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A multi-period optimization model for energy planning with CO_2 emission consideration

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ABSTRACT

A novel deterministic multi-period mixed-integer linear programming (MILP) model for the power generation planning of electric systems is described and evaluated in this paper. The model is developed with the objective of determining the optimal mix of energy supply sources and pollutant mitigation options that meet a specified electricity demand and CO_2 emission targets at minimum cost. Several time-dependent parameters are included in the model formulation; they include forecasted energy demand, fuel price variability, construction lead time, conservation initiatives, and increase in fixed operational and maintenance costs over time. The developed model is applied to two case studies. The objective of the case studies is to examine the economical, structural, and environmental effects that would result if the electricity sector was required to reduce its CO_2 emissions to a specified limit.

1. Introduction

The optimization of the power system planning problem is a very challenging undertaking that requires consideration of various drivers and decision criteria. There are various supply technologies that may be used in order to meet the demand of a power system. These supply options differ based on several factors; including economical variability, environmental impact, operational characteristics, and construction lead time. For instance, some technologies offer lower capital and operating cost at high emission rates, while others have higher associated costs but lower environmental impacts. In addition to the different supply technologies, there are several pollutant mitigation options, such as Carbon Capture and Storage (CCS), which may be utilized. The underlining question then becomes, what is the optimal mix of supply technologies and pollutant mitigation options that should be selected in order to meet the annual electricity demand and environmental limits of a given power system, while minimizing the overall cost? This question is further complicated by introducing additional external multi-period factors such as annual fuel price fluctuations and conservation and demand management (CDM) strategies.

Numerous works have been published on using multi-period optimization methods for planning purposes. Iyer et al. (1998) have developed a multi-period mixed-integer linear programming (MILP) model for the planning and scheduling of offshore oil field facilities. This mathematical model employs a general objective function that optimizes a selected economic indicator. Maravelias and Grossmann (2001) proposed a complex multi-period optimization model to address the challenge of planning for the production of a new product in highly regulated industries, such as pharmaceuticals and agrochemicals. The model uses a multi-period MILP model that maximizes the expected net present value of a multi-period project. The model, although comprehensive, does not account for the lead time required for construction of new plants. Mo et al. (1991) developed a stochastic dynamic model for handling the uncertainties in generation expansion problems. The model makes it possible to identify the connection between investment decisions, time, construction periods, and uncertainty.

Hashim et al. (2005) and Elkamel et al. (2009) developed a single-period deterministic MINLP optimization model aimed at predicting a fleet-wide system configuration which simultaneously satisfies electricity demand and CO_2 emission constraints at minimum cost. The mathematical model developed was linearized using exact linearization techniques in order to overcome the inherent problems with solving non-linear models. Although the model developed by Elkamel et al. (2009) is very comprehensive and complex, its single-period mathematical structure does not allow the incorporation of multi-period factors such as construction lead time and fuel price fluctuations over time. A number of other studies that deals with energy planning models appeared

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also in the literature. We refer the reader to the survey paper by Hobbs (1995) that provides a review of optimization models for electric utility resource planning. Jebaraj and Iniyan (2006) also presented a comprehensive review of the literature on the various emerging issues related to the energy modeling problem.

In this paper, a novel deterministic optimization model was developed. This model considers multi-period factors and CO_2 mitigating technologies in order to select the optimal mix of energy supply sources that will meet current and future electricity demand and CO_2 emission targets, and will minimize the overall cost of electricity. In the following section we present the mathematical formulation for the deterministic multi-period MILP model. The mathematical formulation includes an objective function that minimizes the overall cost, and several model constraints to satisfy energy demand, CO_2 emission limits, operational restrictions, and logic-defined limitations. We then apply the developed model to two case studies directed towards the electricity sector of the province of Ontario, Canada. The results of the two case studies are presented and analyzed in order to examine the economical and structural impact on Ontario's electricity sector when forced to comply with a given CO_2 emission limit.

2. Model formulation

The indices, sets, variables, and parameters used in the planning model are as follows.

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
F^c	Coal Power Plant
NF	Non-fossil fueled
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 ($/GJ)
G_{ij}	Heat rate of boiler i using fuel j (GJ/MWh)
R_{it}	Cost associated with fuel-switching coal-fired boiler i during period t ($/MW)
S_{it}	Capital cost of power plant i during period t ($/MW)
T	Time horizon (year)
$[(CCost)]_t$	Cost of carbon credits during period *t* ($/tonne of CO_2)
$(CO2)_{ij}$	CO_2 emission from boiler *i* using fuel *j* (tonne of CO_2/MWh)
E_k^{max}	Maximum supplemental energy required for *k*th 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* (tonne of CO_2)
α_{ijktl}	Parameter used in linearizing cross terms

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*= 0 otherwise
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)
E_{ilt}	Power allocation from boiler i for load block l during period t (MW)
$[(Cre)]_t$	Carbon credits purchased during period t (tonne of CO_2)

All parameters listed above and which are related to costs represent discounted present values.

