An Analysis of Capacity and Price Trajectories for the Ontario Electricity Market Using Dynamic Nash Equilibrium under Uncertainty

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Abstract: This paper studies investments in the Ontario Electricity Market which is currently being restructured. Our methodology is based on the concept of S-adapted open-loop Nash equilibrium. We examine the evolution of capital investments and pricing behavior of suppliers as uncertain electricity demand evolves over time (in Ontario). This study is particularly interesting since we compare the implications of two policies: *i*) the current setting in which Ontario Power Generation (OPG) retains its generation units; *ii*) the policy (set up in 2003) that required the divestiture of the largest supplier, OPG, and aimed to increase the number of independent suppliers in Ontario. We mainly focus on the independent generators like Bruce Nuclear. We use the tools of Stochastic Programming to compute the S-adapted open-loop Nash equilibrium market outcomes. We find that in the three-player market total capacity installation and market prices are higher than the ones in the five-player market. That is higher capacity may not necessarily alleviate exercise of market power. We also confirm the prediction by the National Energy Board that in a market with five major players, OPG's market share may reduce to a percentage between 35% and 40%.

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1. Introduction

This paper studies capital investment decisions in production of electricity in the Ontario wholesale market. In the Ontario context we consider stochastic equilibrium problems in which players have a significant stake in technology, and meet their production commitments by investing in a variety of technologies.

Our main goal is to analyze equilibrium predictions of capital investment decisions and price trajectories. In particular we focus on strategic behavior of independent generators NUGA and Bruce Nuclear and understand how they adjust their capital investment choices when the market share of Ontario Power Generation (OPG) possibly reduces. We study two cases in terms of number of suppliers: a three-player market and a five-player market. In Ontario, a five-player market is/was possible as a result of divestiture of the largest supplier OPG. Below we explain the reasons under which we consider two policies of the market structures. We will also focus on noncooperative Nash equilibrium rather than dominant firms with competitive fringe equilibrium. The former is relevant, because independent generators (e.g. non-untility generators, NUG) own gas-fired technologies, which are often price-setters. We will employ the S-adapted open-loop Nash equilibrium concept, which is more appropriate to handle dynamic games considered in this paper. The sensitivity analysis of this study also explores the roles of salvage value, depreciation rates and demand growth rates on the equilibrium predictions.

The formulation that we use is called 'games with probabilistic scenarios (GPS)', which is based on Genc, Reynolds and Sen (2005) (hereafter, GRS). In the GPS setting the players make production and investment decisions based on collection of probabilistic scenarios. The trajectories (investment, production, price) will depend on the scenario that unfolds, and they will be required to obey a non-clairvoyance condition which states that decisions cannot depend on information revealed in the future. In contrast to the formulation provided in Haurie, Zaccour and Smeers (1990), GRS adopt an equivalent scenario-based formulation. The resulting equilibrium conditions are easily applicable for problems with significant lags, and moreover, this formulation is amenable to solution methods for complementarity problems. This helps avoid recursive value function approximations which is the source of the curse of dimensionality in dynamic programming. GRS propose several oligopolistic dynamic games, including GPS. The paper by GRS is mainly devoted to demonstrating that stochastic programming (SP) provides a viable computational framework for extremely large dynamic games that are well beyond the scope of dynamic programming.

This paper takes the next step by addressing a realistic case-study arising from the turmoil of re-structuring the electricity market in Ontario, Canada (the home province of the University of Guelph). Whereas the GRS paper was methodological, this paper focuses on policy issues related to restructuring the Ontario market. This work adopts the same spirit as Pineau and Murto (2003), who study investment and production decisions in a medium time horizon in the Finnish electricity market. Their approach uses variational inequalities and the market is assumed to evolve along a sample-path adapted open-loop information structure. Furthermore, their modeling assumptions and structures are very different. Within the context of the GRS paper, the study of Pineau and Murto (2003) is similar to the model we refer to as Games with Expected Scenarios (GES of the GRS paper), where the players assume that the future will evolve according to some expected values, and a sample path is used to study the trajectory of investment and production decisions. In contrast, the GPS model presented in the GRS paper presumes that the firms are cognizant of uncertainty, and account for it within their decision-making process. Indeed, the GRS paper argues that GPS is the more tenable model, and we continue with this framework in the current paper.

To the best of our knowledge, this is the only paper that provides a thorough model-based exploration of the impact of restructuring the Ontario market under uncertainty. Our models help us compute (or predict) capacity investments, and equilibrium production and price trajectories under a variety of scenarios. In addition, we study the effects of demand growth, salvage value, and capital depreciation on capacity investments. Moreover, we discuss policy implications of our findings.

The structure of the paper is as follows. Section 2 introduces the Ontario wholesale electric market setting and specifies the data used. Section 3 describes the model formulation, the equilibrium type and the computational approach. Section 4 presents the results and performs comparative statics, and section 5 concludes with policy implications for Ontario.

2. The Ontario Wholesale Electricity Market

For more than ninety years Ontario Hydro, a government-owned vertically integrated electric utility, has produced, transmitted and distributed electricity to its customers in Ontario, the largest province in Canada. By the late 1990's Ontario Hydro had accumulated significant amount of debt, and various constituents associated with the power company had been critical of its performance. In November 1998 the Government of Ontario passed the Energy Competition Act, which divided Ontario Hydro into several companies including the Independent Electricity Market Operator (IMO), Hydro One and

Ontario Power Generation (OPG). The IMO was renamed the Independent Electricity System Operator (IESO) in 2004. The Act aimed to create a competitive electricity market over the subsequent decade or so. Market operations in Ontario started on May 1, 2002 with the participation of 93 local distributing companies, 89 wholesale consumers, 19 generators, 4 transmission firms and 34 non-facility participants (see www.theimo.com). Trebilcock and Hrab (2005) present an overview of the electricity restructuring process in Ontario.

Currently the IESO is the market administrator and is responsible for a fair and competitive marketplace. It runs a uniform-auction. In addition, it addresses reliability issues, and ensures that aggregate supply matches total demand in a least cost manner. Currently Hydro One mainly transmits power, and OPG generates the bulk of the electricity. While some end-user customers pay fixed regulated prices, utilities distribute power and purchase electricity at the market price. For example, low-volume customers like homeowners and small businesses and certain designated consumers (e.g., universities and hospitals) pay the distributors a fixed rate of 5 cents/kWh for the first 1000 kWh per month and 5.8 cents for each additional kWh. These prices are expected to change in May 2006. The Ontario Energy Board (OEB) regulates these rates. On the other hand, large-volume customers (e.g., industrial) pay the wholesale market price if they consume more than 250 MWh/year. Another component of the market is the Ontario Power Authority (OPA), created in late 2004 to develop an Integrated Power System Plan. Since there is no contract market in Ontario, the OPA will be responsible for contracting with market players to ensure capacity targets, technology to be used and conservation targets. In Table 1 we present Ontario's existing generation resources, installed capacities, ownership and the number of stations (see the IMO report 0172v2.0, April 2004).

