A Multi-Period Optimal Energy Planning With CO_2 Emission Consideration

by

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I hereby declare that I am the sole author of this thesis. This is a true copy of the thesis, including any required final revisions, as accepted by my examiners.

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ABSTRACT

A multi-period optimal energy planning program for Ontario has been developed in mixed-integer non-linear programming using General Algebraic Modeling System, GAMS. The program applies both time-dependent and time-independent constraints. These include, but not limited to, construction time, fluctuation of fuel prices, and CO_2 emission reduction target. It also offer flexibility of fuel balancing and fuel switching of the existing boilers and option purchasing of Carbon credit if the reduction target is not achievable. The objective function incorporates all these constraints as well as minimizes over all the cost of electricity and meets the projected electricity demand over the 30 years horizon.

A number of Ontario study cases are performed utilizing this 30 years model. These cases include a number of CO_2 emission reduction target from 6% to 75% below that of 1990 levels by 2014, doubling of natural gas over the forecasted price in 2020, an arbitrary year. A study case in appliance with the Environmental Protection Act where no new or existing coal-fired power stations are available after 2014, as well as study cases where no new nuclear power stations are available.

The overall cost of the electricity for different CO_2 emission reduction targets increases linearly with slope of ~ 5. The fuel switching, fuel balancing for coal stations, and retrofitting of the carbon capture and storage are the main strategy in order to keep the cost of electricity relative low and satisfy the CO_2 emission constraints.

Nuclear power is an essential supply technology to the fleet especially when CO_2 emission is concerned. An additional 248 Mt of CO_2 emission is observed over the reference case when no new nuclear supply is offered. Eliminating all coal technologies by 2014 in accordance to the Environmental Protection Act may also reduce the CO_2 emission with less additional expenditure normally associated with the emission reduction processes. This however also reduces the energy port folio diversity, forcing the system to depend on a smaller group of supply technologies and decreasing the reliability of the system overall.

These results help us better understand the factors affecting the fleet's structure. It may also help plan the energy direction of Ontario and perhaps serve as an example for other provinces, territories, states, and even countries.

ACKNOWLEDGEMENTS

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DEDICATION

To my parents, brother and sister, and my beloved Carissa

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List of Acronyms

CANDU	CANada Deuterium Uranium
CCS	Carbon capture and storage
CDM	Conservation and Demand Management
CO_2	Carbon dioxide
COE	Cost of electricity
EIA	Energy Information Administration
GAMS	General Algebraic Modeling System
GHG	Greenhouse gas
GJ	Gigajoule
IESO	Independent Electricity System Operator
IGCC	Integrated gasification combined cycle
MEA	Monoethanolamine
MILP	Mixed-integer linear programming
MINLP	Mixed-integer non-linear programming
Mt	Megatonnes
MW	Megawatts
MWh	Megawatt-hour
NEB	National Energy Board
NG	Natural gas

NGCC	Natural gas combined cycle
O&M	Operating and maintenance
OPA	Ontario Power Authority
OPG	Ontario Power Generation
PC	Pulverized coal
TWh	Terawatt-hour

Nomenclature

Indices

t	Time period (years)
i	Boiler
j	Fuel type (coal or natural gas)
l	Load block (peak or base-load)
k	Carbon capture technology
ρ	Factor for transmission and distribution losses
T	Time horizon (years)
β_i	Construction lead time for power station i (years)
ε_{ikt}	Percent of CO_2 captured from boiler i using carbon capture technology k during period t (%)
Q_i	Cost of carbon capture and storage for boiler i (\$/tonne of CO_2)
D_{tl}	Electricity demand during period t for load l (MWh)
B_{tl}	Conservation and demand management during period t and load block l (MWh)
$(CO_2)_{ij}$	CO2 emission from boiler i using fuel j (tonne of CO_2/MWh)
E_{kmax}	Maximum supplemental energy required for kth capture technology
$CLimit_t$	Specified CO_2 limit during period t

Sets

F	Fossil fueled power plants
NF	Non-fossil fuel
new	New power plants
$new{-}cap$	New power plants with carbon capture

Parameters

F_{ijt}	Fixed operating cost of boiler i using fuel j during period t ($/MW)
V_{ijt}	Variable operating cost of boiler i using fuel j during period t ($/MWh)
C_{ij}	Capacity of boiler i using fuel j (MW)
P_{lt}	Duration of load block l during period t (hrs)
U_{jt}	Fuel cost for fuel j during period t ($/GJ)
G_{ij}	Heat rate of boiler i using fuel j (GJ/MWh)
R_{it}	Cost associated with fuel-switching coal-fired boiler i during period t
S_{it}	Capital cost of power plant i during period t
$(CCost)_t$	Cost of carbon credits during period t ($/tonne of CO_2)

Continuous variables

E_{ijlt}	Power allocation from boiler i using fuel j for load block l during period t (MW)
$(Cre)_t$	Carbon credits purchased during period t (tonne of CO_2)

Binary variables

n_{it} =1 if power plant i is built during period t = 0 otherwise

y_{it} =1 if power plant i is operational during period t = 0 otherwise

x_{ijt} =1 if coal-fired boiler i is operational while using fuel j during period t =0 otherwise

h_{it} =1 if coal-fired boiler i undergoes fuel-switching during period t =0 otherwise

z_{ijkt} =1 if the carbon capture technology k is used on boiler i, which uses fuel j, during period t.

1. INTRODUCTION

Satisfying the electricity demand for any one territory is a challenging undertaking. Doing it, while abiding the Kyoto Protocol, is an even more overwhelming task to achieve. Canada, like 36 other developed countries in Annex A, had ratified the Kyoto Protocol which commits it to reduce the greenhouse gas (GHG) emission to 6% lower than that of 1990 level by 2008-1012 (UNFCCC). This amounts to approximately 558Mt of emissions per year.

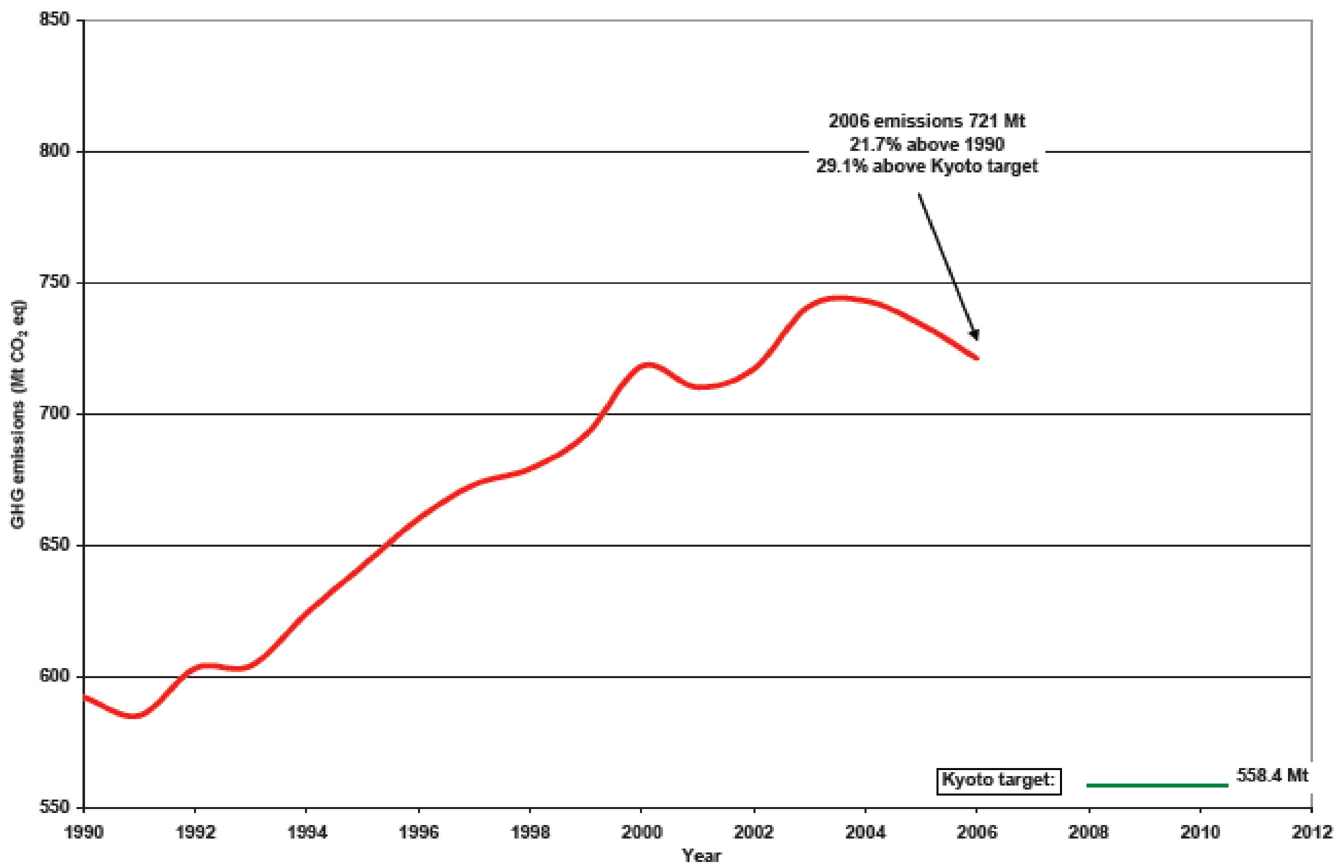


Figure 1 Greenhouse Gas Emission Trend and Kyoto Target (Environment Canada, 2008)

As depicted in Figure 1, Canada's GHG emissions has been climbing continuously until as recently as 2004 where the emissions peaks at 743 Mt and start to decline slightly. 721 Mt of GHG were reported by Environment Canada in the 1990-2006 National Inventory Report which was submitted to the UN Framework Convention on Climate Change (UNFCCC).

Greenhouse gases are of many physical forms and can be as common as water vapour and CO_2. While it is not the most potent of all GHGs, CO_2 is the most abundant yet.

As much as 72% of Canada's total emissions in 2006 were from fossil fuel combustions, primarily transportations and electricity generation respectively. (Environment Canada, 2008) Similar scenarios are revealing all over the world sending the atmospheric concentration of CO_2 toward 400 ppm, an alarming 120 ppm higher than the pre-industrial era average (World Data Centre for Greenhouse Gases, Japan Meteorological Agency/World Meteorological Organization).

This study aims to produce an energy strategy which will satisfy electricity demand and the carbon dioxide emission constraint at minimum cost, using province of Ontario, Canada as a case study.

1.1 Ontario's Supply Mix

As of April 2009, Ontario has 33,121 MW of installed capacity (IESO). Majority of the installed capacity is of nuclear sources 34% as depicted in Figure 2. To satisfy the daily demand in Ontario, nuclear power is typically used to generate a minimum of 50% of the total electricity. This source of power is very important to Ontario's supply mix and is expected to be continuously refurbished.

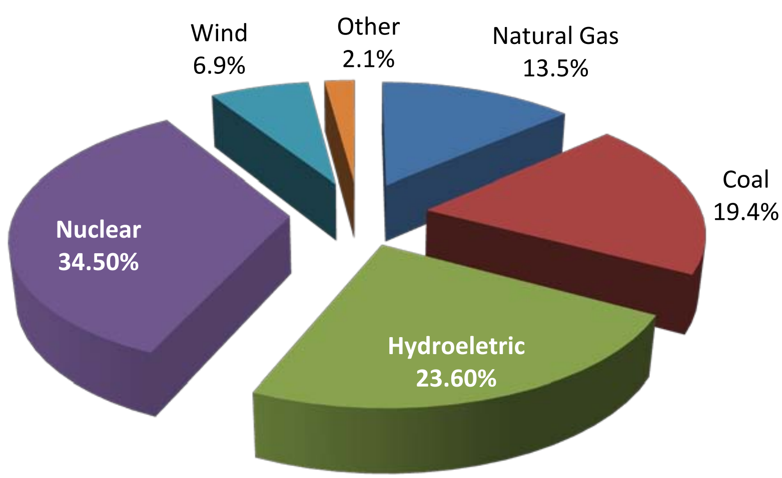


Figure 2 Ontario's installed capacity in MW as of April 2009 (IESO)

One great hurdle to overcome is the cessation of coal as a source of fuel in Ontario in compliance with the Environmental Protection Act. Under this act, all coal-fired power stations must cease burning coal by December 31st 2014 (Ontario Regulation 496/07, 2007). Eliminating coal will lessen Ontario's energy portfolio's diversity and increase its reliance on other sources of energy.

Currently, there are more than 6,000 MW of installed coal capacity. In addition to projected annual electricity demand, this void of a significant portion of Ontario energy supply will apply even more pressure to the system as a whole if an alternative solution is not found. In an attempt to keep these supply structures utilitarian, trial runs of biomass are being conducted at all of Ontario's coal-fired power stations (Ontario Power Generation, 2008). Biomass such as wood and straw pallet, excluding food crops, is a fuel of choice particularly for the carbon-neutral label; amount of carbon released during combustion is equal to the amount removed during growth. Ontario Power Generation also announced that it will seek to purchase the biomass from local markets which will provide a further stimulus to the local economy.

In addition to the effort in keeping the existing coal structures operational, wind installed capacity has increased considerably, doubling its capacity in the last 5 years. As a result, Ontario now has the largest installed wind capacity in Canada and is expected to be 1,100 MW by summer of 2009 (Independent Electricity System Operator, Dec 2008). Surprisingly, despite the current Ontario's installed wind capacity, roughly 5 times more capacity totaling 5,000 MW can still be added to the supply mix (Ontario Power Authority, 2007). However, due to the sporadic nature of wind, the capacity should not exceed 10% of the total installed capacity (IESO, 2006) (IESO, June 2008).

1.2 Literature review

Several previous optimization models had been performed on various industries. Mentioned hereafter are studies which are relevant to the current project.

In line with their previous studies in 1995 and 1996, the study performed by A. Vlachou et al. used Dynamic Programming (DP) to find the least-cost strategy for electricity production with CO_2 emission reduction using Greece as a reference case (A. Vlachou, 1998).The study utilizes the WASP-III software suite which spans the horizon of 30 years, from 1995-2025, where specific technical and economical characteristics are being explicitly considered. The study, however, does not consider any possible modifications, such as fuel switching and fuel balancing to increase the roll and potential of the existing generating stations in the overall CO_2 reduction scheme. It also did not include the option of CO_2 capture and sequestration, perhaps due to the lack of the maturity of said processes at the time the study was carried out.

Using state of Karnataka, India, as a study case, P. Balachandra et al. uses a linear programming to minimize the social cost associated with the process of dynamically matching electricity supply and demand where limited electricity resources are available. These may caused by an inadequate of investment or unpredictable fuel supplies. The model also incorporates seasonal and structural variations in the supply sources as part decision parameters (P. Balachandra, 2003). This study, however, is only unique to the situation where demand could not be met conventionally. The model lacks versatility and may not be utilized for many other jurisdictions where projected annual electricity demand is required to be met.

Later in 2006, P. Chan et al. used a multi-period linear probabilistic optimization model to consider long-term electricity contract selection for chemical production plants where large amount of electricity importation is required. The selection was based on time zone and loading curve with the consideration of the demand uncertainties to compensate for the overage and shortage typically encountered. A complex set of optimization models were also used in the study by G. Garcia in 2007 to find an optimal combination of energy production in the bitumen extraction and upgrading processes in the oil sand industries. The study predicts the correlation between energy demands, cost of production as well as CO_2 emissions during normal operations utilizing a range of production technologies.

A work done by M. Wise et al. considers the CO_2 capture and geological storage strategy for all the electric power regions across United States. The model was done using the Battelle CO_2-GIS to examine the logistics of transport and storage and Battelle Carbon Management Electricity Model to analyze the physical capacity. These physical parameters include the installed capacity, expansion and dispatching. Four study cases were applied where combinations of hypothetical carbon emission prices and natural gas delivered prices increases at different rates. The study takes into account the potential geological storage capacity available in each of the electric power regions, prioritizing those with the value-added sites first; a site with possibility of enhancing oil recovery using CO_2 injection is considered a value-added site, for example. By the sheer size of the study, it offers a big picture of the nationwide possibilities and not a detailed plan for each state. One of the significant findings from the study is that despite the escalating penalty of CO_2 emissions, fossil fuel technologies still remain prominent members in the electricity generation system. In fact, the first order response to the CO_2 emission restriction is to reduce the generating capacity of coal-fired power stations and increases the generation from the natural gas fueled stations (M. Wise, 2007), which is consistent with the finding from our study.

(A. Poullikkas, 2009)

In 2009, A. Poullikkas et al. proposed a study using WASP 2006 software package to find the optimal energy generating system for the island of Cyprus with the least economical and environmental impact. The study covers the period of 2007-20036. The ability to monitor all of the imported fuel and energy related materials prove a great advantage for choosing an island as a case study. No renewable sources and only three major types of fossil fueled generating capacity were considered including pulverized coal, integrated gasification combined cycle, and natural gas combined cycle. However, an extensive list of pre and post-combustion application of the CCS system were considered where available. A number of study cases with different forecast prices of natural gas in combination with various CCS system applications were carried out. It should be noted that, similar to many previous studies, the options to fuel switch, fuel balance, or retrofit the existing generating stations with CCS system were not considered. Furthermore, due to the lack of potential geological storage sites on or in close proximity to the island, the logistics of the CO_2 sequestration were also not considered.

Similar to the case study done on the island of Cyprus by A. Poullikkas et al., J. Johnson et al. proposed a study for island of Hawaii, a 24-year horizon from 2007-2030. The study uses wedges of efficiency programs and supply technologies to achieve the overall emission reduction target. The solution is linked to the physical characteristic of the topography (J. Johnson, 2009), certain emission reduction oriented measures are more effective than others. For example, on the island of Hawaii, wind resources offer much greater potential than perhaps building efficiency restrictions, thus the magnitude of the wedge for the wind program is larger than that of the building restrictions. The size of these wedges varied and a number of them are required to produce a significant emission reduction. Other than the proven advantage in the ability to monitor the imports and exports of all energy related matters, the electricity unit price for Hawaii is approximately tripled the U.S. average. This increases the potential of high efficiency energy products and supply technologies which may not be economically viable for many other average cities and states. The study concerns a very comprehensive list of energy efficiency programs and strategies. It is not specifically tailored to the energy generation sector but the population as a whole requiring many wedges-in-action. As a result, many parameters concerning a specific and unique plan for the energy generation sector were not being considered which included the construction lead time and detailed generation parameters. The paper also supports the controversial biofuel for both transportation and power generation.

The most relevant works to this study are the two previously done by H. Hashim et al. in 2005 and H. Mirzaesmaeeli et al. in 2007. The work done by H. Hashim and P. L. Douglas was a Mix-Integer Non-Linear Programming (MINLP) single period deterministic optimization model. The model produces the fleet structure where the electricity demand and CO_2 emission constraint are satisfied at the least cost. However, as stated earlier, this study is a single period model where a given short period of time is involved thus many time-dependent variables were not being considered. In order to produce a more generic result, the time-dependent variables including, but not limited to, construction lead time, fuel price fluctuation, and annual CO_2 emission reduction target should be considered. The most recent work done by H. Mirzaesmaeeli included these time-dependent variables. It also uses similar linearization techniques which allow non-linear models to be simplified and examined without the problems in non-linear nature. Mirzaesmaeeli's multi-period model spans a horizon of 14 years.

This study extends Mirzaesmaeeli's deterministic multi-period model to span any given horizon of 30 years and introduces renewable source, wind in particular, as an additional supply technology. This will help improve the existing model to be able to produce more generic results where wind is making head way in Ontario.

2. ENERGY MIX

Supply Technologies

In order to satisfy the electricity demand, Ontario uses various types of supply technologies. Five major groups of supply technologies are offered as possible sources of new power to the existing fleet. These sources will be briefly discussed to grasp a big picture of the current and possible future installed capacity.

Coal

One of the most controversy source of fuel, coal is the most abundant and well contributed over the topography. As a result, coal is one of the cheapest fuels available and is very reliable for the way it is combusted. Coal quality is rated by the carbon and moisture content and consequently the heat rate given out during the combustion processes. And this perhaps is the source of the coal controversy; coal offers the cheapest cost per unit power generated and superb reliability while contains the highest carbon content of all fuel which is regarded as a dreadful proposition in the emission awareness era.

Two prominent technologies are involved in coal combustion; Pulverized coal and Integrated Gasification Combined Cycle (IGCC)

Pulverized coal:

Coal is pulverized and combusted. The heat released is used to produce steam and drive the steam turbine and ultimately generates the electricity. Pulverized coal combustion is a very old and reliable technology. Generally, coal-fired power station has an expected life cycle of 50 years or more. A PC plant can be equipped with post-combustion CCS system. A typical scrubbing process uses monoethanolamine as a scrubbing agent absorbing the CO_2 content. These CO_2 is then release into the steam-heated generator. Due to the low efficiency in a typical aging PC plant, drawing energy in the form of steam to remove any amount of CO_2 will even further decreases this efficiency (A. Poullikkas, 2009).

Integrated Gasification Combined Cycle (IGCC):

Coal is gasified into synthetic gas (syngas) which is then use as fuel to drive a gas turbine. The waste heated gas however, is recovered and used to generate steam and simultaneously generating electricity, hence the combined cycle. Sulphur dioxide content and other particulates are reduced with very high efficiency before it is combusted. IGCC is the most recent coal-fired technology. The gasification process turning coal into syngas allows for CO_2 removal via acid gas remover. The CO_2 will then be compressed for ease of transportation and storage. Similar to the CCS system equipped on a PC plant, steam is required in the process of CO_2 removal. By removing CO_2 from the feed prior to the combustion process, an additional amount of coal will be required to necessitate the combustion in the turbine (A. Poullikkas, 2009). A post-combustion CCS system can also be installed on the exhaust, similar to that for PC.

Under the Environmental Protection Act, all Ontario's coal-fired power stations must cease burning coal by December 31st 2014. There is, however, a renewed interest in coal due the recent advances in carbon capture and storage (CCS) system. Province of Alberta and Saskatchewan are returning to coal technology (National Energy Board, November 2007) since the emission issue is now being addressed.