2.1. Objective function

The objective function of the deterministic multi-period MILP model is to minimize the total discounted present value of the cost over a specified planning horizon, and is presented as follows:

$$
\begin{aligned}
\min f(i,j,k,l,t) = {} & \underbrace{\sum_{i\in F}\sum_{j}\sum_{t} F^F_{ijt} C^F_{ij} x_{ijt} + \sum_{i\in NF}\sum_{t} F^{NF}_{it} C^{NF}_{i} y^{NF}_{it}}_{\text{Fixed O\&M cost of existing power plants}} + \underbrace{\sum_{i\in F}\sum_{j}\sum_{l}\sum_{t} V^F_{ijt} E^F_{ijlt} P_{lt} + \sum_{i\in NF}\sum_{l}\sum_{t} V^{NF}_{it} E^{NF}_{ilt} P_{lt}}_{\text{Variable O\&M cost of existing power plants}} + \\
& \underbrace{\sum_{i\in F}\sum_{j}\sum_{l}\sum_{t} U_{jt} G^F_{ij} E^F_{ijlt} P_{lt}}_{\text{Fuel cost for fossil fuel plants}} + \underbrace{\sum_{i\in F}\sum_{t} R_{it} h_{it}}_{\substack{\text{retrofit cost for}\\ \text{fuel switching}}} + \underbrace{\sum_{i\in\, new}\sum_{t} S^{new}_{it} C^{new}_{i} n_{it}}_{\substack{\text{capital cost for new}\\ \text{power plant}}} + \underbrace{\sum_{i\in\, new}\sum_{t} F^{new}_{it} C^{new}_{i} y^{new}_{it}}_{\substack{\text{Fixed O\&M cost of new}\\ \text{power plant}}} + \\
& \underbrace{\sum_{i\in\, new}\sum_{l}\sum_{t} V^{new}_{it} E^{new}_{ilt} P_{lt}}_{\substack{\text{Variable O\&M cost of new}\\ \text{power plant}}} + \underbrace{\sum_{i\in\, new}\sum_{l}\sum_{t} U_{it} G^{new}_{i} E^{new}_{ilt} P_{lt}}_{\substack{\text{Fuel cost for new}\\ \text{power plant}}} + \underbrace{\sum_{t} (Cre)_t (CCost)_t}_{\substack{\text{Cost of purchasing } CO_2\\ \text{emission credits}}} + \\
& \underbrace{\sum_{i\in F}\sum_{j}\sum_{k}\sum_{l}\sum_{t} Q_i (CO2)_{ij} \varepsilon_{ikt} \alpha_{ijktl} P_{lt}}_{\substack{\text{Carbon capture and storage cost}\\ \text{for existing power plants}}} + \underbrace{\sum_{i\in\, new^{cap}}\sum_{l}\sum_{t} Q_i (CO2)_{i} \varepsilon_{ikt} E^{new}_{ilt} P_{lt}}_{\substack{\text{Carbon capture and storage cost}\\ \text{for new power plants}}}
\end{aligned}
$$

where

$$\alpha_{ijktl} = E^{F}_{ijtl} z_{ijkt} \qquad \forall i, \forall j, \forall t, \forall k, \forall l \tag{1}$$

$$0 \le \alpha_{ijtl} \le C^{F^{\max}}_{ij} \qquad \forall i, \forall j, \forall t, \forall l \tag{2}$$

$$E^{F}_{ijtl} - C^{F^{\max}}_{ij}\left(1 - z_{ijkt}\right) \le \alpha_{ijtl} \le C^{F^{\max}}_{ij} z_{ijkt} \qquad \forall i, \forall j, \forall t, \forall k, \forall l \tag{3}$$

The construction of new power plants involves the use of postulated power plants that have a pre-assigned capacity and operational parameters. Energy production from these new hypothetical power plants can only occur at periods when they are already built. Several constraints have been formulated in order to prevent the generation of electricity from new power plants that have not yet been constructed.

It is important to note that the above objective function is a linearized version of the non-linear function that included the product of binary variables with continuous ones. These non-linear terms have been linearized through the exact linearization scheme that was described by Oral and Kettani (1992) and Torres (1991) and the model reduced subsequently to a mixed-integer linear program (MILP).

2.2. Model constraints

The objective function that is discussed above is subject to the following constraints.

2.2.1. Annual electricity demand

The annual electricity demand is satisfied by the following mathematical formulation:

$$(1-\rho)\left(\sum_{i\in F}\sum_{j} E^{F}_{ijtl} P_{lt} + \sum_{i\in NF} E^{NG}_{ilt} P_{lt} + \sum_{i\in new} E^{new}_{ilt} P_{lt} - \sum_{i\in F^{c}}\sum_{k} E_{ikt}\right) \ge D_{tl} - B_{tl} \quad \forall t, \forall l \tag{4}$$

2.2.2. Capacity constraint for existing power stations

In terms of the capacity allocation, the net power capacity (MW) of any power station cannot be exceeded.

$$\sum_{l} E^{F}_{ijlt} \le C^{F^{\max}}_{ij} x_{ijt} \qquad \forall i\in F, \forall t, \forall j \tag{5}$$

$$\sum_{l} E^{NF}_{ilt} \le C^{NF^{\max}}_{ij} y^{NF}_{it} \qquad \forall i\in NF, \forall t \tag{6}$$