Table 1: Ontario's existing power generation structure

Ownership	Technology	Installed capacity (MW)	# of stations
OPG + Bruce	nuclear	10,831 (35.5%)	5
OPG	coal	7,564 (24.8%)	5
OPG and affiliates	hydroelectric	7,676 (25.2%)	61
OPG + NUGA	oil/gas	4,364 (14.3%)	22
OPG	green	66 (0.2%)	4

In this table we denote wind, solar, biomass and geothermal generation resources as "green" technology. The total installed generation capacity accounts for 30,501 MW.

OPG owns three nuclear stations characterized by one or more generating units. There are four existing units at Darlington, four units at Pickering B and one unit at Pickering A, with a total capacity of 6,103 MW. The Darlington units have 3,524 MW total installed capacities. Pickering units have a total of 2,579 MW in capacity. Bruce Nuclear (hereafter, Bruce), Ontario's largest independent power generator, has two nuclear generation stations: Bruce A and Bruce B. These stations have been leased by OPG to Bruce, which is governed by a consortium of TransCanada Co, Cameco Co, and BPC Generation Infrastructure Trust. OPG's hydroelectric generation divisions are Niagara, Northeast, Northwest, Ottowa/St.Lawrance plant groups and OPG Evergreen Energy Division. OPG has 7,033 MW hydroelectric generation capacities out of the total 7,676 MW hydro-power in the province. All of the five coal fired stations (Atikokan, Lakeview, Lambton, Nanticoke, and Thunder Bay) are owned by OPG. OPG also owns Lennox Generating Station, which is fueled by natural gas and oil with an installed capacity of 2,140 MW. The other less significant power source is wind power. OPG owns three wind stations, and its capacity is estimated to be less than 50 MW. There are other non-utility generators (NUG) in Ontario that are mostly fueled by natural gas and oil. According to APPrO (Association of Power Producers of Ontario), NUG has 1307 MW capacities of gas fueled generation stations. Also ATCO Power Ltd., the giant Alberta utility, is operating a 625 MW plant in Windsor, Ontario. This plant is natural gas-fired. In addition, Imperial Oil Ltd and Northland Power Inc installed totally 130 MW gas-fired turbines in 2004 in Ontario. All the capacity data mentioned above are obtained from the IESO, OPG, APPrO and Hydro-One web pages. There are also less significant suppliers, according to the IESO reports, that some are already affiliated with OPG and some are independent generators. In Table 2 NUGA refers to the power provided by the summation of NUG, ATCO Power, Imperial Oil and Northland Power Inc.

We execute a stochastic programming model (described next) for six periods in which each period (t) represents a year. It might be more appropriate to run the model for more than six periods, but this is the maximum number of periods that is handled by the PATH solver for the size of the problem we consider. The dimension of the state vector, including the number of players with multiple technologies, has increased the computational complexity; hence the solver could not compute equilibrium points. We base our demand formulation on the hourly data between May 1, 2002 (opening of the competitive wholesale market) and May 1, 2004. We transformed the hourly data to daily data by simple averaging. In the analysis time stage t =0 corresponds to May 1, 2004 - May 1, 2005, t =1 corresponds to May 1, 2005 - May1, 2006, and similarly others up to t = 5, which is the interval of May 1, 2009 – May 1, 2010.

First we predict the equilibrium outcomes based on the year 2005 setting (a market with three-players) in which OPG, Bruce and NUGA are the main suppliers. Trebilcock and Hrab (2005) note that the new provincial government elected on October, 2003 had stated that the government will not sell any publicly owned assets, and considered expanding the OPG's production capacity. On the other hand National Energy Board's energy market assessment report (2001) indicates that Market Power Mitigation Agreement requires OPG to divest its fossil generation capacity and to have at most 35% of the total generation capacity. On page 36, the report states that "*Within 10 years of market opening, OPG would be allowed to control no more than 35 percent of total generation capacity and no other supplier would be able to accumulate more than 25 percent of generation capacity in Ontario*." Also the IESO's 10-year outlook highlights from January 2005 to December 2014 indicate that (p. 1) "*Ontario's electricity system faces significant challenges over the next 10 years. The uncertainty surrounding the return to service of Pickering A nuclear units, the lack of new generation investment and the commitment to shut down 7,500 MW of coal fired generation by December 31, 2007, all contribute to a potentially severe shortfall*." The other on-going debate regarding phasing out the coal facilities is that Canada's coal reserves are rich, and coal-fired generators contribute to lower electricity prices in the market. The environmental concerns about coal-fired generators can be handled by proper carbon-emissions controls. Therefore, despite the commitment to shut down coal-fired plants, electricity shortages may prompt the coal-fired plants to be retained.

Given the uncertainties discussed above, constantly changing provincial government plans and the controversy regarding the future of OPG, our study will investigate two policy settings: *i*) a three-player market with the players OPG, Bruce and NUGA. *ii*) a five-player market, which considers divestiture of OPG's fossil fuel (coal and oil/gas) generation capacity to 'new' players, and will assume that OPG will keep its hydro, nuclear and green power facilities. The other players are of course NUGA and Bruce. We consider these two cases of market structures because the pledges of the governments have been changed many times since the starting of restructuring process (see Trebilcock and Hrab (2005)). Besides in Section 4 we will investigate policy implications of these cases in terms of capacity investment incentives of the suppliers, and the equilibrium output/price outcomes.

In Table 2 we represent the players, their generation technologies, available in-use capacities, and average variable operation and maintenance costs of the technologies. The energy supply distribution by fuel type from May 2003 to April 2004 is as follows: 42% nuclear, 23% hydro, 21% coal, 8% other (including natural gas, oil, wind, solar, biomass) and 6% imports (see the IMO year in review report 2003-2004). We use this distribution data to compute average available in use-capacities of each player. We attribute imports from other jurisdictions (New York, Michigan, Minnesota, Manitoba and Quebec) to OPG and NUGA, since in general marginal units that cleared the market are gas and oil fueled generators, and OPG and NUGA have oil/gas plants. Accordingly we increase their in-use capacities for oil/gas plants at the average level of imports. Approximate import capability of Ontario is 4,000 MW. Since in the Ontario market setting it is not clear how imports are handled and incorporated in to system, we do not model imports explicitly in a competition framework.

