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Optimization of Energy Usage for Fleet-Wide Power Generating System Under Carbon Mitigation Options

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This article presents a fleet-wide model for energy planning that can be used to determine the optimal structure necessary to meet a given CO_2 reduction target while maintaining or enhancing power to the grid. The model incorporates power generation as well as CO_2 emissions from a fleet of generating stations (hydroelectric, fossil fuel, nuclear, and wind). The model is formulated as a mixed integer program and is used to optimize an existing fleet as well as recommend new additional generating stations, carbon capture and storage, and retrofit actions to meet a CO_2 reduction target and electricity demand at a minimum overall cost. The model was applied to the energy supply system operated by Ontario power generation (OPG) for the province of Ontario, Canada. In 2002, OPG operated 79 electricity generating stations; 5 are fueled with coal (with a total of 23 boilers), 1 by natural gas (4 boilers), 3 nuclear, 69 hydroelectric and 1 wind turbine generating a total of 115.8 TWh. No CO_2 capture process existed at any OPG power plant; about 36.7 million tonnes of CO_2 was emitted in 2002, mainly from fossil fuel power plants. Four electricity demand scenarios were considered over a span of 10 years and for each case the size of new power generation capacity with and without capture was obtained. Six supplemental electricity generating technologies have been allowed for: subcritical pulverized coal-fired (PC), PC with carbon capture (PC+CCS), integrated gasification combined cycle (IGCC), IGCC with carbon capture (IGCC+CCS), natural gas combined cycle (NGCC), and NGCC with carbon capture (NGCC+CCS). The optimization results showed that fuel balancing alone can contribute to the reduction of CO_2 emissions by only 3% and a slight, 1.6%, reduction in the cost of electricity compared to a calculated base case. It was found that a 20% CO_2 reduction at current electricity demand could be achieved by implementing fuel balancing and switching 8 out of 23 coal-fired boilers to natural gas. However, as demand increases, more coal-fired boilers needed to be switched to natural gas as well as the building of new NGCC and NGCC+CCS for replacing the aging coal-fired power plants. To achieve a 40% CO_2 reduction at 1.0% demand growth rate, four new plants (2 NGCC, 2 NGCC+CCS) as well as carbon capture processes needed to be built. If greater than 60% CO_2 reductions are required, NGCC, NGCC+CCS, and IGCC+CCS power plants needed to be put online in addition to carbon capture processes on coal-fired power plants. The volatility of natural

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gas prices was found to have a significant impact on the optimal CO_2 mitigation strategy and on the cost of electricity generation. Increasing the natural gas prices resulted in early aggressive CO_2 mitigation strategies especially at higher growth rate demands. © 2009 American Institute of Chemical Engineers *AIChE J,* 55: 3168–3190, 2009
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Introduction

A cost effective reduction strategy of greenhouse gas emissions is vital to the national interests of many countries to comply with international agreements to reduce greenhouse gas emissions without losing their economic competitiveness. Recent studies point to a broad array of emerging carbon dioxide capture and sequestration technologies that could help meet carbon dioxide emission goals for the next century. This article proposes optimal solutions to effectively manage carbon dioxide reduction, capture, and sequestration. These carbon management solutions can include physical and natural processes associated with decarbonization; carbon dioxide capture, transport, and sequestration; the use of new and/or improved fuel sources (nuclear, fossil fuels, renewables); improved efficiency of energy conversion and utilization; economic and market analysis; and alternative energy policy options.

In general terms, the carbon management problem involves the energy conservation, process efficiency, fuel switching, capture, transportation, and storage of CO_2. For instance, different processes can be used to effectively capture CO_2 (absorption, adsorption, membrane separation, cryogenic separation, etc.). Depending on the nature of the gas stream and the method of capture used, additional treatments might be required to render the stream appropriate, in terms of purity, pressure, and temperature, to the anticipated mode of transportation and intended storage site. This additional treatment can involve purification, pressurization, and/or cooling. A number of choices are also available for CO_2 transportation ranging from truck, rail, pipeline, or ship. If transportation by pipeline is chosen as is often the case for relatively large quantities of CO_2, a decision must be made on the optimal pipeline network that has to be built along with decisions on which CO_2 sources should supply which storage site. Different types of CO_2 storage can be considered: oil and gas reservoirs, coal beds, deep saline aquifers, salt domes and rock caverns or even forests. There are also a number of constraints that have to be taken into consideration in order to be able to successfully formulate a carbon management plan or framework. Among these are the physical constraints imposed by the CO_2 production capacities of CO_2 sources and the storage capacities of the geological formations into which the CO_2 is to be injected. In situations involving deep water, transportation by ship may be the only alternative. There are also a number of economic constraints. The economical ideal CO_2 source is a single, stationary point that generates a large volume of relatively pure CO_2, and that is close to the point of storage. An economically ideal storage site for CO_2, is a single point of large storage capacity, generates revenues, and is close to the source(s) of CO_2.

The above discussion clearly illustrates the complexity of the carbon management problem and the utility of a systems approach. Only such an approach can take into account all the interactions among the subproblems, the associated solution alternatives and lead to a successful solution.

A large number of studies appear in the literature that deal with energy planning models. Jebaraj and Iniyan[1] presented a comprehensive review of the literature on the various emerging issues related to the energy modeling problem. Gonzalez-Monroy and Cordoba[2] presented a tool that optimizes the energy supply system and which takes into account financial costs, the consumption of primary energy, and the amount of harmful emissions to the environment. Oliverira and Antunes[3] presented an input-output model for evaluating interrelations between economic activities. Saeed et al.[4] focused on minimizing energy consumption at the process level through the use of interprocess heat exchange. Stefanis et al.[5] focused also on process systems and presented a methodology that embeds LCA principles within a formal process optimization framework. Looking at a broader scale, Turkey and coworkers[6,7] proposed a systematic framework that identifies the synergy among the energy production systems of multiple process systems and which is able to suggest improvements in financial and environmental performance.

The above models dealt with the planning and environmental aspects of energy production systems and did not emphasize the role of carbon management and advanced technologies. Numerous other researchers have developed energy models for assessing conventional and advanced technologies and investigated the role of carbon capture and sequestration technologies on CO_2 emissions abatement for the electric sector. These studies will be reviewed in more details here since they are more relevant to the current study. Rubin et al.,[8] for instance, developed the integrated environmental control model (IECM) to provide plant level performance, emissions, and cost estimates for a variety of environmental control options for coal-fired power plants. The model is built in a modular fashion that allows new technologies to be easily incorporated into an overall framework. A user can then configure and evaluate a particular environmental control system design. Current environmental control options include a variety of conventional and advanced systems for controlling SO_2, NO_x, particulate and mercury emissions for both new and retrofit applications. The IECM framework now has being expanded to incorporate a broader array of power generating systems and carbon management options.

Rao et al.[9] conducted advanced plant-level analyses of CCS by incorporating uncertainty and variability for about 30 independent model parameters using the integrated environmental control model (IECM). Such an analysis considered the following effects: energy efficiency improvement, changing fuel prices, response of electricity demand on price changes, effect of electricity demand by incorporating advanced power generation and CCS technologies, fuel switching, and plant retirement. Vassos and Vlachou[10] developed a model to investigate strategies to reduce CO_2 emissions from the electricity sector. This model enabled the determination of optimal strategies for satisfying a limit on CO_2 emissions from the electricity sector. The model can also estimate the cost of CO_2 emission limit and the optimal tax required to achieve the optimal strategy for reducing emissions to a desired level. In selecting the optimal strategy, the model considered commercial technologies and other new types of technologies (i.e., new coal or lignite, natural gas technologies with CO_2 capture). John and Kelly[11] reviewed the technologies that could be used to capture CO_2 from the use of fossil fuels. They described three main overall methods of capturing CO_2 in power plants; post combustion capture, oxyfuel combustion, and precombustion capture. They also discussed the impacts of different CO_2 capture technologies on the thermal efficiencies and costs of power plants based on recent studies carried out by process technology developers and plant engineering contractors.

Johnson and Keith[12] proposed a linear programming (LP) model to illustrate the importance of considering competition between new plants with and without capture, and the economic plant dispatch in analyzing mitigation costs. The model results illustrate how both carbon capture and sequestration technologies and the dispatch of generating units vary with the price of carbon emissions, and thereby determine the relationship between mitigation costs and emissions reduction. Wise and Dooley[13] developed the battle carbon management electricity model (CMEM) to explore the effect of carbon taxes and constraints on investment and operating decisions for new generating capacity as well as on the operation and market value of existing plants in a specific region of the United States and across three carbon dioxide scenarios. In computing the least cost decision to meet the constraints, the model considered the economic trade offs among several factors, including capital costs for new plants, capacities of existing plants, efficiencies, operation and maintenance costs, availabilities for new and existing plants, carbon capture and sequestration (CCS) technologies for new plants, and CCS retrofit for existing units, natural gas and coal prices, carbon prices resulting from the imposed CO_2-emissions constraints, and the hourly load profile of electricity demand. Gielen and Taylor[14] analyzed the potential role of CO_2 capture and storage for 15 world regions, using the IEA Secretariat's energy technology perspectives (ETP) model. This model determined the least cost energy system for the period 2000–2050. Emission reduction strategies accounted for in this model included the use of renewable energy, nuclear, energy efficiency improvements, as well as CCS on existing and new fossil plants. The model results indicated that electricity production from coal-fired power plants without CCS will be ceased by 2030 and no new coal-fired power plants without CCS should be built.

Genchi et al.[15] developed a prototype model for designing regional energy supply systems. Their model calculates a regional energy demand and then recommends a most effective combination of eleven different power supply systems to meet required CO_2 emission targets with minimum cost. The new energy system to be installed included cogeneration systems, photo voltaic cell system, unused energy in sewage and garbage incineration, and solar energy water supply. Linares and Romero[16] proposed a group decision multiobjective programming model for electricity planning in Spain based upon goal programming (GP). The objective was to minimize the total cost of electricity generation, CO_2 emission, SO_2, NO_x, and radioactive waste. The model is capable of estimating the capacity to be installed for the year 2020 under four different social groups: regulators, academic, electric utilities, and environmentalists. The preferences by these groups were expressed as weights in the model that affect the different main criteria in the objective function. Mavrotas et al.[17] developed a mixed 0–1 multiple objective linear programming (MOLP) model and applied it to the Greek electricity generation sector for identifying the number and output of each type of power unit needed to satisfy an expected electricity demand. The first objective was to minimize the annual electricity production cost and the second objective dealt with the minimization of the total amount of SO_2 emissions. However, the model did not consider CO_2 mitigation and sequestration. Bai and Wei[18] developed a linear programming model to evaluate the effectiveness of possible CO_2 mitigation options for the electricity sector in Taiwan. The strategies they considered included fuel alternatives, reduced peak load, energy conservation, improving power generation efficiency, and CO_2 capture. They found that the combination of reduced peak production and increased power plant efficiency with CO_2 conservation was an effective strategy to meet significant CO_2 emission reductions. Climaco et al.[19] developed techniques that incorporate multiple objective linear programming and demand-side management (DSM). These techniques are able to determine the minimum expansion cost by changing the levels and forms of the electricity use by the consumers and generated alternatives from the supply side. The model also considered the emissions caused by the electricity production. Loulou and coworkers[20–22] developed optimization models to examine least-cost strategies to reduce GHG emission using MARKAL. MARKAL is a comprehensive energy-economy optimization model. This model has been successfully applied on a multiregional basis in Canada to evaluate trading of emission permits and electricity exchanges between provinces. The MARKAL model was also extended to examine the energy system in US and India to evaluate mitigation strategies for the industrial, commercial, and the residential sectors and for power plants and transportation. The model considered a detailed description of a region's reference energy/environmental system (RES). RES is a set of inputs and outputs of the energy system and economic parameters, such as annual fixed costs, variable costs, bounds on market shares, etc. In this manner, all aspects of the transformation of energy to supply end-use demands through a series of technologies by representing technology components and demand activities are described with detailed information. Process technologies include refinery, power plants, and transportation of energy carriers within the region.

The objective of this article is to present a fleet-wide model that is able to determine the optimal power generation structure necessary to meet a given CO_2 reduction target while maintaining or enhancing power to the grid. The model incorporates power generation and CO_2 emissions from a fleet of generating stations using a variety of fuels (hydroelectricity, fossil fuels, nuclear, and wind). The model does not contain turbines and electricity production is modeled as a function of fuel flowrate into the boilers. Nevertheless, it can be used to optimize an existing fleet as well as recommend new additional generating stations as well as CCS retrofit on existing generating stations to meet a specified CO_2 reduction target and electricity demand at the minimum overall cost. The model, implemented in GAMS, can determine the best mix of fuel, capacity for existing and new plants and technologies for capturing CO_2. The model is also able to determine the location of carbon capture plants that should be to put online. A case study from Canada is used to illustrate the model.

Canada signed The Kyoto Protocol, committing to reduce greenhouse gas (GHG) emissions by 6% compared to 1990 levels by 2012. In Ontario, Ontario power generation (OPG) produces 75% of Ontario's electricity from mix of energy sources. Coal accounts for 35% of OPG's electricity generating capacity, nuclear supplies 35%, hydroelectric 29%, and the remaining 1% is renewable energy. As a major electricity production in Ontario, OPG generated 115 TWh electricity and emitted about 36.7 million tonne of CO_2 in 2003, which represents about 31% increase in CO_2 emission compared to the 1990 level.[23,24] Furthermore, energy consumption in Ontario is forecasted to grow with an average annual growth rate of 0.9%.[25] Therefore, in the case study considered in this article, three potential CO_2 mitigation strategies have been proposed which include fuel balancing (optimal adjustment of the operation of existing generating stations to reduce CO_2 emissions without making structural changes to the fleet), fuel switching (switching from carbon intensive fuel to less carbon intensive fuel, e.g., coal to natural gas), and CSS. Furthermore, since CCS is energy intensive, new power plants to supply electricity to the grid based on growth rate demand, as well as to eventually supply supplemental energy for the CO_2 capture processes, are also investigated. Six categories of electricity generating technologies are considered in order to compensate with energy penalty due to capture process as well as to meet substantial growth in demand. These include subcritical pulverized coal-fired (PC), PC with carbon capture (PC+CCS), Integrated coal gasification combined cycles (IGCC), IGCC with carbon capture (IGCC+CCS), natural gas combined cycles (NGCC), and NGCC with carbon capture (NGCC+CCS). The objective is to determine the best strategies to reduce emission at certain target and satisfy substantial growth in demand in the most economical way.