2.2.3. Construction lead time and capacity constraint for new power stations

The multi-period nature of the planning model requires the consideration of construction lead time for new power stations. The construction lead time differs depending on the type of generating technology considered. For new power stations, no power can be supplied to the grid unless the construction of the new power plant has been completed. To achieve this, equation (7) has been formulated to ensure that during the construction phase of a new power plant, no electricity generating capacity is available. Furthermore, the constraint in equation (7) also functions as a capacity constraint in which the net power capacity limit of a new power plant cannot be exceeded.

$$E^{new}_{it'} \le C^{\max}_{i}(1-n_{it}) \qquad \forall i\in new, \ \forall t, \ \forall t' = 1, \dots, [t+(\beta_i - 1)] \tag{7}$$

$$\sum_{t} n_{it} \le 1 \qquad \forall i\in new \tag{8}$$

$$(T-t) - \sum_{t=(t+\beta_i)}^{T} y^{new}_{it} + n_{it} \le \beta_i \qquad \forall i\in new, \ \forall t = 1, \dots, (T-\beta_i) \tag{9}$$

2.2.4. Capacity constraint on capture process

The operation of any capture process requires the use of energy, either from the plant itself or from the grid. Equation (10) is formulated in order to ensure that the energy required for the kth carbon capture process is zero when no capture process is assigned to the ith coal-fired boiler. The parameter $E^{\max}_{k}$ represents the maximum supplementary energy required for the kth carbon capture process. E_{ikt} represents the energy required to operate the kth carbon capture process on the ith boiler, during year t.

$$E_{ikt} \le z_{ikt} E^{\max}_{k} \qquad \forall i\in F^{c}, \forall k, \forall t \tag{10}$$

2.2.5. Fuel-selection and power plant shutdown

Given that the model considers the option of fuel-switching existing coal-fired boilers with a less carbon-intensive fuel, such as natural gas, a constraint must be formulated in order to restrict the use of two different fuel types on the same boiler. To achieve this goal, equation (11) has been formulated. The binary variable x_{ijt} represents the fuel type (coal or natural gas) for the ith fossil fuel boiler during time period t and could have a value of zero if the ith boiler is shut down.

$$\sum_{j} x_{ijt} \le 1 \qquad \forall i\in F, \ \forall t \tag{11}$$

The binary variables x_{ijt} and h_{it} (decision whether to fuel-switch coal power plant i during time t) can be related by formulating the mathematical relation presented in equation (12).

$$(T-t+1) - \sum_{t=t}^{T} x_{ijt} + h_{it} \ge 1 \qquad \forall t, \forall i\in F, \forall j\in NG \tag{12}$$

Since fuel-switching of a coal power boiler i can occur only once during the time horizon T, the constraint in equation (13) must be included.

$$\sum_{t} h_{it} \le 1 \qquad \forall i\in F \tag{13}$$

2.2.6. Selection of CO_2 capture process

In terms of CO_2 capture process selection for a given boiler, a capture process can only be retrofitted if the boiler is operational. Equation (14) ensures that if an existing coal-fired boiler is shutdown, no CO_2 capture process can be brought online.

$$\sum_{k} z_{ikt} \le \sum_{j} x_{ijt} \qquad \forall i\in F^{c}, \forall t \tag{14}$$

Furthermore, only one type carbon capture technology can be used for a given boiler i during a time period t. The constraint formulated in equation (15) can be used to prevent the use of two carbon capture technologies on the same boiler.

$$\sum_k z_{ikt} \le 1 \qquad \forall i \in F^c, \forall t \tag{15}$$

2.2.7. Carbon dioxide emission constraint

The annual CO_2 emissions produced as a result of electricity generation are limited by the constraint formulated in equation (16). It is assumed that only the power plants that use fossil fuels can generate CO_2 emissions. Power stations that utilize non-fossil fuels, such as nuclear power plants, are assumed to have no CO_2 emissions and are therefore not included in equation (16).

The CO_2 constraint presented in equation (16) also considers the potential of CO_2 reduction by means of carbon credits. The CO_2 emitted by the entire fleet for a particular year may be reduced by the purchase of CO_2 credits for that year.

$$\sum_{i\in F^c}\sum_l\left[\left(\sum_j CO2^F_{ij}E^F_{ijt}P_{lt}\right)\left(1-\sum_k \varepsilon_{ikt}z_{ikt}\right)\right] + \sum_{i\in new}\sum_l CO2^{new}_i E^{new}_{itl}P_{lt} - Cre_t \le CLimit_t \quad \forall i\in t \tag{16}$$

3. Case studies based on Ontario's electricity sector

The model formulated above is applied to two case studies. The case studies presented in this paper were selected in order to examine the economical and structural impact on Ontario's electricity sector when forced to comply with a given CO_2 emission limit. The specified emission limits are based on the Kyoto target of 6% below 1990 levels. Each case study is based on a 14 year time horizon, starting in 2006, and ending in 2020.

The first case study (Case Study I) represents a base case scenario in which no CO_2 emission limits are imposed on Ontario's electricity sector. The second case study (Case Study II) examines a scenario in which CO_2 emissions from the entire fleet must be 6% below 1990 levels after the year 2011. To achieve this, annual CO_2 emissions from the entire fleet must be less than 20 Mt per year after the year 2011.