Table 2: Player-technology-cost-capacity structure in Ontario

Suppliers	Technology	In_use_cap (MW)	Cost ($/MWh)
Bruce	nuclear	3,329	4.56
NUGA	oil/gas	1,458	25.46
OPG	nuclear	4,298	4.56
	green	66	0
	hydro	4,177	0
	oil/gas	1,431	25.46
	coal	3,814	21.96

Table 2 implies that almost 70% of the installed nuclear generation, 55.4% of the total hydroelectric capacity, 50.4% of the total installed coal turbine generation capacity, 31.8% capacity of oil/gas fired stations are available on average to meet the demand for each time. We assume that green technology runs with 100% capacity all the time.

The last column of Table 2 presents the production costs (variable operation cost plus maintenance cost) of technologies, obtained from Energy Information Administration-assumptions to the annual energy outlook 2004 booklet. We adjusted all prices to inflation at the 2.5% yearly rate and prices are in year 2004 dollars. We assume a very simple cost structure and these costs represent constant marginal cost of production up to capacity.

For capital investment decisions we assume constant marginal cost of adding capacity and use the following overnight construction costs of the technologies, provided by Taylor (2002). We note that these cost figures are almost equal to the costs reported by Energy Information Administration-assumptions to the annual energy outlook 2004 booklet. These costs exclude regional multipliers, but include contingency factors, technological optimism and learning factors.

Table 3: Construction costs by technology ($/KW)

Technology	2005 year startup costs
nuclear	1600
coal	1080
large hydro	1800
gas/oil	450
green(wind)	800

3. Modeling

We adopt the framework proposed in Genc, Reynolds, and Sen (2005) (referred to as GRS), where the S-adapted open-loop Nash equilibrium is computed using Games with Probabilistic Scenarios (GPS). The main components of our model are described next.

Demand. Assume a T discrete-period game such that each player i, $i = 1, 2, ..., N$, faces a market demand so that price and quantity relationship are governed by

$aP_t + bQ_t = D_t + \tilde{\delta}_t$, where $\tilde{\delta}_t \sim N(\mu, h^2)$ such that

for t=0, $\tilde{\delta}_0 = 0$ and for t=1,2,3,…,T, $\tilde{\delta}_t = \{\mp(2w-1)\delta_t\}_{w=1}^{2^{t-1}}$, where $a, b > 0$ are given constants, and $\delta_t = h \Big/ \sqrt{2^{1-t}\sum_{w=1}^{2^{t-1}}(2w-1)^2}$. $D_t = D(1+\rho_e)^t$, where $D > 0$, and ρ_e represents demand growth rate for the state e, which might refer to "high" growth, "low" growth, etc. Note that the parameter w in the above expressions accommodates alternative outcomes. Also $P, Q \in \Re_+$ and denote the market price and total output, respectively, and $\tilde{\delta}$ is the random variable. In Figure 1 we illustrate the behavior of the demand curves for three periods. As observed, possible realizations of the stochastic demand form a tree-type structure. In general, the demand states for all $t = 0, 1, ..., T$ can be obtained by the formulation defined above. We also assume that for each time period total demand is met by suppliers. Usually mean reverting processes are recommended to model the behavior of energy prices, however, as noted in GRS this type of formulation is not appropriate when the time intervals enlarge and sample sizes decrease. The other commonly used approach is random walk process. But the main criticism of this process is the increasing price volatilities. The above demand formulation has features of random walk and a constant volatility model.

The above demand formulation implies that the demand follows normal distribution for each time period, and approximation of this nature in the scenario-tree-mode employs the properties of *z*-point ($z = 2^t$) discrete uniform distribution, given that the probabilities of all scenarios are equal to each other. Also conditional probabilities given on the arcs of the tree are the same. This demand model is also used by GRS. The linear demand form has been utilized by Green and Newbery (1992), Wolfram (1999), and Garcia-Diaz and Marin (2003), however the main feature of the above demand formulation is that it is embedded into dynamic scenario representation.

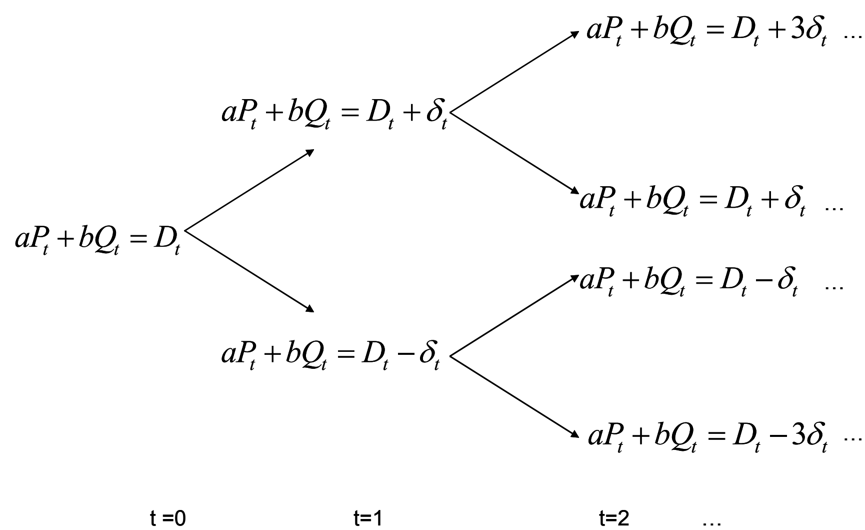

Figure 1: Scenario-tree representation of demand for *t*=0,1,2,…

We assume that the load for a year is normally distributed with $N(\mu, h^2)$. We calculate, based on the IESO predictions on the load volatility for the years 2005 through 2014, that $h = 1,089$ MW. The average hourly price for the year (period), May 1, 2003-Apr 31, 2004, is \$48.2, and the average hourly load for the year is 18,055MW. Hence we obtain $\mu = 18,055$. Let $Q_t(p) = \alpha_t - \beta p$ denote a reduced-form electricity demand, in which $Q_t(p)$ is the hourly load for the time (year) *t* at the price *p*. Also assume that the price elasticity of demand is 0.2. This elasticity level is commonly assumed for the wholesale electricity markets (e.g., Taylor (1975), Branch (1993), Wolfram (1999)). We then calculate $\beta = 75$. However, Elkhafif (1992), and Bentzen and Engsted (1993) estimate price elasticity of electricity demand in the range of 0.4 to 0.6. The elasticity estimates are depending on the estimation method. Furthermore, depending on consumer type, e.g., residential versus industrial, price elasticities of demand vary, but in the demand model it is hard to differentiate these customers. The higher values of price elasticity of demand would imply lower equilibrium prices; hence our price estimates may be an upper bound.

