unit of usable energy than combustion of other fossil fuels like coal or petroleum products. However, a study recently published in the scientific journal *Climatic Change* suggests that emissions of methane (a powerful greenhouse gas) during the lifecycle of natural gas may be much higher than conventional estimates (such as those by Environment Canada and the U.S. EPA), and that total lifecycle greenhouse gas emissions may, as a result, be close to, or even higher than, those from coal — particularly in the case of shale gas.[128,129] The study's lead author has acknowledged that the study is necessarily based on "sparse" and "poorly documented" information.[130] However, there is clearly a need for research to quantify much more reliably the methane emissions associated with natural gas.

An increased reliance on natural gas in Scenario 2 would result in an additional 3.1 million tonnes of CO_2 over the study period.

Unless CCS is applied, natural gas combustion results in 117 lb of CO_2 per MMBtu (approximately 53 kg/MMBtu).[131] This applies to any gas-fired generation technology that does not control CO_2 emissions. Emissions per unit of electricity generated will depend on the efficiency of the generator (the amount of fuel turned into useful energy). Table 10 shows CO_2 emission estimates for new gas-fired generators based on reported heat rates for current turbine models and configurations. Slightly different assumptions about these factors result in different efficiencies, accounting for the differences between studies.

Table 10: CO_2 emission rates from new gas-fired electricity generation

Combustion Technology	CO_2 emission rate (kg CO_2/ MWh)			
	CEC[132]	EIA[133]	IEA[134]	Martin[135]
Conventional Simple Cycle	492	576	-	-
Advanced Simple Cycle	454	517	-	-
Conventional Com'd Cycle	368	-	-	-
Adv. Com'd Cycle	345	341	330[136]	-
Industrial CHP	-	-	-	254

The emission rates above give a sense of the efficiency of the technologies represented. They also provide an indication of how carbon pricing would affect them, oulined more explicitly in Table 11.

As expected, the least efficient (highest emitting) gas-fired technologies bear the biggest cost burden under carbon pricing. Efficiency improvements reduce this cost by decreasing the emissions per unit of electricity produced (thus shrinking the number of allowances required or the carbon "tax base"). This becomes more pronounced as the cost of emissions — and therefore the value of added efficiency — rises.

Table 11: Illustrative compliance costs for gas-fired generation under different carbon prices[137]

Combustion Technology	Compliance Cost ($/MWh)			
	Carbon Price ($/t CO_2)			
	10	30	50	100
Conventional Simple Cycle	6	17	29	58
Advanced Simple Cycle	5	16	56	52
Conventional Combined Cycle w/ duct-firing	4	11	19	37
Advanced Combined Cycle	3	10	17	34
2020 Combined Cycle (IEA)[138]	3	10	17	33
Industrial CHP[139]	3	8	13	25

5.2.3. Increasing Ontario's use of shale gas

According to the Association of Power Producers of Ontario, shale gas is projected to account for nearly 30 per cent of Ontario's total gas supply by 2020.[140]

There are considerable concerns about the environmental impacts of shale gas production. Since shale gas is expected to account for the bulk of new natural gas production, any moves by governments to restrict shale gas production in light of those concerns could have a significant impact on gas supply and prices. It is difficult to gauge the likelihood of such restrictions, but one recent example is the Quebec government's decision to halt shale gas exploration pending a two-year "strategic environmental assessment."[141] Meanwhile, lawmakers in New York are working to extend the state's current moratorium on horizontal drilling and hydraulic fracturing for another year while further studies are conducted.[142]

Spills or inadequate disposal of "produced water" — water that comes out of the well along with the gas when rocks are hydraulic fractured (a process known as "fracking") — pose a significant risk of contamination of fresh water. In general, produced water is a combination of (typically very salty) water naturally occurring in the gas deposit, and the "flowback" portion of the fracture fluids. The industry's recent track record in this area has been poor in Pennsylvania (which is currently at the forefront of shale gas development), with many documented spills and leaks.[143] Congress has directed the U.S. Environmental Protection Agency (EPA) to investigate the risk to drinking water posed by hydraulic fracturing.[144]

5.3. Potential natural gas plant locations

The major difference between the two generation scenarios is the relative reliance on natural gas. There are a number of risks associated with an increased reliance on natural gas for Ontario's electricity supply, particularly as shale gas is likely to increasingly become a larger and larger proportion of the overall mix. This section discusses some of the implications besides costs that are likely to result from an increased long-term reliance on natural gas.