Natural gas

Natural gas is a sensible alternative in the fossil fuel group since, varied by the sources, it contains considerably less carbon content than coal. There are a number of natural gas technologies used. In this study, Natural Gas Combined Cycle is used as a predominant type of natural gas-fire station offered in the model due to the relative high efficiency.

Natural Gas Combined Cycle (NGCC):

Compressed air is injected into the combustion chamber along with the natural gas fuel, expanding in the combustion process, driving the gas turbine. Similar to the IGCC, the waste gas is recovered and utilized in steam generation and simultaneously producing electricity, hence combined cycle.

Natural gas does not contain nearly as much NO_x, SO_x, and particulates as coal and therefore emit much less undesired particles from combustion. As a result, it can be integrated into city infrastructures where much of the energy is needed, further reducing stress on transmission system since the distance between the sources and demand locations is abbreviated.

Similar to IGCC, both pre and post-combustion CCS system are available for NGCC.

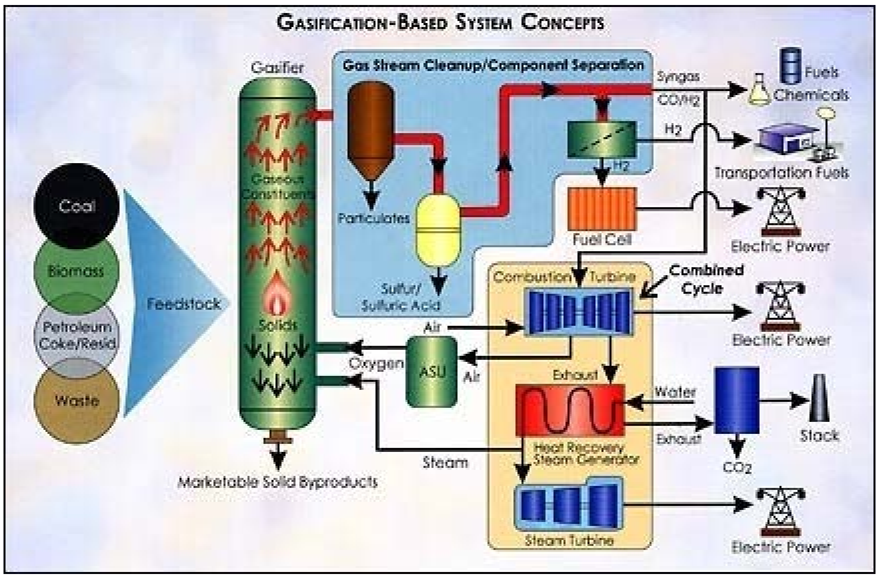


Figure 3 Gasification-based system (U.S. Department of energy)

Renewable

Great effort by Ontario governing body has gone into increasing over all renewable capacity of the fleet. Proven hydroelectric technology and other maturing renewable technologies such as wind are becoming an important component of many provinces and territories throughout Canada. Mainly two sources of renewable technologies are used in Ontario: hydroelectric and wind turbine.

Hydroelectric

An old and proven technology has been well exploit in Ontario and many other provinces in Canada, especially Quebec. A damn or outlet system is built into the water way and used to generate electricity by driving the water turbine, converting potential energy into kinetic energy. The water turbine blades may be tilted according to the amount of water available to extract the most energy possible.

Taking advantage of the Niagara escarpment, large amount of electricity is produced throughout the year, an essential generating source in southern Ontario.

Table 1. Ontario's Installed Capacity (IESO)

Fuel	**Installed Capacity (MW)**
Nuclear	34.5%
Hydroelectric	23.6%
Coal	19.4%
Natural Gas	13.5%
Wind	6.9%
Other	2.1%

As demonstrated in table 1, more than 23% of electricity in Ontario installed capacity, second largest portion, is hydroelectric. Similar to the wind sources, hydroelectric cannot be used on demand. The hydroelectric production rate does not vary much throughout the day but rather seasonal according to the time of year. As such, hydroelectric sources are more reliable than wind. It should be mentioned that the effect of the global warming may creates drought in some area and increase precipitations in others. Due to these effects, it may become harder to predict the level of water available for electricity generation.

Wind turbine

A turbine rotated by wind power, generating electricity. A long coast line surrounding Ontario presents a great wind source. Ontario has double in wind capacity within the last 5 years and currently has the largest installed wind capacity in Canada (Independent Electricity System

Operator, Dec 2008). Tilting of wind rotor blades may also increase the electricity extraction in accordance with wind condition.

Wind technology also presents many unique challenges. For instance, The locations of the wind sources are, in many cases, not in close proximity to the demand locations. This implies that modifications and additions to the aging transmission system will have to be made if the electricity is not being distributed locally. The storage medium such as battery is quite essential due to the sporadic nature of wind and its inability to generate the electricity on demand.

In the face of these challenges, wind is still a renewable supply technology of choice in various jurisdictions around the world, as depicted in table 2.

Table 2. Wind capacity from other leading jurisdictions (Independent Electricity System Operator, Dec 2008)

Jurisdiction	**Wind Capacity (MW)**	**Total Installed Capacity (MW)**	**Local Approach**
California	2,600 (4.6% of total installed capacity)	56,136	Actively involved in storage technology initiatives. Recent transmission planning study focused on the integration of large volumes of wind to determine load following, hourly ramping requirements, regulation capacity and over-generation issues.
Texas (ERCOT)	6,023 (9.8% of total installed capacity)	61,552	Proactively involved in enhancing high-voltage transmission system to accommodate wind generation.
Spain	15,039 (17% of total installed capacity)	86,231	Wind power is facilitated by pumped generation storage and 40,000 MW of reserve capacity in excess of peak demand. Wind capacity expected to increase by 3,500 MW per year
Germany	22,247 (17.5% of total installed capacity)	127,000	Infrastructure supports renewables with high rates of transmission capacity and population density.
Denmark	3,125 (24% of total installed capacity)	12,969	Infrastructure supports renewables with high rates of transmission capacity and population density

Nuclear

There are three nuclear stations in Ontario, totaling more than 10.8GW of installed capacity and is used to fulfill, by far, the majority of Ontario electricity demand at any given time. It is an important structure to the fleet and is being constantly refurbished. Nuclear reactors are perhaps the most complex energy extraction processes used in Ontario’s fleet. The issues of operational security concerns are an ongoing challenge. To satisfy these operational security parameters, a typical nuclear reactor site may takes seven years or more to complete. The radioactive waste also presents a problem where no permanent solutions exist to neutralize them. On the other hand, low fuel cost and virtually no GHGs emission are very attractive propositions.

The most common type of nuclear reactor used in electricity generation is the Pressurized Water Reactor where water is used as medium to carry the energy released from the splitting of Uranium atoms. Heavy water, D_2O, may be used as an alternative to light water, H_2O, to control the amount of energy released due to the speed of the split atoms. The energy released in the process produces pressurized high temperature water vapor which is used to drive the turbine. The CANada Deuterium Uranium (CANDU) reactor is an example of such reactor.

Import and Export

Ontario is not new to the import and export electricity market. In fact, Ontario's grids are connected to Quebec, Manitoba, New York, Minnesota, and Michigan offering greater opportunities to export electricity to the neighbouring territories and import it when more is needed. Table 3 exhibits import and export scenarios in the recent years.

Table 3. Ontario Import and Export Capacity (IESO)

Year	Imports (TWh)	Exports (TWh)	Net Imports (TWh)
2008	11.3	22.2	-10.9
2007	7.2	12.3	-5.1
2006	6.2	11.4	-5.2
2005	11.0	10.2	0.8
2004	9.8	9.5	0.3
2003	10.4	6.3	4.1
2002	7.1	3.9	3.2
2001	4.3	4.1	0.2
2000	5.1	5.5	-0.4

The most recent high voltage grid connection is the Ontario-Manitoba Interconnection Project (OMIP). The project has the potential of 1,500 MW to transmit the electricity generated from the Nelson's river dam in Manitoba (6th Annual Ontario Power Summit, Hydro One Inc., June 2007).

The connected gird is an excellent way to send and receive the supplement electricity. But the blackout effect can send an undesired ripple effect along the grid as well, as was evident in the infamous 2003 blackout.

Carbon Capture and Sequestration System

The capture and sequestration process has been used in the oil industry for decades; pressurized CO_2 is injected into the well to increase extraction pressure. Such sequestration is only used with small amount of pressurized gas and is not of industrial capacity.

While the technology is widely accepted as a potential solution to the GHG emission problem, not many countries has the experience of the procedure. A handful of European countries has been sequestrated CO_2 for the past decade in relatively small projects over time. Many safety challenges such as the transportation, sequestration pressure, and the leakage from the sequestration sites due to substandard well integrity are of great concerns.

In a typical electricity generating station, CO_2 is extracted via a pre or post-combustion system mention previously. The CO_2 is then purified and compressed for ease of transportation by means of network pipelines or vehicles. The purified CO_2 can then be sequestrated on the selected site. These sites can be off shore or inlands, depleted oil or gas reservoir. Due to the complexity of ecosystem and interconnected roll we do not fully understand, deep sea sites present a greater concern to science community should the leakage happens.

The CO_2 extraction process may be utilized prior to combustion, pre-combustion, producing CO and Hydrogen gas where it is further reacted with water, H_2O to produce CO_2 and H_2. The CO_2 can also be extracted after combustion, post-combustion, in an absorption process using monoethanolamine (MEA) solvent. MEA is the CO_2 scrubbing process offered in this model. Flue gas stream is sent through a relatively cold aqueous MEA solution. This mixture is then heated to extract the CO_2 and regenerate the MEA solvent. The process is repeated.

The CCS system can be fitted to a new power station or retrofitted to the old power station. There are usually higher energy penalty associated with older stations where the efficiency may not be as high as the recent technologies used (A. Rubin, 2002). Increasing the efficiency of a particular power station before being retrofitted is of the best interest. However, both processes are relatively expensive and time consuming. They may not be economically feasible to many companies and governing entities. At times, improving the efficiency of the existing boilers can be a more effective solution where less fossil fuel is used to produce the same amount of energy, reducing the emission. A retrofit procedure on an existing coal-fired power station may cost 2004 USD $2,000 per MW of electricity produced (H. Hashim, 2005).

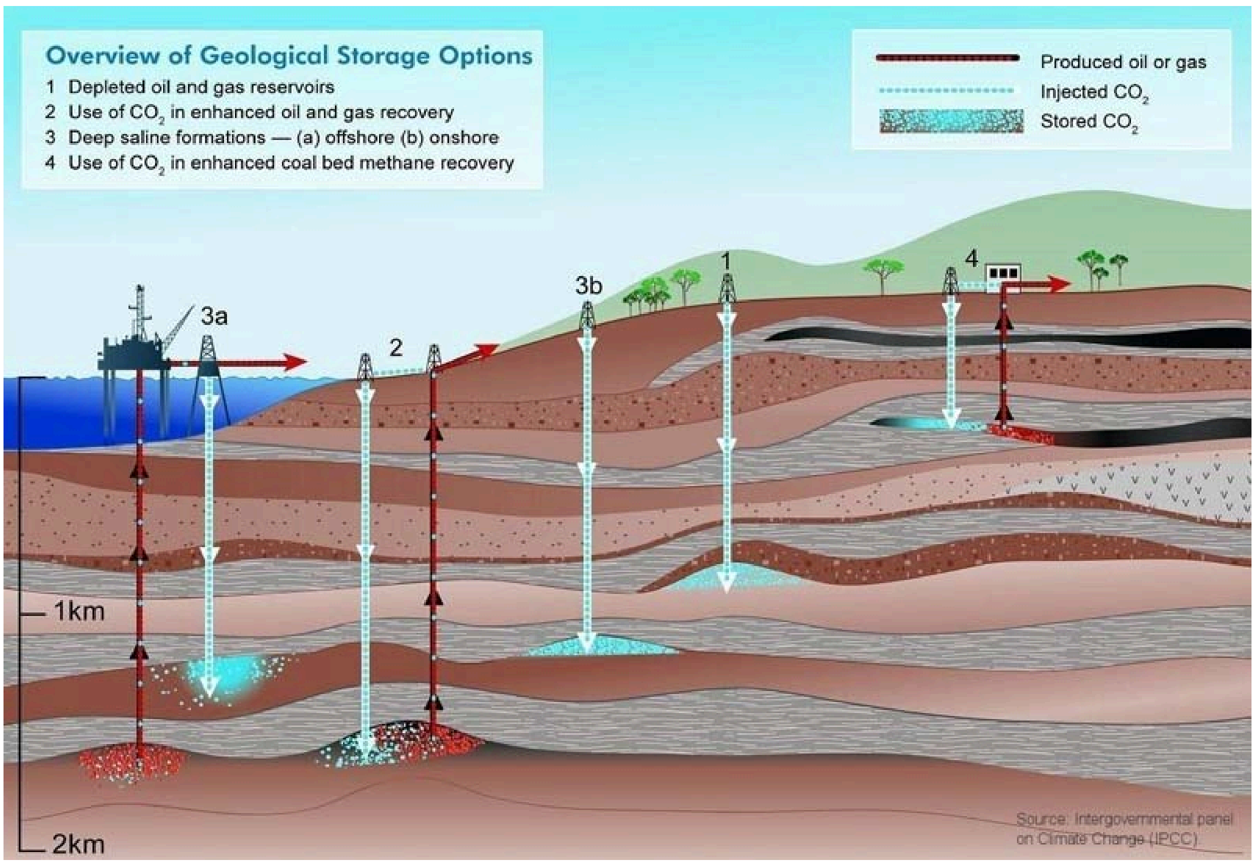


Figure 4. Geological storage options, intergovernmental panel on climate change (World Meteorological Organization)

A study was done in 2004 by A. Shafeen et al. approximating the storage capacity of the sequestration sites within the Great lakes, 289 Mt in Lake Huron and 442 Mt in Lake Erie. The subsequent study also indicates the prerequisite depth of, the site where CO_2 is to be injected, 800 meters. Other supercritical states where a number of physical parameters have to be satisfied greatly limits the number of possible sequestration sites. This is partly a contributing factor to the small number of an ongoing sequestration attempts.

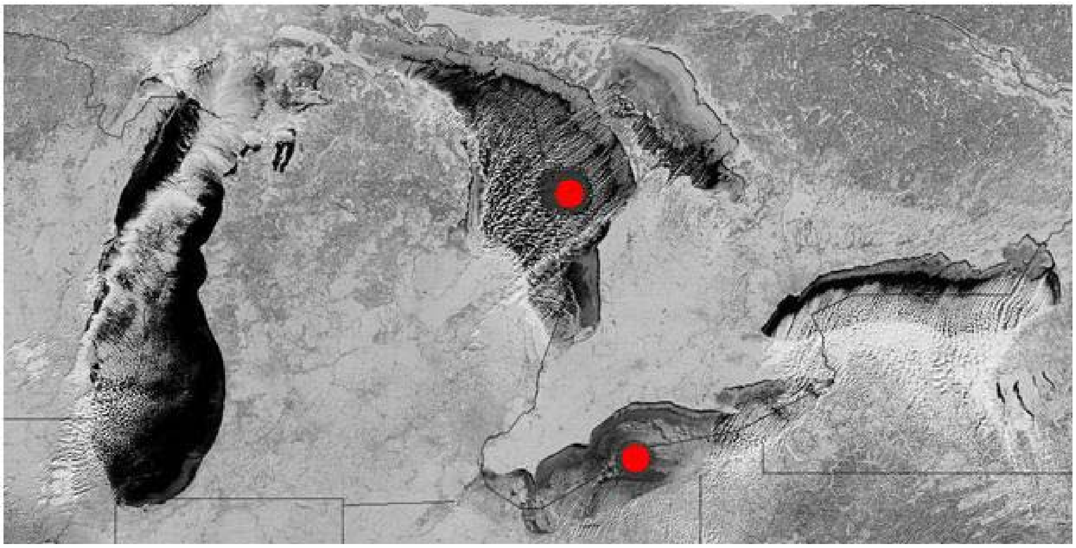


Figure 5. Sequestration sites in Ontario. Marked in red, Lake Huron (top) and Lake Erie (bottom)

Procurement

A large gap between energy supply and demand is rapidly increasing. With unavoidable imposing restrictions such as the Environmental Protection Act and Kyoto Accord, the task is indeed overwhelming. Several energy procurements are underway. These project includes wind, hydroelectric, natural gas, and nuclear. Contracts capacity and expected dates of operation are listed in table 4 below.

Table 4. Contract projects under development (Ontario Power Authority, Third quarter 2008)

Project Name	Average Contract Capacity (MW)					
	2008	2009	2010	2011	2012	2013
Wind Projects, total = 771 MW						
Melancthon II	132					
Kingsbridge II	158.7					
Enbridge Ontario Wind Power Project		181.5				
KEPA	101.2					
Wolfe Island		197.8				
Hydroelectric Projects, total = 116 MW						
Umbata Falls	23					
Island Falls		20				
Lac Seul	29.3					
Hound Chute Generating Station		9.5				
Wawaitin Generating Station		15				
Sandy Falls Generating Station		5.5				
Lower Sturgeon Generating Station		14				
By-product Gas Projects, Total = 63 MW						
Algoma CHP		63				
Natural Gas Projects, Total = 3,977 MW						
St. Clair Energy Centre		577				
Greenfield Energy Centre	1,005					
Greenfield South Power Plants				280		
Goreway		839.1				
Portlands Energy Centre		300				
Halton Hills			631.5			
Great Northern Tri-Gen	11.5					
East Windsor CHP		84				
Thorold CHP			236.4			
Countryside London CHP	12					
Nuclear Refurbishment Projects, Total = 3,000 MW						
Bruce A Unit 1 Refurbishment		750				
Bruce A Unit 2 Refurbishment	750					
Bruce A Unit 3 Refurbishment						750
Bruce A Unit 4 Refurbishment					750	
Total Capacity Under Development = 7,927 MW						

3. MODEL

As previously stated, this thesis will utilize the multi-period General Algebraic Modelling System (GAMS) model by H. Mirzaesmaeli et al. with various modifications in order to produce a more genuine result. These modifications include input manipulation as well as the source code.

For ease of demonstration, the model is be discussed in three key parts: input, computation, and output

Input

A large amount of data is an integrated part of the model considering the long horizon of a given 30 years. User friendly interface is of considerable importance. Microsoft excel spreadsheet is used as an input source. The master data file contains 18 sheets and more than 1,400 KB of data. Followings are the data fields being considered by the model and will be discussed briefly.

Forecasted energy demand

A stochastic model was used in the study by Chui et al. in 2006, forecasting Ontario electricity demand from 2005 to 2025. The study used forecasts from Ontario Ministry of Finance and various weather scenarios to aid the model. The demand growth in Canada is said to be roughly 1% annually (IESO, 2006). The example forecasts are depicted in figure below. The forecasts are then extrapolated until 2040 as needed.

Load duration curve is also used to aid the scheduling of the facility. The load duration curve is generated by rearranging the demand in their respective order from high to low. To simplify the problem, the load duration curve, as depicted in Figure 7, (left) can be linearized (right). As a result, the operation can be simplified into two modes: peak and base. This will ultimately help eliminate the inherent problem with non-linear systems.

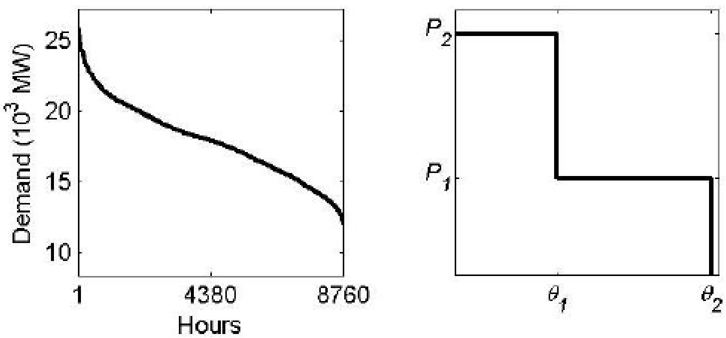


Figure 6 Load duration curve (right), linearized load duration curve (left) (Chui, 2007)

Fixed and Variable O&M cost

Both fixed and variable operation and maintenance cost are also being considered. Fixed O&M cost is the maintenance cost per MW while the variable O&M cost is the associated maintenance cost per MWh which may include the cost of required chemicals and parts. Insurance charges, expenditure on personnel are considered fixed O&M cost. The variable O&M cost is varied according to hours it operates. These costs are generally higher on the boilers with CCS system fitted due to, among others factors, the apparent energy required for the CCS processes.

Fuel price

Various sources of fuel price forecasts are available and conflicting at times. The fuel price input is designated into 15 periods to be able to deal with the fluctuation. In the Canada's energy future report by the National Energy Board, reference case to 2030 is presented. The 'reference case and continuing trends' forecast a constant coal delivered price of 2.29 2005 Canadian dollars, a constant from 2006 to 2030. Similarly, the natural gas price is a constant of $7.0 2005 CND. The report also presents two other scenarios; triple E case where well functioning energy market and international cooperation and the fortified islands case where lack of international cooperation and geopolitical unrest dominate.

Capital cost of new plants

Capital cost for new power stations are part of the decision parameter for the model. Some technology such as wind and nuclear will have a very high capital cost with respect to other supply technology. This is contributed in part by the advantages it offers over other technologies, particularly the desired lack of GHGs emissions. In addition, new power stations with CCS tend to have higher associated capital cost.

Construction lead time

One of the time dependent variables, construction lead time clause ensure that no electricity is available before the physical structure of the power station exists. This period varies between technology types. Typical construction period for a nuclear power station can take 7 years or more. PC and IGCC required a similar construction time of 5 years. NGCC however, only takes 3 years to build, but may not last as long as a typical PC plants.

Annual CO_2 emission targets

Total annual aggregate CO_2 emission can be specified in the input data for the desired level of emission. Two major sources of the emissions are the existing coal and natural gas stations without CCS system installed.

Cost carbon capture and sequestration

The decision weather a power station, existing or new, should be fitted with the CCS system will be made by the model. The cost for CCS to be fitted for each specific plant is required. The exception is the renewable energy and nuclear stations where no CO_2 emission exists. Should the CCS be fitted to a specific power station, existing or new, the local sequestration site, Lake Erie or Lake Huron, will also be designated.