In order to meet the future electricity demand as forecasted in our previous work (Chui et al., 2009), several supply sources are considered in the case studies. The technologies that are considered include nuclear, natural gas, coal, hydroelectricity, pulverized coal combustion (PC), integrated gasification combined cycle (IGCC), natural gas combined cycle (NGCC) power plants, and long-term out-of-province hydroelectric import projects. Although additional power plant technologies exist, for purposes of this paper only the above-mentioned technologies are considered as possible supply candidates for the case studies. The supply technologies' economical and operational parameters used in the case studies are presented in Appendix A.

The developed model was programmed and implemented in the GAMS optimization package. The model was solved using the ILOG CPLEX 10.1 solver, which uses a branch and cut algorithm in order to solve complex problems. The programmed GAMS model was executed on an AMD Athlon 2.59 GHz, 2 GB RAM computer. Once executed, GAMS was able to find an optimal solution after a runtime of approximately 1 h for Case Study I and 9 h for Case Study II. The GAMS model statistics are presented in Table 1.

Table 1
GAMS model statistics outlining block of equations, blocks of variables, non-zero elements, number of single equations, number of single variables and discrete variables.

Blocks of equations	63	Single equations	14903
Blocks of variables	37	Single variables	11476
Non-zero elements	82119	Discrete variables	2595

Table 2
Comparison of new power plants built for Case Studies I and II. The table presents the type of technology, net capacity, and the year in which construction should commence.

	Technology	Net capacity (MW)	Start of construction	Total capacity (MW)
Case Study I	PC-31	526.5	2006	526.5
	NGCC-22	1013	2006	5318.5
	NGCC-31	759.8	2008	
	NGCC-32	1519.6	2010	
	NGCC-23	1519.5	2014	
	NGCC-21	506.5	2016	
Case Study II	NGCC-21	506.5	2006	4305.5
	NGCC-32	1519.6	2007	
	NGCC-33	2279.4	2009	
	NGCC-21+CCS	2279.4	2009	2711.7
	NGCC-31+CCS	432.3	2009	
	ACR-700 nuclear unit	1406	2006	1406

3.1. Case studies assumptions

The following assumptions are made in the case studies presented in this paper:

- The electricity generated from nuclear power units is only used for base-load demand.
- All existing nuclear units in Ontario are to be refurbished before their end-of-service dates. The time required to refurbish a single unit is assumed to be two years (Winfield et al., 2004). During the refurbishment process, the unit being refurbished is shutdown and consequently no electricity can be produced from that unit.
- The total hydroelectric capacity available to serve base-load demand in Ontario is approximately 3424 MW. The hydroelectric capacity to meet intermediate and peak-load demand is approximately 3299 MW (Atomic Energy of Canada Limited, 2005).
- No significant new renewable supply sources are realized within the time horizon of the case studies presented in this paper.
- Fixed and variable O&M (Operation and Maintenance) costs for all power stations are assumed to remain constant over time.
- No carbon credit system or market is available; hence no carbon credits can be purchased in order to meet CO_2 limits.
- It is assumed that the technology for CCS is available, and that CO_2 sequestration within the two reservoirs in Ontario, Lake Huron and Lake Erie, can be realized.

3.2. Results and discussion of case studies

3.2.1. New power stations

Table 2 presents the outcomes of the model's decision on construction of new power stations for the two case studies.

As can be seen in Table 2, for the base case (Case Study I), one PC power plant and five new NGCC power plants were built, whereas for the case study with CO_2 emission limits (Case Study II), three NGCC, two NGCC + CCS, and one nuclear power plant were built. There were no new coal-fueled supply technologies built in Case Study II.

Table 3
Comparison of fuel-switching (coal to natural gas) and CCS retrofit implementation between Case Study I and Case Study II.

Existing coal power plant	Fuel-switching		CCS retrofit	
	Case Study I	Case Study II	Case Study I	Case Study II
Lambton (1975 MW)	No	No	No	Yes
Nanticoke (3938 MW)	No	Yes	No	No
Atikokan (215 MW)	No	Yes	No	No
Thunder Bay (310 MW)	No	Yes	No	No