To determine where new gas plants are likely to be located we have examined the previous energy plan developed by the OPA, the IPSP from 2006. A list of planned gas facilities from the 2006 IPSP is contained in Table 12.

Table 12: 2006 IPSP forecast natural gas plants

Facility	Location	MW
Contracted Facilities		
Brighton Beach Power Station	Windsor	580
Greenfield Energy Centre	Sarnia	1005
Goreway Station	Brampton	860
Portland Energy Centre	Toronto	538
St. Clair Energy Centre	Sarnia	570
Halton Hills Generating Station	Halton Hills	600
Greenfield South Power Plant	Mississauga	280
2006 IPSP Planned Facilities		
Northern York Region (SCGT)	York	350
Kitchener-Waterloo-Cambridge-Guelph (CCGT)	K-W	450
Southwest GTA (CCGT)	GTA	850
GTA (SCGT)	GTA	550
NUG Replacement (SCGT/CCGT)	N/A	469
Unspecified/Proxy Gas (SCGT/CCGT)	N/A	650
Total		**7,402**

Table 13 denotes the new and projected gas plants called for in the 2010 LTEP.

Table 13: LTEP new and projected gas plants

Facility	In-Service	MW
Brighton Beach Power Station	2004	541
Greenfield Energy Centre	2008	1005
Goreway Station	2009	839
Portland Energy Centre	2009	550
St. Clair Energy Centre	2009	577
Halton Hills Generating Station	2010	642
York Energy Centre	2012	393
Greenfield South Power Plant	2014	280
Total		**4,827**

The gas plants proposed in the 2006 IPSP add up to approximately 2,500 MW more than those in the LTEP, suggesting they are likely candidates to meet the shortfall if renewable targets are decreased. Based on the difference between the IPSP and LTEP, new gas power plants might be likely in:

- Kitchener-Waterloo-Cambridge-Guelph: 450 MW
- Southwest GTA: 850 MW
- GTA: 550 MW
- Unknown location(s): 650 MW

In general these power plants are likely to be built in the densely populated Greater Golden Horseshoe region where there has been a concerted effort to reduce smog and improve overall air quality (a driving reason behind closing the coal plants). However, there is also vocal opposition in the region to such power plants.[145] In 2010 the government cancelled a 975 MW natural gas power plant planned for Oakville. There is also opposition to the Greenfield South Power Plant project, which has just been issued a building permit. To meet the required 2,500 MW at least two projects of a size similar to the cancelled Oakville power plant would likely be required.

5.4. Risks with increased reliance on renewables

5.4.1. Surplus baseload

Ontario has recently been facing challenges of surplus baseload, a condition where the output from the baseload facilities exceeds the demand for electricity in the province. The output of large steam facilities, notably nuclear power plants, can be challenging to adjust quickly, and the system operator has limited options to balance supply and demand.[146] An oversupply of electricity lowers the market price, which in turn may drive industrial consumption up, reducing the problem in the longer term; however, demand is much more sensitive to time than to price. At times prices have fallen to the point they are negative: the system operator pays consumers to consume electricity. While undesirable, this is essentially the same as paying for ancillary services on the grid that can respond to changes in supply and demand to help regulate system stability. Done for short periods of time, this is more cost effective than removing entire baseload units from operation, as these can take several days to restart.

However, load response and negative pricing do have overall system costs and are undesirable. There are limits to how much adjustment can be made to domestic demand, as well as how much energy can be exported, and so excessive surplus baseload is undesirable. This situation can be compounded as additional variable output sources such as wind energy are added to the grid. Output from wind farms can be curtailed if necessary more easily than larger thermal generating units; however, as their output is variable, it is more difficult to manage the system with wind farms on the margin rather than more dispatchable sources such as large hydro or natural gas facilities.

Ontario currently faces surplus baseload situations relatively frequently as much of its nuclear fleet is operating and system demand has been falling. This situation will begin to correct itself as nuclear units are removed from service starting in 2015 for refurbishment. However, if the entire nuclear fleet is returned to service and additional nuclear plants are built, Ontario could return to surplus baseload situations beyond 2022 if domestic demand has not increased as forecast. Additional variable output renewables may compound this issue if energy storage is not also added to the system during that time frame.