Overview of CO_2 Capture in the Electricity Sector

Electricity generation is one of the major sources of carbon dioxide emissions, particularly coal-fired power plants. Capture and sequestration significantly reduce CO_2 emissions from power plants. Retrofitting the existing fleet of coal-fired plants with carbon capture could be promising given the recent increase in natural gas prices. Retrofitting CCS on existing natural gas plants would also possible. CCS can reduce CO_2 emissions by 85 to 95% compared to the same processes without CCS but it is a relatively costly emission reduction strategy.[25] Furthermore, CCS required a large amount of energy especially for regeneration. This reduces the overall energy efficiency of power generation typically by 10% which is a large energy penalty and results in a substantial increase in the cost of power generation by 40% above the current level.[26] There are two main options for coal-fired power plants with CO_2 capture: flue gas scrubbing with amine solvent and oxyfuel combustion. Amine scrubbing is generally considered to be the most technically proven option, but also the most expensive due to the large energy input required for solvent regeneration. Other processes like membrane separation, cryogenic fractionation, and adsorption technologies are also possible to separate the carbon from the flue gases but they are even less energy efficient and more expensive than chemical absorption.[27] Typical chemical solvents are amine or carbonate based, such as monoethanolamine (MEA), diethanolamine (DEA), ammonia, and potassium carbonate.[25] MEA is the most commonly used for flue gas applications. The physical absorption process typically uses a solvent such as dimethylether of polyethylene glycol (Selexol) and cold methanol (Rectisol®). Because the existing coal power plants have low CO_2 concentration (13–15% wet basis) in the flue gas, amine-based solvents have been viewed as the potential solution to this problem.[28] On the other hand, Selexol is a better CO_2 capture solvent for IGCC due to the high pressure synthesis gas. Chemical absorption imposes an energy penalty of about 15 to 30% for natural gas and 30 to 60% for coal plants.[27] Regeneration of physical solvents is not as energy intensive as for chemical absorption, and energy penalties for IGCC plants are about 15%.[29] Thus, the incremental cost of applying capture is lower for IGCC plants than for conventional natural gas and coal plants. The CO_2 capture system is energy intensive. The energy requirement is about 22% of gross plant capacity, mostly for sorbent regeneration (54%) and CO_2 product compression (36%). Sorbent circulation and fan power account for the remaining share (10%) of the total energy consumption of a CO_2 capture unit.[8]

Methodology

Superstructure representation

The superstructure representing a power generating fleet and CO_2 emission reduction techniques such as fuel balancing, fuel switching, and CCS is presented in Figure 1. This is an extension to our earlier superstructure where we considered a simplified version of the current problem.[30–32] The following notation is adopted throughout this article: C, NG, O, N, H, and A represent a set of coal, natural gas, oil, nuclear, hydroelectric, and alternative energy power plants, respectively. C_i, NG_i, O_i, N_i, H_i, and A_i represent existing coal, natural gas, oil, hydroelectric, and alternative energy power plants, respectively. Hypothetical new power plants are represented by N_i^{new}, H_i^{new}, A_i^{new}, PC_i^{new}, NG_i^{new}, IG_i^{new}, for nuclear, hydroelectric, alternative energy, supercritical pulverized coal (PC), natural gas combined cycle (NGCC), and integrated gasification combined cycle (IGCC) power plants. $C\text{-}C_i$, $C\text{-}NG_i$, $C\text{-}O_i$, represent CO_2 capture on existing

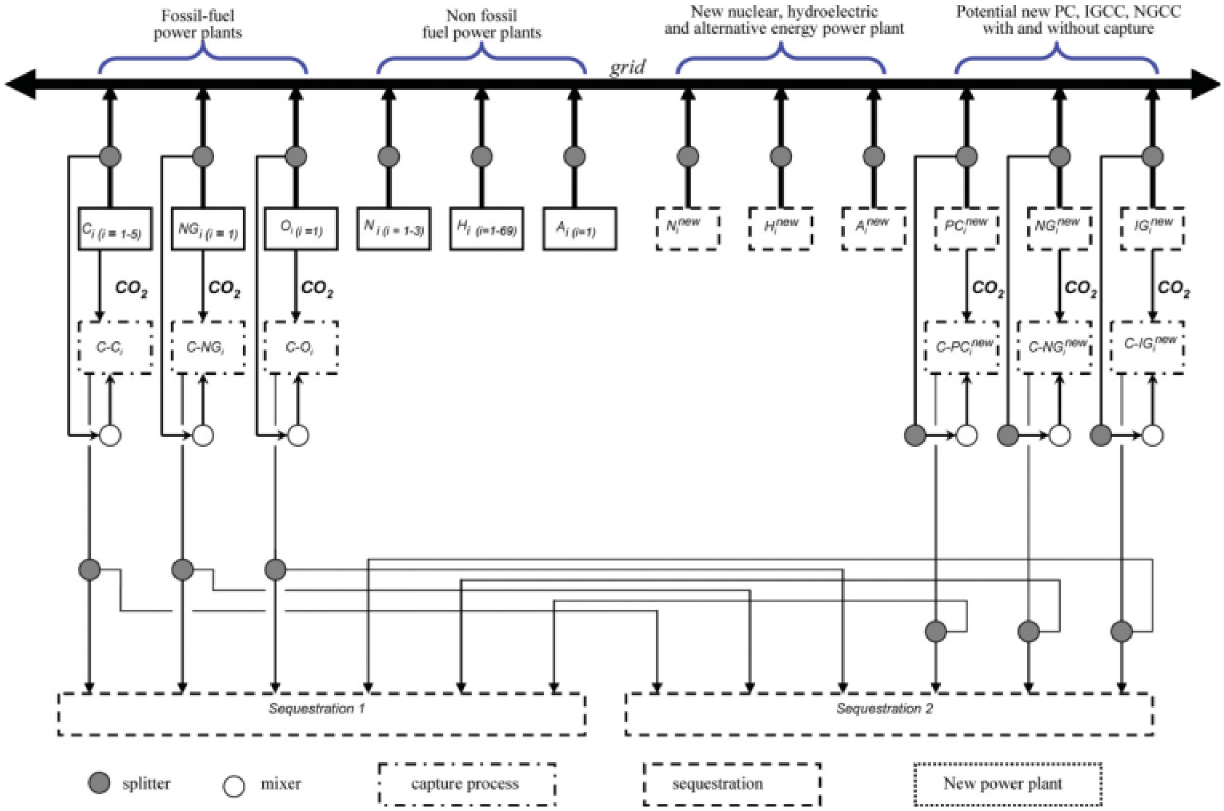

Figure 1. Superstructure representing a power generation fleet.

[Color figure can be viewed in the online issue, which is available at www.interscience.wiley.com.]

plants, whereas C-PC_i^{new}, C-NG_i^{new}, C-IG_i^{new} represents CO_2 capture on new fossil plants. Sequestration 1 and Sequestration 2 represent potential locations for CO_2 sequestration in Ontario. More than two locations can of course be considered.

Fuel balancing represents the technique of decreasing CO_2 emissions by adjusting the operation of the fleet of existing electric generating stations (e.g., increasing the load on existing nonfossil fuel power plants and decreasing the load on existing fossil fuel power plants). In this case, it is desired to determine the optimal distribution load for all power stations to maintain electricity to the grid while reducing CO_2 emission to a certain target.

The fuel switching technique represents switching from carbon intensive fuels to lower carbon intensive fuels.

If significant amounts of CO_2 emissions from fossil fuel power plants need to be reduced, it will generally be necessary to employ CO_2 capture and sequestration technologies. The superstructure takes into account CCS on existing and hypothetical new power generating stations and also illustrates the supply of energy for CO_2 capture processes on a given coal plant, from the plant itself which leads to a decrease in net plant output. Therefore, new power plants need to be constructed to make up for this energy short-fall. The mix of all electricity generated is injected to the grid.

Model Formulation

The objective of this problem is to determine what is the best generating plant load distribution (existing and new), mix of fuels, and CO_2 capture processes to meet electricity growth in demand for a given CO_2 reduction target.

Two main groups of continuous variables are defined:

(1) E_{ij} represents electricity generated/load distribution from the ith fossil fuel boiler using fuel j (e.g., $j = 1$ for coal and $j = 2$ for natural gas).

(2) E_i represents electricity generated/load distribution from the ith existing nonfossil power plants (e.g., nuclear, hydroelectric, alternative energy power plants, and new candidate power plant such as PC, IGCC, NGCC, with and without capture). The fuel type or source of energy does need to be specified here since the nature of the plant dictates what source of energy is to be used.

Four sets of binary variables are also defined:

(1) Fuel switching (coal to natural gas) for the ith coal-fired boiler is represented by the binary variable, X_{ij}

$$X_{ij} = \begin{cases} 1 & \text{if } j\text{th fuel is used in } i\text{th coal-fired boiler} \\ 0 & \text{otherwise} \end{cases}$$

(2) The existence/nonexistence of ith potential new boiler with and without capture is defined by the binary variable, y_i

$$y_i = \begin{cases} 1 & \text{if } i\text{th plant is selected} \\ 0 & \text{otherwise} \end{cases}$$

(3) The binary variable, z_{ik} is introduced to model the selection of kth capture process on ith existing coal-fired boiler

$$z_{ik} = \begin{cases} 1 & \text{if } i\text{th capture process is put online} \\ 0 & \text{otherwise} \end{cases}$$

(4) Selection of sth potential location for CO_2 sequestration from ith power plant is indicated by the binary variable, w_{is}.

$$w_{is} = \begin{cases} 1 & \text{if } s\text{th location of sequestration is selected} \\ 0 & \text{otherwise} \end{cases}$$

The formulation of the model is presented below.

Objective function

The objective of this study is to synthesize a power generation fleet and to incorporate carbon capture (CCS) on existing coal-fired power plants and construct new power plants with or without capture to meet a given CO_2 reduction target while maintaining or enhancing electricity to the grid at a minimum overall cost. The cost function represents the total system cost that includes operating costs of electricity generation for the fleet of generating stations, retrofit costs associated with fuel switching from coal to natural gas, retrofit costs for carbon capture retrofit on existing coal-fired power plants, and capital and operational costs for hypothetical new power plants and sequestration costs. Note that in the case of a fossil fuel already operating on gas ($j = 1$), there is no retrofitting cost involved (i.e., $R_{i1} = 0$).

The objective function can be written as:

$$\begin{aligned} \mathrm{OF} = & \underbrace{\sum_{i\in F}\sum_{j} C_{ij}E_{ij} + \sum_{i\in \mathrm{NF}} C_i^{\mathrm{NF}}E_i}_{\text{operational cost for existing plants}} + \underbrace{\sum_{i\in F^c}\sum_{j} R_{ij}X_{ij}}_{\text{retrofit cost}} \\ & + \underbrace{\sum_{i\in P^{\mathrm{new}}} S_i^{\mathrm{new}}E_i^{\max}y_i + \sum_{i\in P^{\mathrm{new}}} C_i^{\mathrm{new}}E_i^{\mathrm{new}}}_{\text{capital and operational cost for new additional stations}} \\ & + \underbrace{\sum_{i\in F^c}\sum_{k} S_{ik}^{c}z_{ik} + \sum_{i\in F^c}\sum_{k} C_k^{c}E_{ik}}_{\text{capital and operational cost of carbon capture retrofit}} + \underbrace{\sum_{i\in F^c\cup P^{\mathrm{new}}}\sum_{s} C_{is}^{\mathrm{seq}}\alpha_{ik}^{\mathrm{seq}}w_{is}}_{\text{sequestration cost}} \end{aligned} \quad (1)$$

where C_{ij} is the electricity generation cost per MWh if jth fuel is used in ith fossil-fuel boiler; C_i (C_i^{new}) is the electricity generation cost per MWh for ith nonfossil-fuel power plant (ith new hypothetical boiler); C_k^c is operational cost for kth CO_2 capture process (\$/MWh); C_{is}^{seq} is sequestration cost from ith boiler to sth storage location (\$/tonne CO_2 captured); E_i (E_i^{new}) is the electricity generated (MWh/year) from ith nonfossil-fuel power plant (ith hypothetical boilers); E_{ij} is the electricity generated (MWh/year) from ith fossil-fuel boiler when using jth fuel; E_{ijk} is electricity required for kth CO_2 capture process (MWh/year) incorporated in ith coal-fired boiler which running with jth fuel; R_{ij} is the retrofitting cost for switching ith coal-fired boiler to jth fuel (natural gas) expressed in US\$/year; S_i^{new} is capital cost for new power plant in \$/KW; S_{ik}^c is annualized capital cost for kth capture process in \$/year; ε_{ik} is the fraction of CO_2 capture; F is the set of fossil-fuel boilers including coal (F^c) and natural gas (F^{ng}); NF is the set of nonfossil-fuel power stations, including nuclear, hydroelectric, and wind turbine sources; and P^{new} is the set of hypothetical new boilers that includes pulverized coal, P^{PC} (P^{PCcap}), integrated gas combined cycle, P^{IGCC} (P^{IGCCcap}) and natural gas combined cycle, P^{NGCC} (P^{NGCCcap}) with and (without capture). In the case of nonfossil-fuel plants, no associated binary variables are defined, as the fuel type for these plants is known a priori. Note that in the above costs, all technology-related costs are assumed to be independent of actual utilization. However, since the cost coefficients are selected to correspond to each type of plant according to the plant generating method, size, and capacity, the errors involved with each choice are minimized. Furthermore, the present study is not dynamic in nature and the model can be used at different years with different cost coefficients. In this latter case, appropriate escalation factors can be used in the objective function to reflect changes in cost over time.