Cost of CO_2 credits

Purchasing CO_2 credit is rather a radical concept for North American market. The idea has been proven to be quite lucrative as is evident in Europe. This will allow the GHG emissions to become economically viable. The market or the government may offer certain incentives to achieve the reduction target. Cost of CO_2 credit can be varied year by year in the input data sheet. A higher credit cost per tonne of CO_2 should be high to discourage the model from easily purchase the credit in order to achieve the emission target, which is not a preferred strategy.

Conservation and Demand Management

Conservation and demand management are two related concepts. Conservation can be achieved, throughout the history, via the advances of technologies or changing the consumption pattern of the consumers. Demand management can similarly help reduce peak loads as well as the stress on the generating and distribution system. Combining the two can greatly increase the reliability of the system. This can be done by wisely shifting the peak load to off-peak periods as depicted in figure below.

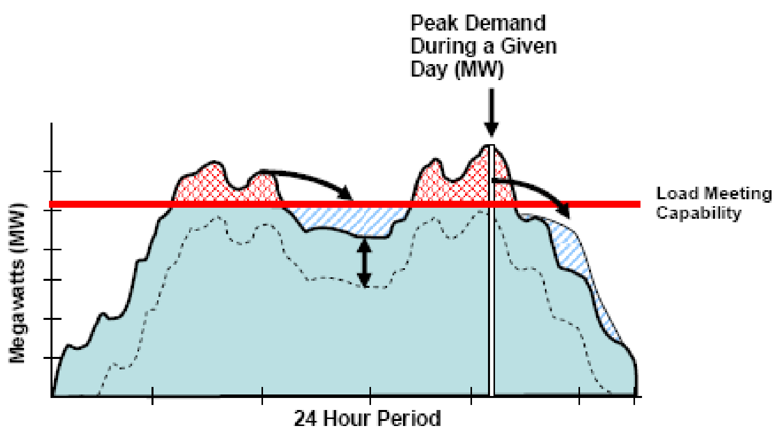


Figure 7 Conservation and Demand Management strategy (Ontario Power Authority, 2005)

While the technology advancement is very hard to predict, Ontario has set a short term CDM targets at 1 000 MW (Independent Electricity System Operator, March 2007). A portion of CDM is considered to be quite constant over the horizon as depicted in the plot given in the OPA mix advice and recommendations report.

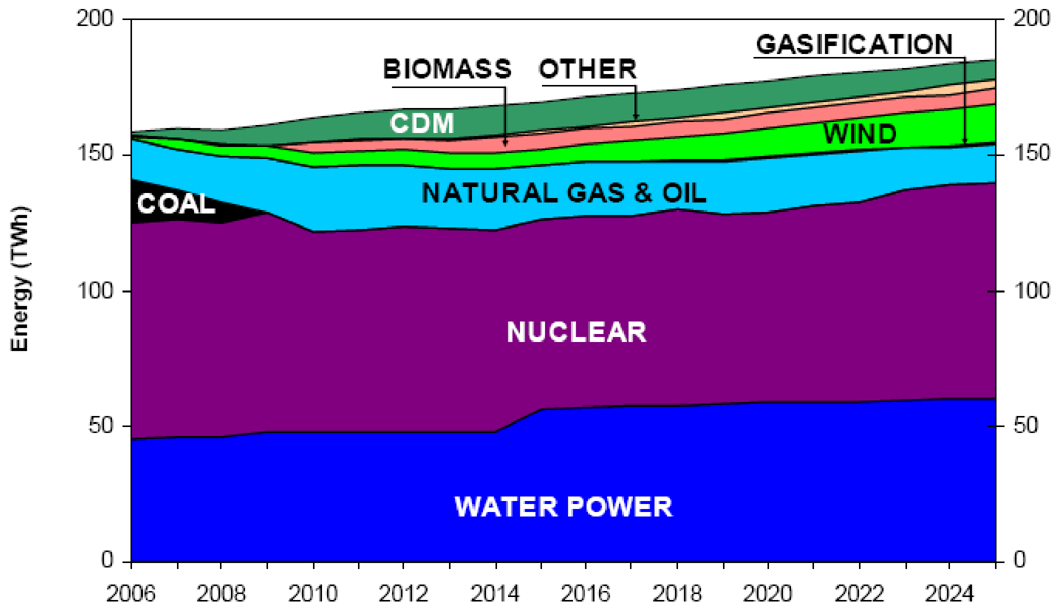


Figure 8 Projected Conservation and Demand Management

over the next 20 years (Ontario Power Authority, 2005)

Objective Function

In this section, the content is of reference to Mirzaesmaeeli's work as most of the content has not been changed.

The objective function for the deterministic multi-period MINLP is as follow:

$$
\begin{aligned}
\min\ f(i,j,k,l,t) = {} & \underbrace{\sum_{i\in F}\sum_{j}\sum_{t} F_{ijt}^{F} C_{ij}^{F} x_{ijt} + \sum_{i\in NF}\sum_{t} F_{it}^{NF} C_{i}^{NF} y_{it}^{NF}}_{\text{Fixed O\&M cost of existing power plants}} + \underbrace{\sum_{i\in F}\sum_{j}\sum_{l}\sum_{t} V_{ijt}^{F} E_{ijlt}^{F} P_{lt} + \sum_{i\in NF}\sum_{l}\sum_{t} V_{it}^{NF} E_{ilt}^{NF} P_{lt}}_{\text{Variable O\&M cost of existing power plants}} + \\
& \underbrace{\sum_{i\in F}\sum_{j}\sum_{l}\sum_{t} U_{jt} G_{ij}^{F} E_{ijlt}^{F} P_{lt}}_{\text{Fuel cost for fossil fuel plants}} + \underbrace{\sum_{i\in F}\sum_{t} R_{it} h_{it}}_{\text{retrofit cost for fuel switching}} + \underbrace{\sum_{i\in P^{new}}\sum_{t} S_{it}^{new} C_{i}^{new} n_{it}}_{\text{capital cost for new power plant}} + \underbrace{\sum_{i\in P^{new}}\sum_{t} F_{it}^{new} C_{i}^{new} y_{it}^{new}}_{\text{Fixed O\&M cost of new power plant}} + \\
& \underbrace{\sum_{i\in P^{new}}\sum_{l}\sum_{t} V_{it}^{new} E_{ilt}^{new} P_{lt}}_{\text{Variable O\&M cost of new power plant}} + \underbrace{\sum_{i\in P^{new}}\sum_{l}\sum_{t} U_{it} G_{i}^{new} E_{ilt}^{new} P_{lt}}_{\text{Fuel cost for new power plant}} + \underbrace{\sum_{t} (Cre)_t (CCost)_t}_{\text{Cost of purchasing CO2 emission credits}} + \\
& \underbrace{\sum_{i\in F}\sum_{j}\sum_{k}\sum_{l}\sum_{t} Q_i (CO2)_{ij}\, \varepsilon_{ikt} E_{ijlt}^{F} z_{ijkt} P_{lt}}_{\text{Carbon capture and storage cost for existing power plants}} + \underbrace{\sum_{i\in P^{new-cap}}\sum_{l}\sum_{t} Q_i (CO2)_i \varepsilon_{ikt} E_{ilt}^{new} P_{lt}}_{\text{Carbon capture and storage cost for new power plants}}
\end{aligned}
$$

The program may choose to purchase a new power station(s) with pre-assigned capacity and other operational parameters. It should be noted that no binary variable is associated with the cost of the carbon capture and storage (CCS) for the new station(s). And for every new station(s) there is one option with CCS and one without, both having identical operational parameters.

The indices, sets, variables, and parameters used in the planning model are the following:

Indices

t	Time period (years)
i	Boiler
j	Fuel type (coal or natural gas)
l	Load block (peak or base-load)
k	Carbon capture technology

Sets

F	Fossil fueled power plants
NF	Non-fossil fuel
new	New power plants
$new{-}cap$	New power plants with carbon capture

T	Time horizon (years)
$(CO_2)_{ij}$	CO2 emission from boiler i using fuel j (tonne of CO_2/MWh)
E_{kmax}	Maximum supplemental energy required for kth capture technology
ε_{ikt}	Percent of CO_2 captured from boiler i using carbon capture technology k during period t (%)
β_i	Construction lead time for power station i (years)
Q_i	Cost of carbon capture and storage for boiler i (\$/tonne of CO_2)
D_{tl}	Electricity demand during period t for load l (MWh)
B_{tl}	Conservation and demand management during period t and load block l (MWh)
ρ	Factor for transmission and distribution losses
$CLimit_t$	Specified CO_2 limit during period t

Parameters

F_{ijt}	Fixed operating cost of boiler i using fuel j during period t ($/MW)
V_{ijt}	Variable operating cost of boiler i using fuel j during period t ($/MWh)
C_{ij}	Capacity of boiler i using fuel j (MW)
P_{lt}	Duration of load block l during period t (hrs)
U_{jt}	Fuel cost for fuel j during period t ($/GJ)
G_{ij}	Heat rate of boiler i using fuel j (GJ/MWh)
R_{it}	Cost associated with fuel-switching coal-fired boiler i during period t
S_{it}	Capital cost of power plant i during period t
$(CCost)_t$	Cost of carbon credits during period t ($/tonne of CO_2)

Binary variables

n_{it}	=1 if power plant i is built during period t = 0 otherwise
y_{it}	=1 if power plant i is operational during period t = 0 otherwise
x_{ijt}	=1 if coal-fired boiler i is operational while using fuel j during period t =0 otherwise
z_{ijkt}	=1 if the carbon capture technology k is used on boiler i, which uses fuel j, during period t.
h_{it}	=1 if coal-fired boiler i undergoes fuel-switching during period t =0 otherwise

Continuous variables

E_{ijlt}	Power allocation from boiler i using fuel j for load block l during period t (MW)
$(Cre)_t$	Carbon credits purchased during period t (tonne of CO_2)

In order to linearize the model, several parameters in the objective function shall be dealt with, using exact linearization method as follow:

Non-linear term from cross product of E^F_{ijtl} and Z_{ijkt} where the CCS retrofit for an existing station are being considered: decision to put binary variable Z with k^{th} carbon capture technology on the i^{th} boiler using j^{th} fuel during time t and the power allocation E from i^{th} fossil fuel boiler using j^{th} fuel type during period t and l^{th} demand.

Defining α_{ijktl} as a new continuous variable

$$\alpha_{ijktl} = E^{F}{}_{ijtl}\, Z_{ijkt}$$

Replace α_{ijktl} into the equation (1) below:

$$\sum_{i\in F}\sum_{j}\sum_{k}\sum_{l}\sum_{t} Q_i (CO2)_{ij}\, \varepsilon_{ikt}\, E^{F}_{ijtl}\, z_{ijkt}\, P_{lt} \tag{1}$$

Thus we have,

$$\sum_{i\in F}\sum_{j}\sum_{k}\sum_{l}\sum_{t} Q_i (CO2)_{ij}\, \varepsilon_{ikt}\, \alpha_{ijktl}\, P_{lt} \tag{2}$$

To ensure that this reformulation will yield the same results as its non-linear counterpart, additional constraints are defined as following:

$$0 \le \alpha_{ijtl} \le C^{F^{max}}_{ij} \qquad \forall i, \forall j, \forall t, \forall l \tag{3}$$

$$E_{ijtl}{}^{F} - C^{F^{max}}_{ij}(1 - z_{ijkt}) \le \alpha_{ijtl} \le C^{F^{max}}_{ij}\, z_{ijkt} \qquad \forall i, \forall j, \forall t, \forall k, \forall l \tag{4}$$

The objective function is now reduced to its final MILP form:

$$\min\ f(i,j,k,l,t) = \underbrace{\sum_{i\in F}\sum_{j}\sum_{t} F^{F}_{ijt} C^{F}_{ij} x_{ijt} + \sum_{i\in NF}\sum_{t} F^{NF}_{it} C^{NF}_{i} y^{NF}_{it}}_{Fixed\ O\&M\ cost\ of\ existing\ power plants} + \underbrace{\sum_{i\in F}\sum_{j}\sum_{l}\sum_{t} V^{F}_{ijt} E^{F}_{ijlt} P_{lt} + \sum_{i\in NF}\sum_{l}\sum_{t} V^{NF}_{it} E^{NF}_{ilt} P_{lt}}_{Variable O\&M\ cost\ of\ existing\ power plants} +$$

$$\underbrace{\sum_{i\in F}\sum_{j}\sum_{l}\sum_{t} U_{jt} G^{F}_{ij} E^{F}_{ijlt} P_{lt}}_{Fuel\ cost\ for\ fossil\ fuel\ plants} + \underbrace{\sum_{i\in F}\sum_{t} R_{it} h_{it}}_{\substack{retrofit\ cost\ for\\ fuel\ switching}} + \underbrace{\sum_{i\in P^{new}}\sum_{t} S^{new}_{it} C^{new}_{i} n_{it}}_{\substack{capital cost\ for new\\ power plant}} + \underbrace{\sum_{i\in P^{new}}\sum_{t} F^{new}_{it} C^{new}_{i} y^{new}_{it}}_{\substack{Fixed\ O\&M\ cost\ of\ new\\ power plant}} +$$

$$\underbrace{\sum_{i\in P^{new}}\sum_{l}\sum_{t} V^{new}_{it} E^{new}_{ilt} P_{lt}}_{\substack{Variable O\&M\ cost\ of\ new\\ power plant}} + \underbrace{\sum_{i\in P^{new}}\sum_{l}\sum_{t} U_{it} G^{new}_{i} E^{new}_{ilt} P_{lt}}_{\substack{Fuel\ cost\ for new\\ power plant}} + \underbrace{\sum_{t} (Cre)_t (CCost)_t}_{\substack{Cost of\ purchasing\ CO2\\ emission credits}} +$$

$$\underbrace{\sum_{i\in F}\sum_{j}\sum_{k}\sum_{l}\sum_{t} Q_i (CO2)_{ij}\, \varepsilon_{ikt}\, \alpha_{ijktl} P_{lt}}_{\substack{Carbon capture and storage cost\\ for existing power plants}} + \underbrace{\sum_{i\in P^{new-cap}}\sum_{l}\sum_{t} Q_i (CO2)_i\, \varepsilon_{ikt} E^{new}_{ilt} P_{lt}}_{\substack{Carbon capture and storage cost\\ for new power plants}}$$

Model Assumptions

In order to achieve the 30 years horizon, the subsequence assumptions are made.

- Each of the 15 periods of data will now be considered as a two year period with the overall horizon of 30 year. As such, all time-related numbers used will be even numbers and the average two year value where applicable. These include, but not limited to, construction lead time, refurbishment period, peak, and base demand.
- Fixed and variable operation and maintenance cost are constant over time.
- Carbon capture system and CO_2 sequestration sites are available, namely, Lake Erie and Lake Huron.
- Due to the design and security related issues, all power generated from the nuclear power station will be used only for base-load demand
- All existing nuclear power stations will be refurbished before their expected life cycle, thus kept operational over the study horizon. Refurbishment required 2 years to complete for a single unit (M. Winfield, 2004).
- Wind is offered as a renewable supply technology with the total of 5,000 MW of installed capacity as suggested in several reports by IESO.

4. RESULTS

Five study cases are performed and their results are presented in the subsequence parts of this section.

Case I: Reference case

Reference case is a control case where no CO_2 emission constraint is applied. Thus the result strategy will only concern the minimization of electricity cost, establishing the control case which will be used in comparison with other subsequence cases.

Cost of electricity

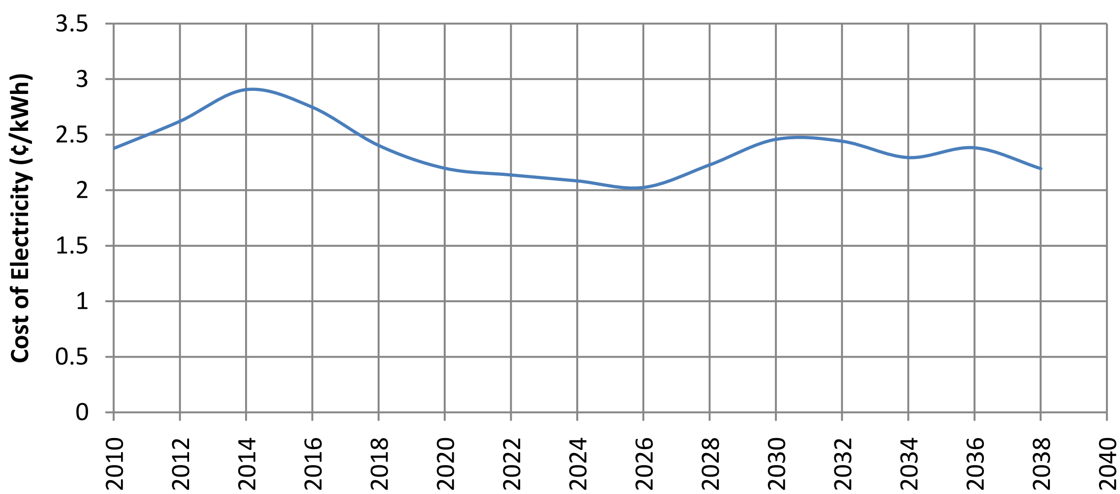


Figure 9. Overall cost of electricity

A trough is observed during the period of 2024 to 2028 where cost of electricity is, counter intuitively, lower than that in 2010, the beginning of the study. This is due to the expenditure curve which will be discussed later. Overall average cost of electricity is 2.37 ¢/kWh.

CO_2 emissions

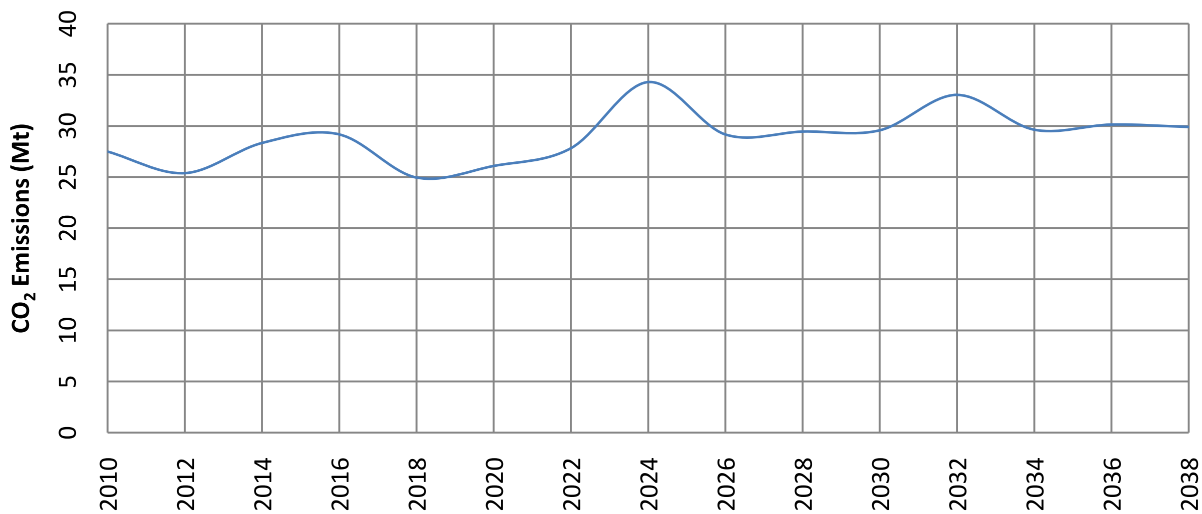


Figure 10. Overall CO_2 emission: base case

Total CO_2 emission over 30 year horizon is 869 Mt. There are 2 sharp peaks and a relatively high emission period observed during 2016, 2024, and 2032 respectively. These peaks result from the CO_2 emission of the new sources of power as they become available. Since there are no emission constraints, the model relies on natural gas and particularly coal more than any other cases. And as they start the electricity generation, these distinct emission peaks are observed.

Expenditure

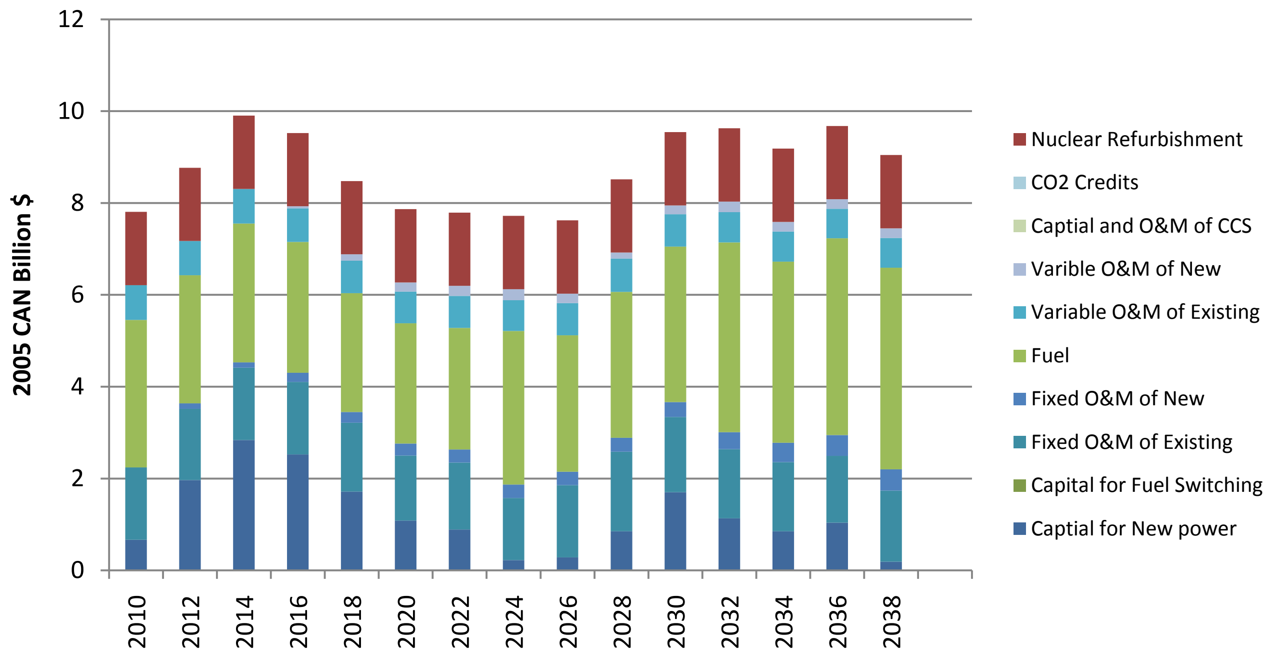


Figure 11. Detail expenditure: base case

As part of the base case, there are no CO_2 credit purchased, nor capital spending on fuel switching and CCS system. The results are as expected, depicted in figure 12. There are two distinct cycles of capital spending on new power peaking in 2014 and 2030. These peaks in capital spending correspond to the spikes in cost of electricity previously shown. Furthermore, over 38% of expenditure is being spent on various fuels as part of the fleet to supply the growing demand. Various supply technologies used in the growing fleet causing slight increase in operation and maintenance cost of both new and existing stations.