5.4.2. Integration

Ontario is in the process of rapidly ramping up its renewable energy capacity. In 2010, less than 1,500 MW of variable output renewable energy sources (wind, solar and run of-river hydro) on its system, by 2018, the LTEP forecasts 10,700 MW of renewable energy sources will be built. As these technologies operate differently than many traditional electricity sources there are new challenges that grid operators need to deal with.

Integrating increasing proportions of variable output technologies has been the subject of much study for the past decade as countries around the world move to take advantage of technologies that do not emit greenhouse gases or local air pollutants.[147] The Utility Wind Integration Group was formed in North America to focus specifically on integrating large amounts of wind energy into traditional electricity systems.[148]

A recent book published by the IEA suggests that that many regions have much higher technical potential to integrate and balance larger shares of variable renewable energy than traditionally thought. Using the systems and generation fleets that already exist, the potential to integrate variable output renewables (wind, solar, etc.), ranges from 19 per cent in areas such as Japan with less-flexible grids, up to 63 per cent in countries such as Denmark with well-connected grids and ready access to large hydro systems.[149] Other results from the IEA are shown in Table 14.

Table 14: Potential to integrate variable renewable energy into electrical systems

Region	Integration Potential (%)
British Isles	31
Mexico	29
Western Interconnection (U.S)	45
New Brunswick System Operator area	37
Denmark	63
Japan	19

SOURCE: IEA[150]

In Ontario, a study completed by General Electric in 2006 found minimal system operation impacts for wind capacity of up to 5,000 MW; with some additional regulation that could be handled within the current system operation framework, Ontario could integrate up to 10,000 MW of wind energy.[151] Since that time, significant levels of natural gas have been added to the system, which would further increase the system's capacity to balance the output of wind generation. The long-term energy plan scenario forecast only 7,500 MW of wind, well below what was technically possible even in 2006 prior to the recent gas build.

Nonetheless, there are challenges to integrating variable output renewables as they do not behave as traditional electricity sources have. Ontario's independent electric system operator has begun stakeholder consultations on integrating renewables[152] and is already taking steps to incorporate additional variable generation including improved resource forecasting; ensuring that systems over 5 MW that are embedded in the distribution system are visible to the operator; and improving its ability to dispatch renewables.

6. Conclusions

6.1. Rising prices inevitable

This study developed an integrated and dynamic model of realistic scenarios for electricity prices in Ontario, including projected growth rates for renewable power, various sensitivities to key price parameters, as well as realistic potential of natural gas generation development possibilities. The model examines the 20-year time period between 2010 and 2030.

This study's results illustrate that electricity prices will increase in Ontario as the major infrastructure investments, system refurbishments and changes to the electricity generation fleet are developed. Given the long-term nature of much of the electricity contracts in Ontario, be they nuclear, natural gas or renewable energy, relatively few realistic alternatives can be foreseen, particularly as nuclear and hydroelectricity continue to dominate the overall generation fleet.

The analysis for this study indicates that there is little to gain in cancelling Ontario's feed-in tariff, particularly just prior to a pricing review which is likely to result in decreases to original rates. There is at best a small savings to be made by shifting from more natural gas, and would result in likely to be no noticeable impact on consumer rates in the short term, and which poses modest consumer risks if the system grows increasingly dependent on natural gas markets.

6.2. Minimal price differences

With a renewed commitment to nuclear power in Ontario in addition to already existing natural gas and hydroelectric facilities, there are limited options to significantly alter the price of electricity in the coming years. While an increased reliance on natural gas in place of renewable sources is likely to result in a slightly lower increase in electricity prices in the medium term, the difference between this increase and that forecast under the current plans of continuing to expand the renewable electricity sector remains very small.

As natural gas prices slowly increase, action on climate change and other air emissions continues to tighten and the costs of new renewable facilities decreases, prices difference may switch as early as 2025 from slightly favoring natural gas to slightly favouring a system more heavily reliant on renewable energy technologies.

6.3. Further emphasis on natural gas risky

Natural gas has been instrumental in helping Ontario reduce and eventually completely retire its coal powered generation. Natural gas will also continue to play a role in helping Ontario balance its electricity system and supply reliable energy during the eight years when much of the nuclear fleet is being refurbished and retired.

However, there are several risks associated with a further emphasis on natural gas, including forecast price increases, unknowns associated with further reliance on shale gas, additional pollution and greenhouse gas emissions. These risks partly depend on how the natural gas demand will evolve in North America over the next 20 years, but also on how shale gas is developed.