Constraints

The minimization of the objective functions represented by Eq. 1 is subjected to the following constraints:

Energy Balance/Demand Satisfaction. The total electricity injected to the grid comes from existing nonfossil power, from new boilers ($E_i^{\mathrm{NF}}/E_i^{\mathrm{new}}$) and from fossil generating stations operating with jth fuel, E_{ij}.

$$\left[\sum_{i\in \mathrm{NF}} E_i^{\mathrm{NF}} + \sum_{i\in P^{\mathrm{new}}} E_i^{\mathrm{new}} + \sum_{i\in F}\sum_{j} E_{ij}\right] \quad (2a)$$

The supplemental energy required for CO_2 capture processes, however, results in an electricity reduction/power derate. As a generalization, the total energy required for a capture process on an existing boiler can be supplied from the existing nonfossil power generation, $E_i^{\mathrm{NF}'}$, potential new boilers, $E_i^{\mathrm{new}'}$, from fossil fuel boiler itself operating with jth fuel, E'_{ij}, or as energy from the grid, G_k.

$$\sum_{i}\sum_{k} E_{ik} = \left[\sum_{i\in \mathrm{NF}} E_i^{\mathrm{NF}'} + \sum_{i\in P^{\mathrm{new}}} E_i^{\mathrm{new}'} + \sum_{i\in F^c}\sum_{j}\sum_{k} E'_{ijk} + G_k\right] \quad (2b)$$

The net electricity generation for the whole fleet must be equal to the desired total electricity demand, i.e.,

$$\left[\sum_{i\in \mathrm{NF}} E_i^{\mathrm{NF}} + \sum_{i\in P^{\mathrm{new}}} E_i^{\mathrm{new}} + \sum_{i\in F}\sum_{j} E_{ij}\right] - \sum_{i}\sum_{k} E_{ik} = \mathrm{Demand} \quad (2c)$$

Energy Balance on Capture Process. The energy requirement E_{ik} of a kth CO_2 capture process can be supplied from the grid, G_k, from an lth existing nonfossil power generation, or from new additional power plants:

$$E_{ik} = \sum_{l\in P^{\mathrm{new}}}\sum_{k} E_{lk} + \sum_{i}\sum_{j} E_{ijk} + G_k \quad (3)$$

In the case when the energy for a CO_2 capture process is to be extracted from the steam cycle of the existing fossil power plant itself, therefore Eq. 3 can be simplified to:

$$E_{ik} = \sum_i \sum_j E_{ijk} \qquad \forall k \qquad (4)$$

Capacity Constraint on Capture Process.

$$E_{ik} \leq z_{ik} E_k^{\max} \qquad \forall i \in F^c, \forall k \qquad (5)$$

The parameter $E_k^{\max}$ represents the maximum supplemental energy required for the kth capture technology. It also ensures that the energy required for any kth capture process is zero when no capture process is assigned to the ith coal-fired boiler. Note that capture processes are considered to be incorporated only on coal-fired boilers because natural gas is less carbon intensive. z_{ik} is the binary variable that represents the selection of the kth retrofit carbon capture process on the ith existing coal-fired boiler.

Fuel Selection and Plant Shut-Down. For an ith fossil fuel boiler, either the process is operating with one chosen fuel or is shut down. This constraint is represented by introducing the binary variable, X_{ij} that represents the fuel selection (coal or natural gas) or plant shut down:

$$\sum_j X_{ij} \leq 1 \qquad \forall i \in F \qquad (6)$$

Plant Capacity Constraints. Existing fossil fuel boilers

$$E_{ij} \leq M X_{ij} \qquad \forall i \in F, \forall j \qquad (7a)$$

Nonfossil power plants

$$E_i \leq M \qquad \forall i \in \mathrm{NF} \qquad (7b)$$

New power plants

$$E_i \leq M y_i \qquad \forall i \in P^{\mathrm{new}} \qquad (7c)$$

The above constraints set upper bounds on energy produced from the different electricity generating stations. They also ensure that the energy production from fossil fuel plants ($i \in F$) is zero when no fuel is assigned to the plant and a decision of plant shut-down has been made. The parameter M is any large number and represents an upper bound on energy production for the ith nonfossil power plant/new hypothetical boiler. M should be chosen to be the maximum installation capacity, $E_{ij}^{\max}$ for fossil fuel boilers and $E_i^{\max}$ for nonfossil fuel plant and new hypothetical boilers in order to ensure a tight formulation.

Upper Bound on Operational Changes. The electricity generated from the ith unit cannot exceed the current electricity generation E_i^{current} for the unit by r_i (the maximum allowable increase in the base load or reserve margin) due to operational considerations, i.e.,

Existing fossil fuel boilers:

$$E_{ij} \leq (1 + r_i) E_i^{\mathrm{current}} X_{ij} \qquad \forall i \in F, \forall j \qquad (8a)$$

Nonfossil power plants:

$$E_i^{\mathrm{NF}} \leq (1 + r_i) E_i^{\mathrm{current}} \qquad \forall i \in \mathrm{NF} \qquad (8b)$$

New power plants:

$$E_i^{\mathrm{new}} \leq E_i^{\max} y_i \qquad \forall i \in P^{\mathrm{new}} \qquad (8c)$$

$E_{\mathrm{i}}^{\max}$ is the maximum installed capacity of an ith potential new boiler.

Comparing constraints (7b) and (8b), it is clear that both represent an upper bound on E_i. Because constraints (8b) are tighter, constraints (7b) are redundant and do not have to be included in the model. Constraints (8a and 8c), on the other hand include binary decision variables that are essential in the model implementation, especially in the case of plant shutdowns and to indicate existence/nonexistence of new boilers.

Lower Bound on Operational Constraints. The annual capacity factor for each power plant must be greater than some minimum; otherwise the plant will be shut down.

Existing fossil fuel boilers:

$$f_{ij} \geq l_{ij} X_{ij} \qquad \forall i \in F, \forall j \qquad (9a)$$

Nonfossil power plants:

$$f_i \geq l_i \qquad \forall i \in \mathrm{NF} \qquad (9b)$$

New power plants:

$$f_i \geq l_i \, y_i \qquad \forall i \in \mathrm{NF} \qquad (9c)$$

where l_{ij} (l_i) is the minimum annual capacity factor for the ith fossil fuel boiler (nonfossil fuel plant and hypothetical new boiler) and f_{ij} (f_i) is the corresponding annual capacity factor. The relationship between the annual capacity factor and electricity generation is given below:

Existing fossil fuel boilers

$$E_{ij} = f_{ij} E_{ij}^{\max} \qquad \forall i \in F, \forall j \qquad (10a)$$

Nonfossil power plants

$$E_i = f_i E_i^{\max} \qquad \forall i \in \mathrm{NF} \qquad (10b)$$

New power plants

$$E_i = f_i E_i^{\max} y_i \qquad \forall i \in P^{\mathrm{new}} \qquad (10c)$$

where $E_{ij}^{\max}$ ($E_i^{\max}$) is the installed capacity of the ith fossil (nonfossil power plants/new hypothetical boilers).

If the Existing Coal-Fired Boilers Shut Down, No Capture Process Will Be Put Online.

$$z_{ik} \leq \sum_j X_{ij} \qquad \forall i \in F^{\mathrm{c}} \qquad (11)$$

This constraint is associated with constraints (7a) which indicates that, the ith fossil fuel boilers will be shut down if the binary variable (fuel selection variable), X_{ij}, is equal to 0. The above constraints are to ensure that no capture process will be put online if the coal-fired boilers are shut down.

Selection of Hypothetical New Power Plants. In this study, six types of technologies have been considered to supply supplemental energy for capture processes as well as to meet growth rate demand. These technologies are supercritical pulverized coal (PC), supercritical pulverized coal with capture (PC+CCS), integrated gas combined cycle (IGCC), integrated gas combined cycle with capture (IGCC+CCS), natural gas combined cycle (NGCC), and natural gas combined cycle with capture (NGCC+CCS). Different boilers' performances and sizes for each technology can be incorporated in the model, i.e.,

$$\sum_i y_i \le b \qquad \forall i \in P^{\text{new}} \tag{12}$$

where y_i represents the existence/non existence of the ith hypothetical new boilers for every technology to supply supplemental energy for the capture process and to inject electricity to the grid. The parameter b represents the number of boilers of new technology that can be incorporated in the model. This constraint is not necessary in the model formulation and is included only if the decision maker would like to put a restriction on the number of new technologies to be implemented.

Selection of CO_2 Sequestration Location. For identical coal-fired boilers

$$\sum_s w_{is} \le 1 \qquad \forall i \in F^{\text{c}} \cup P^{\text{PCcap}} \cup P^{\text{IGcap}} \cup P^{\text{NGcap}} \tag{13a}$$

This constraint is used if only one sequestration site is to be selected for one identical coal-fired boiler.

For coal-fired stations

Only one sequestration location will be selected for one coal-fired stations and new power plants with capture that consist of several identical boilers

$$w_{is} + w_{i's'} \le 1 \qquad \forall i \in F^{\text{g}} \cup P^{\text{new}}, \forall s, i' \ne i, s' \ne s \tag{13b}$$

where w_{is} is a binary variable that indicates the selection of the sth potential location for CO_2 sequestration and F^{g} is coal-fired power plants that consist of several boilers.

CO_2 Sequestration Must Be Determined Once Capture Process Is Put Online. Once carbon capture retrofit is implemented on an ith existing coal-fired boiler or on a new hypothetical boiler with a capture process, the sth potential location for CO_2 sequestration is determined in order to store the CO_2 captured securely and permanently.

$$\sum_s w_{is} = \sum_k z_{ik} \qquad \forall i \in F^{\text{c}} \cup P^{\text{PCcap}} \cup P^{\text{IGCCcap}} \cup P^{\text{NGCCcap}} \tag{14}$$

Emission Constraint/CO_2 Balance. CO_2 emissions from all existing coal-fired boilers and new potential boilers, α_i (million tonne/yr) are defined as below:

Existing fossil fuel boilers

$$\alpha_i = \sum_j \text{CO}_{2ij} E_{ij} \qquad \forall i \in F \tag{15a}$$

New power plants

$$\alpha_i = \text{CO}_{2i} E_i \qquad \forall i \in P^{\text{new}} \tag{15b}$$

where CO_{2ij} is the CO_2 emission from an ith existing fossil fuel boiler using the jth fuel per electricity generated and CO_{2i} is CO_2 emission from a new hypothetical boilers (tonne CO_2/MWh). CO_{2ij} and CO_{2i} are calculated using basic chemical equations that relate the production of CO_2 emission to the quantity and quality of fuel burned, i.e.,

Existing fossil fuel boilers

$$\text{CO}_{2ij} = 0.03667(\text{EF})_{ij} \qquad i \in F \tag{16a}$$

New power plants

$$\text{CO}_{2i} = 0.03667(\text{EF})_i \qquad \forall i \in P^{\text{new}} \tag{16b}$$

where 0.03667 is the conversion factor from coal to CO_2, EF_{ij} is the CO_2 emission factor of the ith fossil fuel station using jth fuel and EF_i is the CO_2 emission factor of the ith potential new boiler as represents below:

Existing fossil fuel boilers

$$\text{EF}_{ij} = \frac{1}{\eta_{ij}}\left(\frac{\%\text{C}}{\text{HHV}_{ij}}\right) \qquad \forall i \in F, \forall j \tag{17a}$$

New power plants

$$\text{EF}_i = \frac{(1-\varepsilon_{ik})}{\eta_i}\left(\frac{\%C}{\text{HHV}_{ij}}\right) \qquad \forall i \in P^{\text{new}} \tag{17b}$$

where η_{ij} is the efficiency of the ith fossil fuel boiler while operating on jth fuel and η_i is the efficiency of a potential new boiler. $\%C$ represents the percentage of carbon content and HHV_{ij} is the fuel higher heating value.

In constraints (16), CO_2 emissions from fossil power plants, α_i will be captured in the kth capture process also can be defined as $\alpha_i^{\text{seq}} + \alpha_i^{\text{released}}$, where α_i^{seq} is CO_2 captured by the kth capture process and $\alpha_i^{\text{released}}$ is CO_2 emitted to the atmosphere. For the case of CO_2 capture with kth capture process, $z_{ik} = 1$ and ε_{ik} is the fraction of CO_2 captured, i.e.,

$$\alpha_i^{\text{released}} = \alpha_i\left(1 - \sum_k \varepsilon_{ik} z_{ik}\right) \qquad \forall i \in F^c \tag{18a}$$

$$\alpha_i^{\text{seq}} = \alpha_i \sum_k \varepsilon_{ik} z_{ik} \qquad \forall i \in F^c \tag{18b}$$

If no CO_2 capture exists, $z_{ik} = 0$, then all CO_2 emitted from the ith fossil fuel boilers, α_i, will be released to the atmosphere,

$$\alpha_i^{\text{released}} = \alpha_i \qquad \forall i \in F^c \tag{19a}$$

$$\alpha_i^{\text{seq}} = 0 \qquad \forall i \in F^c \tag{19b}$$

Note that constraints (19a, 19b) and (20a, 20b) only apply to existing coal-fired boilers. This case is also called carbon capture retrofit and the binary variable, z_{ik}, indicates the existence/nonexistence of a CO_2 capture process on the ith existing coal-fired boilers. Besides CO_2 emission from existing fossil fuel boilers, the new hypothetical boilers, e.g., PC, IGCC, and NGCC with and without capture also contribute to the total CO_2 emissions. Thus, the total CO_2 emission (million tonne per year) from existing fossil fuel boilers and new hypothetical boilers can be written as:

$$\sum \alpha_i^{\text{released}} = \sum_{i \in F} \alpha_i \left(1 - \sum_k \varepsilon_{ik} z_{ik}\right) + \sum_{i \in P^{new}} CO_{2_i} E_i \quad (20)$$

Substituting Eq. 15a into Eq. 20 will results in the following:

$$\sum \alpha_i^{\text{released}} = \sum_{i \in F} \left[\left(\sum_j CO_{2ij} E_{ij}\right)\left(1 - \sum_k \in_{ik} z_{ik}\right)\right] + \sum_{i \in P^{\text{new}}} CO_{2i} E_i \quad (21)$$

Annual total CO_2 emissions from all existing fossil fuel boilers and potential new boilers must satisfy a specific CO_2 reduction target, $\%CO_2$.

$$\sum_{i \in F} \left[\left(\sum_j CO_{2ij} E_{ij}\right)\left(1 - \sum_k \varepsilon_{ik} z_{ik}\right)\right] + \sum_{i \in P^{\text{new}}} CO_{2i} E_i \leq (1 - \%CO_2) CO_2 \quad (22)$$

Logical Constraints. Other constraints can be imposed on the model. These include:

- geographical/management constraint—certain power plants are assigned to supply certain locations while other plants cannot supply some specific locations.
- fuel or resource constraint—the fuel supply (i.e., natural gas) is limited by pipeline capacity.