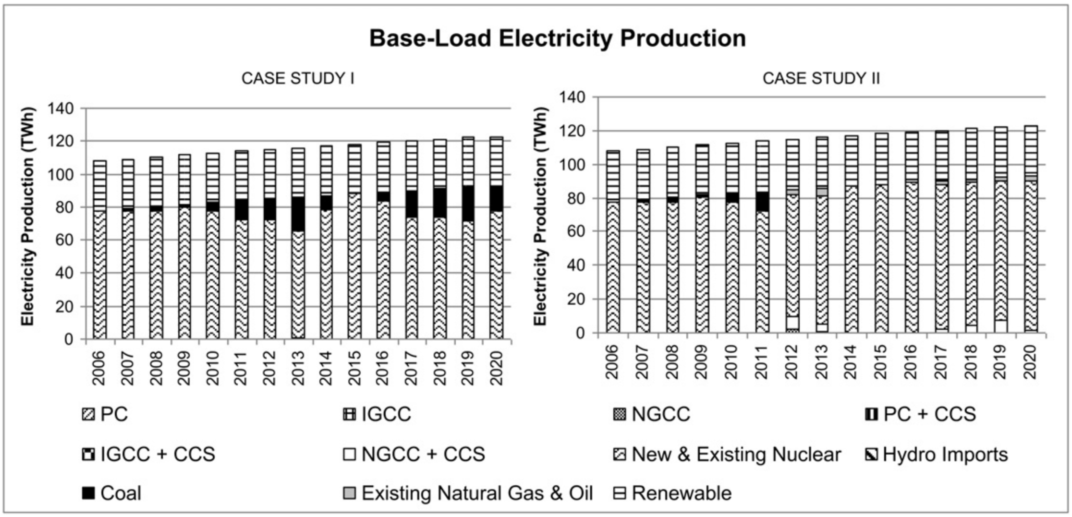

Fig. 1. Electricity production generated to meet base-load demand (TWh) in Case Studies I and II.

Since there are no annual CO_2 emissions limits imposed on Case Study I, the decision criteria for the optimal solution was strictly based on economical and operational considerations. The supply technologies selected by the optimizer were based on parameters such as the construction lead time, capital and operation costs, and fuel price forecasts. Since there were no requirements for reduction in CO_2 emissions, it was not economically justified to implement any CCS systems for this case.

Even though PC power plants have lower fuel cost than NGCCs, the outcome from the model specifies that five new NGCC power stations and only one new PC be built in Case Study I. The construction of the five new NGGC power stations is due to the lower capital cost and construction lead time of NGCC power plants.

For Case Study II, the optimal solution involves considering the power plant technologies that meet specified CO_2 emission requirements. The optimizer has to be mindful of CO_2 emissions when choosing to build a new power plant. Unlike the base case, two NGCC plants were built with an integrated CCS system and no PC was built. No PC power plants were selected to be built due to the high CO2 emission from a PC compared to NGCC.

3.2.2. Existing coal power plants

In regard of the existing coal power plants, there are several notable differences between base case (Case Study I) and Case Study II. These include: the implementation of fuel-switching; retrofitting with CCS; and the power generated from each power plant in order to meet demand.

Table 3 shows whether fuel-switching and CCS retrofitting was implemented for each existing coal power plant in the two cases studied. As shown in Table 3, Nanticoke, Atikokan, and Thunder Bay power plants were fuel-switched for Case Study II, while none of the coal power plants were fuel-switched in the base case. This is because the capital costs and the fuel costs associated with switching an existing coal power plant to NG are considerable. The driving force behind fuel-switching is to lower CO_2 emissions, and since there are no CO_2 emission constraints, no incentives exist to choose this option in the base case.

For the same reasons as listed above, Lambton was retrofitted with a CCS system in 2018 for Case Study II but no CCS was implemented in Case Study I (Table 3). Once again, retrofitting

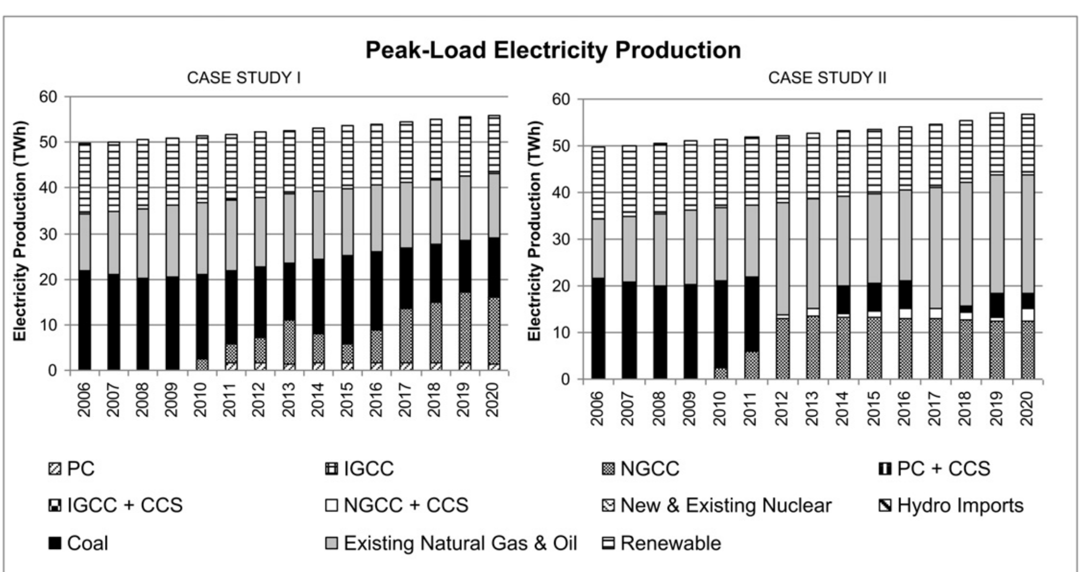

Fig. 2. Electricity production generated to meet peak-load demand (TWh) in Case Studies I and II.

Table 4
Comparison of total expenditure (2006 $CAN billion) between Case Study I and Case Study II.