Fleet structure and electricity production

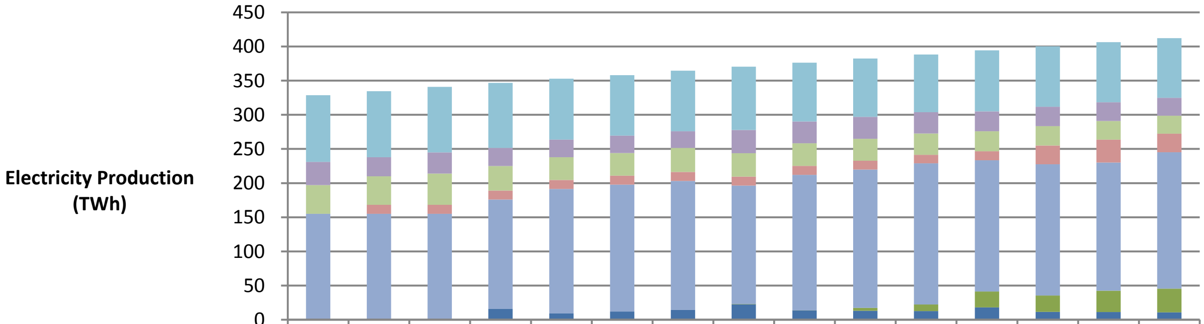
Table 5. Fleet structure: base case

	Capacity (MW)	2010	2012	2014	2016	2018	2020	2022	2024	2026	2028	2030	2032	2034	2036
PC	458														
PC	527														
PC	1053														
PC	527														
NGCC	253														
NGCC	507														
NGCC	760														
NGCC	1520														
NGCC	2279														
NGCC	3039														
Nuclear	3012														
Import	1250														
Wind	2500														

Table 5 depicted capacity (MW) and the construction time (year) for each particular supply technology. Highlighted in orange is the period of construction. The year thereafter is when electricity production commenced.

Total of 17,684 MW of new installed capacity is observed. This is the only case where the largest investment in coal technology is observed, totalling 2,564 MW. An even larger new NGCC installed capacity of 8,358 MW is observed. The decision to build such large fleet of new NGCC may results from a rather cheap capital for new NGCC stations. This however, does not implicate the level utilization of these plants as is shown in figure 13. Most electricity demand, however, is still satisfied by nuclear power. Nearly 50% of the total electricity generated over the study horizon are by way of nuclear sources. The new NGCC plants are used only minimally toward the end of the study period.

The new wind supplies are used at capacity throughout the whole horizon. Additional imported electricity is also utilized towards the end of the study period, introduced to the fleet in 2028.



	2010	2012	2014	2016	2018	2020	2022	2024	2026	2028	2030	2032	2034	2036	2038
Renewable	97	97	96	95	89	88	89	93	86	85	85	89	89	88	87
Existing NG & Oil	34	28	31	26	26	26	25	34	32	32	31	29	28	27	26
Coal	42	42	46	36	33	33	35	34	33	32	31	29	28	27	26
Hydro Imports + Wind	0	13	13	13	13	13	13	13	13	13	12	13	28	33	27
Nuclear	155	155	155	160	182	186	189	173	198	203	207	192	192	188	200
NGCC + CCS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
IGCC + CCS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PC + CCS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NGCC	0	0	0	0	0	0	0	0	0	4	10	23	24	31	35
IGCC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PC	0	0	0	16	9	12	14	23	14	13	13	18	12	11	11

Figure 12. Electricity Production (TWh)

Summary

In the reference case, where no CO_2 emission constraint is applied, the average cost of electricity is 2.37 ¢/kWh. 869 Mt of CO_2 is emitted while spending $131 billion. The overall expenditure peaks and troughs are, mostly, caused by the cycle capital spending on new power and fuel cost. The largest portion of the expenditure, over 49%, is being utilized on fuel. The fleet rely quite heavily on coal when comparing to other cases. Since there is no CO_2 emission constraint specified, no CCS or fuel switching technique are employed. Nuclear generating stations, new and existing, are of the most important to the fleet since they are used to generate nearly 50% of the total electricity generated over the study horizon.

Case II: Various CO_2 emission constraints

A wide range of emission restriction ranging from 6%, according to the Kyoto Accord, to 75% reduction targets are applied to the model. The results will be shown and discussed in this section. For ease of comparison and discussion, the reference case will be shown in this part as well. In all cases, the CO_2 emission constraints commence in 2014 period.

Cost of electricity

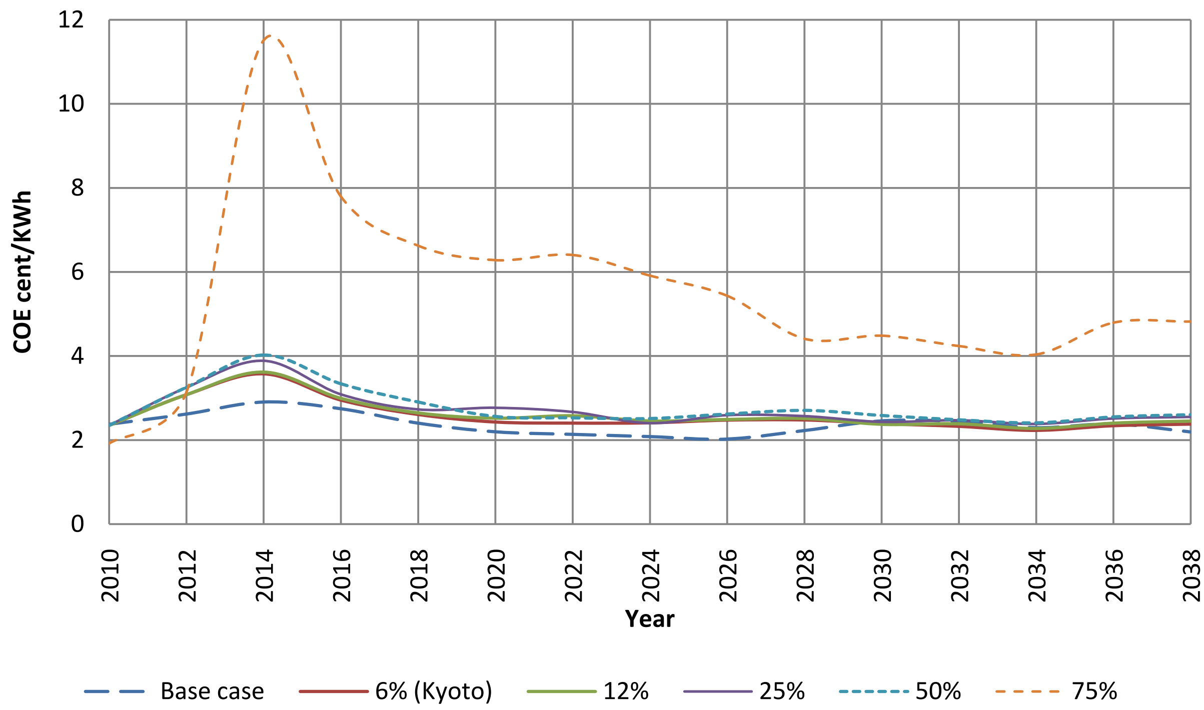


Figure 13. Overall cost of electricity

With an exception of the base case and the case of 75% CO_2 emission reduction target, all of the study cases follow the same general trend where the cost of electricity is considerably higher during 2014 than any other period. A large expenditure is being invested during this period to prepare the fleet for an increasing electricity demand in following years. Dramatic fluctuations in the 75% CO_2 emission reduction case are observed. In particular, the soaring peak during 2014 is caused by the large amount of CO_2 credit purchased. This is an unusual strategy caused by the highly restrictive emission reduction target. The fleet may not be able to elevate the appropriate supply in short period of time to satisfy the CO_2 constraint and electricity demand simultaneously. As such, CO_2 credit is being purchased to satisfy the CO_2 constraint during this early period.

CO_2 emission

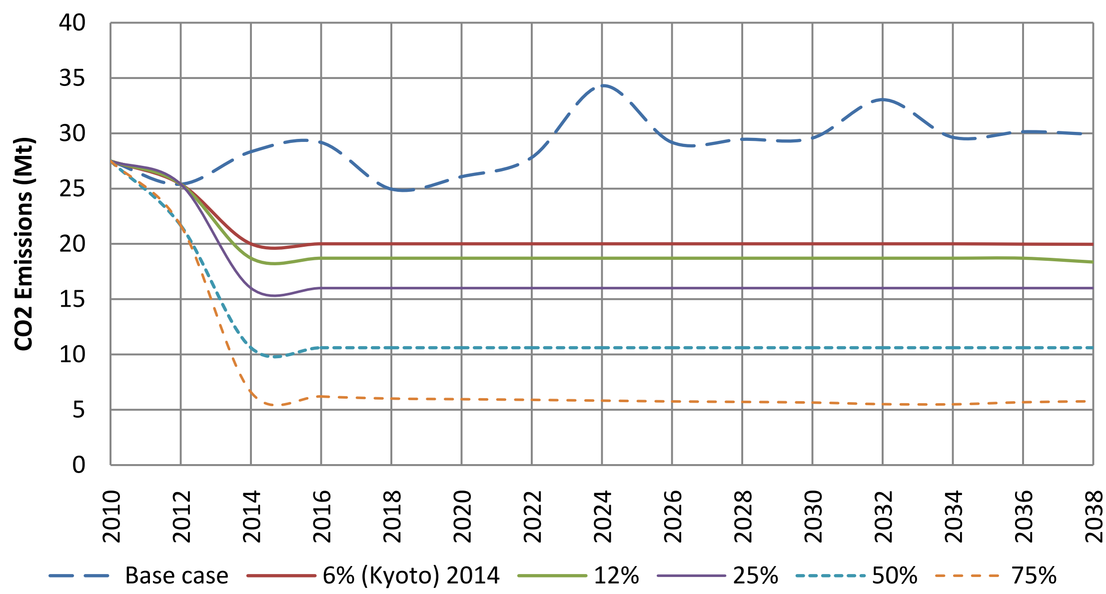


Figure 14. Overall CO_2 emission

As shown in figure 14, the overall emissions are as specified.

Expenditure

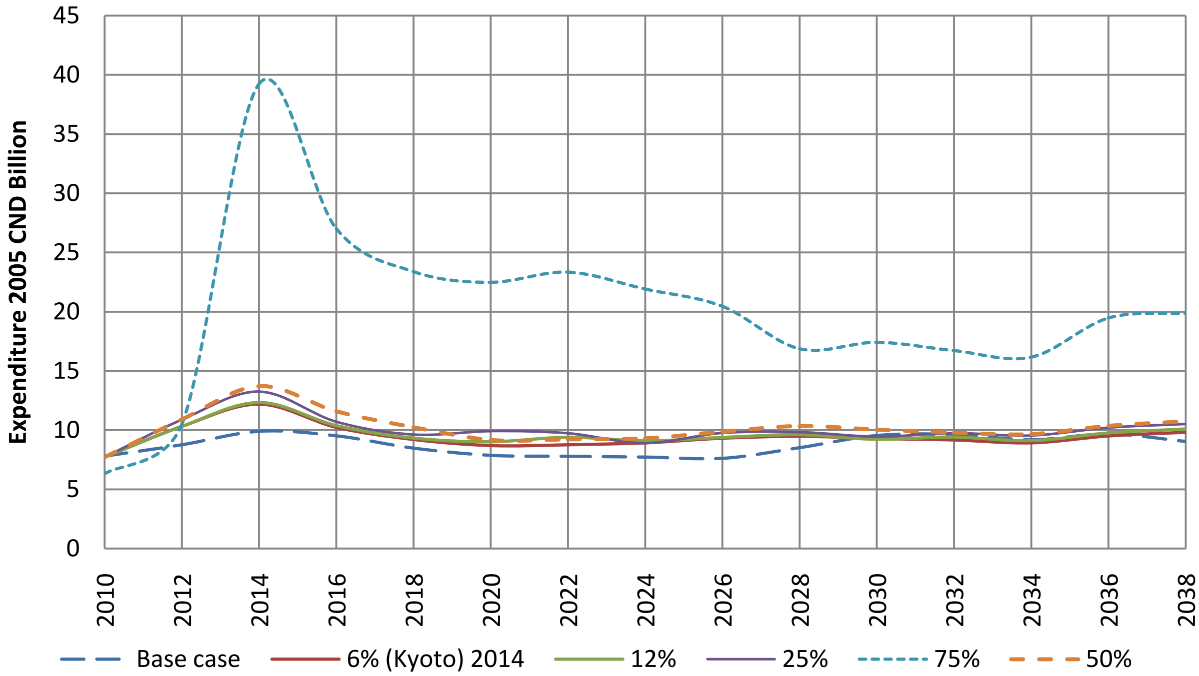


Figure 15. Overall expenditure

Virtually identical to the cost of electricity plot, the expenditure plot shows, figure 15, the overall spending for each case. Cases with CO_2 emission reduction target from 6% to 50% follow a very similar trend where the largest investment on new power is made earlier on, especially during 2014 where a highest peak is observed in all cases.