The optimization problem, therefore, consists of minimizing Eq. 1 subject to constraints (2)–(22). The model is a mixed integer nonlinear program (MINLP). In this model, nonlinearity comes from two sources: (1) Sequestration cost in the objective function (Eq. 1) due to the multiplication of the binary variable, w_{is} (selection of sth potential location for CO_2 sequestration) with the continuous variable, E_{ij} (electricity generation from ith power plant using jth fuel); and (2) The CO_2 emission constraint (Eq. 22) due to the multiplication of the binary variable, z_{ik} (selection of carbon capture retrofit on existing coal-fired boilers) with the continuous variable, E_{ij} (electricity generation from ith power plant using jth fuel).

The nonlinear terms can be easily linearized through the exact linearization scheme that was described by Oral and Kettani[33] and Torres[34] and the model is reduced to a mixed integer linear program (MILP). Through this linearization process, the objective function becomes:

$$\begin{aligned} OF = & \underbrace{\sum_{i \in F} \sum_j C_{ij} E_{ij} + \sum_{i \in \text{NF}} C_i^{\text{NF}} E_i}_{\substack{\text{operational cost for} \\ \text{existing plants}}} + \underbrace{\sum_{i \in F^c} \sum_j R_{ij} X_{ij}}_{\text{retrofit cost}} \\ & + \underbrace{\sum_{i \in P^{\text{new}}} S_i^{\text{new}} E_i^{\text{max}} y_i + \sum_{i \in P^{\text{new}}} C_i^{\text{new}} E_i^{\text{new}}}_{\substack{\text{capital and operational cost} \\ \text{of carbon capture retrofit}}} \\ & + \underbrace{\sum_{i \in F^c} \sum_k S_{ik}^c z_{ik} + \sum_{i \in F^c} \sum_k C_k^c E_{ik}}_{\substack{\text{capital and operational cost} \\ \text{of carbon capture retrofit}}} + \underbrace{\sum_{i \in F^c \cup P^{\text{new}}} \sum_s C_{is}^{\text{seq}} \lambda_{ijs} CO_{2ij} \varepsilon_i}_{\text{sequestration cost}} \end{aligned} \quad (1')$$

and the nonlinear constraints in Eq. 22 are transformed to:

$$\sum_{i \in F} \left[\left(\sum_j CO_{2_{ij}} E_{ij} - \sum_j CO_{2_{ij}} \sum_k \varepsilon_{ik\varphi_{ijs}}\right)\right] + \sum_{i \in P^{\text{new}}} CO_{2i} E_i \leq (1 - \%CO_2) CO_2 \quad (22')$$

In the linearization process, new variables λ_{ijs} and φ_{ijk} are introduced:

$$\lambda_{ijs} = w_{is}.E_{ij} \quad (23)$$

$$\varphi_{ijk} = z_{ik}.E_{ij} \quad (24)$$

as well as more constraints:

$$0 \leq \lambda_{ijs} \leq E_{ij} \quad (25)$$

$$E_{ij} - M(1 - w_{is}) \leq \lambda_{ijs} \leq M.w_{is} \quad (26)$$

$$0 \leq \varphi_{ijs} \leq E_{ij} \quad (27)$$

$$E_{ij} - M(1 - z_{ik}) \leq \varphi \leq M.z_{ik} \quad (28)$$

Case Study

Currently, Ontario power generation (OPG) operates 79 electricity generating stations, 5 coal fired, C(i = 1–5), 1 natural gas, NG(i = 6), 3 nuclear, N(i = 7–9), 69 hydroelectric, H(i = 10–78), and 1 wind turbine, A(i = 79). At nominal levels, OPG generates about 115.8 TWh and injects it into the grid. No CO_2 capture process currently exists at any OPG power plant; about 36.7 million tonnes of CO_2 was emitted in 2002, mainly from fossil fuel power plants. There are 27 fossil fuel boilers at the 6 fossil fuel stations: 4 boilers at Lambton (L1-L4), 8 boilers at Nanticoke (N1-N8), 8 boilers at Lakeview (LV1-LV8), 1 boiler at Atikokan (A1), 4 boilers at Lennox (L1-L4), and Thunder Bay has 2 boilers (TB1-TB2). Currently, 4 (out of 27) boilers operated by Lennox are running on natural gas and the other 4 boilers are running on coal.

To better compare the different technologies proposed in this case study, the original parameters are adjusted to the same economic reference, which is described in Table 1. A summary of OPG's current fossil fuel generating stations is given in Table 2.

Table 1. Specification of Economic Parameters

Economic life time	30 years
Interest rate of return	15%
Fuel cost	
Coal	US\$1.2/GJ
Natural gas	US\$4.0/GJ

All cost are in 2004 USD.

Table 2. Ontario Power Generation Fossil Fuel Power Stations

Station	Fuel	Heat Rate (GJ/MWh)	Installed Capacity (MW)	Number of Units	Annual Capacity Factor	Operational Cost ($/MWh)	CO_2 Emission (tonne/MWh)
Nanticoke 1 (N1)	Coal	9.88	500	2	0.75	20	0.93
Nanticoke2 (N2)	Coal	9.88	500	6	0.61	20	0.93
Lambton1 (L1)	Coal	9.84	500	2	0.5	22	0.94
Lambton2 (L2)	Coal	9.84	500	2	0.75	17	0.94
Lakeview (LV)	Coal	10.8	142	8	0.25	23	0.98
Lennox (LN)	NG	7.82	535	4	0.15	47	0.65
Thunder Bay (TB)	Coal	11.7	155	2	0.55	20	1.03
Atikokan (A)	Coal	9.82	215	1	0.44	20	1.03

Table 3. Parameters of Retrofit CO_2 Capture on Existing Coal-Fired Power Plants

	N1		N2		L1		L2		LV		TB		A	
Parameters	Ref	Cap	Ref	Cap	Ref	Cap	Ref	Cap	Ref	Cap	Ref	Cap	Ref	Cap
Gross capacity (MW)	512	512	512	512	515	515	515	515	150	150	163	163	230	230
Net power gen. (MW)	490	382	490	382	493	385	493	385	142	111	155	120	215	168
Heat rate, HHV (GJ/MWh)	9.88	12.7	9.88	12.7	9.84	12.6	9.84	13.1	10.8	13.8	9.82	12.5	9.82	12.5
Capacity factor, ACF	0.75	0.75	0.61	0.61	0.5	0.5	0.75	0.75	0.25	0.25	0.55	0.55	0.44	0.44
CO_2 capture (%)	–	90	–	90	–	90	–	90	–	90	–	90	–	90
CO_2 emission (tonne/MWh)	0.93	0.09	0.93	0.09	0.94	0.09	0.94	0.09	0.98	0.09	1.02	0.11	1.02	0.11

The operating cost for nuclear, hydroelectric, and wind turbine was estimated to be US$21/MWh, US$3.30/MWh, and US$2.70/MWh, respectively. Note that, in this base year natural gas is the most expensive fuel used by OPG which is US$47/MWh (OPG, 2002). Since the main objective of this article is to study CO_2 emission reduction through fuel balancing, fuel switching and CO_2 capture, no attempt is made to study the effect of improved technology. Index i (i = 1–79) represents all of OPG's power plants. The index j (j = 1–2) represents the fuel selection, $j = 1$ (coal), 2 (natural gas). The retrofit cost was estimated to be US$20 million/1000 MW with a 30 year lifetime and 15% annual interest rate. To translate CO_2 emissions into cost, $\beta = 0.03$ US$/kg CO_2 emission was assumed from the literature (ESCAP-UN, 1995).

An improvement in boiler technology will lead to an efficiency higher than our assumed efficiency of 35%. We have recently investigated the effect of efficiency enhancement

Table 4. Cost Comparison of Retrofit CO_2 Capture on Existing Coal-Fired Power Plants

	N1		N2		L1		L2		LV		TB		A	
Parameters	Ref	Cap	Ref	Cap	Ref	Cap	Ref	Cap	Ref	Cap	Ref	Cap	Ref	Cap
CO_2 capital cost (M$)	–	236	–	236	–	238	–	270	–	290	–	86	–	121
O&M cost ($/MWh)	20	13.9	20	13.9	22	13.9	17	13.9	23	13.9	20.0	13.9	20.0	13.9
COE (¢/KWh)	2.0	4.01	2.0	4.27	2.2	4.55	1.7	4.16	2.3	8.0	2.0	5.11	2.0	5.75
Capture cost ($/tonne CO_2 avoided)	–	24.0	–	27.1	–	26.6	–	27.1	–	64.5	–	33.8	–	40.7

Table 5. Plant Performance for PC With and Without Capture

	PC Without Capture		PC With Capture		
Plant Performance	PC1*	PC2†	PC+CCS1*	PC+CCS2*	PC+CCS3†
Gross plant size (MW)	500	575	500	670	710
Net power generation (MW)	458	524	341	458	492
Heat rate, HHV (GJ/MWh)	9.12	9.16	12.19	12.17	12.1
Plant efficiency, HHV	39.4	39.3	29.6	29.5	29.9
Capacity factor, ACF	75	75	75	75	75
CO_2 emission (tonne/MWh)	0.919	0.89	0.122	0.122	0.118
CO_2 capture (%)	–	–	90	90	90
CCS energy penalty (%)	–	–	24.9	24.9	23.9

*PC1 is a supercritical boiler equipped with SCR, ESP, and FGD, PC+CCS1 is a plant that used the same coal input as PC1 results to lower net power generation due to supplemental energy for MEA capture process, PC+CCS is a bigger plant sizes constructed so that the CO_2 capture plant produces the same net power generated as PC1.[9]

†PC2 and PC+CCS3 are a supercritical boiler equipped with SCR, ESP, and FGD followed by MEA system for CO_2 capture, respectively.[8]

Table 6. Economic Evaluation of PC With and Without Capture

Cost Parameters	PC Without Capture		PC With Capture		
	PC1*	PC2†	PC+CCS1*	PC+CCS1*	PC+CCS2†
Plant capital cost ($/KW)‡	1588	1413	2613	2468	2271
Cost of electricity ($/MWh)‡					
Capital	36.0	32.3	59.7	56.3	51.8
O&M	2.5	2.47	18.0	18.1	18.2
Fuel	10.9	11.0	14.6	14.6	14.5
Capture cost ($/tonne CO_2 avoided)‡	–	–	59.3	55.3	50.2

*PC1 is the plant reference for PC+CCS1 and PC+CCS2.[9]
†PC2 is the plant reference for PC+CCS3.[8]
‡Cost is adjusted according to standard methodology and reported in 2004 US$ using Chemical Engineering Plant Cost Indexes (Chemical Engineering Magazine, 1990–2004) with coal price is US$1.2/GJ.

Table 7. Plant Performance for IGCC With and Without Capture

Plant Performance	IGCC Without Capture			IGCC With Capture	
	IGCC1*	IGCC2†	IGCC3‡	IG+CCS1†	IG+CCS2†
Gross plant size (MW)	315	400	675	650	653
Net power generation (MW)	250	350	583	489	513
Heat rate, HHV (GJ/MWh)	7.37	7.9	8.78	10.46	9.97
Plant efficiency, HHV	48.9	45.4	41	34.4	36.1
Capacity factor, ACF	85	85	85	85	85
CO_2 emission (tonne/MWh)	0.7	0.75	0.81	0.176	0.39
CO_2 capture (%)	–	–	–	80	60
CCS energy penalty (%)	–	–	–	16.1	12.0

*Based on real plant cost from Tampa Electric, used single train includes one GE 7FA gas turbine.[37]
†The gasification plant consists of two gasifier trains. This includes two GE 7FA gas turbines, two HRSGs and one steam turbine. IG+CCS1 represented IGCC with 80% CO_2 capture, whereas IG+CCS2 represented IGCC with 60% CO_2 capture (CO_2 emission equal to that of a NGCC). Both used Selexol-based CO_2 capture process[36vc].
‡The same plant configuration as IGCC2 except used Westinghouse 501G gas turbine.[38]

measures on the energy planning problem in a separate study[31,32] and the interested reader should consult that study for more details. The reserve margin, r_i for load distribution for all OPG's fleet power plants was set to 1% higher than the current operational level due to the design constraints and the lower bound was set to be 10%. In other words, the plants have to operate at least with 10% annual capacity factor (ACF); otherwise the plants will be shut down. Note that the 1% reserve margin used in this case study is only for illustration purposes and was made in conjunction with the desires of the OPG plant personnel.

The current estimated cost of retrofitting an existing pulverized coal plants with MEA capture is about \$190/tC.[35] David and Herzog[29] have proposed an effective way to compare the mitigation costs of different plants. The mitigation cost in \$/tonne CO_2 avoided with the net power generated by the two plants remaining the same output can be calculated as:

$$\text{Cost of CO}_2\text{ avoided }(\$/\text{tonne CO}_2\text{ avoided}) = \frac{\mathrm{COE}^{cap} - \mathrm{COE}^{ref}}{\mathrm{CO}_2^{cap} - \mathrm{CO}_2^{ref}} \tag{29}$$

where COE^{cap} = cost of electricity for plant with carbon capture (\$/MWh); COE^{ref} = cost of electricity for reference plant (\$/MWh); $\mathrm{CO}_2^{cap} = \mathrm{CO}_2$ emission from plant with carbon capture (tonne/MWh); $\mathrm{CO}_2^{ref} = \mathrm{CO}_2$ emission from reference plant (tonne/MWh).