	Total expenditure (2006 $CAN billion)		
	Case Study I: base case	Case Study II: 6% below 1990 levels	Difference (Case II – Case I)
Nuclear refurbishment	11.97	11.97	0
Capital for new power	4.88	8.17	3.29
Capital for fuel-switching	0	0.1	0.1
Fixed O&M of existing	22.43	21.33	−1.1
Fixed O&M of new	0.87	1.03	0.16
Fuel	25.22	30.34	5.12
Variable O&M of existing	5.58	5.07	−0.51
Variable O&M of new	0.05	0.54	0.49
Capital and O&M of CCS	0	0.54	0.54
Total	70.99829	79.09674	8.09846

a power plant with a CCS system is only justified when CO_2 emissions need to be reduced.

3.2.3. Base-load and peak-load demand

Figs. 1 and 2 illustrate the electricity generated to meet base load and peak load respectively for each case study. In both case studies, the electricity generated to meet base-load demand is predominantly produced from nuclear power plants. As shown in Fig. 1, the electricity generated from nuclear plants accounts for more than half of Ontario's base-load electricity demand.

In the base case, the remaining base-load demand is satisfied by renewable (essentially hydroelectricity), existing coal, and PC energy. The production of electricity from PC power plants is only introduced in the year 2013, at which time it produces 1 TWh to help meet base-load demand.

For Case Study II, the base-load demand that is not satisfied by nuclear power is met using the following supply technologies: renewable, existing coal, NGCC, NGCC + CCS, and existing NG and oil (Fig. 1). After 2011, coal power plants are no longer used in order to meet Ontario's base-load electricity production demand. The underlining reason as to why the model decided to decrease electricity production from coal power plants is due to the CO_2 emission targets set after the year 2011. This decrease in electricity production from coal power plants is compensated by increasing the electricity production output of other supply technologies.

The total new installed capacity is greater for Case Study II compared to Case Study I. This is because increased capacity from the new power suppliers is required in order to compensate for the decreased supply from existing coal power plants.

For the base case, energy production required to meet peak-load electricity demand is generated from various supply sources. Renewable, existing NG and oil, and coal generate most of the electricity to meet peak-load demand from 2006 through 2020 (Table 2). By 2018–2019, NGCC sources become a large contributor of electricity.

For Case Study II, renewable, existing NG and oil, and coal generate most of the electricity to meet peak-load demand from 2006 through 2011 (Fig. 2). After 2011, coal power plants play a less significant role in energy production for peak-load demand, and other supply technologies, such as NGCC, become large contributors to electricity generation.

3.2.4. Economic analysis and annual CO_2 emissions

Table 4 presents a comparison of the total expenditure for Case Study I and Case Study II for the entire study period of 2006–2020.

From Table 4, the cost of capital for new power plants is higher by $3.29 billion for Case Study II compared to the base case. This is due to the higher cost of building low-CO_2 emission facilities, such as NGCC + CCS. In particular, the cost of building a new nuclear plant is a major factor in the higher capital costs seen in Case Study II.

From Table 4, the cost of fuel is higher for Case Study II than the base case, since more power plants using natural gas are employed in this case. Since the cost of natural gas is higher compared to other fuel sources, the overall cost is higher for Case Study II.

Fixed and variable O&M costs of existing plants were lower for Case Study II compared to the base case. This is mainly due to the fact that the coal power plants in Case Study II are operated less frequently than in the base case. However, fixed and variable O&M costs for new plants were higher for Case Study II since operating costs of new plants, such as NGCC + CCS, are higher than for NGCCs with no CCS systems. Furthermore, the new power plants are utilized more in order to meet demand, and hence the associated O&M costs are higher.

The annual CO_2 emissions from the entire fleet for Case Studies I and II are presented in Fig. 3. From Fig. 3, the total CO_2 produced in

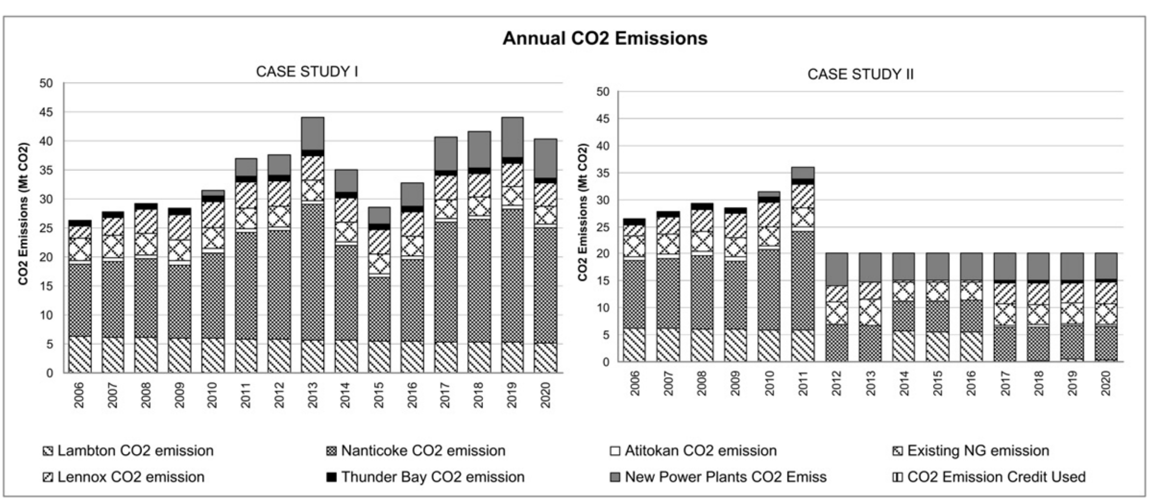

Fig. 3. Annual carbon dioxide emissions from entire fleet for Case Studies I and II.