Furthermore, as more and more industrial capacity and local content requirements work their way into the Ontario renewable energy market, consumer electricity prices for renewable energy increasingly result in investments in Ontario, compared to fees paid for natural gas, most of which is imported from outside the province.

6.4. Renewables as pricing hedges

Between 2004 and 2007, the average price of wind energy contracts was lower than that of combined cycle natural gas. Recent natural gas market price reductions, combined with higher-priced FIT contracts, will mean in the short term new high-efficiency natural gas fired electricity is likely to be less expensive, while adding dispatchable capacity to the system. However, in the medium to longer term it is likely that these trends will change course. New FIT contract prices are likely to decline as the solar and wind energy industries further establish themselves in Ontario while technology improvements continue globally as they have for the past several decades. At the same time, natural gas prices are most likely set to increase again, although there are many factors that could affect the rate of increase. Action on climate change may further accelerate the net price increase in natural gas fired electricity systems.

Furthermore, nuclear projects have a history in Ontario of not being built on price and on schedule. Additionally, long lead times to build or rebuild nuclear power plants also run the risk of increasing interest rates from their currently low levels, potentially driving up the costs of nuclear power in the longer term, as well as increasing the use of non-nuclear sources while the plants are being refurbished.

This study does not examine the option of further expanding the use of renewable energy technologies to reduce Ontario's use of nuclear energy, helping to hedge against potential increased nuclear prices.

Figure 20: Canada's first co-operatively-owned wind project was a turbine installed by the Toronto Renewable Energy Co-operative
PHOTO: TORONTO RENEWABLE ENERGY CO-OPERATIVE

Glossary

Capacity factor

The average percent of any power plant's actual outputcompared to its maximum rated output over a period of time.

Note: This is usually expressed over a one-year period and is found by dividing the actual electrical energy generated by a power plant over a year by the generator's rated capacity multiplied by the number of hours in a year (8,760).

Decommissioning

Process of dismantling a power plant and restoring the site to pre-project conditions or another agreed-upon outcome, including contaminated sites and materials.

Demand

The electricity drawn by electrical loads.

Depreciation

Accounting method used to attribute the cost of an asset over the span of its useful life

Note: The project cost, or a portion of the project cost, can be assigned as a loss on the project's balance sheet to reduce the tax base of the project.

Discount rate

Interest rate used in determining the value of future cash flows in present-day funds.

Distributed generation

Electricity generators that are distributed throughout a utility's service area instead of being concentrated at a central location

Note: This term is commonly used to indicate non-utility sources of electricity, including on-site generation. In effect, all generators regardless of size are "distributed" because they are located in many places around the province.

Distribution generation

Electricity generator connected to the electrical distribution system

Distribution system

The poles, wires, transformers, insulators, disconnects, breakers, fuses, and other associated equipment that deliver electric energy from the local substation to individual consumers.

Note: Typically, the distribution system is defined as electrical lines and associated equipment where the operating voltage is less than 34.5 kilovolts.

Grid

The network of transmission or distribution lines used to move a commodity from its source to consumers

Independent Power Producer (IPP)

Owner of an electricity generator that is not owned by a public utility.

Integrated Power Systems Plan (IPSP)

Ontario's Ministry of Energy issued the Supply Mix Directive, requiring the Ontario Power Authority to prepare a 20-year Integrated Power System Plan (IPSP) to meet the province's electricity system goals.

Internal rate of return (IRR)

Financial calculation that compares the present value of a project's expected revenues with the present value of its expected costs

Note: An IRR calculation is used to determine the discount rate at which the two present values are equal. By doing this calculation, investors are able to see the project's expected rate of return.

Kilowatt (kW)

Unit of power of any form of energy, that is, a measure of the rate of doing work or instantaneous rate of energy use

Note:1 kW is equal to 1,000 watts. A 100-watt light bulb uses 100 watts when it is illuminated.

Kilowatt-hour (kWh)

Unit of energy of any form, that is, a measure of how much energy is used over time

Note:1 kWh is equal to 1,000 watt-hours. This is the basic unit for measuring electric energy. A 100-watt light bulb that is illuminated for 10 hours uses 1 kilowatt-hour of energy (10 hours x 100 watt-hours = 1 kWh).

Load

1) The amount of electric energy consumed over a duration of time
2) An electricity-consuming device or devices that are connected to an electrical system

Note: Peak load is the greatest amount of electrical energy consumed over an hour in a year.