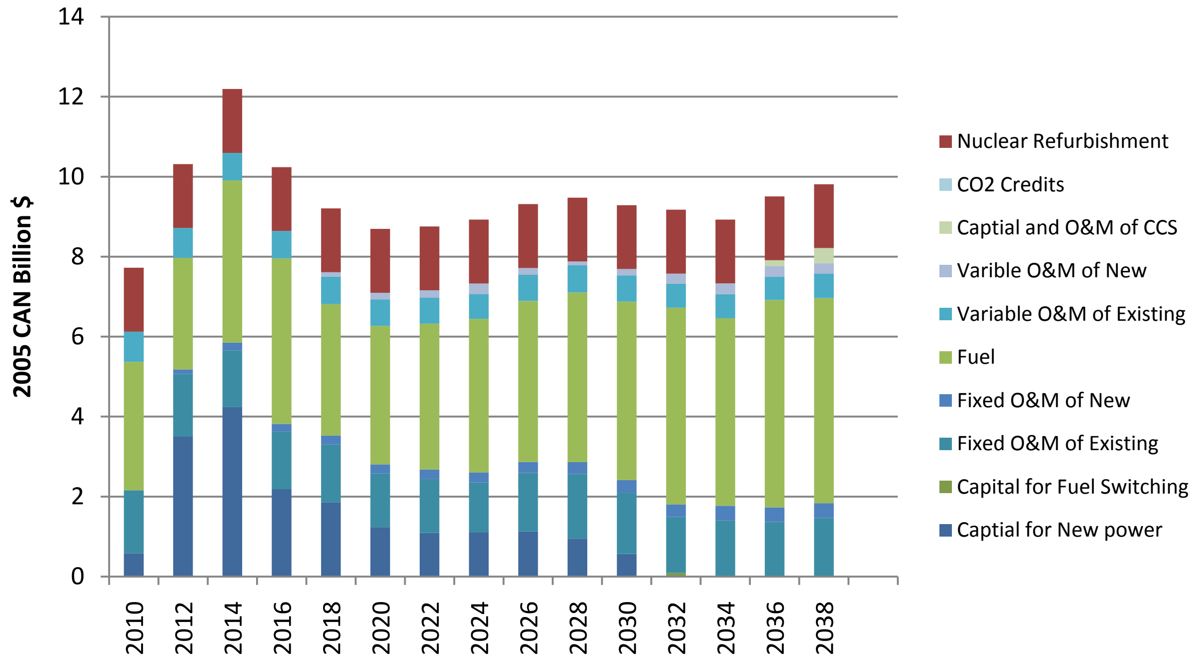


Figure 16. Detail expenditure: 6% CO_2 emission reduction target

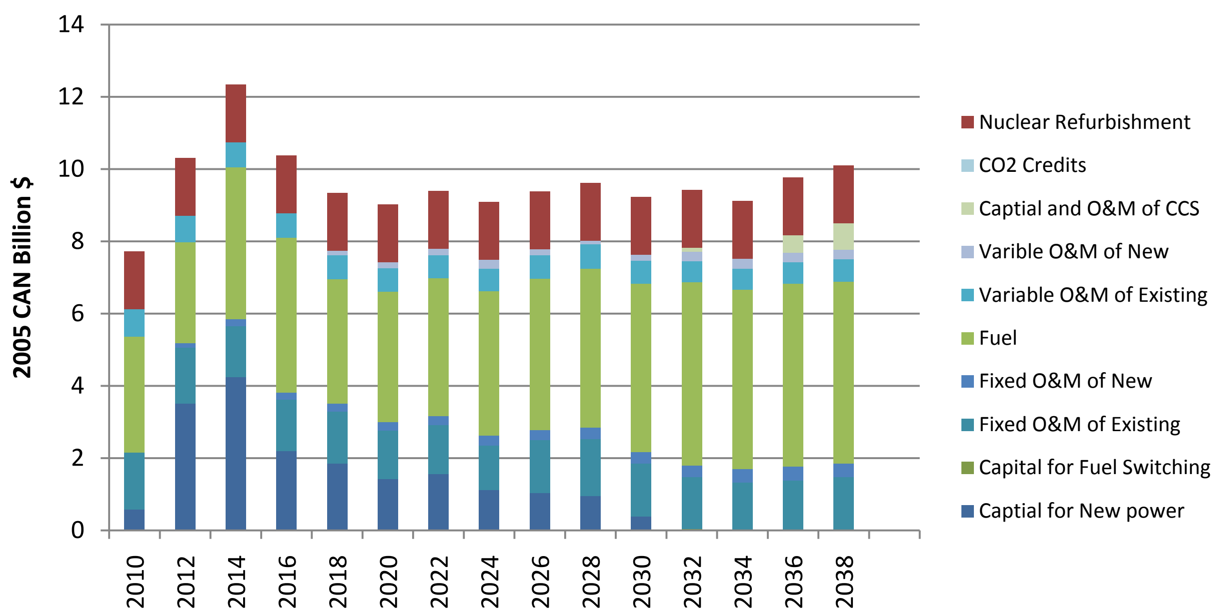


Figure 17. Detail expenditure: 12% CO_2 emission reduction target

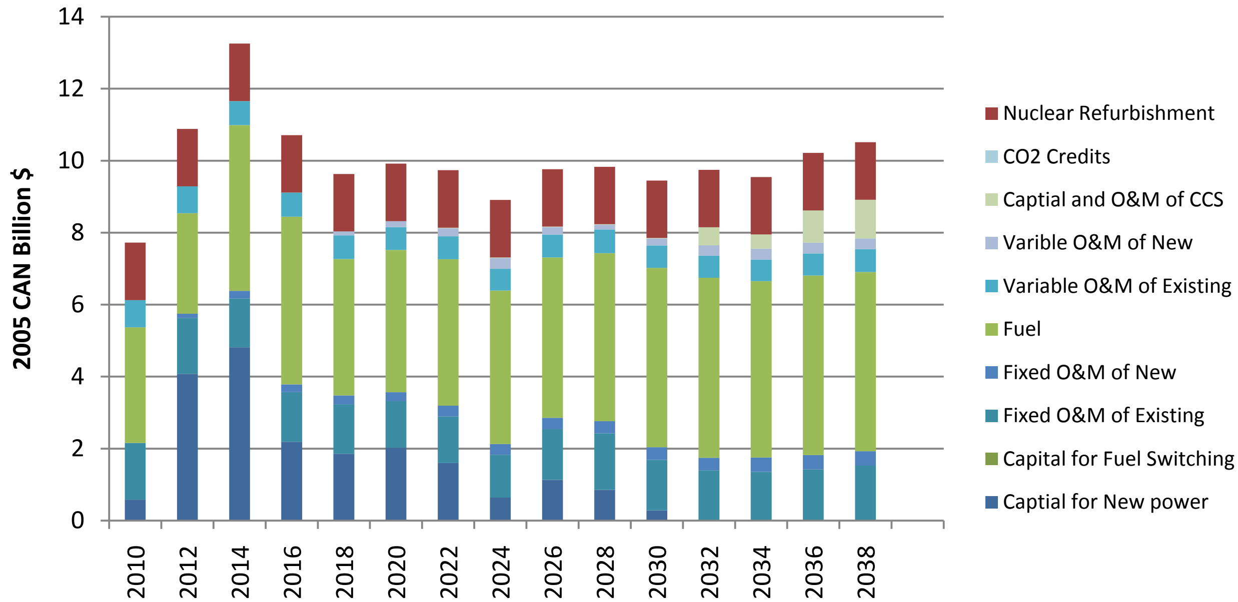


Figure 18. Detail expenditure: 25% CO_2 emission reduction target

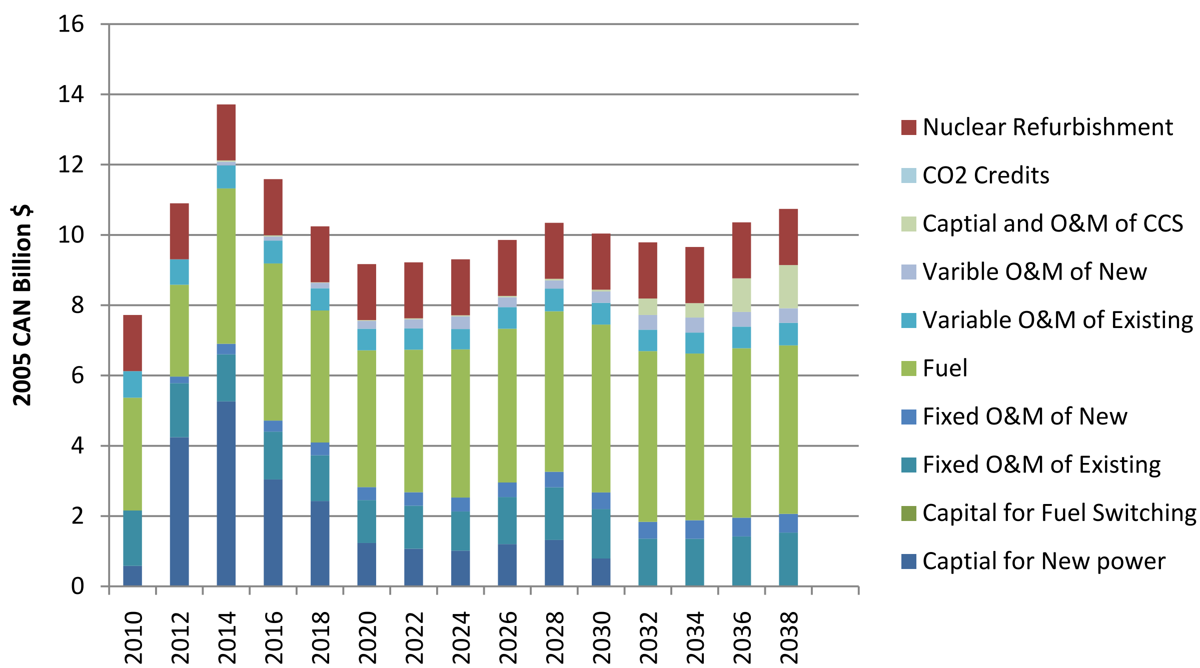


Figure 19. Detail expenditure: 50% CO_2 emission reduction target

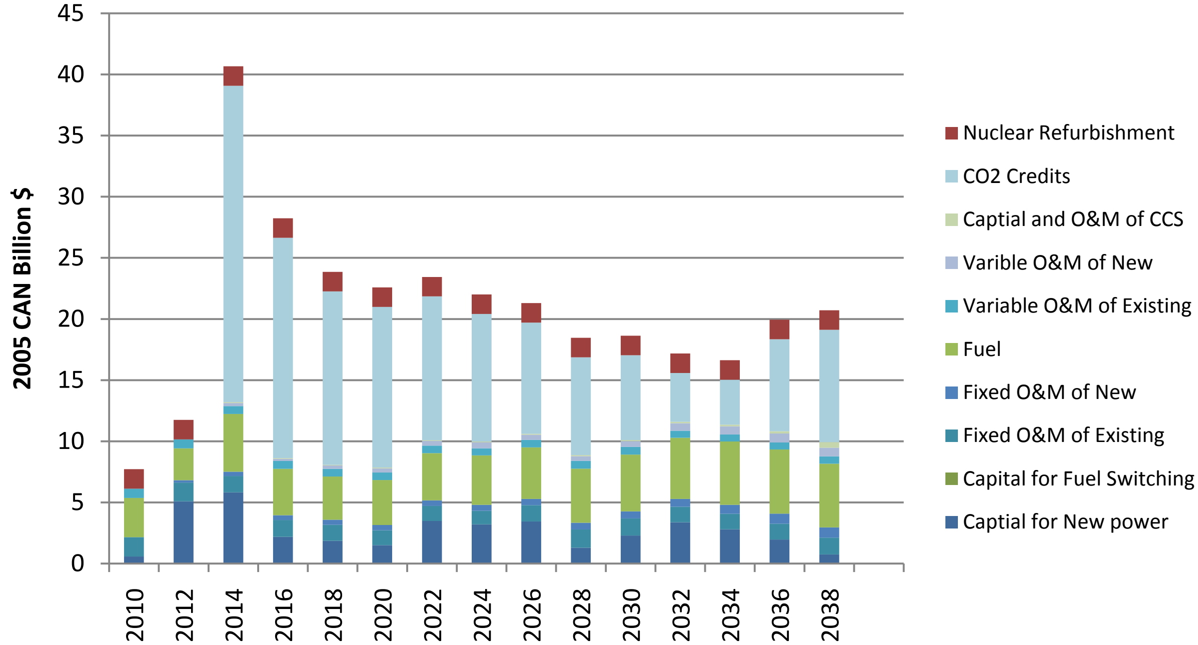


Figure 20. Detail expenditure: 75% CO_2 emission reduction target

Figure 16 – 20 shows detail expenditure for each CO_2 emission reduction case. With exception of 75% emission reduction target, all the cases do not have capital spending on new power in the last 8 years. The strategy shifted in the 75% CO_2 emission reduction case where CO_2 credit is being purchased to satisfy a strict emission constraint. This makes up for 47% of the entire expenditure, the largest portion yet. Over $25 billion worth of CO_2 credit is being purchased during 2014 period to compensate for the new power supply which is not yet available. This disproportionate spending reduces as the study proceeds. These generating facilities acquired in earlier years are being utilized as soon as they are available.

Fleet structure and electricity production

Table 6. Detail fleet structure: 6% reduction of 1990 CO_2 emisssions by 2014

6% (Kyoto)	Capacity (MW)	2010	2012	2014	2016	2018	2020	2022	2024	2026	2028
NGCC	1013										
NGCC	1519										
NGCC	760										
NGCC	1520										
NGCC	2279										
NGCC	3039										
Nuclear	1506										
Nuclear	3012										
Import	1250										
Wind	2500										

Table 7. Detail fleet structure: 12% reduction of 1990 CO_2 emisssions by 2014

12%	Capacity (MW)	2010	2012	2014	2016	2018	2020	2022	2024	2026	2028
NGCC	506										
NGCC	1013										
NGCC	20										
NGCC	760										
NGCC	1520										
NGCC	2279										
NGCC	3039										
Nuclear	1506										
Nuclear	3012										
Import	1250										
Wind	2500										

Table 8. Detail fleet structure: 25% reduction of 1990 CO_2 emisssions by 2014

25%	Capacity (MW)	2010	2012	2014	2016	2018	2020	2022	2024	2026	2028
NGCC	1013										
NGCC	1520										
NGCC	760										
NGCC	1520										
NGCC	2279										
NGCC	3039										
NG + CCS	1297										
Nuclear	1506										
Nuclear	3012										
Import	1250										
Wind	2500										

Table 9. Detail fleet structure: 50% reduction of 1990 CO_2 emisssions by 2014

50%	Capacity (MW)	2010	2012	2014	2016	2018	2020	2022	2024	2026	2028
NGCC	253										
NGCC	760										
NGCC	1520										
NGCC	3039										
NG+CCS	432										
NG+CCS	864										
NG+CCS	648										
NG+CCS	1297										
NG+CCS	2594										
Nuclear	1506										
Nuclear	3012										
Import	1250										
Wind	2500										

Table 10. Detail fleet structure: 75% reduction of 1990 CO_2 emisssions by 2014

75%	Capacity (MW)	2010	2012	2014	2016	2018	2020	2022	2024	2026	2028	2030	2032
IGCC+CCS	700												
IGCC+CCS	1401												
NG+CCS	216												
NG+CCS	432												
NG+CCS	648												
NG+CCS	864												
NG+CCS	432												
NG+CCS	865												
NG+CCS	1297												
NG+CCS	1729												
NG+CCS	648												
NG+CCS	1297												
NG+CCS	1945												
NG+CCS	2594												
Nuclear	1506												
Nuclear	3012												
Import1	1250												
Wind	2500												

Table 6-10 shows the detail of fleet structure. The total installed capacity of new power increases with the CO_2 emission reduction target. Highlighted in orange is the period of construction. The year thereafter is when electricity production commenced.

The CCS is a system of choice when the reduction target increases, as can be noted especially in 75% reduction case where all the new fossil fuel station are CCS equipped. Due to the energy consumption by the CCS system, the overall installed capacity increases to satisfy both electricity demands from the end users as well as the equipped CCS.

Summary

Table 11. Summary detail

	Reference case	**6% (Kyoto)**	**12%**	**25%**	**50%**	**75%**
New installed capacity (MW)	17,684	18,399	18,905	19,695	19,676	21,236
Total Expenditure (2005 CND Billion)	131	141	144	150	162	301
Cost of electricity (c/kWh)	2.37	2.56	2.61	2.71	2.93	5.45
Total CO_2 emission (Mt)	869	618	591	522	381	250
$/tonne of emission avoided	-	39.84	47.28	53.95	63.52	274.91
CCS Retrofit	-	L	N	N, L	L, N, A	L
CO_2 Credit purchased	-	-	-	-	-	47% of expenditure
Fuel Switching	-	TB & N	TB, A, L	TB	TB	-
Additional info	Only case where new PC is utilized	No capital on new power spent in the last 8 years	No capital on new power spent in the last 8 years	Highest new power capital spending during 2014-2015 period	Almost 6,000MW of NGCC+CCS ~ 30% of total new power	71% of new power is CCS equipped

TB = Thunder Bay
LN = Lennox
A = Atitokan
N = Nanticoke
L = Lambton

As depicted in table 11, the CCS retrofitting strategy are used along with new CCS quipped stations in higher emission reduction cases. Fuel switching technique is predominantly used when the CO_2 emission reduction constraint is low. Total expenditure also increases with the CO_2 emission reduction target. In most cases, there is no capital spending on new power in the last 8 years.

The CO_2 managing technique such as fuel switching and CCS application on an existing power station are not utilized when the emission reduction constraint is very high. This may caused by the heavy cost and energy penalties associated with the existing generating stations. Most of the existing coal-fired power stations are shut down or minimally utilized to satisfy demand.

Case III: No Coal After 2014

In this case study, the Environmental Protection Act (EPA) is applied, where all coal supplies are not available after 2014. An additional case where the price of natural gas is doubled starting in an arbitrary year, 2020, is also performed. For ease of comparison, the reference case results will also be displayed as well.

Cost of electricity

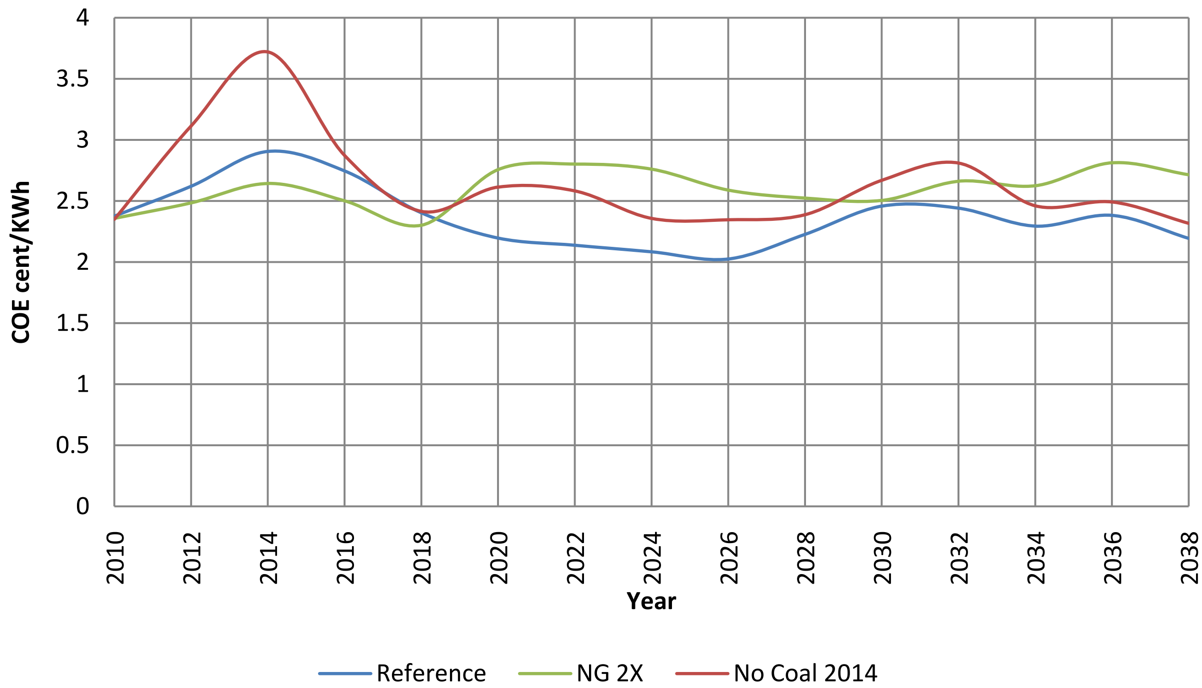


Figure 21. Overall cost of electricity

All three cases follow a general trend where a peak during 2014 is observed due to large amount of capital spent on new power sources. The coal cut case, where no new or existing coal is available after 2014, has a particularly high cost of electricity during the early years. A large capacity of existing coal power supply has gone offline, forcing the model to purchase a large amount of new supply technologies to prepare the fleet for this urgent lack of generating capacity.

CO_2 emission

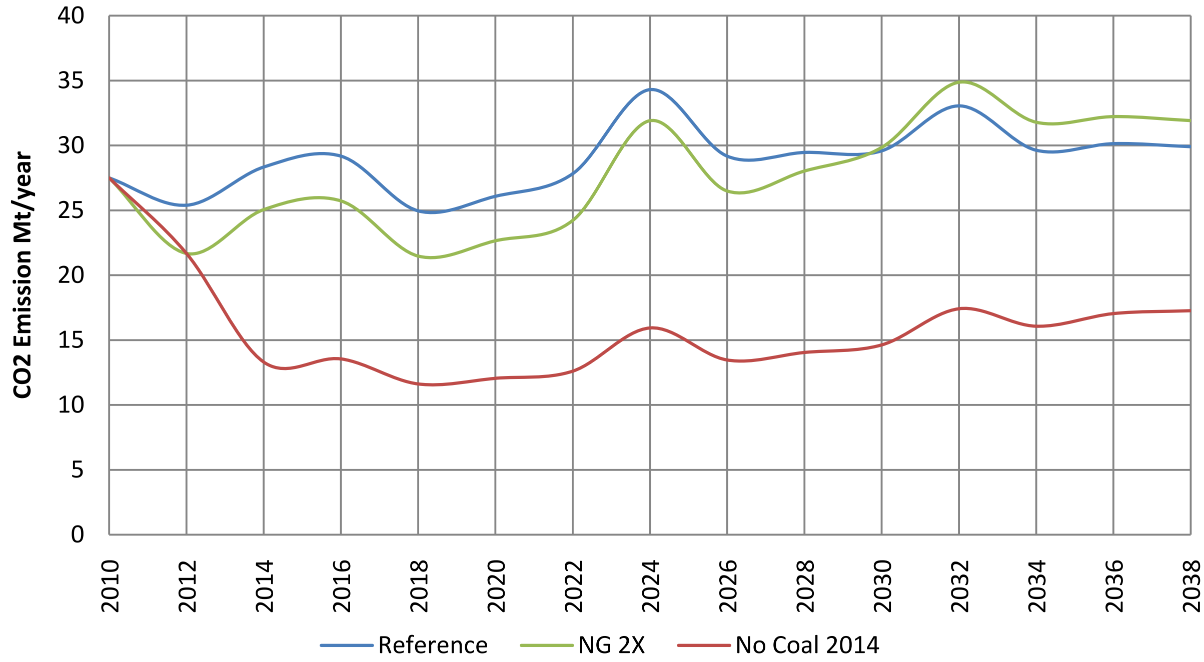


Figure 22. Overall CO_2 emission

No CO_2 emission reduction constraint is applied in any case. Total CO_2 emission from the doubled natural gas price case and EPA case is 476Mt and 830 Mt respectively compare to 869Mt in the reference case. Depicting in figure 22, the same general trend is observed in the three peaks during 2016, 2024 and 2032, similar to the reference case. In the EPA case, the overall emission is reduced dramatically due to the elimination of both new and existing coal-fired power stations, the largest emission source of all technologies.

Expenditure

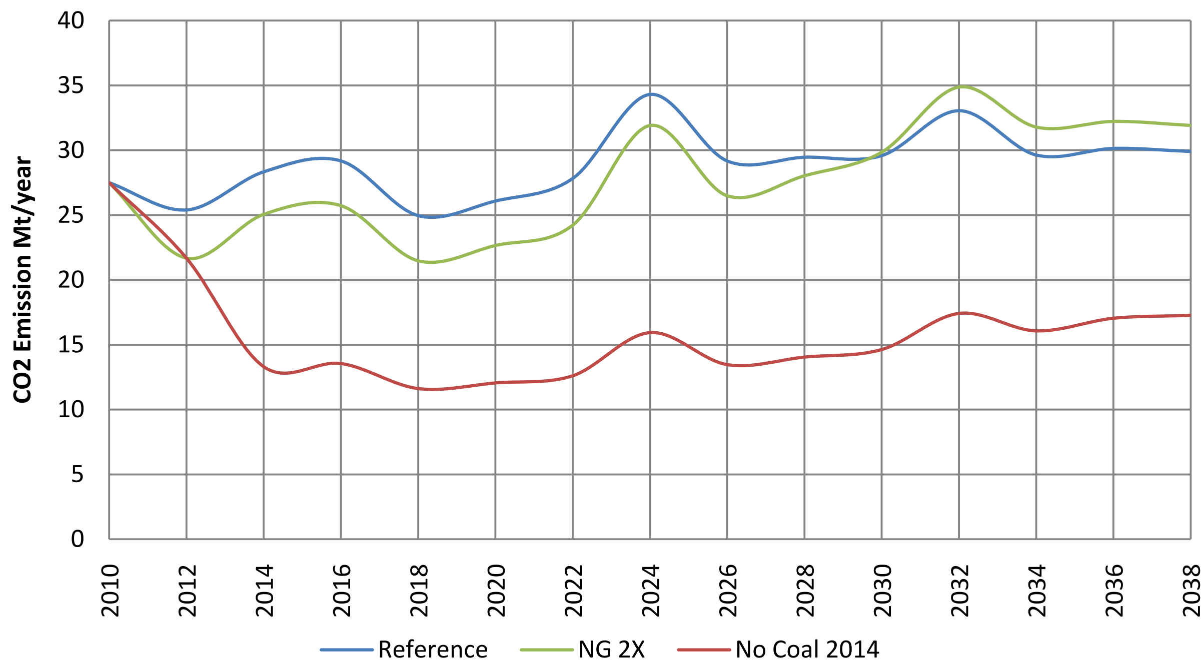


Figure 23. Overall expenditure

Very similar to the cost of electricity plot, all three cases follow the same general trend. Only in the reference case, however, a trough is shown during 2020-2026 as already discussed earlier.

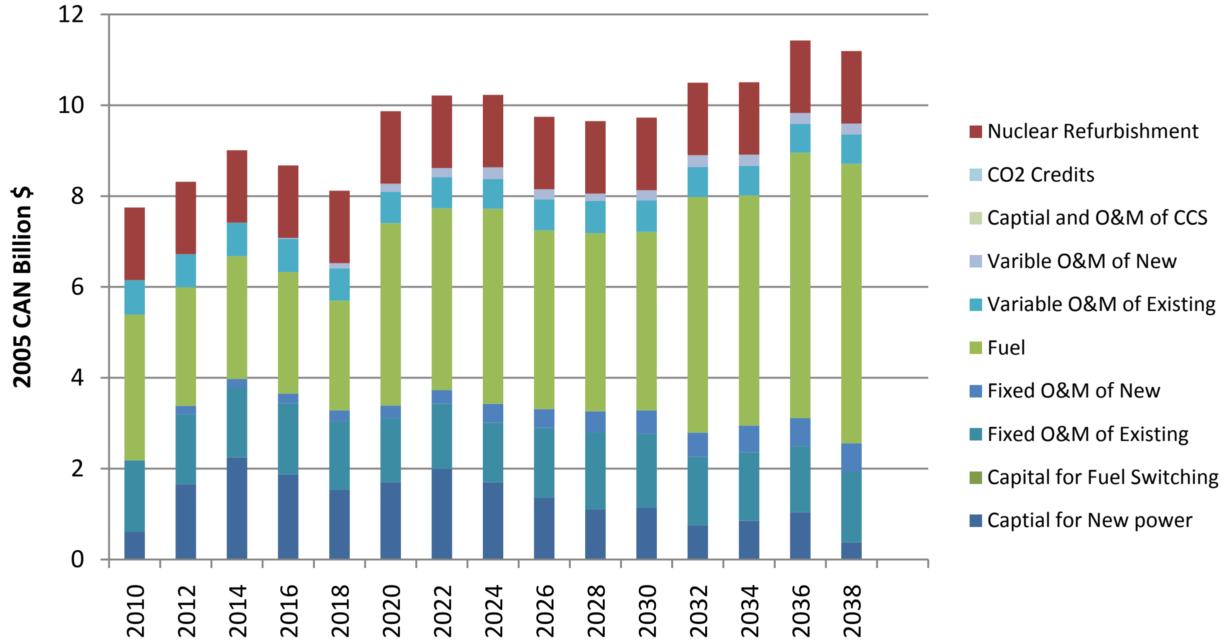


Figure 24. Detail expenditure: NG 2X

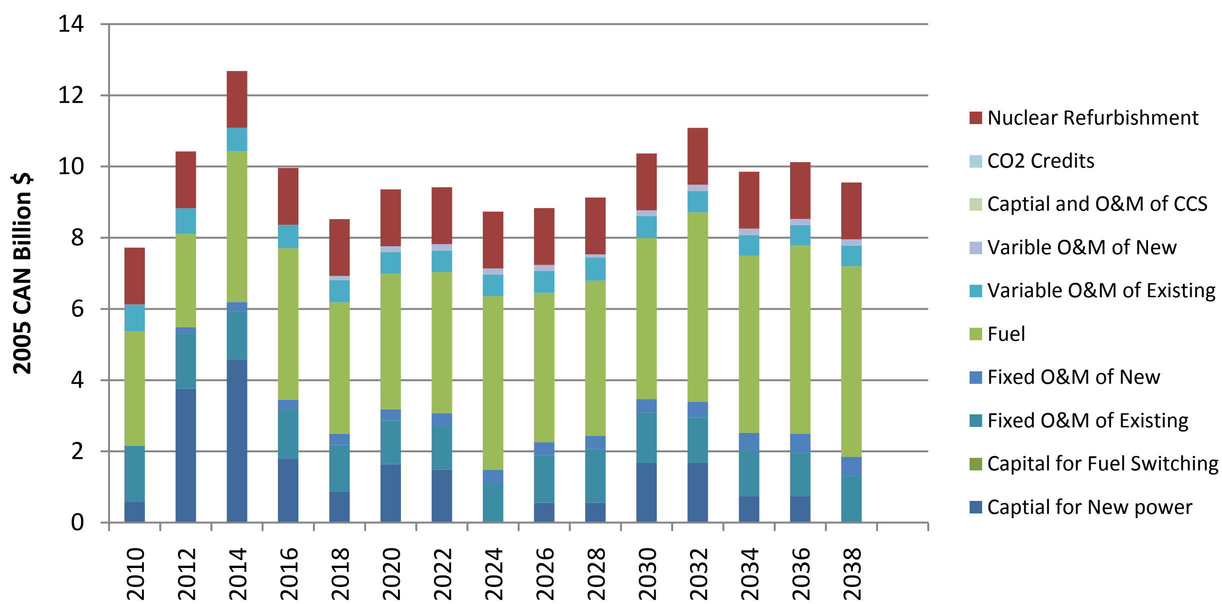


Figure 25. Detail expenditure: EPA

Two distinct cycles of capital spending on new power is observed in the EPA plot in figure 25. A different building strategy is employed when natural gas price is doubled; relatively constant ambient capital spending on new power is observed throughout the study period. The fuel expenditure in both cases are similar, increasing with the demand, 64% of total expenditure in the EPA case and 60% in the other.