Case Study I and Case Study II is 525 Mt and 359 Mt, respectively. Thus, there is a total of 166 Mt less CO_2 produced in Case Study II. This equates to a CO_2 reduction of approximately 32% for Case Study II when compared to the base case. From Table 4, the total expenditure for Case I is \$70.99 billion, and for Case II it is \$79.09 billion, a difference of \$8.1 billion. This amounts to an increase of 11.4% in cost. This amount represents the total additional investment required to meet a CO_2 target of 6% below 1990 levels after 2011 for Case Study II. Hence, the total cost associated with CO_2 reduction, per ton of CO_2, is \$48.79/ton CO_2 reduced.

4. Summary and conclusions

A deterministic multi-period mixed-integer linear programming (MILP) model for the power generation planning of electric systems was described and evaluated in this paper. The model was developed in order to determine the optimal mix of energy supply sources and pollutant mitigation options that meet a specified electricity demand and CO_2 emission targets at minimum cost. To accomplish this, an objective function was formulated that seeks to minimize the total discounted present value of the cost of electricity over a given time horizon. The formulation incorporated several time-dependent parameters, such as forecasted energy demand, fuel price variability, construction lead time, conservation initiatives, and an increase in fixed operational and maintenance costs over time. The model was applied to two case studies specific to Ontario's electricity sector: a base case in which no CO_2 emission targets are imposed; and a case scenario in which Ontario's electricity sector must comply with an annual CO_2 emissions limit of 20 Mt (per Kyoto's target of 6% below 1990 level) after year 2011. The electricity supply sources that were considered for the case studies were limited to nuclear, natural gas, coal, hydroelectric, PC, IGCC, NGCC and long-term out-of-province hydroelectric import projects. The relative impacts of the two cases were analyzed based on economical, structural, and environmental affects.

The results showed that for Case Study I, one PC power plant and five new NGCC power plants were built between 2006 and 2020. The total net capacity of all new NGCC and PC units was 5318 MW and 526.5 MW, respectively. No NGC + CCS, IGCC + CCS, PC + CCS and IGCC were constructed during the time horizon considered in the base case. Furthermore, it was found that no economic justification existed to implement any CCS systems or fuel-switching, since there were no requirements to reduce CO_2 emissions. Instead, the majority of base-load demand was met through utilization of renewable, coal, and nuclear power. Peak-load demand was satisfied by various supply sources, including NGCC, renewable, coal, PC and existing NG and oil. Coal power plant usage was maximized in order to help meet the base-load and peak-load demand. The total CO_2 emission over the study period amounted to 525 Mt for Case Study I. The total expenditure for the entire study period was \$79.10 billion.

For Case Study II, three NGCC, two NGCC + CCS, and one nuclear power plant were built between 2006 and 2020. The total net capacity of new NGCC, NGCC + CCS, and nuclear power plants was 4305.5 MW, 2711.7 MW, and 1406 MW, respectively. There were no new coal-fueled supply technologies built in Case Study II. The annual CO_2 target of 20 Mt was met after year 2011. This target was achieved by implementing a combination of fuel-switching, CCS retrofitting, power balancing, and construction of low-emission supply technologies. Nanticoke, Atikokan, and Thunder Bay power plants were fuel-switched in years 2012, 2017, and 2017, respectively. The fuel-switching was implemented in order to reduce the CO_2 emitted from these power plants. The optimizer determined that it was more economically feasible to fuel-switch the above-mentioned coal power plants than to shut them down. The capital cost of fuel-switching these power stations is \$10 million. It was determined that the option of retrofitting an existing coal power plant with a CCS system is a sound and economically feasible endeavor. In Case Study II, a CCS system was retrofitted in Lambton coal power plant in year 2018. The overall cost of implementing and operating this CCS system amounted to \$54 million. Maximum coal power plant utilization was employed from years 2006 to 2011 in order to meet base-load and peak-load demand in Case Study II. After year 2011, coal power plants were minimally operated to meet peak-load demand, and were not used at all to meet base-load demand. Coal power plants were not utilized for base-load demand after year 2011 due to the high CO_2 emissions associated with these plants. In order to compensate for the gap in power production created by not using coal power plants, other supply technologies were used in Case Study II to meet demand, such as NGCC + CCS, NGCC and new nuclear. The total CO_2 emission over the study period amounted to 359 Mt for Case Study II. This is a CO_2 reduction of approximately 32% when compared to the base case. The annual CO_2 emissions from the entire fleet remained constant at 20 Mt after the year 2011. The total expenditure for the entire study period was \$79.10 billion. The total expenditure for Case Study II was approximately 11.4% higher than for the base case. The higher cost observed in Case Study II is due to the additional expenditure required to mitigate and meet the specified CO_2 limit. Fuel cost and capital expenditure for new power stations are the main two factors that drive up the total cost of Case Study II. The increased fuel cost is due to the operation of more expensive fuel sources such as natural gas. The increase in capital expenditure is due to the construction of more expensive, less carbon-intensive, power plants such as NGCC + CSS and nuclear units. The total cost associated with reducing the CO_2 emissions to 6% below 1990 levels, per ton of CO_2, was \$48.79/ton CO_2 reduced.