Let $\alpha_t = D(1+\rho_e)^t + \delta_t$. The IESO expects that $(\rho_e)_e = \{0.006, 0.009, 0.013\}$, (*e* = low, medium, high), are the yearly growth rates of demand for the future. Given the above information, for *t* = 0 (initial node), in which $\delta_0 = 0$, we calculate that $D = 21,670$. Hence we have the demand curve $Q_0(p) = 21,670 - 75p$ in the initial node. Following the demand evolution process above, for *t* = 1 we use an "up" demand scenario of $Q_{1,up}(p) = D(1+\rho_e) + \delta_1 - \beta p$, and a "down" demand scenario of

$Q_{1,down}(p) = D(1+\rho_e) \; -\delta_1 - \beta p$, where $\delta_1 = h = 1,089$, with equal probabilities ½ and ½ . Demand scenarios at $t = 2$ are as follows: For the "up-up" scenario the demand will be $Q_{1,upup}(p) = D(1+\rho_e)^2 + 3\delta_2 - \beta p$, for the "up-down" scenario the demand will be $Q_{1,updown}(p) = D(1+\rho_e)^2 + \delta_2 - \beta p$, for the "down-up" scenario it will be $Q_{1,downup}(p) = D(1+\rho_e)^2 - \delta_2 - \beta p$, for the "down-down" scenario it will be $Q_{1,downdown}(p) = D(1+\rho_e)^2 - 3\delta_2 - \beta p$, in which $\delta_2 = h/\sqrt{5} = 486$. Similarly, we can obtain demand levels of other stages as described above, and calculate that $\delta_3 = 237$ in $t = 3$, $\delta_4 = 118$ in $t = 4$, and $\delta_5 = 59$ in $t = 5$.

Costs and Technology. Let strategy space (pairs of production quantity and capital investments) be compact and convex. The investment decisions from each technology will be made under uncertainty, which is modeled in Figure 1. Capital investment made in time *t* will be available in use in period *t*+1. The supply conditions for a firm are related to its production and investment cost functions. We allow firms to have multiple technologies which have different characteristics. For example, in one technology production cost may be higher than investment cost, for some technologies it may be vice-versa, even some technologies may have negligible (almost zero) production cost with fixed investment cost. Also we assume that these cost functions are convex, and increasing.

Objective function. Each supplier/player chooses a strategy (production and investment quantities) given a set of strategies of other suppliers to maximize discounted expected profit subject to production and capacity constraints for each time and scenario. (An alternative (though equivalent) recursive formulation is provided in the GRS paper.)

Explicitly for each player i, ($i = 1, 2, ..., N$), maximization of the discounted expected profit problem is:

For each period $t = 0, 1, 2, ..., T$, for all technology $k = 1, 2, ..., m$ and for all (demand) scenario $s \in \{1, 2, 3, ..., \omega\}$, $\omega < \infty$

$$\max \sum_{s=1}^{\omega} p_s \sum_{t=0}^{T} \beta^t \sum_{k=1}^{m} \Pi_{i,s}^t (q_{i,s,k}^t, I_{i,s,k}^t, Q_s^t) + \sum_{s=1}^{\omega} p_s \sum_{t=T} \beta^t \sum_{k=1}^{m} K_{i,s,k}^t F'^{\,t}_{i,s,k} \upsilon \qquad (1.0)$$

subject to

$$q_{i,s,k}^t - K_{i,s,k}^t \leq 0 \qquad (1.1)$$

$$Q_s^t - \sum_{i,k} q_{i,s,k}^t = 0 \qquad (1.2)$$

$$K_{i,s,k}^{t+1} - (1-r) K_{i,s,k}^t - I_{i,s,k}^t = 0 \qquad (1.3)$$

$$I_{i,k}^t - E(I_{i,s,k}^t) = 0 \qquad (1.4)$$

$$q_{i,s,k}^t \geq 0 \text{ , } K_{i,s,k}^t \geq 0 \text{ , } I_{i,s,k}^t \geq 0 \qquad (1.5)$$

where β is a discount factor, υ is salvage value parameter, p_s is the probability of scenario s, F' is the installment (or replacement) cost of each unit of technology. For player i at time t from technology k and in scenario s, $q_{i,s,k}^t$, $K_{i,s,k}^t$ and $I_{i,s,k}^t$ represent production quantity, capacity, and capital investment, respectively.

In the objective function (1.0), the first term is the firm i's expected discounted sum of payoffs and the second term is the salvage value at the end of the planning horizon, T, and it is assumed to be the cost of acquisition of an equivalent amount of capital.

The constraint (1.1) is the production constraint, (1.2) is the market clearing condition for each time and scenario. The constraint (1.3) specifies the state equation, that is the total capacity level at time t+1 is equal to summation of investment made in time t and the remaining (net of depreciated) capacity in time t. The constraint (1.4) is called "non-anticipativity" or "non-clairvoyance" condition, which requires that decisions at a given moment do not depend on information available in the future. This constraint helps us decompose the demand scenarios and formulate and solve the problem like deterministic counterparts. Finally, non-negativity constraints are imposed by (1.5). We ignore transmission pricing, since its cost is negligible relative to production cost.

Equilibrium type. The above dynamic game assumes complete information structure over players' payoffs. GRS argue that one way to solve for optimal decisions of each player in this large-scale dynamic game setting is to employ S-adapted open-loop Nash equilibrium concept. This equilibrium concept was introduced by Zaccour (1987) and Haurie, Zaccour and Smeers (1990) and later extended by Haurie and Moresino (2001, 2002), and Haurie and Zaccour (2004). An S-adapted open-loop strategy of a firm specifies its production and investment decisions and is conditioned on the time period, demand state and initial capacity state. An S-adapted open-loop equilibrium is a set of strategies for players, and each player's strategies maximizes its discounted expected profit given the strategies of the other players. It is a compromise between closed-loop and open-loop Nash equilibrium, since decisions are made over not a single path but over a collection of sample paths/scenarios. But the solution may not yield a subgame perfect equilibrium. An alternative to the open-loop concept is an equilibrium in feedback strategies – the recent economics literature refers to this as a Markov perfect equilibrium (e.g., Lockwood (1996)) or a subgame perfect equilibrium. However, to date, equilibria of this type have not been computed for large-scale models like the one in this paper. In contrast, open-loop models may be more tractable since dynamic programming is not necessary to compute open-loop equilibria. Furthermore, for the medium time horizon capacity investment planning, firms may not condition their decisions on past and current investment decisions of rivals but condition on, for example, external shocks that affect demand conditions. Hence, the equilibrium concept that we adapt applies. For a more elaborate defense of S-adapted open-loop Nash equilibrium concept for the solution of investment-production under uncertainty type dynamic games see Pineau and Murto (2003).

Equilibrium Computation Method. For the maximization problem defined for each player i in (1.0) – (1.5) we can utilize the SP methodology given that decisions at time t do not alter the structure of the stochastic process at time t+1. We illustrate the SP approach as follows. For the sake of simplicity, let t = 0,1. First we split the tree in Figure 1 into branches (scenarios). Assume two states at each node, then the number of branches at time t is 2^t. If we would have more than two possible states (e.g., a bunch of arcs from each node), then we would use the same approach that we describe below. As in Figure 2 we decompose the problem (1) into sub-problems (or, scenario problems). We solve each sub-problem separately, but connect these sub-problems via non-anticipativity constraint in (1.4) and the market clearing condition in (1.2).