Since no CO_2 emission reduction target is specified, no CCS system, or fuel switching technique is observed, hence, no capital spending on any of the CCS related matters.

Fleet structure and electricity production

Table 12. Detail fleet structure: natural gas price doubled in 2020

NG 2X	Capacity (MW)	2010	2012	2014	2016	2018	2020	2022	2024	2026	2028	2030	2032	2034
PC	458													
PC	915													
PC	527													
PC	1053													
PC	527													
PC	1053													
IGCC	830													
NGCC	253													
NGCC	507													
NGCC	1013													
NGCC	760													
NGCC	1520													
Nuclear	3012													
Import	1250													
Wind	4000													

Table 13. Detail fleet structure: No coal available after 2014

No Coal 2014	Capacity (MW)	2010	2012	2014	2016	2018	2020	2022	2024	2026	2028	2030	2032
NGCC	1000												
NGCC	2000												
NGCC	1500												
NGCC	3000												
NGCC	4500												
NGCC	6000												
Nuclear	3012												
Import	1250												
Wind	4000												

Highlighted in orange is the period of construction. The year thereafter is when electricity production commenced.

In the EPA case, depicted in table 13, new NGCC station makes up 68% of the total new installed capacity. The fleet energy supply is limited to a handful of technologies when all coal technologies are eliminated.

On a contrary, when the natural gas price is double, the fleet rely on more coal technologies making up 30% of the total new installed capacity, largest of any new supply technologies used.

It becomes very evident that coal and natural gas technologies are two predominant technologies used as preferred fuel used. By eliminating all coal technologies, the energy supply diversity is reduced. As a result, any critical fluctuation of fuel prices and unreliability in the system will be greatly magnified, causing the system to be unstable and drastic changes in cost of electricity for end users.

Summary

Table 14. Summary detail

	Reference case	NG double in 2020*	Coal Cut**
New installed capacity (MW)	17,684	26,262	17,676
Total Expenditure (2005 CND Billion)	131	145	146
Cost of electricity (c/kWh)	2.37	2.63	2.60
Total CO_2 emission (tonnes)	869	830	476
$/tonne of emission avoided	-	384	35
CCS Retrofit	-	-	-
CO_2 Credit purchased	-	-	-
Fuel Switching	-	-	-
Additional info	47% of new power is NGCC	30% of new power is coal technologies	68% of new power is NGCC

**Coal Cut = no coal technologies, new or existing, available after 2014

*NG double in 2020 = Natural gas price doubled in an arbitrary year, 2020

Even though the structure of the newly installed capacity is different in both cases, this does not imply that all the technologies are equally utilized. Both the EPA and the case where natural gas price is doubled, nuclear power is still the single most utilized source of power. Nearly 50% of total electricity produced over the entire study period comes from nuclear sources.

This different rate of production from various sources also explains the reduction of CO_2 emission in NG 2X case even though no emission constraint is applied. While both new and existing NGCC plants reduce their energy production as expected, in addition to electricity production from coal sources, the model also increases the electricity import rate to satisfy the demand. The imported electricity from Manitoba comes from hydroelectric source and therefore no CO_2 emission is taken into account, hence, the slight reduction in the overall CO_2 emission from the reference case.

It is evident when all coal technologies are eliminated from the fleet, the CO_2 emission is reduced dramatically without large spending. This, however, also introduces a dilemma where the system now becomes less reliable. Natural gas is the preferred alternative fossil fuel when all coal is removed. It should be mentioned that, unlike oil trading, no international market exist for natural gas. Natural gas prices are based on individual trading agreement between participating parties (A. Poullikkas, 2009). Given a volatile energy market, it is ill-advised to limit the system to only a small number of supply technologies. Perhaps the solution is not a one energy strategy but rather a well-balanced mix of technologies.

Case IV: No New Nuclear After 2014

Nuclear is the Ontario largest installed capacity and is most utilized. Two following case studies, one with CO_2 emission reduction at 6% and another without the emission target, are performed where no new nuclear sources are available. Only the existing nuclear stations are operational and assume to be refurbished before their expected life cycles. The reference case will be presented as well for ease of comparison.

Cost of electricity

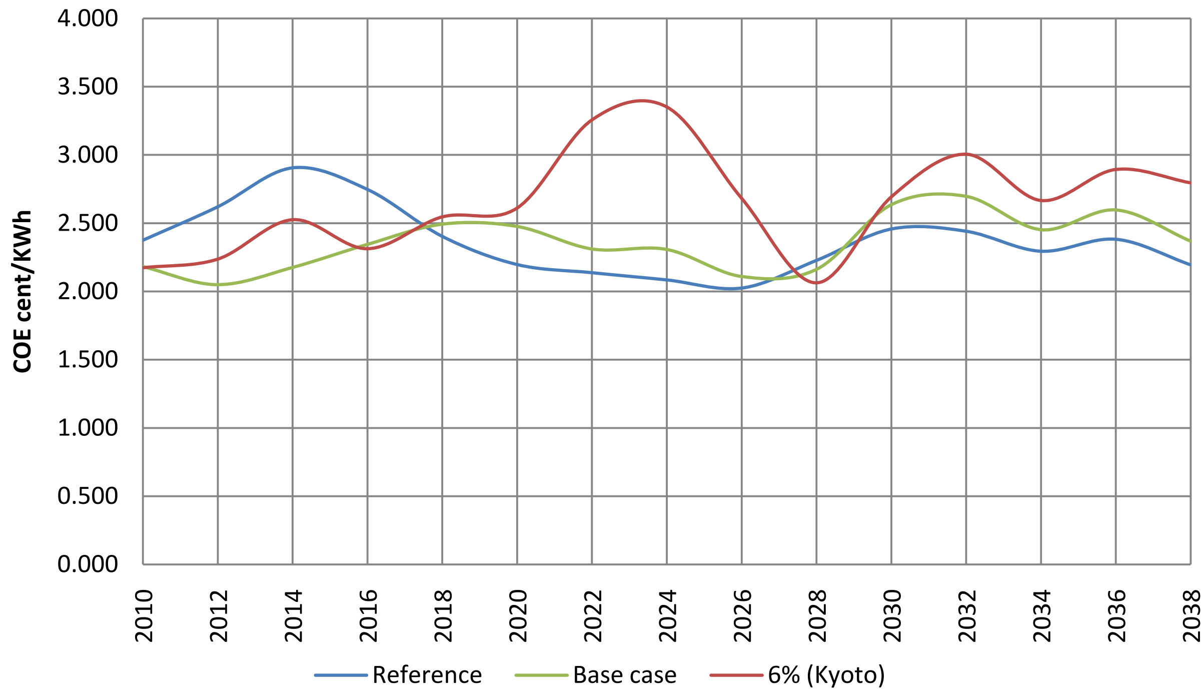


Figure 26. Overall cost of electricity

Unlike any of the previous cases, the strategy applied when no new nuclear power is available is quite different in both cases, when comparing to the reference case. One distinct peak is observed during the 2024 period, in the case where Kyoto constraint is applied. This is caused by the capital spending on the new power during 2022 and an additional expenditure on fuel in 2024. A trough during 2028 period is also observed where the cost of electricity during said period is cheaper than that of 2010, the beginning of the study. This is a result of a combination of the very small amount of capital spending on new power and the similar amount of energy generated during the same period causing a very sharp drop in cost of electricity. One similar peak with the control case is also observed reflecting the trend displayed in a number of other cases. Quite contrary with the case without CO_2 emission constraint, a trough is observed in place of a peak usually seen previously. A small capital is spent on new power but an additional source of imported power is utilized thus reducing the expenditure on fuel and the overall expenditure temporarily.

Overall cost of electricity of the reference and the base case is 2.37 and 2.36 c/kWh respectively. It is counter intuitive to have a lower cost of electricity than the reference case where the lowest electricity cost is the prime objective. The cost of electricity is calculated by dividing the annual overall expenditure with the amount of electricity produced. These annual cost of electricity over the 30 years horizon may not be very well represented by an average and thus can be misguiding. In addition, as part of the case study restriction, nuclear capacity is not allowed. This may inadvertently change the least-cost strategy.

CO_2 emission

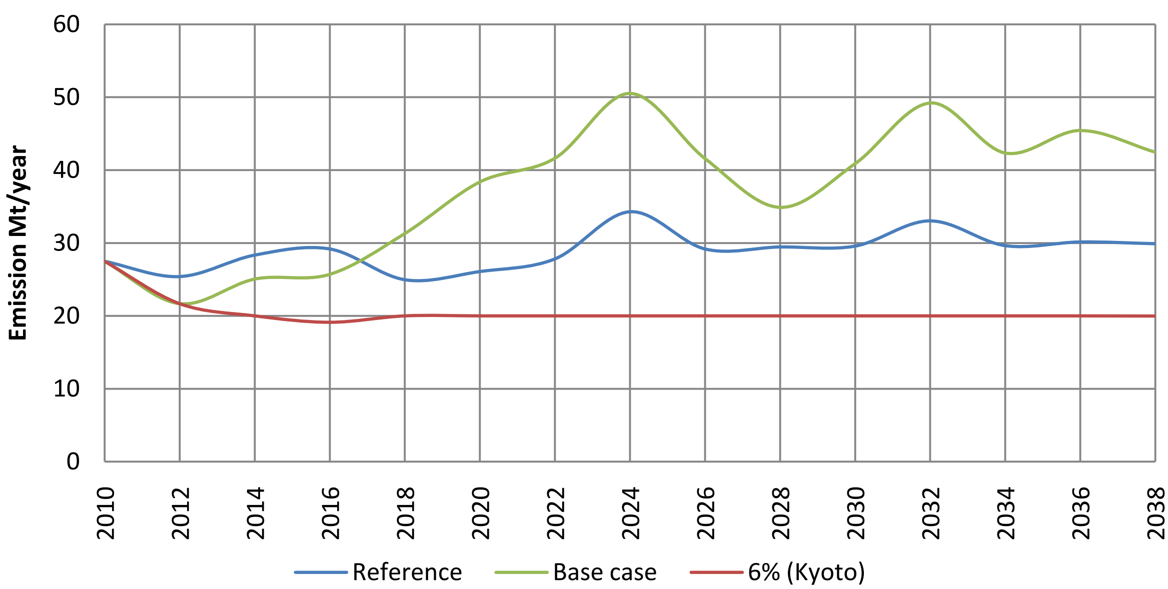


Figure 27. Overall CO_2 emission

The similarities between the reference case and the base case are very striking. A small different during 2016-2018 period where the control case already invested in a nuclear plant, the other base case could not, due to the no new nuclear constraint. As such, the long term CO_2 emission is much greater. This exhibits the importance of an early investment in new power sources such as nuclear power, in order to achieve a long term emission reduction target. The reference case emits 869 Mt of CO_2 in total, compare with 1,117 Mt in the base case. Total of 617 Mt of CO_2 emissions is observed in the case with 6% emission reduction.

Expenditure

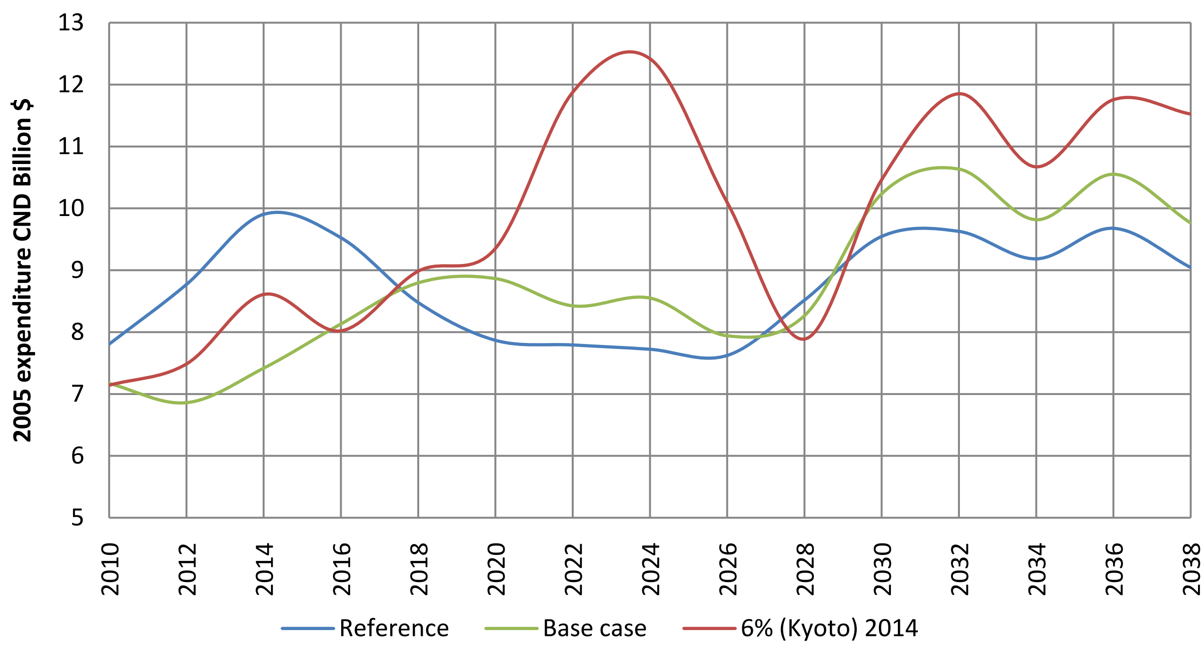


Figure 28. Overall expenditure

Overall expenditure plot corresponds with the cost of electricity very well. These peaks and troughs are substantiated mostly by the fluctuation of capital on new power and fuel cost, as will be shown in the following figures.

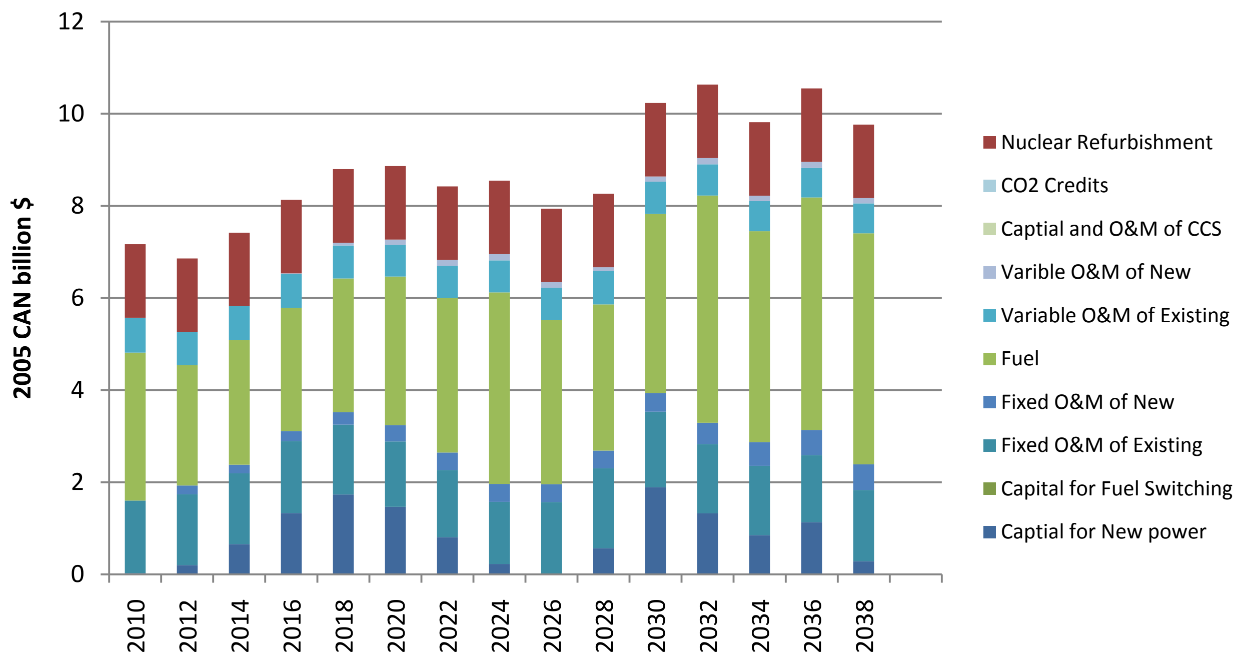


Figure 29. Detail expenditure: No CO_2 emission constraint

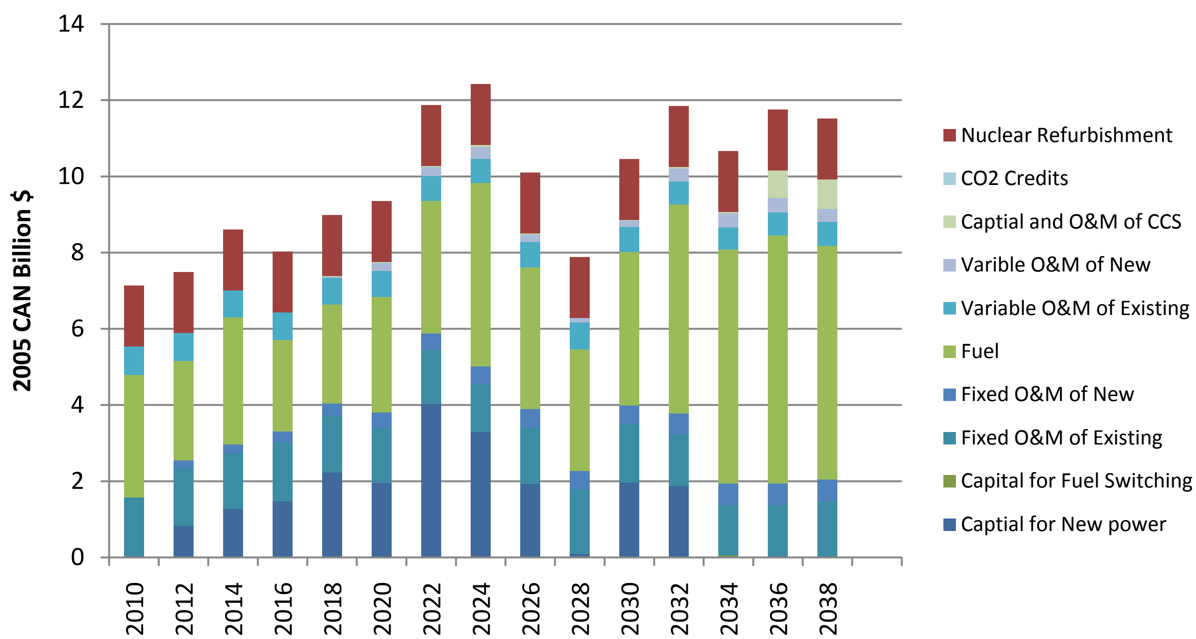


Figure 30. Detail expenditure: 6% CO_2 emission reduction target

There are some capital spending on new power virtually every year in the base case. A drop in expenditure observed during 2012 period is caused by the reduction in the expenditure for fuel of almost $1 billion. This reflects in reduction of the cost of electricity. The largest expenditure is utilized on fuel, 55% of the overall expenditure.

There is a void of capital for new power in the last 6 years in the 6% reduction case. The capital for new power and the fuel cost combined drives the annual expenditure quite dramatically in this case. Similar to the base case, the largest expenditure is utilized fuel, over 60% of the overall expenditure.

Fleet structure and electricity production

Table 15. Detail fleet structure: no new nuclear after 2014

Base case	Capacity (MW)	2010	2012	2014	2016	2018	2020	2022	2024	2026	2028	2030	2032	2034
PC	458													
PC	527													
PC	1053													
PC	527													
PC	1053													
NGCC	500													
NGCC	1000													
NGCC	1500													
NGCC	3000													
NGCC	4500													
NGCC	6000													
Import	1250													
Wind	4000													

Table 16. Detail fleet structure: no new nuclear after 2014 with an additional 6% reduction of 1990 CO_2 emisssions by 2014

6% (Kyoto)	Capacity (MW)	2010	2012	2014	2016	2018	2020	2022	2024	2026	2028
NGCC	500										
NGCC	1000										
NGCC	4000										
NGCC	1500										
NGCC	3000										
NGCC	4500										
NGCC	6000										
IGCC+CCS	700										
IGCC+CCS	1400										
NGCC+CCS	432										
Import	1250										
Wind	4000										

Highlighted in orange is the period of construction. The year thereafter is when electricity production commenced.

In the base case where no CO_2 emission constraint is applied, PC contributes more than 14% of the total new installed capacity. The largest new installed capacity is the NGCC without CCS, 65% of new installed capacity. There is no CO_2 credit purchase, nor CCS or fuel switching technique used.

When CO_2 emission reduction target of 6% is applied, NGCC is utilized quite heavily making up over 72% of the new installed capacity. However, new power station with CCS system equipped is also used in joint with the NGCC without CCS in order to satisfy the CO_2 emission constraint. Similar to the base case, there is no CO_2 credit purchased.