Megawatt (MW)

Unit of power of any form of energy

Note:1 MW is equal to 1,000 kilowatts or 1 million watts. 1 MW of electrical power can light up 10,000 of 100 W light bulbs.

Megawatt-hour (MWh)

Unit of energy of any form

Note:1 MWh is equal to 1,000 kilowatt-hours or 1 million watt-hours.

Off-peak

Electricity supplied during periods of low system consumption.

OPA

The Ontario Power Authority is an independent, non-profit corporation who reports to Ontario's Ministry of Energy. The OPA is responsible for assessing the long-term adequacy of electricity resources, forecasting future demand and the potential for conservation and renewable energy, preparing an integrated system plan for conservation, generation, transmission, procuring new supply, transmission and demand management either by competition or by contract, when necessary, and achieving the targets set by government for conservation and renewable energy.

Peak demand

The greatest demand placed on an electric system in a given year.

Power

Rate of energy flow.

Note: The standard unit of measure is a joule per second, which is encapsulated in the term watt (W).

Surplus Baseload

A situation that occurs when electricity production from baseload facilities exceeds provincial electricity demand.

Transmission

Transfer of high-voltage electric power from generating plants to customer loads or distribution systems at a distance ranging from nearby to hundreds of kilometres

Watt (W)

Unit of power of any form of energy

Note:1 W is equal to a flow of one joule of energy per second.

Appendix: Data

A.1. Cost data

2011 Feed-in tariff data

Renewable fuel	Size tranches	Contract price (¢/kWh)
Biomass		
	≤ 10 MW	13.8
	> 10 MW	13.0
Biogas		
On-Farm	≤ 100 kW	19.5
On-Farm	> 100 kW ≤ 250 kW	18.5
Biogas	≤ 500 kW	16.0
Biogas	> 500 kW ≤ 10 MW	14.7
Biogas	> 10 MW	10.4
Waterpower		
	≤ 10 MW	13.1
	> 10 MW ≤ 50 MW	12.2
Landfill gas		
	≤ 10 mw	11.1
	> 10 MW	10.3
Solar PV		
Rooftop	≤ 250 kW	71.3
Rooftop	> 250 ≤ 500 kW	63.5
Rooftop	> 500 kW	53.9
Ground Mounted	≤ 10 MW	44.3
Wind		
Onshore	Any size	13.5

FIT Adders

Renewable fuel	Wind	Solar PV (Ground Mounted)	Water	Biogas	Biomass	Landfill Gas
Maximum Aboriginal Price Adder (¢/kWh)	1.5	1.5	0.9	0.6	0.6	0.6
Maximum Community Price Adder (¢/kWh)	1..0	1.0	0.6	0.4	0.4	0.4

SOURCE: OPA

Assumed fuel costs over model period

Fuel costs (constantCanadianDollar2010 / GJ)										
Fuel type	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Coal	$2.45	$2.38	$2.34	$2.31	$2.32	$2.35	$2.36	$2.35	$2.36	$2.37
Heavy oil	$18.97	$17.32	$17.71	$18.14	$18.56	$19.41	$20.15	$20.80	$21.43	$21.79
Petroleum coke	$13.35	$13.15	$13.50	$14.06	$14.51	$15.05	$15.47	$15.95	$16.30	$16.26
Natural gas	$5.20	$5.12	$5.11	$5.07	$5.15	$5.19	$5.23	$5.29	$5.37	$5.52
Biomass	$2.45	$2.38	$2.34	$2.31	$2.32	$2.35	$2.36	$2.35	$2.36	$2.37
Fuel Type	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Coal	$2.39	$2.41	$2.42	$2.46	$2.47	$2.49	$2.50	$2.52	$2.55	$2.56
Heavy oil	$22.08	$22.37	$22.65	$23.09	$23.36	$23.63	$23.88	$24.14	$24.37	$24.58
Petroleum coke	$16.60	$16.98	$17.38	$17.64	$17.92	$18.16	$18.38	$18.53	$18.65	$18.59
Natural gas	$5.67	$5.82	$5.99	$6.17	$6.35	$6.48	$6.62	$6.71	$6.78	$6.84
Biomass	$2.39	$2.41	$2.42	$2.46	$2.47	$2.49	$2.50	$2.52	$2.55	$2.56