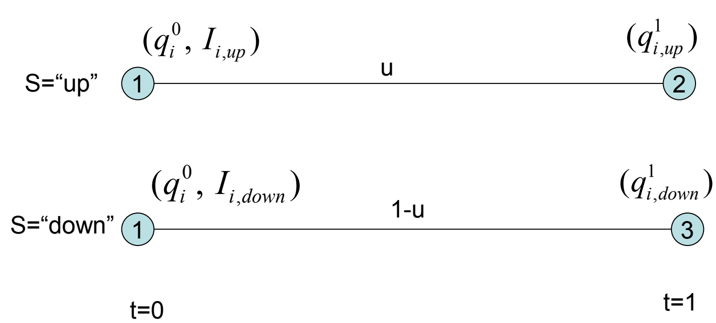

Figure 2: Decomposition of demand scenarios for two-period problem.

Demand at time 0 for node 1 is $aP_0 + bQ_0 = D_0$. The demand at time 1 and node 2 is $aP_1 + bQ_1 = D_1 + \delta_1$, and the demand at time 1 and node 3 is $aP_1 + bQ_1 = D_1 - \delta_1$. Players encounter "up" (demand) scenario with probability 'u' and "down" (demand) scenario with probability '1-u'. Players solve the maximization problem for each scenario with the above probabilities. In that case, the players have two (2^t, where t=1) different optimization problems. But that means that the players are possibly making two different investment decisions at time 0 for the future period 1 given that investment should be made under uncertainty and it precedes the time 1 production. We resolve this issue by implementing the non-anticipativity constraint defined in (1.4). That implies that we must enforce the constraint $I_{i,k}^t - E(I_{i,s,k}^t) = 0$, which implies that the 'up' scenario optimization problem must have the constraint (investment vectors) $I_{i,up}^0 = I_i^0$, and in the 'down' scenario we must enforce the constraint $I_{i,down}^0 = I_i^0$. Given these scenario problems, the optimality conditions can be written as linear complementarity conditions (which are in the form of $x\,f(x) = 0$, where *x* is a vector and *f* is a vector of linear functions) for the maximization problem of each player. Next we use the PATH solver (see the Argonne National Lab's NEOS server) to solve for these conditions, and obtain the unique S-adapted equilibrium outcomes. (Equilibrium outcomes will be unique, if we utilize strictly convex cost functions (see GRS (2005)). This formulation allows one to consider different construction lags between technologies. Some technologies could be available in *t*+1 if constructed/improved in *t*, but others would require less or more time.

Player's Decision Models. For our study, we assume six-stages ($t = 0, 1, 2, 3, 4, 5$) in the game, and assume that technology depreciation rate takes values $r \in \{0, 1/30\}$. More than six time stages would be more realistic for capacity expansion planning. But six stages are the maximum number of periods that PATH solver is handled. When we run the model for seven stages, for example, the algorithm of the solver did not converge to the optimal values. When we consider depreciation we will assume each technology has a 30 year of life time, and it depreciates, for the sake of simplicity, linearly each year. In reality the life periods of the generators vary and depend on technological factors such as capacity, but it is harder to determine their true life times. Here a 30 year of life time is a reasonable assumption for the electric generation industry. Although we assume linear technology depreciation rate, our model formulation allows any class of rates and time lags of depreciation. We use a discount factor at the rate of 2.5% inflation for Canada (i.e., $\beta = 0.975$). This rate is obtained from Statistic Canada. We consider three cases for salvage value; no salvage value, 90% and 95% salvage values. That is $\upsilon \in \{0, 0.9, 0.95\}$. We let the salvage value for each type of technology equal salvage value parameter times a high percentage of the replacement of the capacity. We add the salvage value at the final period into the payoff function of each player. The salvage value parameters are chosen zero (i.e., $\upsilon = 0$, which implies irreversible investment), one minus two times inflation rate (i.e., $\upsilon = 1 - 2(1-\beta)$) and one minus four times inflation rate (i.e., $\upsilon = 1 - 4(1-\beta)$).

We model the market as a game with probabilistic scenarios, and compute the unique S-adapted open-loop equilibrium strategies to explore the capital investment incentives of independent power generating firms in Ontario. We use the above demand and cost data and run the stochastic programming model using the NEOS server-PATH solver in the AMPL environment. The PATH solver is best known for complementarity problems. The AMPL code is available from the authors upon request.

4. Results

The main goal of this exercise is to predict evolution of capital investments over a six period horizon for the independent generators, NUGA and Bruce, as demand growth levels and/or the number of players and/or salvage values vary. The five-player case involves the situation in which OPG divests its oil/gas generation facilities to Player 5 and its coal fired units to Player 4 in the beginning of the game. (For the players' capacity and cost levels see the last two columns of the Table 2.) Since the timing and certainty of the divestiture is not clearly known, in the five-player case we will investigate the consequences of the spinoff of OPG at the initial period. Recall that the first three players are OPG, Bruce and NUGA.

In the three or five player setting, the number of variables (production, investment, and dual variables) is 4032. The number of the first order necessary (Karush-Kuhn-Tucker) conditions is the same. The computational time is about three seconds.

In Tables 3 and 4 we focus on NUGA and report expected capital investment levels (and expected total capacity, MW) for high demand growth ($\rho_{high} = 0.013$) in the three-player (n=3) and five-player (n=5) markets, respectively. NUGA represents a group of non-utility generators and there are many in Ontario. In the tables the first column represents the forecast time horizon, the second, fourth and sixth columns correspond to expected investment levels, and the rest represents the expected total capacities. Our model predicts that NUGA will undertake significant generation-capacity additions, in comparison to the other players. This may stem from the fact that it has oil/gas generators which has the lowest capital costs (among power generation technologies) and market clearing prices were always greater than its marginal production costs so that it might be profitable to make capacity installments. This is actually consistent with the IESO ten-year outlook highlights from January 2005 to December 2014, in which many generation additions (oil/gas plants) are expected.

From the tables it is also observed that as the salvage value increases, so do the actual investment levels. We note that the total capacity decreases at the rate of depreciation ($r = 1/30$ per year) in the fifth and seventh columns of Tables 3 and 4.