Summary

Table 17. Summary detail

	Reference case	Nuclear cut*	Nuclear cut Kyoto**
New installed capacity (MW)	17,684	25,367	28,284
Total Expenditure (2005 CND Billion)	131.1	131.4	148.1
Cost of electricity (c/kWh)	2.37	2.36	2.65
Total CO_2 emission (tonnes)	869	1,117	617
$/tonne of emission avoided	-	-	67.5
CCS Retrofit	-	-	N
CO_2 Credit purchased	-	-	-
Fuel Switching	-	-	TB, A, L
Additional info	47% of new power is NGCC	Capital on new power is being spent every year	9.4% of new power is CCS equipped

*Nuclear cut = no new nuclear power available after 2014

**Nuclear cut Kyoto = ‘Nuclear cut’ with an additional CO_2 emission reduction constraint of 6%

TB = Thunder Bay LN = Lennox A = Atitokan

N = Nanticoke L = Lambton

Largest overall CO_2 emission of any study cases, 1,117 Mt, is observed when no new nuclear is available. While the average electricity cost is slightly smaller than that of the reference case, it does not reflect the entire fluctuation of the electricity demand and expenditure over the horizon used to calculate the cost of electricity. Total expenditure is, however, still higher in the base case than the reference case where minimizing cost of electricity is the primary objective. The average cost of electricity, in this case, does not represent the overall cost very well.

A large build up of new capacity is observed in the nuclear cut case while the total expenditure is virtually constant when compared to the reference case. It should be noted that these new installed capacity is not being utilized uniformly. When no new nuclear power is available to the system, existing coal technologies are being heavily utilized, doubling in the generation rate reflecting on the total CO_2 emission.

Case V: No CCS

CCS technology is regarded as one of the potential solution in reducing CO_2 emissions. It is, however, has not been thoroughly examined. As part of any new technologies, malfunction and unexpected setback are unavoidable. This study case will examine the strategy where CCS technology is not offered to the model, particularly when the emission reduction constraint of 6% is applied. The results will be compared to the reference case and the previous Kyoto case.

Cost of electricity

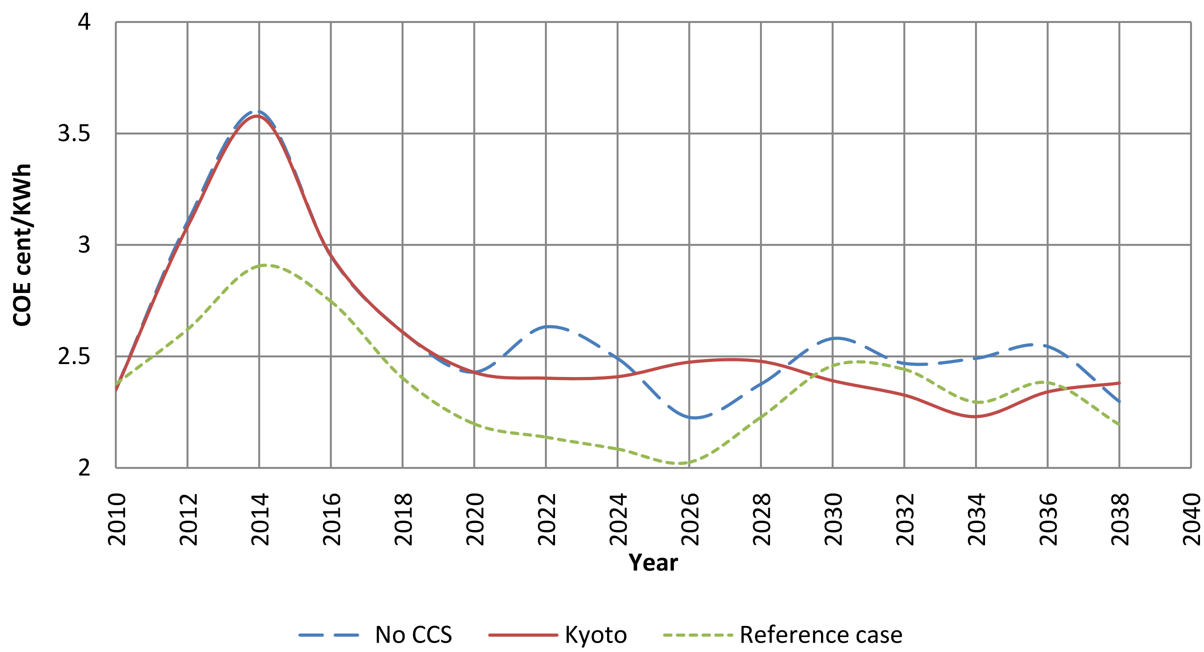


Figure 31. Overall cost of electricity

Both the no CCS and the 6% Kyoto case have an identical trend up until the year 2020. While both index are driven by the capital spending on new generating capacity, the magnitude are different. These measures are first observed in 2020 where additional new supply technologies are being purchased. In the no CCS case produce a very similar trough as in the reference case where the cost of electricity is lower than the starting period. As will be shown later, the capital spending on new supply technologies is the driving force in both no CCS and reference cases.

CO_2 emission

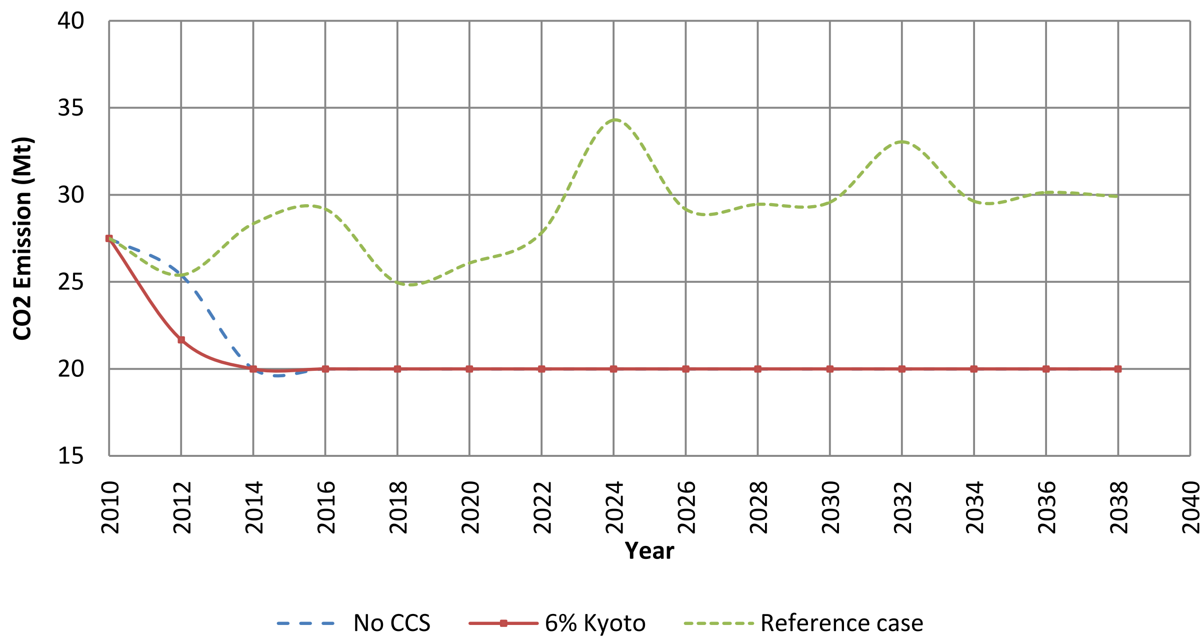


Figure 32. Overall CO_2 emission

Both the no CCS case and the 6% Kyoto case achieve the emission reduction target as specified. The strategies are different as is evident in the beginning of the horizon. This slightly different strategies undertaken result in emission different of approximately 8Mt over the study period.

Expenditure

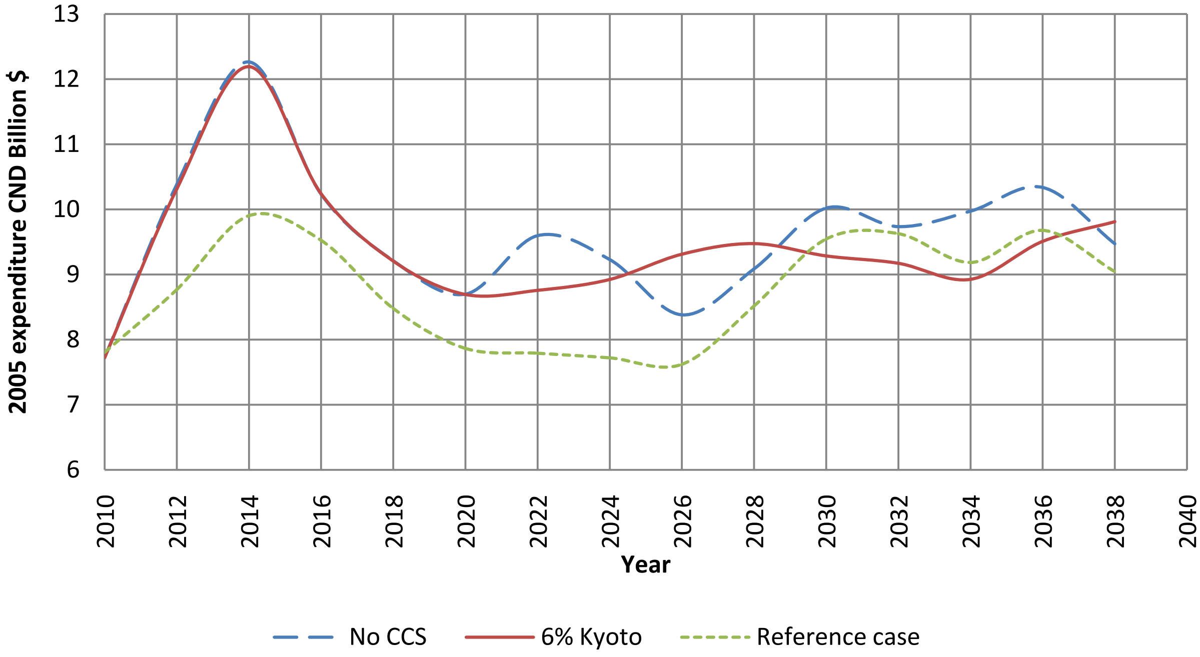


Figure 33. Overall expenditure

The expenditure and the cost reflect the cost of electricity plot as expected. The same trough in both no CCS and the reference case are present in the expenditure plot driven by the capital spending on new generating capacities as will be shown in detail in the following plots. It is important to note that even at the beginning of the study period, 2010, there is already a relatively small amount of capital being spent on new installed capacities. The lacks of these spending during 2026 result in the trough exist in both no CCS case and the reference case.

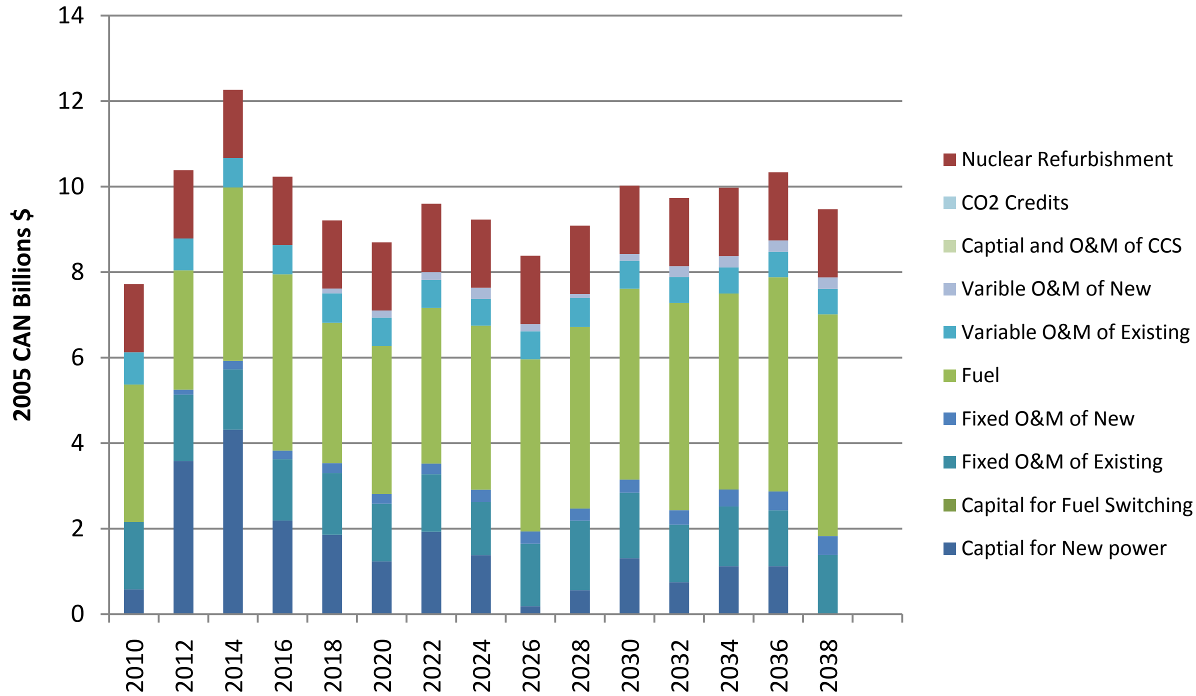


Figure 34. Detail expenditure: No CCS, 6% emission reduction target

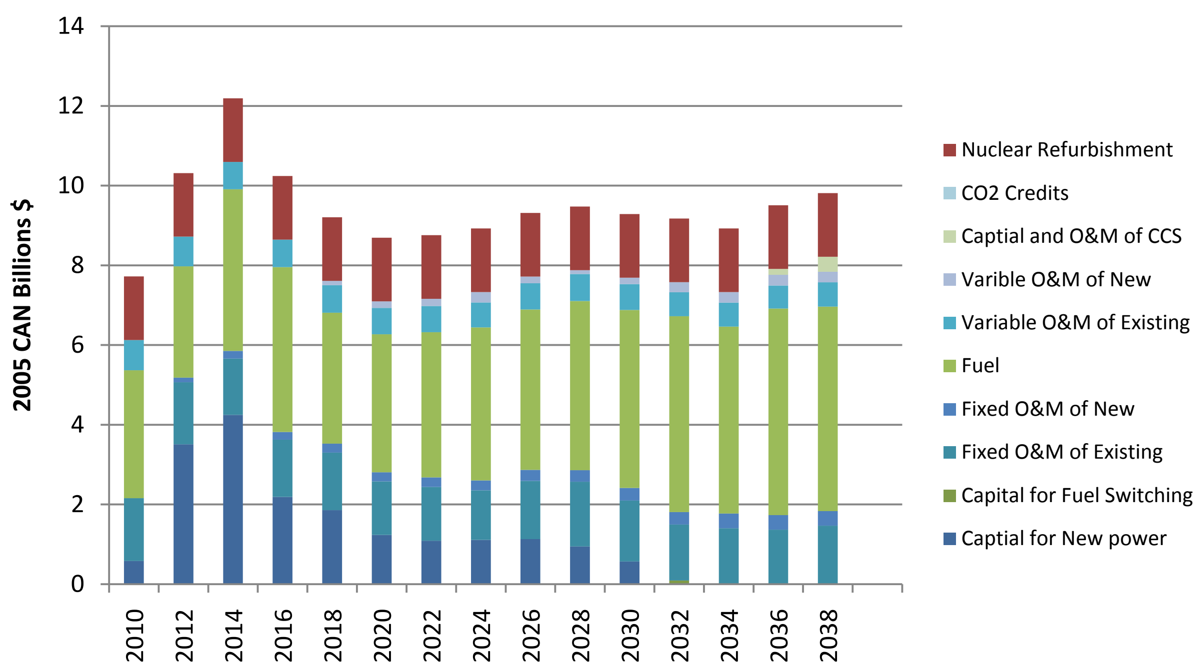


Figure 35. Detail expenditure: 6% CO_2 emission reduction target

Total expenditure for the no CCS case is approximately 2005 CND $144 billion, 3 billion higher than that of the previous 6% Kyoto case. Largest portion of the total expenditure is utilized for fuel supply in both no CCS and previous Kyoto case. Distinct peak of spending on new capital for new power during 2014 is observed in both cases.

There is no spending on CO_2 credit in all three cases. Due to the CCS constraint, there is no CCS system used in new or retrofitted to the existing generating stations. Furthermore, accommodating techniques such as fuel switching and fuel balancing are not used at all in the no CCS case. Virtually shot down, coal generation sources are only used minimally to satisfy the peak demand. In fact, the accumulated generation from coal-fired power stations in the last 10 years of the study only account for 12% of the total electricity generated. This is much lower than the earlier period where coal was used to generate as much as 13% of the total electricity annually during 2010-2014. On the contrary, coal supplies are utilized for both peak and base demand, more so in the previous Kyoto case, throughout the study period.

Fleet structure and electricity production

Table 18. Detail fleet structure: No CCS and 6% reduction of 1990 CO_2 emisssions by 2014

No CCS	**Capacity (MW)**	**2010**	**2012**	**2014**	**2016**	**2018**	**2020**	**2022**	**2024**	**2026**	**2028**	**2030**	**2032**
NGCC	505												
NGCC	1013												
NGCC	1520												
NGCC	760												
NGCC	1520												
NGCC	2300												
Nuclear	1506												
Nuclear	3012												
Import	1250												
Wind	2500												

Table 19. Detail fleet structure: 6% reduction of 1990 CO_2 emisssions by 2014

6% (Kyoto)	Capacity (MW)	2010	2012	2014	2016	2018	2020	2022	2024	2026	2028
NGCC	1013										
NGCC	1520										
NGCC	760										
NGCC	1520										
NGCC	2279										
NGCC	3039										
Nuclear	1506										
Nuclear	3012										
Import	1250										
Wind	2500										

Highlighted in orange is the period of construction. The year thereafter is when electricity production commenced.

Similar new power purchases in both no CCS and the 6% Kyoto case are observed. Neither new coal supply technologies nor CCS equipped generating stations are observed in either case. In fact, three supply technologies including nuclear, import, and wind of the same sizes are being purchased at the same time in both cases. NGCC is still the primary source of new power, similar to many previous study cases.

Summary

Table 20. Summary detail

	Reference case	6% (Kyoto)	No CCS Kyoto
New installed capacity (MW)	17,684	18,399	17,365
Total Expenditure (2005 CND Billion)	131	141	144
Cost of electricity (c/kWh)	2.37	2.56	2.61
Total CO_2 emission (Mt)	869	618	626
$/tonne of emission avoided	-	42.98	53.50
CCS Retrofit	-	L	-
CO_2 Credit purchased	-	-	-
Fuel Switching	-	TB & N	-
Additional info	Only case where new PC is utilized	No capital on new power spent in the last 8 years	All coal supplies are only used marginally for peak demand

TB = Thunder Bay LN = Lennox A = Atitokan

N = Nanticoke L = Lambton

5. ANALYSIS AND COMPARISON

Following are the comparative analysis of the new results and that produced in the previous model by H. Mirzaesmaeeli et al. The results from both models may not be compared on the same figure as the time scale is not the same. Later in this section the results will also be compared to the Ontario Power Authority publications.

Cost of electricity

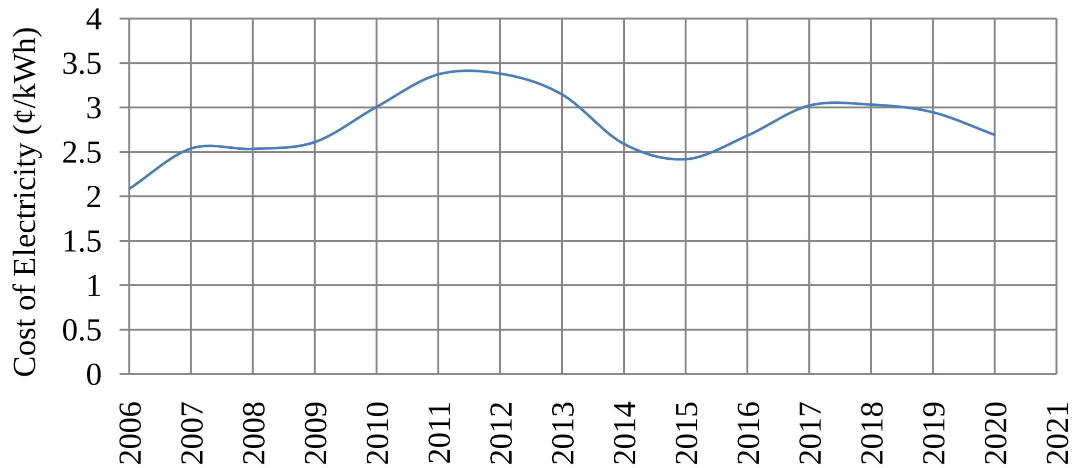


Figure 36. Overall cost of electricity: H. Mirzaesmaeeli et al. base case

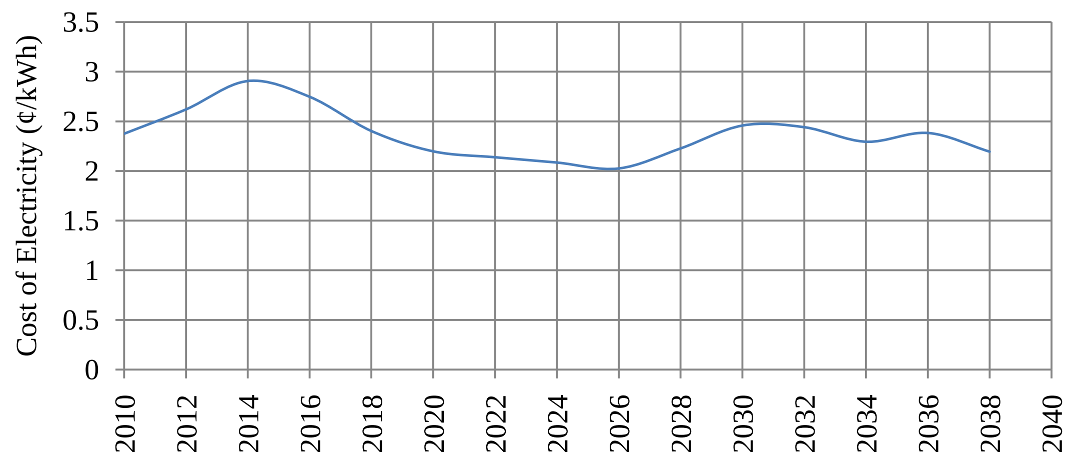


Figure 37. Overall cost of electricity: Reference case

An average cost of electricity of 2.80 ¢/kWh and 2.37 ¢/kWh in H. Mirzaesmaeeli et al. and the reference case respectively. The trough observed in the reference case is not present in H. Mirzaesmaeeli et al. case mostly due to the spending strategy of capital for new power. Both models purchase a large number of generating facilities early in the study period. Larger investment is observed in the reference case preparing the fleet for an extended higher demand period, driving the early peak during 2014. The trough observed later during 2026 results from the lack of this investment for new generating facilities, while the electricity is still being generated at similar capacity to the adjacent years, driving the cost of electricity down. In both cases, the cost of electricity varied quite considerably. The trough observed during 2015 in H. Mirzaesmaeeli et al. case is due to the lack in capital spending on new power and the subsequent lack of nuclear refurbishment during that period. Considering the shorter study horizon, a given amount of expenditure may result in larger fluctuation of the cost of electricity since the overall annual budget is much smaller. In fact, nuclear refurbishment has much greater effect on Mirzaesmaeeli's study than that of capital spending on new generating facilities. In contrast, greater effect is observed from the capital spending on new generating facilities, driving the cost of electricity up or down. Due to the lack of spending in both cases toward the end of the study period, the cost of electricity also reduces as is evident in both plots.