SOURCE: US DEPARTMENT OF ENERGY

Pollution from natural gas electricity generation

Type of natural gas generation	Pollutant (kg/MWh)					
	CO_2e	NOx	VOC	CO	SOx	PM_{10}
Conventional Simple Cycle	490	0.127	0.024	0.167	0.006	0.061
Advanced Single Cycle	452	0.045	0.014	0.086	0.004	0.028
Conv Combined Cycle w/ duct-firing	374	0.034	0.143	0.008	0.004	0.019
Advanced Combined Cycle	344	0.029	0.008	0.025	0.002	0.014

SOURCE: CALIFORNIA ENERGY COMMISSION[153]

Variable costs

Variable Costs	(¢/kWh)
Debt retirement charge (DRC) — collected by LDCs to pay for debt of former Ontario Hydro.[1]	$0.7
Distribution cost[2]	$0.1572
Wholesale market service charge — cost for IESO, etc	$0.65

Notes

[1] Ontario Hydro debt was $38 billion. $17 billion of this was assigned to Ontario Hydro successor companies. Balance is being paid off by DRC. DRC will continue until debt is fully paid. OEFC estimates the debt will be fully paid "between 2012 and 2020".[154]

[2] Distribution utilities (LDCs) charge a monthly connection fee as well as a variable cost per kW or per kWh (depending on rate class). Distribution charge above is for the variable portion (per kWh) only.

Assumed generator rate of return

	Rate of return
For FIT program	11% after taxes
For Hydro contracts	Confidential[1]

Notes

[1] OEB uses rates for LDCs and HydroOne - currently set at 9.58% (as of May 1, 2011)[155]

Assumed conservation program costs

American Council for an Energy Efficient Economy reported in 2009 that the cost for utility conservation programs was holding steady at around 2.5 cents per kWh (US)[156]

Assumed asset book life

U.S. Discount Rates and Capital Charge Rates in EPA Base Case v4.10

Investment Technology	Capital Charge Rate	Discount Rate	Book Life
Environmental Retrofits	11.30%	5.50%	30
Advanced Combined Cycle	12.10%	6.20%	30
Advanced Combustion Turbine	12.90%	6.90%	30
Supercritical Pulverized Coal and Integrated Gasification Combined	14.10%	7.80%	40
Advanced Coal with Carbon Capture	11.10%	5.50%	40
Nuclear without Production Tax Credit (PTC)	10.80%	5.50%	40
Nuclear with Production Tax Credit (PTC)2	9.10%	5.50%	40
Biomass with ARRA Loan Guarantees3	9.30%	4.60%	40
Biomass without ARRA Loan Guarantees	11.10%	6.20%	40
Wind and Landfill Gas with ARRA Loan Guarantees2	10.10%	4.60%	20
Wind and Landfill Gas without ARRA Loan Guarantees	12.20%	6.20%	20
Solar and Geothermal with ARRA Loan Guarantees2	10.10%	4.60%	20
Solar and Geothermal without ARRA Loan Guarantees	12.20%	6.20%	20

Notes:

The discount rates appearing in the table were used in deriving these capital charge rates. However, as noted in the text, a single U.S. discount rate of 6.15% is used across all technologies in EPA Base Case v.4.10.

[1] The capital charge rate for these technologies includes a 3% climate change uncertainty adder.

[2] The capital charge rate for this technology reflects the impact of the PTC provided under the Energy Policy Act of 2005.

[3] The capital charge rate for these technologies reflects the impact of ARRA loan guarantees.

SOURCE: U.S. EPA[157]