Table 3: NUGA's expected capacity investment and total capacity for $(n, \rho) = (3, 0.013)$

	$\upsilon = 0, r = 0$		$\upsilon = 0.9,\ r = 1/30$		$\upsilon = 0.95,\ r = 1/30$	
Period	Inv. (I)	Capc. (K)	Inv. (I)	Capc. (K)	Inv. (I)	Capc. (K)
0= 4.04-05	2879.6	1458	2981.9	1458	2981.9	1458
1= 4.05-06	196	4337.6	172.9	4391.3	172.9	4391.3
2= 4.06-07	0	4533.6	149.8	4417.8	149.9	4417.8
3= 4.07-08	0	4533.6	267.4	4420.4	206.4	4420.4
4= 4.08-09	0	4533.6	134.4	4540.4	231.3	4479.5
5=4.09-10	N/A	4533.6	N/A	4523.5	N/A	4561.5

Table 4: NUGA's expected capacity investment and total capacity for $(n, \rho) = (5, 0.013)$

	$\upsilon = 0, r = 0$		$\upsilon = 0.9,\ r = 1/30$		$\upsilon = 0.95,\ r = 1/30$	
Period	Inv. (I)	Capc. (K)	Inv. (I)	Capc. (K)	Inv. (I)	Capc. (K)
0= 4.04-05	1061	1458	1378.1	1458	1377.9	1458
1= 4.05-06	115.3	2519	141.8	2787.5	141.9	2787.3
2= 4.06-07	0	2634.3	124.5	2836.4	119.9	2836.3
3= 4.07-08	0	2634.3	203.5	2866.3	161.8	2861.6
4= 4.08-09	0	2634.3	92	2974.3	174.5	2928
5=4.09-10	N/A	2634.3	N/A	2967.1	N/A	3005

We find that if we would employ capacity depreciation but no salvage value (i.e., $\upsilon = 0$ and $r = 1/30$) then investment levels in the second columns of Tables 3 and 4 would also increase, but the total capacity would be less than the total capacity levels (in the fifth and seventh columns of the tables) for the cases of salvage value ($\upsilon \neq 0$) and depreciation ($r \neq 0$). NUGA almost doubles its production capacity during the initial period in the three-player market. In later periods the increases in investment levels are not observed. As the rate of salvage value increases total investment increases given that NUGA realizes that whence the game is over his total capacity has value, that is, the capital investment is partially reversible. We note that in period 5 there is no investment, since the game ends at that period.

In the five-player market of Table 4 NUGA's total investment levels are lower than those in the three-player market. This may stem from the fact that the new players, Player 4 and Player 5, also increase their capacities, and these players' total investments are higher than the investments made for these technologies under the ownership of OPG (three player case). We illustrate this relationship between Table 3 and Table 4 (i.e., NUGA's expected total capacity levels for each market structure and model parameters) in Figure 3.

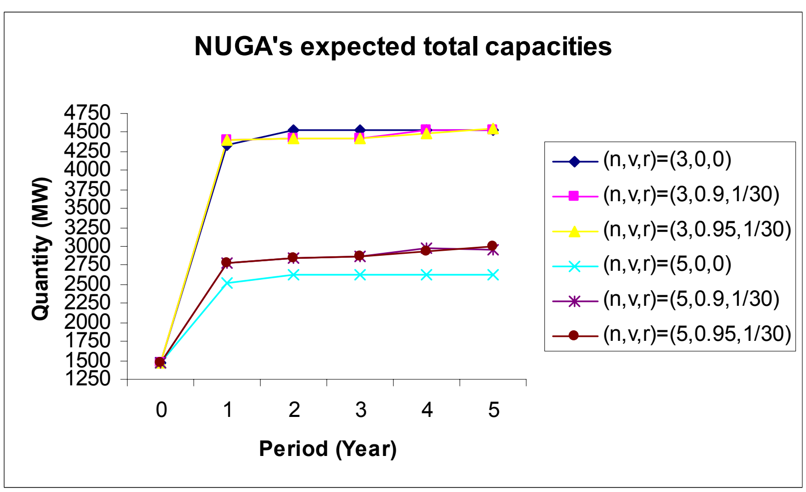

Figure 3: NUGA's expected capacity holding profiles over time.

In Figure 4 we plot NUGA's four (out of sixteen) equilibrium investment scenarios. The first scenario, s1, refers to the (up, up, up, up) state, that is, demand increases all the time during the game. (Clearly, the first component of the s1 represents the demand increase from period 0 to period 1. The second component in s1, "up" state, is that the demand will increase from period 1 to period 2 given that demand increased in the period 1.) The second scenario (s2) considers (down, down, down, down) state in which demand decreases from period to period. Finally, the third scenario (s3) and the fourth scenario (s4) represent (up, down, up, down) and (down, up, down, up) asymmetric states, respectively. As shown in Figure 3 the equilibrium investments mimic the scenario tree structure, that is, when demand increase is expected, investments are made before that to meet the increase in demand. When demand decreases investments may not be undertaken. Since the root scenario begins at period 0 (in which initial investment level of the NUGA is 2982 MW), in the figure we draw investment scenarios starting from period 1.

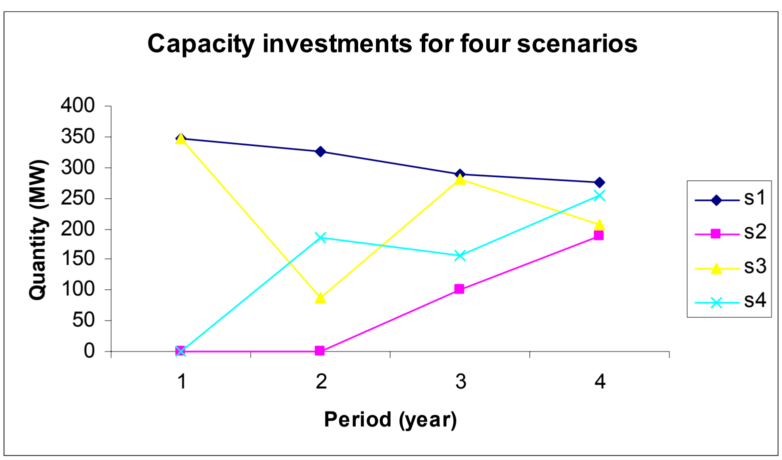

Figure 4: Some NUGA investment scenarios for $(n, \rho, r, \upsilon) = (3, 0.013, 1/30, 0.95)$

For the sake of brevity we do not report investment levels of all players for all cases – demand levels, depreciation amounts, salvage values, etc. Nevertheless, we will focus on another independent electric power producer, Bruce Nuclear. In Table 5 we report Bruce's expected equilibrium capacity investment and total capacity levels for the six-period game in which demand growth rate is high and there are three players in the market. In this table we observe similar capital investment patterns as we observed for NUGA.