COE consists of three main components: COE due to capital cost, COE due to operation and maintenance (O&M), which includes variable cost, VOM (e.g., fuel, chemicals, utilities, waste disposal) and fixed cost, FOM (e.g., rental, interest) and COE due to capture cost. The latter component (COE^{cap}) is applicable only to carbon capture retrofit on existing coal-fired stations and potential new power plants with capture. In this study, capital cost of all existing fossil fuel power stations were assumed to be "paid off," hence

Table 8. Economic Evaluation of IGCC With and Without Capture

Cost Parameters	IGCC Without Capture			IGCC With Capture	
	IGCC1	IGCC2	IGCC3*	IG+CCS1*	IG+CCS2*
Plant capital cost ($/KW)†	2535	2121	1860	2556	2336
Cost of electricity ($/MWh)†					
Capital	51.1	42.7	37.5	43.8	40.0
O&M	8.61	6.91	5.9	7.6	7.1
Fuel	8.84	9.5	10.5	12.6	11.9
Capture cost ($/tonne CO_2 avoided)†	–	–	–	15.8	12.3

*IGCC3 is the plant reference for IG+CCS1 and IG+CCS2.[36]
†Cost is adjusted according to standard methodology and reported in 2004 US$ using Chemical Engineering Plant Cost Indexes (Chemical Engineering Magazine, 1990–2004) with coal price is US$1.2/GJ.

Table 9. Plant Performance for NGCC With and Without Capture

Plant Performance	NGCC Without Capture			NGCC With Capture	
	NGCC1*	NGCC2*	NGCC3†	NG+CCS1†	NG+CCS2‡
Gross plant size (MW)	334	403	517	517	
Net power generation (MW)	326.1	395	507	432	750
Heat rate, HHV (GJ/MWh)	6.32	6.74	6.37	7.48	7.8
Plant efficiency, HHV	50.6	53.4	50.2	42.8	41.0
Capacity factor, ACF	85	85	75	75	85
CO_2 emission (tonne/MWh)	0.398	0.377	0.404	0.047	0.037
CO_2 capture (%)	–	–	–	90	90
CCS energy penalty (%)	–	–	–	14.7	18.3

*Plant performance is gathered from Ref. 38. The plant configuration is the same as NGCC3 except NGCC1 used Westinghouse 501G gas turbine and NGCC2 used General Electric "H" gas turbine.
†NGCC3 equipped with two GE-PG-7241FA gas turbines, three HRSG, and feed a single two-flow, reheat condensing GE D-11 steam turbine. NG+CCS1 equipped by amine system for CO_2 capture.[8]
‡NG+CCS2 used two GE 9FA gas turbine, three HRSG, and one steam turbine.

Table 10. Economic Evaluation of NGCC With and Without Capture

Cost Parameters	NGCC Without Capture			NGCC With Capture	
	NGCC1	NGCC2	NGCC3*	NG+CCS1†	NG+CCS2†
Plant capital cost ($/KW)‡	617	552	442	1437	1207
Cost of electricity ($/MWh)‡					
Capital	12.4	11.1	10.1	24.6	20.7
O&M	8.1	9.37	9.3	9.7	5.3
Fuel	28.4	26.9	25.5	29.9	31.2
Capture cost ($/tonne CO_2 avoided)‡	–	–	–	57.1	37.5

*NGCC3 is the plant reference for NG+CCS1 and NG+CCS2.
†The only additional equipment requirement compare than NGCC3 is amine system which cost about $13.1/MWh for NG+CCS1.[8] Thus, amine system cost for NG+CCS2 is estimated using the 0.6 power law suggested by Peters et al.[28] Thus, amine cost for 750 MW NGCC+CCS was $13.1/MWh $(750/432)^{0.6}$.
‡Cost is adjusted according to standard methodology and reported in 2004 US$ using Chemical Engineering Plant Cost Indexes (Chemical Engineering Magazine, 1990–2004) with natural gas price US$4/GJ. Gas turbine cost is based on vendor quote (World Turbine Magazine, 2004).

COE for existing fossil fuel power plants (COE^{ref}) is determined only by O&M cost of the base plant. Note that, VOM cost is dominated by fuel prices.

According to Rubin et al.,[8] the energy penalty associated with CO_2 capture process can be calculated using the following equation

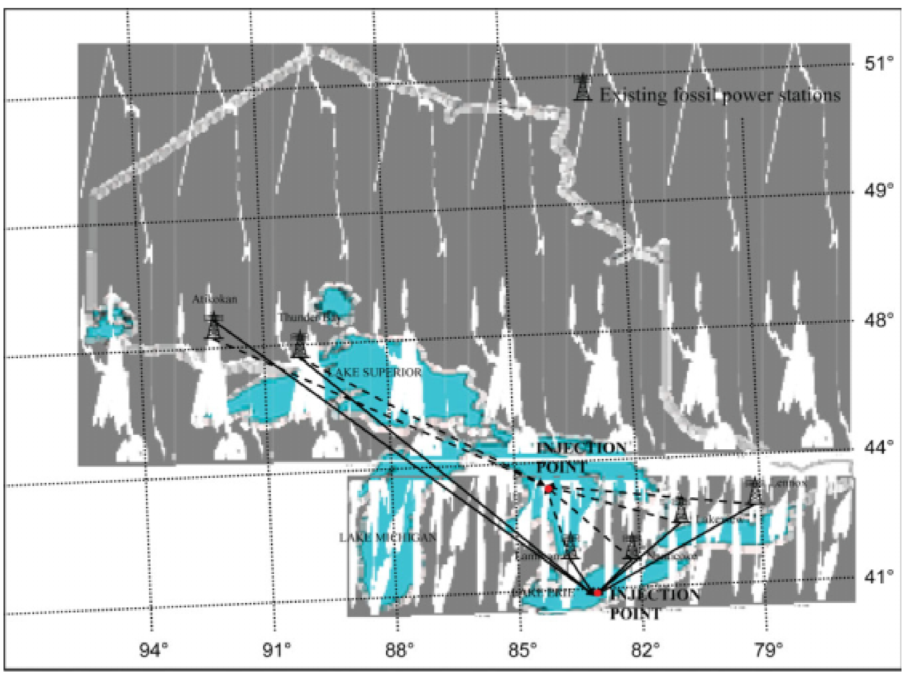

Figure 2. Potential injection point locations for carbon capture retrofit.

[Color figure can be viewed in the online issue, which is available at www.interscience.wiley.com.]

Table 11. Properties and Economic Assumption for CO_2 Sequestration

Item	Properties	Range of Unit Cost (US$/m)	Representative Unit Cost (US$/m)
Pipeline	Diameter = 16 in./406 mm	1000–2250 (offshore) 750–1000 (onshore)	1,000
Injection wells	Depth of well = 1000 m	3000–6000	4,500
Off shore platform	No. of off shore platforms = 1 Depth of platform = 25 m	4,000,000	4,000,000

Table 12. Economic Evaluation of CO_2 Sequestration in Lake Erie

	Length of Pipeline (km)	No. of Injection Wells	Total Capital Cost (US$M)	Operating Cost (US$M/yr)	Storage Cost (US$/ton CO_2 storage)
Nanticoke	110	9	249	19	13
Lambton	125	9	264	20	14
Lakeview	250	3	361	27	63
Thunder Bay	1100	3	1213	91	187
Atikokan	1300	4	1419	106	155
New plants	110	7	244	18	15
PC+CCS1	110	10	255	19.1	12
PC+CCS2	110	11	261	19.5	11
PC+CCS3	110	9	252	18.9	12
IGCC+CCS1	110	10	253	19.0	12
IGCC+CCS2	110	4	227	17.0	28
NGCC+CCS1	110	5	234	17.6	20
NGCC+CCS2					

$$EP = 1 - \frac{\eta CCS}{\eta ref} \tag{30}$$

where EP is the energy penalty (fraction reduction in output), η_{CCS} and η_{ref} are the net efficiencies of the capture plant and the reference plant, respectively. This energy penalty can also be defined as the reduction in plant output for a constant fuel input and is often called "plant derating." For the case of CCS retrofit on existing coal-fired power plant, the energy penalty was assumed at 22% as suggested by Rubin et al.[8] The details of existing coal-fired stations with and without capture characteristics are shown in Table 3. "ref" represents existing coal-fired power plant characteristics, whereas "cap" represents the plant performance once CCS is incorporated.

The cost estimation of retrofit carbon capture on existing coal-fired power plant is estimated based on the calculations performed by Rubin et al.[8] and is presented in Table 4.

New state-of-the-art PC, IGCC, and NGCC with and without capture cost estimation for different sizes required a standard methodology and the same economic assumption. In this study, the performances of power plant were obtained from the literature.[8,36,37] Data for new supercritical PC power plants without capture at two different capacities (500 MW, 575 MW) and with capture at three different capacities (500 MW, 670 MW, 710 MW with 90% CO_2 capture) were obtained from Rubin et al.[8] reported in 2001$US. On the other hand, plant performance and cost (mid 2001US$) for a 250 MW IGCC was gathered from real plant data.[37] Two different plant designs and cost estimation of IGCC with capture (500 MW with 80% CO_2 capture and 513 MW IGCC with 60% CO_2 capture) were based on a study by Ordorica-Garcia et al.[36] The plant performance for NGCC without capture of two different plant sizes (326 MW, 395 MW) were obtained from Parson[38] and for 517 MW from Rubin et al. (2004). Plant characteristics for two different

Table 13. Economic Evaluation of CO_2 Sequestration in Lake Huron

	Length of Pipeline (km)	No. of Injection Wells	Total Capital Cost (US$M)	Operating Cost (US$M/yr)	Storage Cost (US$/ton CO_2 storage)
Nanticoke	400	9	539	40	29
Lambton	325	9	464	35	25
Lakeview	300	3	411	31	72
Thunder Bay	600	3	713	54	110
Atikokan	1000	4	1119	84	123
New plants	400	7	534	40.0	33
PC+CCS1	400	10	545	40.9	25
PC+CCS2	400	11	551	41.3	22
PC+CCS3	400	9	542	40.7	26
IGCC+CCS1	400	10	543	40.7	26
IGCC+CCS2	400	4	517	38.8	64
NGCC+CCS1	400	5	524	39.3	44
NGCC+CCS2					

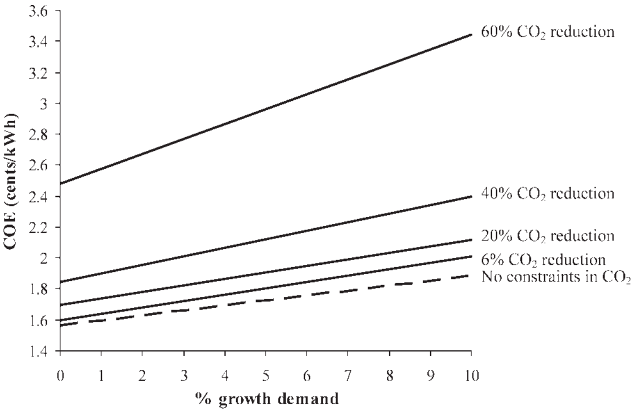

Figure 3. Cost of electricity as a function of % growth demand and CO_2 reduction level.

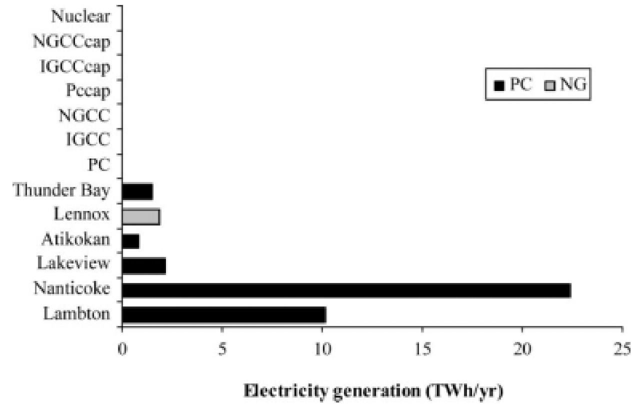

Figure 5. Optimal electricity generation for fossil fuel plants and 3% CO_2 reduction.

sizes of NGCC with capture (517 MW and 750 MW with 90% CO_2 capture) were also obtained from Rubin et al.[8] and Narula et al.,[39] respectively. Finally, the costs of all proposed new power plants were adjusted with the same economic assumption and reported in 2004US$ using Chemical Engineering Plant Cost Indexes (Chemical Engineering Magazine, 1990–2004) with coal price of US$1.2/GJ and natural gas price of US$4/GJ. Tables 5–Table 10 summarize the plant performance and cost comparison for all new hypothetical power plants with and without capture.

For CO_2 capture on existing coal-fired boilers, absorption with MEA was the only option considered. On the other hand, for new power plants with capture, two possible CO_2 recovery techniques have been considered: MEA for PC and NGCC while Selexol-based CO_2 capture was chosen for IGCC with capture. According to Herzog et al. (2002), NGCC have the highest energy requirement for CO_2 capture process (0.354 KWh/kg of CO_2 processed) due to the low content of CO_2 in the flue gas compare to PC plants (0.317 KWh/kg of CO_2 processed). The model in this case study excluded the addition of new nuclear, renewable energy, and hydroelectric capacity.

Two possible CO_2 sequestration sites were identified in Southwestern Ontario by Shafeen et al.[40] One is located in the southern part of Lake Huron and the other is located inside Lake Erie. In his case study, these locations are considered in the superstructure of possible alternatives. According to the study by Shafeen et al.,[40] depending on the depth and availability of the formation rock possible sequestration areas are divided into two zones identified as northern zone and southern zone. The northern zone (NZ) consists of lower half of Lake Huron and the upper most part of the Lambton county. The southern zone (SZ) consists of the northern half of Essex county, southern half of Lake Clair, lower half of Kent, lower half of Elgin, southern part of Haldimand-Norfolk county, and the area inside lake Erie south of these counties. Figure 2 illustrates the two potential locations for CO_2 storage and the distance from CO_2 emission sources for CCS retrofit on existing coal-fired power plants. The distances from new hypothetical power plants to these two possible injections points are estimated in a similar fashion.

The annual emissions of the potential new power plants will be at most 20 million tonne of CO_2, with a maximum flow rate in the range 300 to 600 tonne/h of CO_2 per power plant. In addition, the existing OPG fossil-fuel power plants will emit at most 36.7 million tonnes. At this rate, it can be estimated that if all the CO_2 is to be sequestered in reservoirs located in northern zone (NZ) and southern zone (SZ), and as a worst case scenario it would take only 7 to 10 years before the capacity of the reservoirs are used up.