Assumed new generation cost and performance characteristics

	Plant Characteristics		Plant Costs		
	Nominal Capacity (kilowatts)	Heat Rate (Btu/kWh)	Overnight Capital Cost (2010 $/kW)	Fixed O&M Cost (2010$/kW)	Variable O&M Cost (2010 $/MWh)
Coal					
Single Unit Advanced PC	650,000	8,800	$3,167	$35.97	$4.25
Dual Unit Advanced PC	1,300,000	8,800	$2,844	$29.67	$4.25
Single Unit Advanced PC with CCS	650,000	12,000	$5,099	$76.62	$9.05
Dual Unit Advanced PC with CCS	1,300,000	12,000	$4,579	$63.21	$9.05
Single Unit IGCC	600,000	8,700	$3,565	$59.23	$6.87
Dual Unit IGCC	1,200,000	8,700	$3,221	$48.90	$6.87
Single Unit IGCC with CCS	520,000	10,700	$5,348	$69.30	$8.04
Natural Gas					
Conventional NGCC	540,000	7,050	$978	$14.39	$3.43
Advanced NGCC	400,000	6,430	$1,003	$14.62	$3.11
Advanced NGCC with CCS	340,000	7,525	$2,060	$30.25	$6.45
Conventional CT	85,000	10,850	$974	$6.98	$14.70
Advanced CT	210,000	9,750	$665	$6.70	$9.87
Fuel Cells	10,000	9,500	$6,835	$350	$0.00
Uranium					
Dual Unit Nuclear	2,236,000	N/A	$5,335	$88.75	$2.04
Biomass					
Biomass CC	20,000	12,350	$7,894	$338.79	$16.64
Biomass BFB	50,000	13,500	$3,860	$100.50	$5.00
Wind					
Onshore Wind	100,000	N/A	$2,438	$28.07	$0.00
Offshore Wind	400,000	N/A	$5,975	$53.33	$0.00
Solar					
Solar Thermal	100,000	N/A	$4,692	$64.00	$0.00
Small Photovoltaic	7,000	N/A	$6,050	$26.04	$0.00
Large Photovoltaic	150,000	N/A	$4,755	$16.7	$0.00
Geothermal					
Geothermal – Dual Flash	50,000	N/A	$5,578	$84.27	$9.64
Geothermal – Binary	50,000	NA	$4,141	$84.27	$9.64
MSW					
MSW	50,000	18,000	$8,232	$373.76	$8.33
Hydro					
Hydro-electric	500,000	N/A	$3,076	$13.44	$0.00
Pumped Storage	250,000	N/A	$5,595	$13.03	$0.00

SOURCE: U.S. ENERGY INFORMATION ADMINISTRATION[158]

Table II					
	Overnight Capital Cost ($/kW)			Nominal Capacity KW's[1]	
	AEO 2011	AEO 2010	% Change	AEO 2011	AEO 2010
Coal					
Advanced PC w/o CCS	$2,844	$2,271	25%	1,300,000	600,000
IGCC w/o CCS	$3,221	$2,624	23%	1,200,000	550,000
IGCC CCS	$5,348	$3,857	39%	600,000	380,000
Natural Gas					
Conventional NGCC	$978	$1,005	-3%	540,000	250,000
Advanced NGCC	$1,003	$989	1%	400,000	400,000
Advanced NGCC with CCS	$2,060	$1,973	4%	340,000	400,000
Conventional CT	$974	$700	39%	85,000	160,000
Advanced CT	$665	$662	0%	210,000	230,000
Fuel Cells	$6,835	$5,595	22%	10,000	10,000
Nuclear					
Nuclear	$5,339	$3,902	37%	2,236,000	1,350,000
Renewables					
Biomass	$3,860	$3,931	-2%	50,000	80,000
Geothermal	$4,141	$1,786	132%	50,000	50,000
MSW - Landfill Gas	$8,232	$2,655	210%	50,000	30,000
Conventional Hydropower	$3,078	$2,340	53%	500,000	500,000
Wind	$2,438	$2,007	21%	100,000	50,000
Wind Offshore	$5,975	$4,021	49%	400,000	100,000
Solar Thermal	$4,692	$5,242	-10%	100,000	100,000
Photovoltaic	$4,755	$6,303	-25%	150,000	5,000

[1] Higher plant capacity reflects the assumption that plants would install multiple units per site and that savings could could be gained by eliminating redundancies and combining services.

SOURCE: U.S. ENERGY INFORMATION ADMINISTRATION [159]