Table 5: Bruce's expected capacity investment and total capacity for $(n, \rho) = (3, 0.013)$

	$\upsilon = 0, r = 0$		$\upsilon = 0.9,\ r = 1/30$		$\upsilon = 0.95,\ r = 1/30$	
Period	Inv. (I)	Capc. (K)	Inv. (I)	Capc. (K)	Inv. (I)	Capc. (K)
0= 4.04-05	591.1	3329	2028.6	3329	2028.6	3329
1= 4.05-06	0	3920.1	242.2	5246.6	242.2	5246.6
2= 4.06-07	0	3920.1	242.7	5313.9	242.7	5313.9
3= 4.07-08	0	3920.1	72.2	5379.5	255.2	5379.5
4= 4.08-09	0	3920.1	0	5272.4	95.7	5455.4
5=4.09-10	N/A	3920.1	N/A	5096.6	N/A	5369.3

Similar to Table 5 we present Bruce Nuclear's total expected capacity levels in Table 6 for the five-player and high-demand case. The main difference between Tables 5 and 6 is that in the five player case, the Player 5 oil/gas units invest massively but this incentive was not available when the OPG was the sole owner of these technologies in the three-player market.

Table 6: Bruce's expected capacity investment and total capacity for $(n, \rho) = (5, 0.013)$

	$\upsilon = 0, r = 0$		$\upsilon = 0.9,\ r = 1/30$		$\upsilon = 0.95,\ r = 1/30$	
Period	Inv. (I)	Capc. (K)	Inv. (I)	Capc. (K)	Inv. (I)	Capc. (K)
0= 4.04-05	0	3329	517.5	3329	518.4	3329
1= 4.05-06	0	3329	171.8	3735.5	171.3	3736.4
2= 4.06-07	0	3329	136.9	3782.8	158.3	3783.2
3= 4.07-08	0	3329	33.9	3793.6	214.1	3815.4
4= 4.08-09	0	3329	0	3701.1	42.1	3902.3
5=4.09-10	N/A	3329	N/A	3577.7	N/A	3814.3

We also note that for the case $(n,\rho)=(3,0.013)$ OPG does not make investment for any technology when its investment has no salvage value, nor when there are capital depreciation and salvage value for its investment. For other demand states (low and medium), we also observe the same results. As our model predicts, interestingly, neither in the three-player structure nor in the five-player structure, does the Player 4 (with coal units) make any investment. In our model, this may stem from high investment and operational costs, and limited time horizon. In reality, the government has planned to close-down all coal plants either by the end of 2007 or by the end of 2009. (These legislative plans are subject to change.) Given this, of course, capacity expansions of coal units are not meaningful.

In Figure 5, based on Tables 5 and 6, we plot Bruce's expected total capacities for each market, and parameter values. From this figure, it is clear that the expected capacity in a market with five generating firms is significantly lower than that in a market with three generating firms.

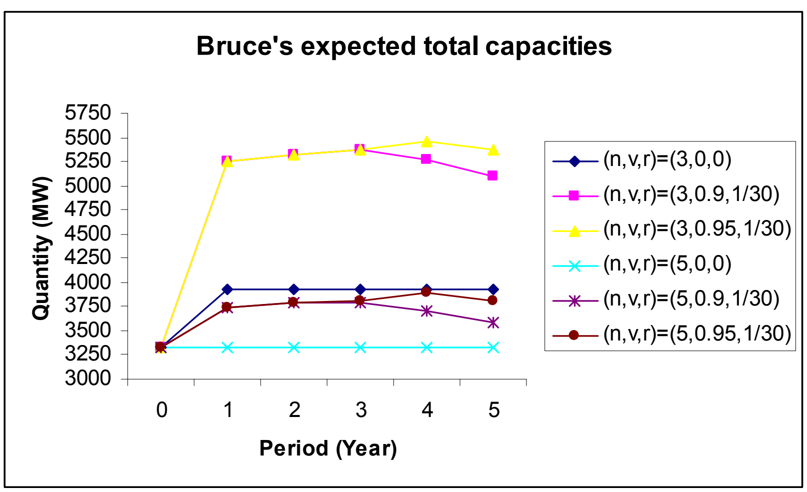

Figure 5: Bruce Nuclear's expected capacity holding profiles over time.

Finally we report equilibrium hourly prices for each projected year in Tables 7a and 7b with 95% salvage value for three-and five-player markets, accounting for depreciation for the technologies. We also compute (but do not report) equilibrium market prices for the salvage value of 90%, since we do not observe significant price changes due to change in salvage value from 90% to 95%. It is observed that allocating the initial period capacities among more suppliers has led to significant welfare improvements over time. For example, our model predicts that yearly average prices will drop 25% and yearly average price volatility will be reduced by approximately 29% as a result of increase in the number of suppliers from three to five. It is interesting to observe that in contrast to financial markets, an increase in the number of suppliers appears to yield lower volatility in the electricity markets. Since we employ a quantity choice (Cournot) model, the prices may look higher in these tables than expected. A more realistic approach to modeling might be one that employs supply function equilibrium to predict the pricing behavior of generators, but this approach predicts higher prices than the realized prices (see, e.g., Wolfram (1999)), and may also yield multiple equilibria and hence equilibrium selection problem.

Table 7a. Yearly predicted equilibrium price levels with $(n, r, \upsilon) = (3, 1/30, 0.95)$ for each ρ

	Demand Growth		
Period	Low (0.6%)	Medium (0.9%)	High (1.3%)
0=4.04-05	(114.8, -, 114.8, 114.8)	(114.8, -, 114.8, 114.8)	(114.8, -, 114.8, 114.8)
1=4.05-06	(85.1, 8.8, 91.3, 78.6)	(85.3, 8.8, 91.5, 79.0)	(85.5, 8.7, 91.6, 79.3)
2=4.06-07	(83.0, 5.4, 89.8, 76.7)	(85.3, 5.3, 92.0, 79.0)	(85.9, 5.3, 92.5, 79.7)
3=4.07-08	(85.5, 4.3, 91.9 , 78.9)	(86.1, 4.3, 92.5, 79.5)	(87.1, 4.2, 93.4, 80.6)
4=4.08-09	(86.0, 3.8, 92.3, 79.7)	(86.9, 3.8, 93.2, 80.6)	(88.1, 3.8, 94.4, 81.8)
5=4.09-10	(87.4, 3.7, 93.7, 81.1)	(88.6, 3.7, 94.9, 82.3)	(90.1, 3.7, 96.4, 83.8)
(Expected price, standard deviation, max price, min price)			

Table 7b. Yearly predicted equilibrium price levels with $(n, r, \upsilon) = (5, 1/30, 0.95)$ for each ρ