Carbon capture and storage involves three stages: (1) capture of CO_2 from the power plant, (2) transportation of the CO_2 to the storage site, and (3) injection into the geological

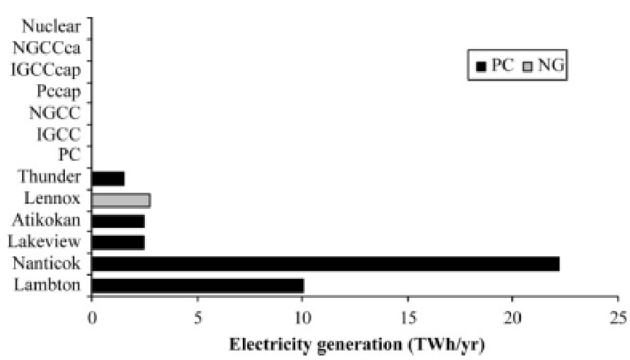

Figure 4. OPG's fossil-fuel electricity generation by plants in 2002.

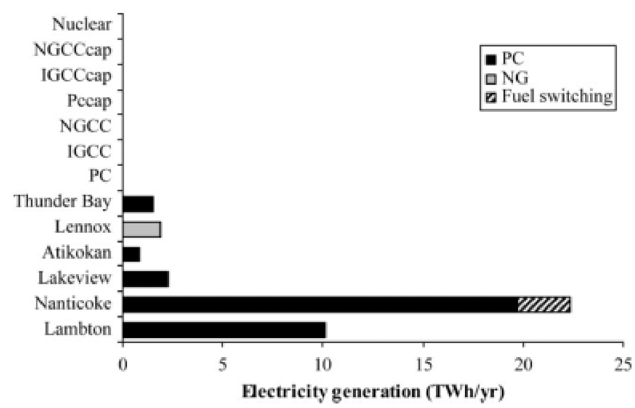

Figure 6. Optimal electricity generation for fossil fuel plants and 6% CO_2 reduction.

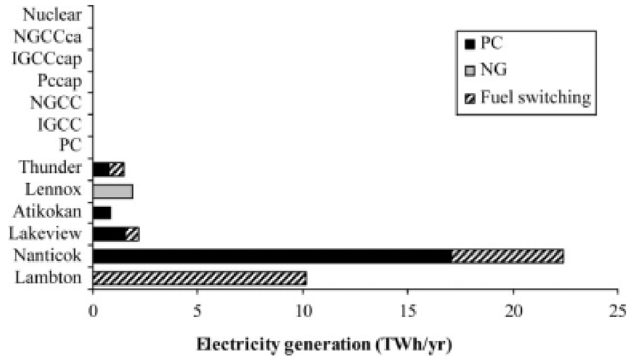

Figure 7. Optimal electricity generation for fossil fuel plants and 20% CO_2 reduction.

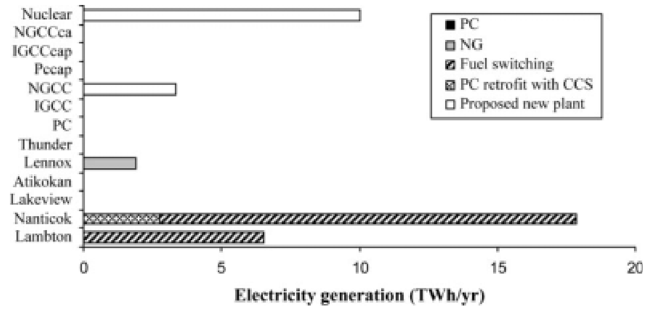

Figure 9. Optimal electricity generation for fossil fuel plants and 60% CO_2 reduction.

reservoir. The cost of transportation includes the capital cost for the pipeline. The cost of pipeline varies depending on the onshore or offshore location. An off shore line is about three times more expensive than that of an on shore line.[41] However, in this study, the distance of CO_2 transportation (from CO_2 emission sources to a disposal site) is assumed as ''crow flies'' regardless of off shore or on shore location. The cost of pipeline is assumed to be equal for on shore and offshore at \$1000/m. The cost of storage includes the cost of the injection system including the injection wells and platforms. Storage cost for off shore reservoirs are also typically double the price of the on shore one.[42]

The capacity approximation of an injection well can be calculated from the flow rate of CO_2 into the reservoir. A simple model used by reservoir engineers can be utilized to estimate the preliminary flow rate.[42–44]

$$q_s = \frac{\rho_r}{\rho_s} \times \frac{2\pi kh}{\mathrm{In}\left(\frac{r_e}{r_w}\right)\mu} \times \Delta P \qquad (31)$$

where q_s is flow rate (Nm^3/s), ρ_r is the density of the gas mixture of CO_2 and N_2 under reservoir conditions (700 kg/m^3), ρ_s is density of the gas under standard conditions (1.95 kg/Nm^3), k is permeability of the reservoir (25×10^{-15} m^2), h is the thickness of the reservoir (31 m), r_w is the radius of the well (m), r_e is radius of the influence sphere of the injection well (m), μ is viscosity of CO_2 at the well bottom (5×10^{-5} Pa s), and ΔP is the pressure difference between reservoir and well bottom pressure (1.71×10^6 Pa). The approximate injection capacity per injection well estimated as 0.68×10^6 Nm^3/day (1335 ton/day). The number of injection wells required according to CO_2 emission rate for existing coal-fired stations and new hypothetical power plants and the CO_2 sequestration cost estimation are based on the study by Shafeen et al. (2004) as shows in Tables 11–13, respectively.

Results and Discussion

This section will discuss two main results: (1) The change in cost of electricity (COE) as a function of CO_2 emission reduction by fuel balancing, fuel switching or capturing and (2) the effect of CO_2 reduction on distribution of electricity generation for existing and new plants for base load demand, low growth demand (1% growth rate), medium-growth (5% growth rate), and high-growth (10% growth rate).

Cost of electricity as a function of CO_2 reduction

Figure 3 shows the effect of CO_2 reduction on cost of electricity. As can be seen, increasing the CO_2 emission reduction would result in an increase in the cost of generating electricity. Currently, OPG electricity cost is 2.36¢/KWh which represents 0% CO_2 reduction. The optimization results show that fuel balancing can contribute to the reduction of

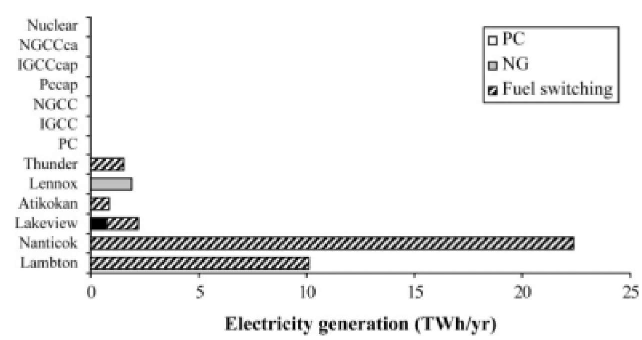

Figure 8. Optimal electricity generation for fossil fuel plants and 40% CO_2 reduction.

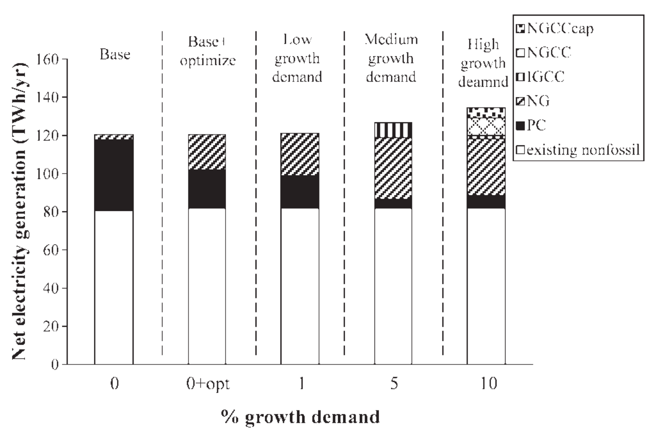

Figure 10. Effect of electricity demand growth on distribution of electricity generation for 20% CO_2 reduction.

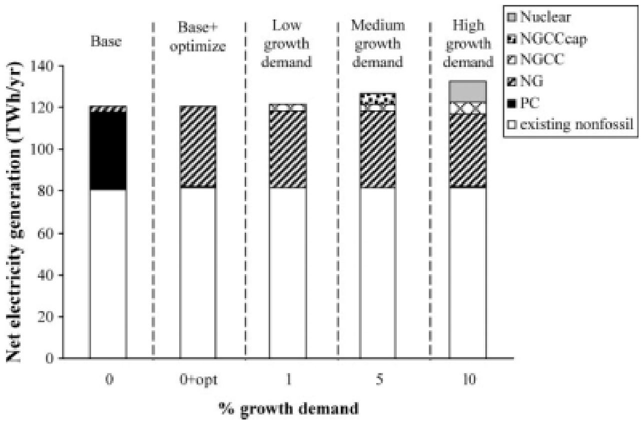

Figure 11. Effect of electricity demand growth on distribution of electricity generation for 40% CO_2 reduction.

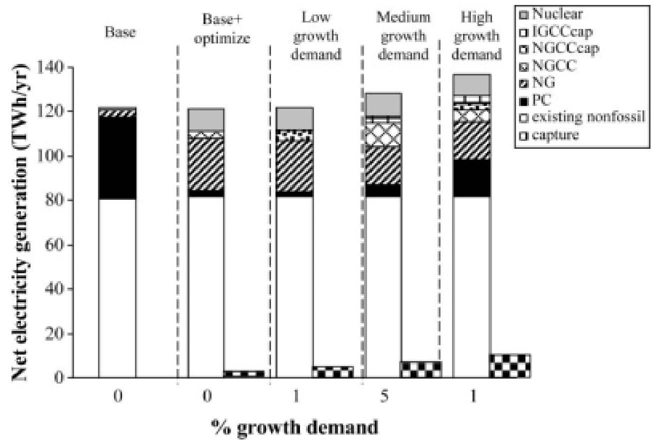

Figure 12. Effect of electricity demand growth on distribution of electricity generation for 60% CO_2 reduction.

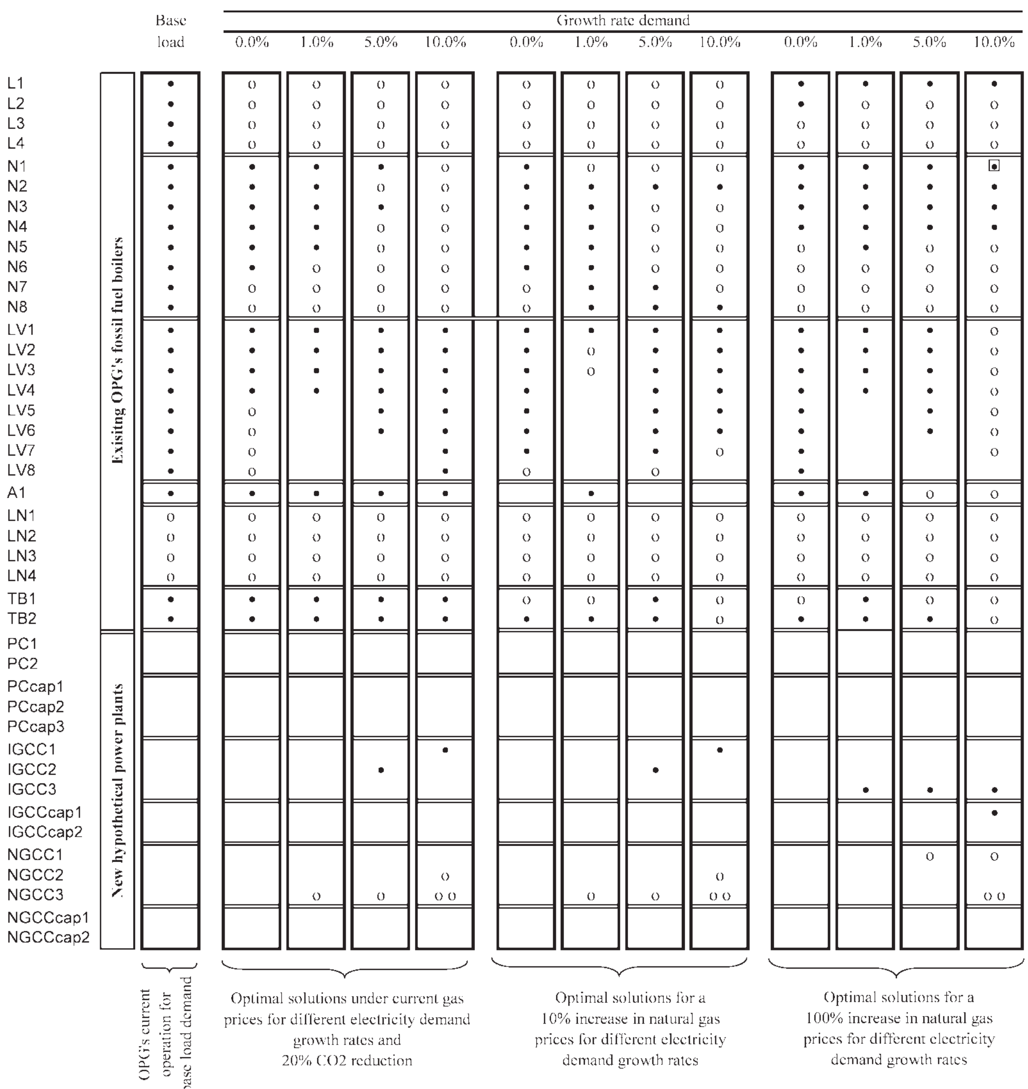

Figure 13. Effect of increasing natural gas prices on CO_2 mitigation strategies for different electricity demand growth.