A.2. Forecast average renewables price data

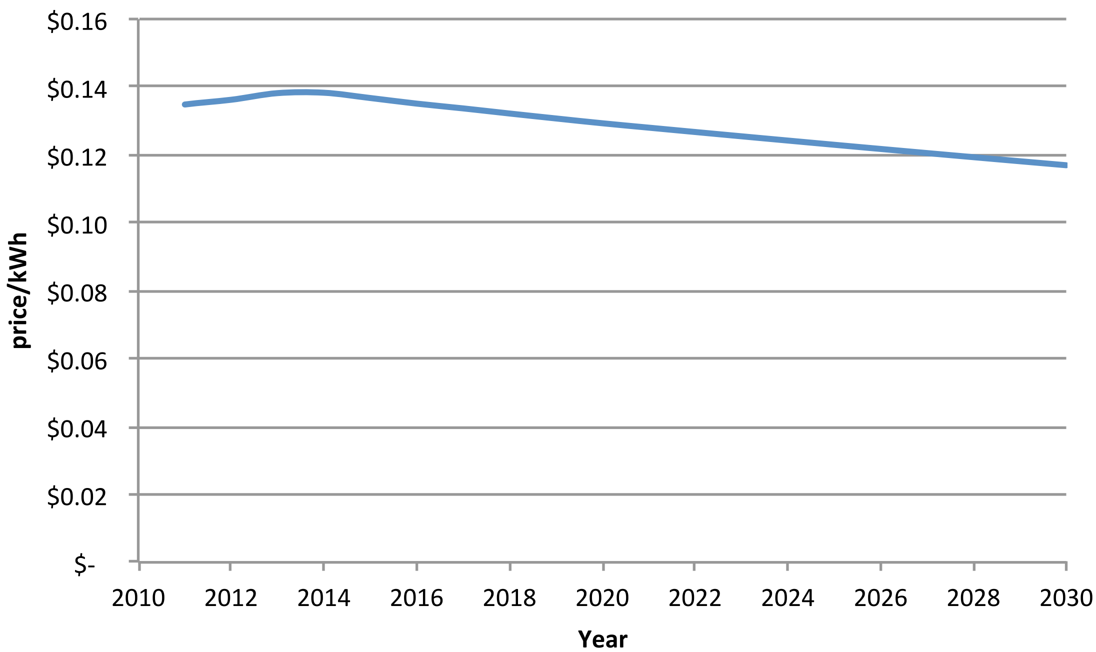

Figure 21: Average modelled new wind energy feed-in tariff rates ($/kWh)

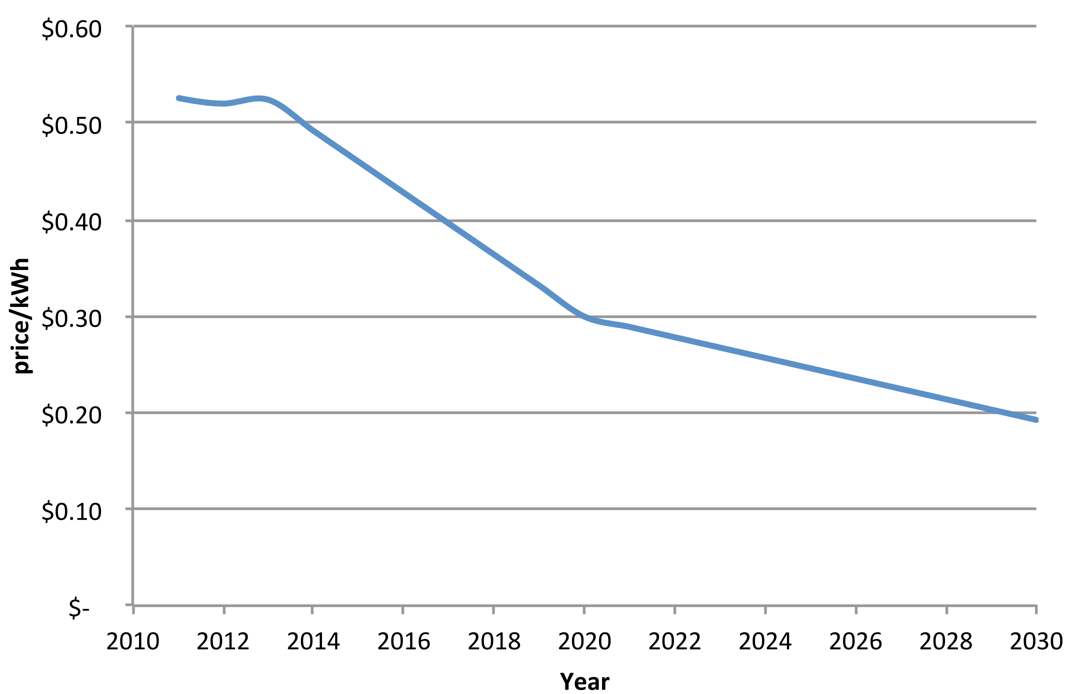

Figure 22: Average modeled new solarphotovoltaic feed-in tariff rates ($/kWh)

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