CO_2 emission

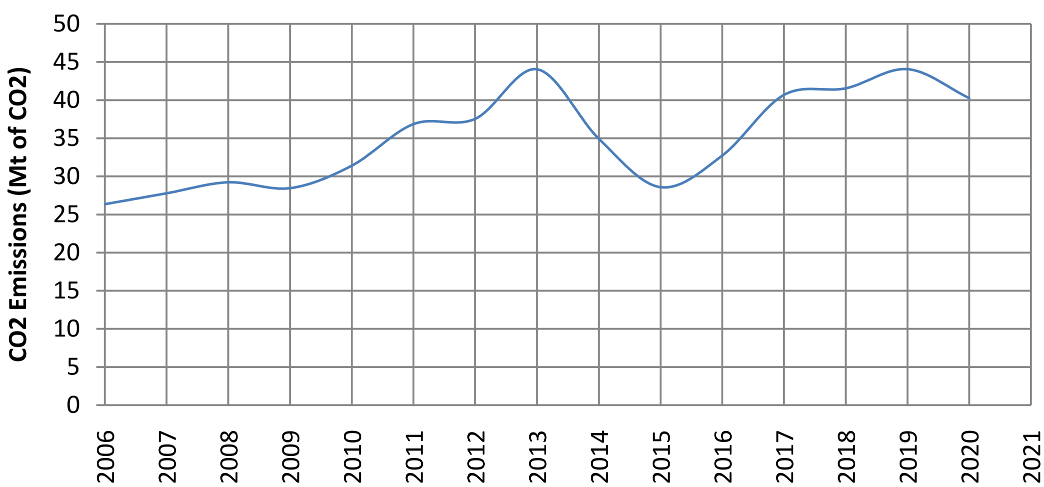


Figure 38. Overall CO_2 emission: H. Mirzaesmaeeli et al.

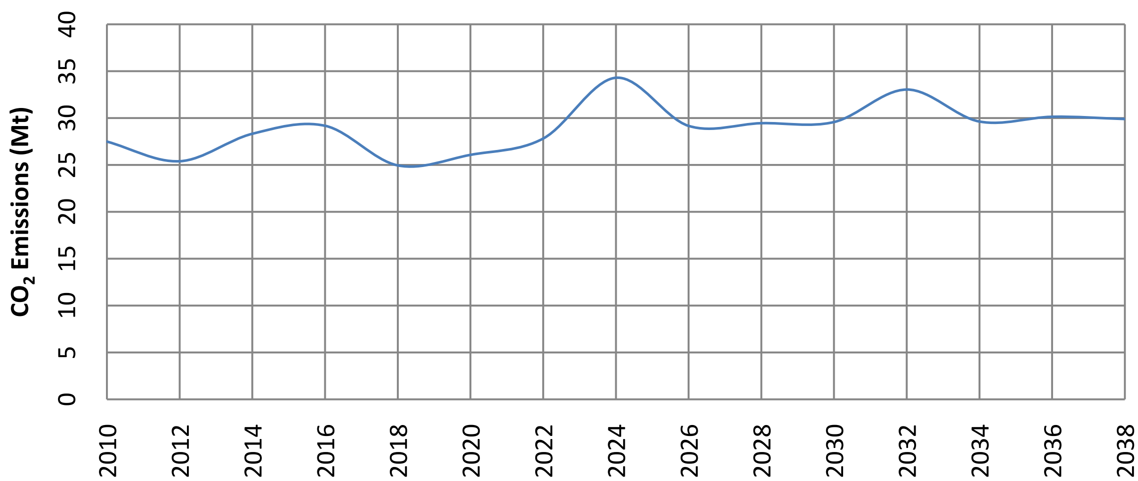


Figure 39. Overall CO_2 emission: Reference case

A trough in emission is observed in H. Mirzaesmaeeli et al. case. This is due to an increase in electricity production from nuclear stations from the adjacent years, thus reducing production from coal-fired power station and eventually the CO_2 emission. As will be presented in the later section, the lack of the refurbishment during 2015 indicates that all of the nuclear units are operational during this period. No significant similarities are observed in the overall CO_2 emissions.

Expenditure

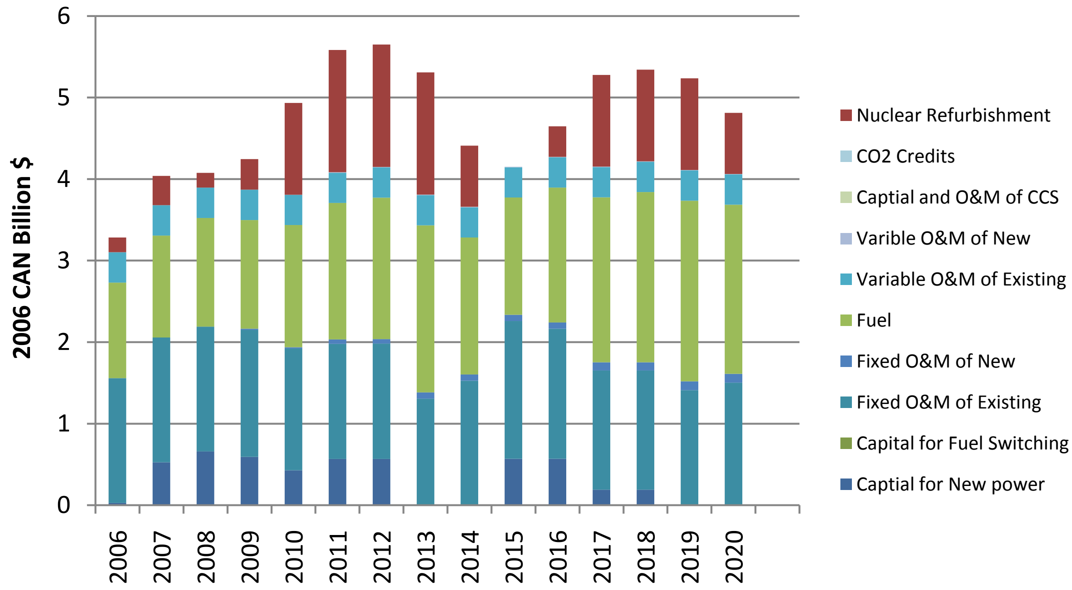


Figure 40. Detail expenditure: H. Mirzaesmaeeli et al.

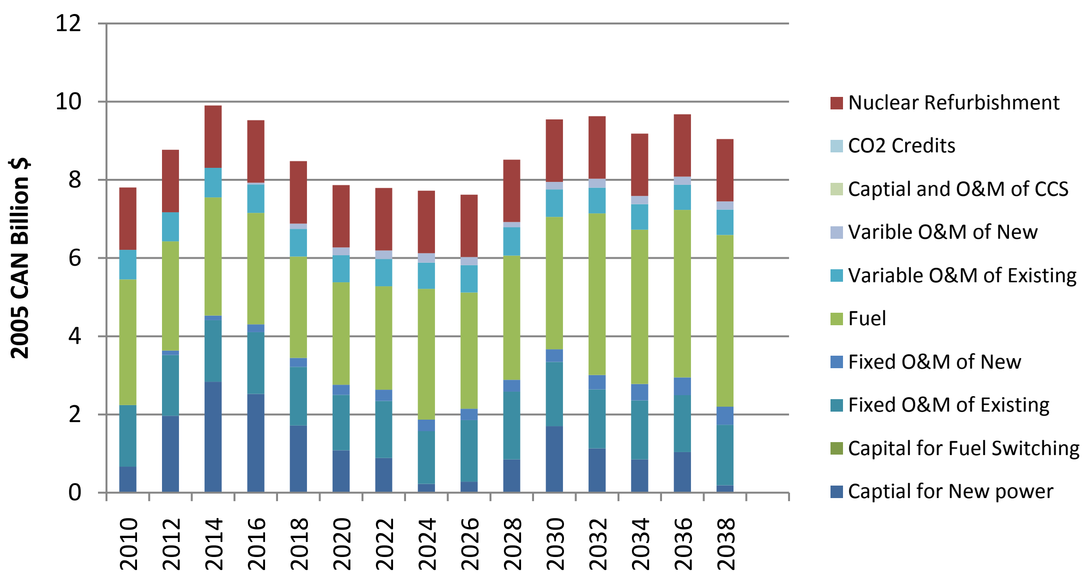


Figure 41. Detail expenditure: Reference case

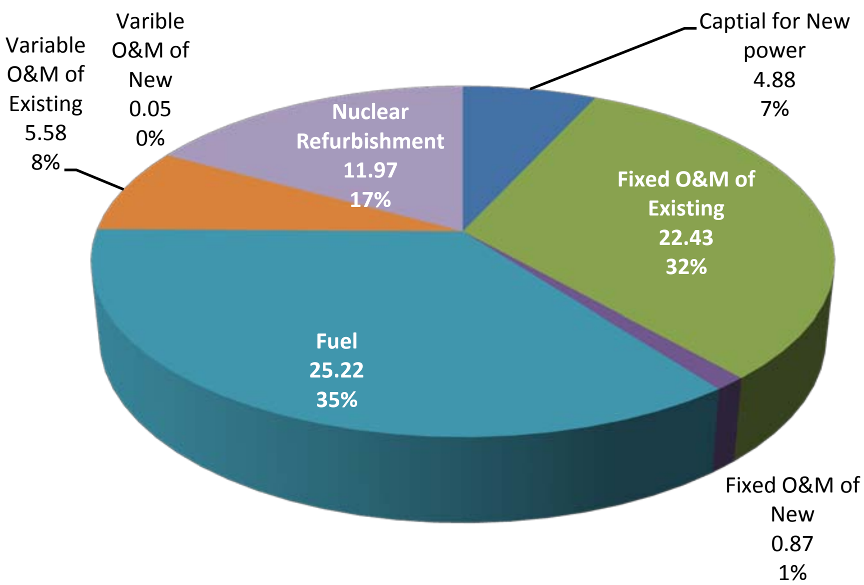


Figure 42. Overall expenditure: H. Mirzaesmaeeli et al.

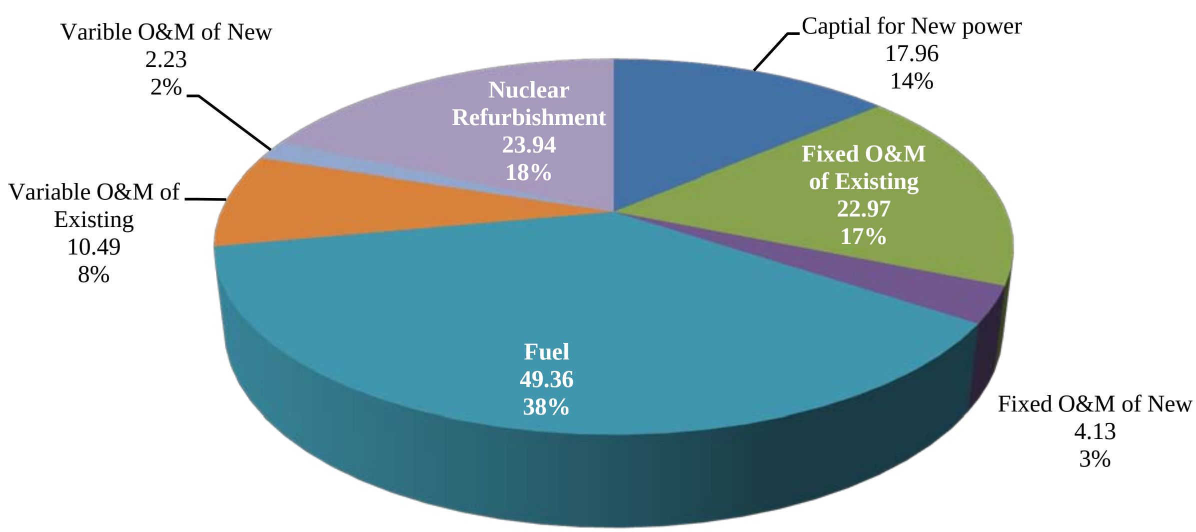


Figure 43. Overall expenditure: Reference case

$131 billion and $71 billion of total expenditure is recorded in the reference case and the H. Mirzaesmaeeli et al. case respectively. Similarities exist in the expenditure trend where fuel is the most substantial portion, but does not see much fluctuation from year to year. The operation and maintenance cost for the existing power stations is almost halved the percentage in that of the reference case. The percentage amount of spending is however very similar, much larger total expenditure and longer time horizon in the reference case may cause this skew. A similar situation also observed in nuclear refurbishment in both cases, where alike percentage show an entirely different number. This results from the heavy utilization and the addition of new nuclear power seen in the reference case.

Fleet structure

Table 21. Fleet structure: Reference case

	Capacity (MW)	2010	2012	2014	2016	2018	2020	2022	2024	2026	2028	2030	2032	2034	2036
PC	458														
PC	527														
PC	1053														
PC	527														
NGCC	253														
NGCC	507														
NGCC	760														
NGCC	1520														
NGCC	2279														
NGCC	3039														
Nuclear	3012														
Import	1250														
Wind	2500														

Table 22. Fleet structure: H. Mirzaesmaeeli et al.

	Capacity (MW)	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
PC	527													
NGCC	1013													
NGCC	760													
NGCC	1520													
NGCC	1520													
NGCC	507													

A total of 5,845 MW of new installed capacity is observed. Similarities exist where large new NGCC installed capacities of 5,318 MW, over 90% of the total new installed capacity, is purchased. No CCS, on new or existing stations, nor fuel switching technique is used.

The NGCC in the reference case is reduced to 47% of the total new installed capacity. NGCC, however, is still the single largest new installed capacity purchased in both base cases. This, however, does not implicate the level of electricity production from each new source.

Nuclear is the most important source of energy in both cases, producing on average of 45% and nearly 50% of the total electricity produced in Mirzaesmaeeli's and reference case respectively. No new nuclear power station was purchased in H. Mirzaesmaeeli et al. case. Perhaps it is more economically feasible to consider this source of energy once the demand is considerably higher and for an extended period of time as is evident in the reference case.

Wind supplies are introduced in the reference case. They are purchased early and utilized at capacity for the entire study period. The late addition of imported electricity also observed and is utilized toward the end of the scenario. This late addition of the importation of electricity may indicate the economic infeasibility of building a new generating structure late in the horizon.

Overall Installed capacity

Supply Mix Advice, released by the Ontario Power Authority in 2005, indicates an expected overall installed capacity of the system. The report is shown in figure below. Coal is eliminated from the fleet as is required by the Environmental Protection Act.

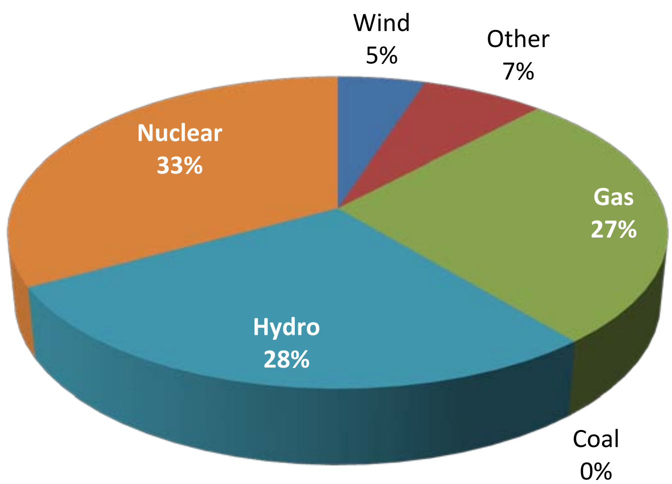


Figure 44. Ontario's projected installed capacity by 2015 (Ontario Power Authority, 2005)

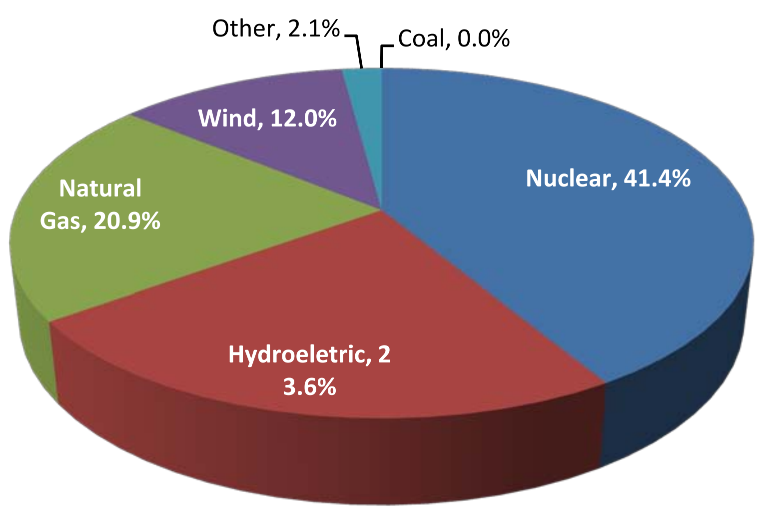


Figure 45. Ontario's projected installed capacity by 2015: Coal cut after 2014

Figure 41 and figure 42 above are the projected installed capacity by 2015. The closest projected installed capacity comparing with the OPA report is the case where all coal-fired power stations are eliminated from the fleet. As shown in the table below, nuclear capacity is slightly higher in the coal cut after 2014 case. The largest different is in the wind supply where it is doubled in the coal cut case. This shows the important role of wind technologies and is introduced to fleet as soon as possible. The ‘other’ category of supply technologies consist of, among other, wood and waste fuelled generating stations which are not part of the supply technologies offered in this study. As a result, this portion of the projected installed capacity is three times smaller than that of OPA’s.

Table 23. Ontario’s projected installed capacity in 2015

Fuel	OPA composition	Coal cut after 2014
Nuclear	33.0%	41.4%
Hydro	28.0%	23.6%
Gas	27.0%	20.9%
Other	7.0%	2.1%
Wind	5.0%	12.0%
Coal	0.0%	0.0%

6. CONCLUSION

Various case studies are performed to gauge the best possible strategy in different situations. Case studies are listed as follow:

Case I: Reference case

Case II: Various CO_2 emission constraints

Case III: No coal after 2014

Case IV: No new nuclear after 2014

Case V: No CCS

CCS system and fuel switching technique is applied where the CO_2 emission reduction target is not very high. However, when this emission reduction target becomes more restrictive, these accommodating techniques and CO_2 credit are purchased to satisfy the reduction target. This reflects very well in the case with 75% CO_2 emission reduction target where the total expenditure is over $300 billion, more than double that of the reference case. And 47% of this expenditure is used to purchase CO_2 credit. Total expenditure is directly related to the CO_2 emission reduction target, excluding the 75% reduction target, the expenditure increases with a linear slop of ~ 5.

One largest source of emission is the coal-fired power stations. As such, Ontario can quite easily reach the Kyoto emission target by eliminating all existing and new coal-fired power stations from the fleet, in line with the Environmental Protection Act. In fact, this was demonstrated quite well in the coal cut 2014, and no CCS case. Removing coal from the fleet, however, implicates the increase reliance on natural gas and a small number of other supply technologies, reducing the diversity of the energy portfolio. Unlike coal, lack of international market for natural gas prices may prove costly for poorly planned and executed strategy. Any fluctuation in fuel prices or unreliability in the system will be greatly magnified, when there are a small number of technologies the system relies on. Coal is cheap, reliable, and most abundant, qualities of important to the fleet. Increasing the efficiency and equipped with CCS system, coal can turn into a rather clean source of energy.

While renewable energy sources are an attractive proposition due to the small carbon foot print, the inability to generate electricity on demand limits these sources of energy to a small capacity in the fleet. Until the storage medium and/or the consumption habit issues are solved, this limitation will be a big hurdle to overcome. Ontario has the largest installed capacity of wind turbine in Canada. The additional wind however, will allow for another of 4,000 MW, adding up to the total of 5,000 MW recommended by IESO and the IPSP report. This wind supply is always utilized in every scenario tested so far.

Nuclear power is currently Ontario's largest installed capacity and is most utilized. Scenarios where no new nuclear power is available are performed, and unsurprisingly, nuclear power is a very efficient strategy in reducing the CO_2 emission. Evidently, by not allowing new nuclear power, CO_2 emission increases an astonishing 248 Mt over the same scenario where new nuclear capacity is available. When the 6% emission reduction constraint is applied in addition to these lacks of new nuclear capacity, the total expenditure of $148 billion is required to achieve the desired effect, causing $68 per tonne of CO_2 avoided. The most similar scenario is the 25% reduction case $150 billion of total expenditure is required, costing $54 per tonne of CO_2 avoided.

While unique solutions are being continuously discovered and presented, one thing remain absolute, the solution is not one single technology or action in isolation. It can only be achieved by a collection of supply technologies and combination of actions from both supply and demand sides of the equation.

The relatively user friendly interface of the model has proved to be quite versatile. Various scenarios can be performed with some input adjustment as required.

Further sensitivity analysis should be performed to measure the model responses to a specific parameter. With some modification, this model is more than capable to be utilized for another territory.

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