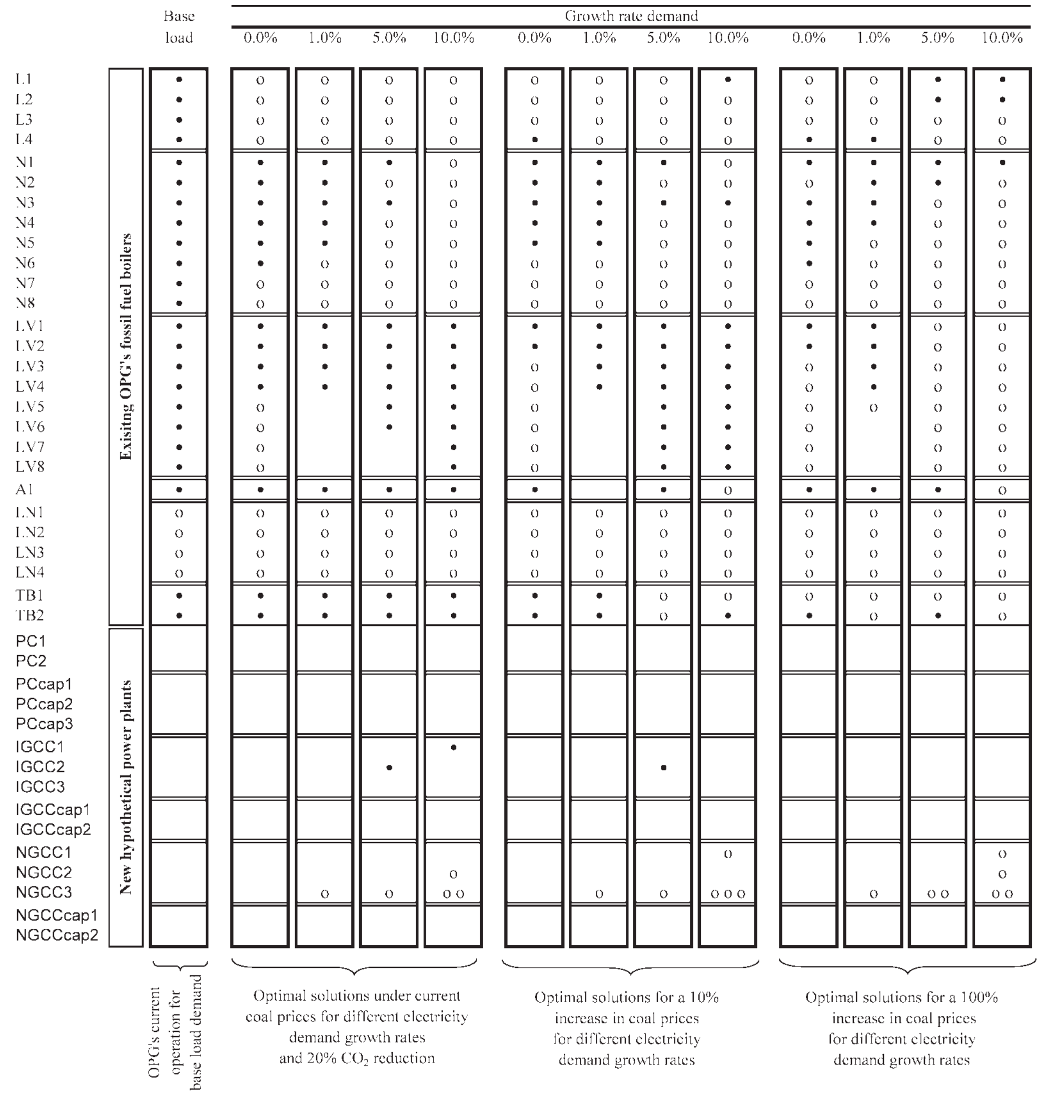

Figure 14. Effect of increasing coal prices on CO_2 mitigation strategies for different electricity demand growth.

CO_2 emissions by only 3%. Fuel balancing also results in a reduction of cost of electricity to 2.32¢/KWh by reducing electricity generation from all four natural gas boilers by 32.1% and two coal-fired boilers by 33.4% and 59.4%, respectively. The electricity generation from other fossil fuel boilers and nonfossil fuel power plants were increased by 1% above the nominal operational level to maintain the electricity to the grid. However, if CO_2 emissions are to be reduced beyond 3% (e.g., 20% for Canada Kyoto Target), more stringent measures that include fuel switching, plant retrofitting and CO_2 capture will have to be used. The optimization results show that the electricity generation from the LN4 natural gas boiler need to be reduced by 32.1%, and that of LN2 by 4.1%. In addition, eight coal-fired boilers (L1,L2,L3,L4, N7,N8,LV3,TB1) need to be switched to natural gas resulting in an increase of cost of electricity of about 7.1%. Finally, the other coal-fired boilers and nonfossil fuel power plants increase the electricity generation by 1% higher than the nominal operational level to meet the electricity demand. For the case of 60% CO_2 reduction, the cost of electricity is increased by 28.3% since 4 new natural gas boilers with capture are put online to compensate the reduction in electricity output due to shut down of all 8 Lakeview boilers, 2 Lambton boilers (L1, L2), and 2 Nanticoke boilers (N7, N8) as well as to achieve greater CO_2 reduction.

Effect of CO_2 reduction on electricity demand distribution

Figures 4–9 illustrate the electricity distribution for the base case, a 3, 6, 20, 40, and a 65% CO_2 reduction target in order to meet current electricity demand. The base case represents OPG's current operational level. As can be seen, increasing CO_2 reduction target leads to switching more coal-fired boilers to natural gas. New power plants with and without capture must also be added to the resource mix to meet the electricity demand requirement. Among the options, NGCC is more favorable although the average coal prices are

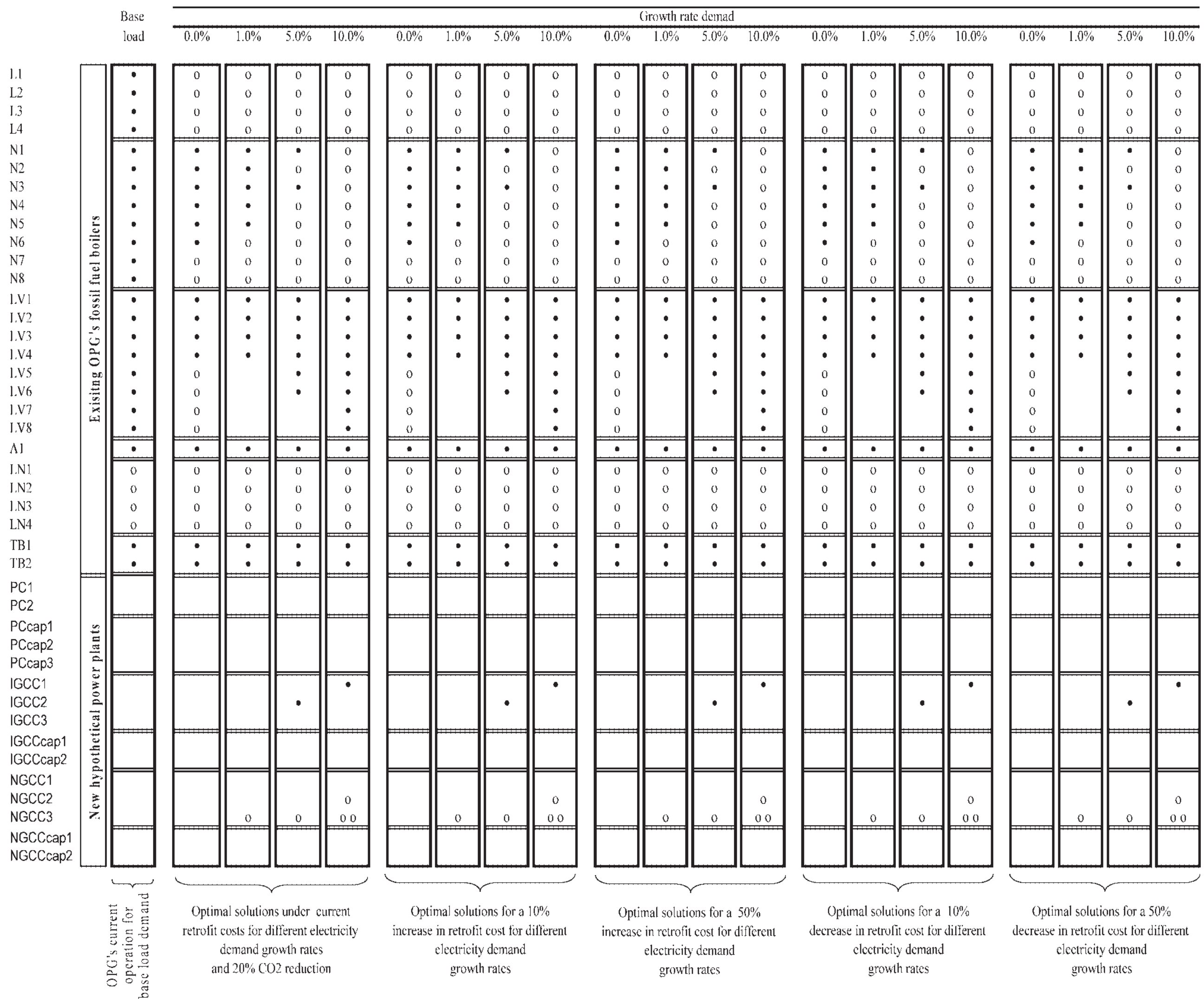

Figure 15. Effect of retrofit cost on CO_2 mitigation strategies different electricity demand growth.

projected to fall throughout the forecast due to lower capital costs, higher fuel efficiency, and lower CO_2 emissions.

Figure 10 shows the electricity distribution for the base case (0), the optimized base case (0 + opt), a 1, 5, and 10% electricity demand growth rate for 20% CO_2 reduction. Figures 11 and 12 show similar results for 40 and 60% CO_2 reduction levels, respectively. New plants with and without CCS will compete with existing plants that have been paid off but remain competitive due to lower overall cost. Figure 10 shows that a 20% CO_2 reduction while meeting current electricity demand could be achieved by implementing fuel balancing and by switching coal-fired boilers to natural gas. However, as demand increases (>5.0% growth rate demand), it becomes necessary to switch more coal-fired boilers to natural gas and also to built new NGCC and NGCC+CCS to replace the aging coal-fired power plants and increase the electricity generation of nonfossil power plants by 1% higher than the nominal operational level to meet the electricity demand.

For the case of 40% CO_2 reduction (Figure 11), the optimization results show that most of the coal-fired boilers are switched to natural gas (i.e., replacing all 8 Lakeview boilers with a new NGCC and NGCC+CCS). To achieve a higher growth rate, it becomes necessary to build four new plants: two NGCC, two NGCC+CCS and to implement carbon capture retrofit on the Nanticoke (N1) coal-fired power plant which is the largest coal-fired boiler in the fleet and is considered as the largest CO2 emitter. The electricity generation of the other coal-fired power plants and nonfossil power plants needs to be increased by 1% higher with respect to the nominal operational level in order to meet the growth in electricity demand.

If greater than a 60% CO_2 reduction is required (Figure 12), the optimization results show that it is necessary to build new plants and carbon capture retrofit on existing coal-fired boilers. Among the attractive options are NGCC, NGCC+CCS, and IGCC+CCS. Finally, the other coal-fired boilers and nonfossil fuel power plants increase the

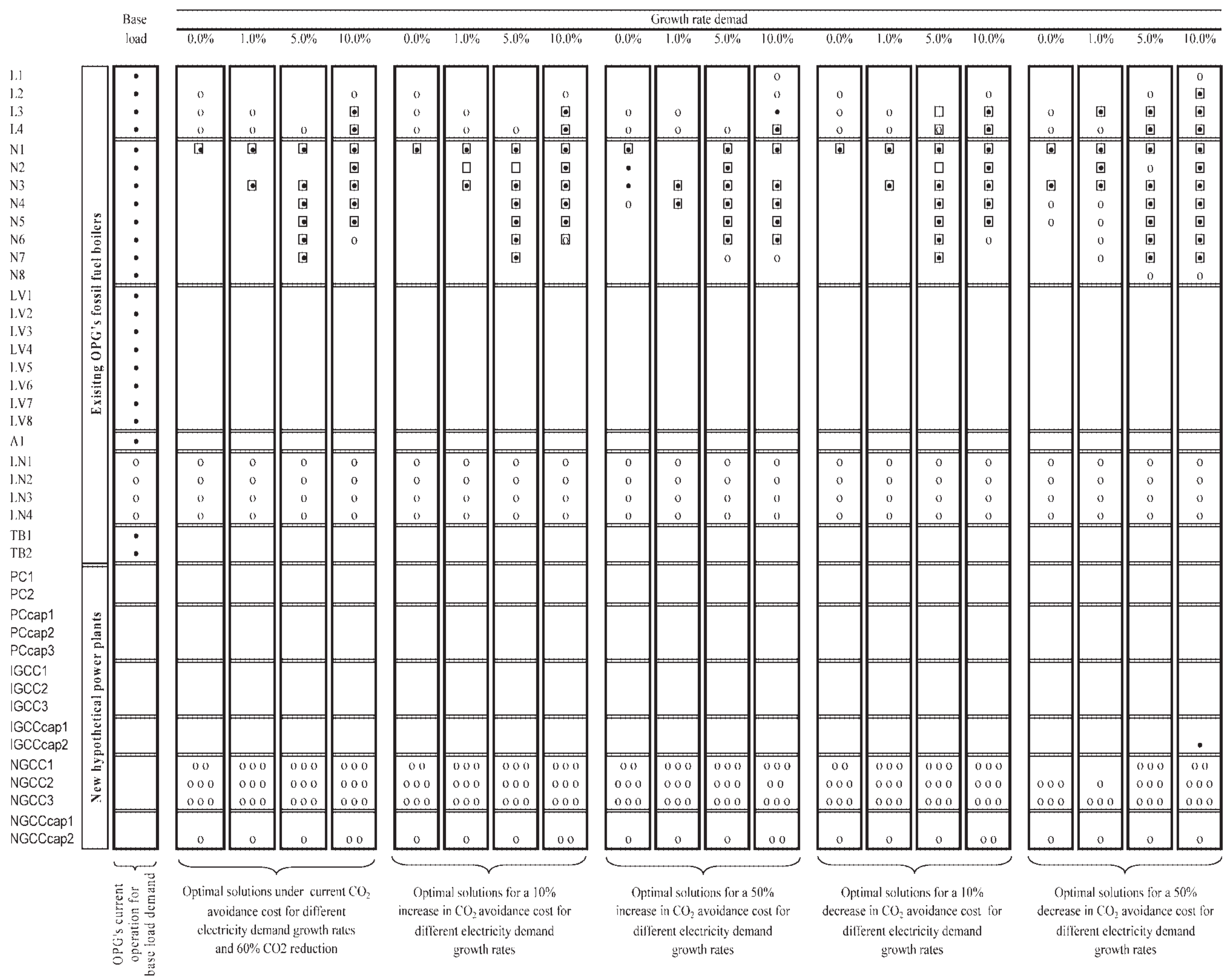

Figure 16. Effect of capture cost (\$/tonne CO_2 avoided) on CO_2 mitigation strategies for different electricity demand growth.

electricity generation by 1% higher than the nominal operational level in order to meet the growth in electricity demand.