This model offers many potential benefits to Ontario's energy sector. In addition to providing an optimal solution for meeting future electricity demand, it can help Ontario realize the optimal way to meet its emissions targets while minimizing the overall cost of electricity. Furthermore, although this project was aimed at Ontario's future energy supply mix, it could also be readily applied to other regions or even countries as a whole.

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Appendix

The economical and operational parameters for the PC, IGCC, NGCC, and nuclear power units used in the case studies are presented in Table A1. The data outlined in Table A1 were obtained from the Integrated Environmental Control Model (IECM) developed by Carnegie Mellon University and the Department of Engineering and Public Policy. The cost of CCS was obtained from Hashim (2006). For the power stations that have an integrated CCS system, the cost associated with CCS is incorporated in the cost and operational parameters.

The economic and operational parameters for nuclear power plants were obtained from Ayres et al. (2004).

The estimates for project cash flow during construction are presented in Table A2. The cash-flow data were obtained from Ayres et al. (2004).

Table A1 Economic and operational parameters for new power plants. This table presents data for single units and units that have been retrofitted with a MEA Carbon Capture and Storage (CCS) system. All costs are expressed in terms of 2005 Canadian dollars.

Technology	*C* (MW)	*U* ($/MWh)	*F* ($/MW)	*S* ($/MW)	CF (%)	*G* (BTU/MWh)	CO_2 (tonne CO_2/MWh)	CCS ($/tonne CO_2)	Lead
PC	457.7	2.86	5.73E+04	1.78E+06	0.75	9.60	0.88	N/A	5
PC	526.50	2.86	5.28E+04	1.72E+06	0.75	9.59	0.87	N/A	5
PC+CCS	337.40	20.281	9.65E+04	3.07E+06	0.75	13.02	0.12	74.28	5
PC+CCS	459.20	19.62	8.33E+04	2.90E+06	0.75	13.01	0.12	69.27	5
PC+CCS	491.70	19.47	8.04E+04	2.85E+06	0.75	13.01	0.12	62.88	5
IGCC	274.80	1.24	9.77E+04	2.38E+06	0.85	11.17	0.99	N/A	5
IGCC	552.40	1.24	7.25E+04	2.22E+06	0.85	11.11	0.98	N/A	5
IGCC	830.30	1.24	6.35E+04	2.14E+06	0.85	11.09	0.98	N/A	5
IGCC+CCS	231.40	12.97	1.45E+05	3.56E+06	0.85	13.36	0.09	19.79	5
IGCC+CCS	465.80	11.16	1.12E+05	3.33E+06	0.85	13.27	0.09	15.41	5
IGCC+CCS	700.50	10.45	7.45E+04	3.33E+06	0.85	13.23	0.09	15.41	5
NGCC	253.30	0.00	2.10E+04	7.53E+05	0.85	7.18	0.37	N/A	3
NGCC	506.50	0.00	1.60E+04	7.49E+05	0.85	7.18	0.37	N/A	3
NGCC	759.80	0.00	1.43E+04	7.46E+05	0.85	7.18	0.37	N/A	3
NGCC+CCS	216.10	8.58	3.93E+04	1.32E+06	0.85	8.41	0.04	71.53	3
NGCC+CCS	432.30	6.68	2.91E+04	1.22E+06	0.85	8.41	0.04	46.98	3
NGCC+CCS	648.40	5.94	2.70E+04	1.24E+06	0.85	8.41	0.04	46.98	3
ACR-700	1506	4	1.12E+04	2.41E+06	0.9	–	0	–	8
CANDU 6	1456	2.3	1.33E+04	3.06E+06	0.9	–	0	–	8

C, gross capacity (MW); *U*, non-fuel variable O&M cost ($/MWh); *F*, fixed O&M cost ($/MW); *S*, capital cost ($/MW); CF, capacity factor (%); *G*, heat rate (BTU/MWh); CO_2, CO_2 emissions (tonne CO_2/MWh); CCS, cost of CCS ($/tonne CO_2); Lead, construction lead time (years).

Table A2 Estimated project cash flow for construction of new power plants.

Technology	Project cash flow
PC and IGCC	Year 0: 3.1% (down payment)
	Year 1: 16.1%
	Year 2: 30.8%
	Year 3: 34.1%
	Year 4: 15.9%
NGCC	Year 0: 0% (down payment)
	Year 1: 50%
	Year 2: 50%
ACR-700 and CANDU 6	Year 0: 3.1% (down payment)
	Year 1: 8.0%
	Year 2: 21.0%
	Year 3: 27.1%
	Year 4: 19.6%
	Year 5: 12.0%
	Year 6:7.2%
	Year 7: 5.1%

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