Sensitivity Analysis

In this section, the effects of natural gas, coal price, retrofit costs, CO_2 avoidance cost, and new power plants capital cost on the configuration of the power plant fleet are studied. As discussed earlier, for the cases 6, 20, and 40% CO_2 emission reduction, fuel switching from coal to natural gas represents a cheaper option than CCS on existing coal-fired stations. Hence, to examine the sensitivity with regard to capture cost, the case of 60% CO_2 emission reduction was chosen.

The sensitivity analysis of the above five major parameters was carried out for four different scenarios: 0% (base load demand), 1, 5, and 10% growth in demand. The ranges in the parameters that were considered include:

(1) Natural gas price (10% and +100% higher than base case natural gas price)

(2) Coal price (+10% and +100% higher than base case coal price)

(3) Retrofit cost (−10%, −50%, +10%, and + 50% from base case retrofit cost)

(4) CCS cost (−10%, −50%, +10%, and +50% from base case CO_2 avoidance cost)

(5) New plants capital cost (−10%, −50%, +10%, and +50% from the base case capital cost for new power plant)

Figures 13–16 show all 27 current boilers divided into six groups, which correspond to the existing six fossil fuel generating stations followed by another six groups of hypothetical state-of-the-art new power plants. The power plants in the different groups are as described in Tables 2–9. The black dots, white dots, and black dots encircled by a square represent coal-fired boilers, natural gas boilers, and CCS implemented on existing coal-fired boilers, respectively. The first column in each figure represents the current operation without a CO_2 emission target. The second column illustrates the optimized current operation. The nest three columns show the optimal fleet configurations for a 1, 5, and a 10% growth in demand.

Sensitivity to natural gas price

Future natural gas price is highly uncertain (Figure 13). According to New York Mercantile Exchange (NYMEX, 2005), the average annual natural gas price for 2005 is predicted to be US$5.7/GJ. In comparison, the reference gas price used in this study was US$4/GJ.

The volatility of natural gas prices provided a significant impact on the configuration of power plants as illustrated in Figure 13. In order to achieve 20% CO_2 reduction for base natural gas price, fuel balancing, and switching from coal to natural gas is the least cost option compared to CCS. The same optimal solution is obtained if natural gas price is increased slightly to 10% higher than the baseline. However, for a 100% increase in natural gas price and a 10% demand increase, the construction of IGCC with capture becomes favorable and the optimization process recommends that the biggest coal boilers continue to use coal (e.g., four out of eight Nanticoke coal-fired boiler that has been switched to natural gas for the 1% demand increase case should continue to burn coal for the 10% demand increase situation). In addition, the incorporation of carbon capture retrofit on existing coal-fired power plant becomes increasingly attractive. This is expected because fuel price is the main variable affecting the COE in natural gas power plant.

Sensitivity to coal price

The variation of coal price has a less significant impact on the optimal configuration of power plants at lower growth in demand if the coal price is increased slightly as illustrated in Figure 14. For instance, a similar pattern as for the base case scenario is observed for a 10% increase in coal price at base load, 1 and 5% increase in demand. However, if the coal price increases significantly at a higher growth in demand, coal-fired boilers shift toward an increasing use of natural gas. For instance, at a 10% growth in demand and a 100% coal price increase, the optimization favors switching 20 out of 23 coal-fired boilers to natural gas and constructing more NGCC rather than IGCC power plants.

Sensitivity to retrofit cost of fuel switching

The optimal fleet configuration is less sensitive to the retrofit cost in the range of $\pm 10\%$ to $\pm 50\%$ from base retrofit cost as illustrated in Figure 15. A similar pattern as for the base case scenario (20% CO_2 reduction at coal price is US$1.2/GJ) is observed for different demand growth.

Sensitivity to capture cost

The optimal fleet configuration significantly changes by varying the cost of CO_2 avoidance by $\pm 50\%$ but the same optimal configuration is maintained if the cost of CO_2 avoidance changes slightly (i.e., by only $\pm 10\%$) (Figure 16). As the price of CO_2 avoidance rises, adding CO_2 capture retrofit on existing coal-fired power plants becomes less attractive. Therefore, the number of new power plant required to make up the electricity short fall caused by energy penalty once a CO_2 capture process is incorporated is reduced. For instance at 10% increase in growth in demand and 50% increase in CO_2 avoidance cost, the optimization process recommended to put 6 carbon capture processes on L1, N1, N3, N4, N5, N6 and only 8 new NGCC and 2 NGCC with capture compared to 7 carbon capture retrofits on L1, L2, N1, N2, N3, N4, N5, and 9 NGCC and 2 NGCC with capture for the base case. Nevertheless, decrease in CO_2 avoidance cost by 50%, results in an increase in the number of CCS implementation.

Sensitivity to new plant capital investment

Varying the price of new plant capital cost by $\pm 50\%$ from the base price results in different optimal fleet configurations (Figure 17). As the capital cost of new power plants is increased by half of the baseline price, NGCC power plants become more favorable than IGCC power plants because of the lower capital costs, higher fuel efficiency, and lower CO_2 emissions. On the other hand, if the capital cost of new power plants is reduced by 50%, constructing new power plants becomes a more competitive alternative than fuel switching. The patterns remain unchanged if the cost of new power plants changes only by $\pm 10\%$.

Conclusions

This article presented a fleet-wide model of the electricity sector that can be used to determine the optimal structure necessary to meet CO_2 reduction targets while maintaining or enhancing power to the grid. The model incorporated power generation and CO_2 emissions from a fleet of hydroelectric, fossil fuel, nuclear, and wind-based generating stations. The model was used to optimize an existing fleet, recommend new additional generating stations as well as CCS retrofit on existing generating stations to meet a specified CO_2 reduction target and electricity demand at the minimum overall cost. Three mitigation options were considered: fuel balancing, fuel switching, and carbon capture and storage on existing coal-fired power plants. Both, fuel switching and retrofitting CO_2 capture on existing coal-fired power plants involve structural changes to the existing fleet. Four different scenarios were examined: (1) base-load demand, (2) a 1% growth in electricity demand, (3) a 5% growth in electricity demand, and (4) a 10% growth in electricity demand. The model is capable of determining the best mix of fuel, annual capacity factor for existing power plants, location and size of CO_2 capture process and finally, the construction of new state-of-the-art power plants, such as supercritical pulverized coal (PC), integrated gas combined cycle (IGCC), or natural gas combined cycle (NGCC) with and without CO_2 capture.

This optimization problem is a mixed integer nonlinear model (MINLP). An exact linearization method was used to reformulate the MINLP as an MILP. The model was implemented in GAMS and was applied to a real case study obtained from Ontario power generation (OPG).

The optimization results for maintaining current electricity demand by OPG showed that fuel balancing could contribute up to 3% CO_2 reduction by increasing all nonfossil fuel power plants by 1% above the nominal operation level, while reducing electricity generation from all four natural gas boilers (the most expensive fuel) by 32.1%. To meet the electricity demand, the optimization suggested increasing all coal power plants by 1% above the nominal annual capacity factor. This resulted in a decrease of COE by 1.2% compared to the current situation (1.57¢/kWh).

However, if CO_2 emissions are to be reduced by more than 3%, more stringent measures that include fuel switching and retrofitting carbon capture on existing coal-fired boilers had to be used. For instance, to achieve 6% CO_2 reduction (Canada's Kyoto target), the largest coal-fired boilers, Nanticoke (N2), needed to be switched to natural gas. In addition, electricity generation from all four existing natural gas boilers was reduced by 32.1%. Finally, electricity generation from the other coal-fired boilers and nonfossil fuel power plants needed to be increased by 1% higher than the nominal operating level. For this scenario, COE is the same as the base case without optimization, which is 1.57¢/KWh.

To achieve greater CO_2 emission reduction (e.g., 60% CO_2 reduction) and generating current electricity generation, the optimization suggested the implementation of CO_2 capture on existing Nanticoke boiler (N1) and put on stream eight new NGCC (two 334 MW, three 403 MW, three 517 MW) and one NGCC with capture (750 MW) resulting in a COE of 2.44¢/kWh. The results also show that, as the electricity demand increases, larger CO_2 capture processes became required. For instance, to achieve 60% CO_2 reduction at 10% growth in demand requires 5.9% larger CO_2 capture processes compared to the 0% growth in demand and 4.2% larger than the 1% growth in demand. In this latter case, besides CCS retrofit at Nanticoke, the optimization process also chose to implement CO_2 capture at Lambton power plants. In addition, nine NGCC (three 334 MW, three 403 MW, three 517 MW) and two 750 MW NGCC with capture needed to be constructed to meet significant increases in demand and also to supply the supplemental energy for CO_2 capture processes. The optimization also recommended to store the captured CO_2 in Lake Erie. This will result in more than doubling the COE compared to the base case (3.37¢/kWh).

Acknowledgments

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Notation

X_{ij} = binary variable representing fuel selection
y_i = binary variable representing existence/nonexistence of new power plants
z_{ik} = binary variable representing selection of possible capture processes
w_{is} = binary variable representing selection of potential sequestration locations
C = set of coal energy power plants
NG = set of natural gas energy power plants
O = set of oil energy power plants
N = set of nuclear energy power plants
H = set of hydroelectric energy power plants
A = set of alternative energy power plants
$C\text{-}C_i$ = CO_2 capture for ith coal-fired boilers
$C\text{-NG}_i$ = CO_2 capture for ith natural gas
$C\text{-}O_i$ = CO_2 capture for ith oil boiler
N_i^{new} = potential new nuclear power plant
H_i^{new} = potential new hydroelectric power plant
A_i^{new} = potential new alternative energy power plant
$C\text{-PC}_i^{new}$ = CO_2 capture for ith pulverized coal power plant with/without capture
$C\text{-NG}_i^{new}$ = CO_2 capture for ith natural gas combined cycle with/without capture
$C\text{-IG}_i^{new}$ = CO_2 capture for ith integrated gas combined cycle with/without capture
Seq 1,2 = potential sequestration location 2
PC_i^{new} = potential ith new pulverized coal power plant with/without capture
NG_i^{new} = potential ith new natural gas combined cycle with/without capture
IG_i^{new} = potential ith new integrated gas combined cycle with/without capture
Carbon_{ij} = % of carbon of jth fuel in plant i
$\text{Cap}F_i$ = capacity factor of ith type power plant
C_i^{new} = operating cost per unit electricity generated for new additional power plants, \$/MWh
C_i^{NF} = operating cost per unit electricity generated for nonfossil plants, \$/MWh
C_i^{seq} = sequestration cost per tonne CO_2 captured, \$/tonne CO_2 captured
C_{ij} = operating cost per unit electricity generated for fossil-fuel boilers running with j fuel, \$/MWh
C_k^c = operating cost per unit electricity generated for capture process, \$/MWh
CO_{2i} = CO_2 emission per unit electricity generated from new power plants, tonne/MWh
CO_{2ij} = CO_2 emission per unit electricity generated from fossil fuel boilers, tonne/MWh
COE^{cap} = cost of electricity for plant with carbon capture (\$/MWh)
COE^{ref} = cost of electricity for reference plant (\$/MWh)
CO_2^{cap} = CO_2 emission from plant with carbon capture (tonne/MWh)
CO_2^{ref} = CO_2 emission from reference plant (tonne/MWh)
$E_i^{current}$ = current fleet electricity generated
E_i^{nf} = electricity generation from ith nonfossil power plants, MWh/yr
E_i^{new} = electricity generation from ith new power plants, MWh/yr
E_{ij} = electricity generated from ith fossil fuel boilers operating with j fuel, MWh/yr
E_{ik} = electricity required of kth capture process, MWh/yr
E_{lk} = electricity generation from lth new power plants
EF_i = emission factor from ith new power plants
EF_{ij} = emission factor for plant ith fossil fuel boilers running with j fuel
E_i^{max} = maximum electricity generated from ith nonfossil and new power plant, MWh/yr
E_{ij}^{max} = maximum electricity generated from ith fossil fuel boilers running with j fuel, MWh/yr
E_k^{max} = maximum supplemental energy required for kth capture technologies, MWh/yr
E_{nom} = nominal electricity generated from ith type power plant, MWh/yr
f_{ij} = fossil power plants annual capacity factor
f_i = new and nonfossil power plants annual capacity factor
G_k = electricity from the grid to supply kth capture process, MWh/yr
HHV_{ij} = high heating value of jth fuel at plant i, MJ/tonne
l_{ij} = minimum annual capacity factor for ith fossil fuel boilers running with j fuel
l_i = minimum annual capacity factor for ith nonfossil fuel boiler or new power plant
M = big number
N = number of power plants
R_{ij} = retrofit cost (\$/yr)
S_i^{new} = capital cost for a new power plant per electricity installed (\$/KW)
S_{ik}^c = capital cost for capture technology (\$/KW)

Greek letters

η_i = power plant efficiency
ε_{ik} = percent of CO_2 capture

α_i = CO_2 emission (tonne/yr)
α_{ik}^{seq} = CO_2 emission to be sequestrate (tonne/yr)
$\alpha_{ik}^{released}$ = CO_2 emission release to the atmosphere (tonne/yr)

Abbreviations

CCS = carbon capture and storage
COE = cost of electricity
FGD = flue gas desulphurization
GAMS = general algebraic modeling system
HHV = high heating value
IESO = independent electricity market operator
IGCC = integrated gas combined cycle
MEA = monoethanolamine
MILP = mixed integer linear programming
MINLP = mixed integer nonlinear programming
NGCC = natural gas combine cycle
OCAA = Ontario clean air alliance
OPG = Ontario power generation
PC = pulverized coal power plants
SCR = selective catalytic reduction

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