	Demand Growth		
Period	Low (0.6%)	Medium (0.9%)	High (1.3%)
0=4.04-05	(79.8, -, 79.8, 79.8)	(79.8, -, 79.8, 79.8)	(79.8, -, 79.8, 79.8)
1=4.05-06	(65.1, 6.2, 69.5, 60.7)	(65.2, 6.2, 69.6, 60.9)	(65.4, 6.1, 69.7, 61.0)
2=4.06-07	(64.9, 3.7, 69.4, 60.4)	(65.2, 3.7, 69.8, 60.7)	(65.6, 3.8, 70.4, 61.2)
3=4.07-08	(65.6, 2.7, 70.2 , 62.2)	(66.1, 2.7, 70.8, 62.7)	(66.7, 2.7, 71.5, 63.4)
4=4.08-09	(65.9, 2.7, 70.8, 61.5)	(66.5, 2.8, 71.5, 62.1)	(67.4, 2.9, 72.4, 62.9)
5=4.09-10	(67.2, 2.9, 72.3, 62.5)	(68.1, 2.9, 73.2, 63.3)	(69.3, 3.0, 74.4, 64.3)
(Expected price, standard deviation, max price, min price)			

Related to prices in Tables 7a and 7b and capital investments (Tables 3-6), for the high growth demand level when the number of players increased from three to five, we find that NUGA's total capital investment on average decreased 47% so that the new player (Player 5 with oil/gas generators) increased its production capacity to serve the load. Per period expected decrease in investments of NUGA starting from period zero to period five are 54%, 16%, 20%, 21%, and 25%, respectively. At the same level of demand growth, we calculate that in the five-player market, players make 23% less capital investment (on average) than the ones in the three-player market. There are two opposing effects: higher prices in a few-player market induce new entries, but over investments in the market deter entry. Further, higher prices in three-player market may stem from this over investment. To be sure, excess capacity is one of the features of oligopolistic markets, and is usually based on entry-deterrence incentives of incumbent firms (see Spence (1977), Reynolds (1986)). This over investment may also be attributed to the capacity competition among incumbent firms. That is, as we observed OPG does not make any investment since he has enough capacities from his technologies, the other players increase their capacities since they have low initial capacities. Furthermore, uncertainty in demand triggers capacity investments in earlier periods to profit from future high demand conditions.

In Table 8 we present the percentage market share of each supplier in terms of installed capacities in the three-player market structure for the high-demand state. In this table, period 0 values are the existing levels of installed capacities. For the case of no depreciation – no salvage value, Bruce and NUGA increase their capacity investments, hence their market shares increase. Bruce makes investment in period 1, but since NUGA makes more investment than Bruce, Bruce's market share decreases from period 1 to period 2. Since OPG has already enough capacities from five different technologies, it does not tend to expand. Starting in period 2 no supplier increases its capacity. In this case, early period investments are reasonable, since their initial capacities are low for meeting high demand states, plus they do not face capacity depreciation. For the case of 3.3% per year capital depreciation of technologies and 90% salvage value, NUGA and Bruce make capacity investments in every period (except period 5 at which the game is over), hence their market shares rise. Since the capacity depreciates and the costs are discounted over time, players increase their capacities gradually. On the other hand OPG makes no investment at all. On average, expected total installed capacity is higher in this case than the previous case; the reason is the existence of salvage value of the total capacity at the end of the planning horizon. For the case of depreciation and 95% salvage value (the third sub-table in Table 8), all players but OPG make investment in every period, hence expected total capacity is higher. However OPG still captures two-thirds of the market.

According to the policy *ii*), the five-player market structure, as indicated in the National Energy Board's energy market assessment report, Market Power Mitigation was developed to reduce OPG's share of the generation capacity. Specifically, it was required that OPG reduce or divest some of its fossil generation capacity and have at most 35% of the total market generation capacity. In Table 9 we investigate consequences of OPG's divestiture of fossil fueled generation units. We assumed that OPG sells its coal-fired generators to a firm so called 'Firm 4', and oil/gas fired generators to a firm so called 'Firm 5'. (We note that, because of the environmental regulations, in the long run the Ontario suppliers may abolish their coal-fired stations.) In this five-player game structure, for no-depreciation and no-salvage value case, only oil/gas fired generation unit owners (i.e., NUGA and Firm 5) make almost equal capacity installments in the first two periods. Expected total industry capacity increases about 2,075 MW in the first period and 194 MW in the second period. For the depreciation and salvage value cases, all firms except OPG (with hydro, green and nuclear technologies) and Firm 4 (with coal generators) make capacity investments. However, capacity investments of the oil/gas generators that require lower capital outlays are higher. Even though investments increase in each period, expected total installed capacity levels reduce over time because of capacity depreciation.

Table 8: Expected Market Share per Firm per Year for $(n, \rho) = (3, 0.013)$

$(\upsilon, r) = (0, 0)$

Period	Expected Market Share per Firm (%) OPG	Bruce	NUGA	Exp. Total Inst. Cap. (K)
0=4.04-05	77.2	15.5	7.3	30,501
1=4.05-06	69.3	15.7	15	33,972
2=4.06-07	68.9	15.6	15.5	34,168
3=4.07-08	68.9	15.6	15.5	34,168
4=4.08-09	68.9	15.6	15.5	34,168
5=4.09-10	68.9	15.6	15.5	34,168

$(\upsilon, r) = (0.9, 1/30)$

Period	Expected Market Share per Firm (%) OPG	Bruce	NUGA	Exp. Total Inst. Cap. (K)
0=4.04-05	77.2	15.5	7.3	30,501
1=4.05-06	66	19.1	14.9	34,485
2=4.06-07	65.2	19.6	15.2	33,760
3=4.07-08	64.4	20.1	15.5	33,028
4=4.08-09	63.7	20.1	16.2	32,267
5=4.09-10	63.5	20	16.5	31,326

$(\upsilon, r) = (0.95, 1/30)$

Period	Expected Market Share per Firm (%) OPG	Bruce	NUGA	Exp. Total Inst. Cap. (K)
0=4.04-05	77.2	15.5	7.3	30,501
1=4.05-06	66	19.1	14.9	34,495
2=4.06-07	65.2	19.6	15.2	33,760
3=4.07-08	64.4	20.1	15.5	33,028
4=4.08-09	63.5	20.6	15.9	32,389
5=4.09-10	62.8	20.7	16.5	31,636

As our model predicts, once the market has five suppliers OPG's market share reduces to 38.5% in six periods, which is very close to the Market Power Mitigation target level. However, on average (with respect to the model parameters such as υ and r), expected total installed capacity under five-supplier market is less than the one under the three-supplier market. This may stem from the increase in the number of suppliers because of the divestiture of the OPG. The relationship between total capacity and market prices are interesting. One might expect that high capacity accumulation market structure may lead to relatively lower prices than a low capacity accumulation market. We find that in the three-player market total capacity installation and market prices (see Table 7) are higher than the ones in the five-player market. That is higher capacity may not necessarily alleviate exercise of market power.

Table 9: Expected Market Share per Firm per Year for $(n,\rho)=(5,0.013)$

$(\upsilon,r)=(0,0)$

Period	OPG	Bruce	NUGA	Firm 4	Firm 5	Exp. Total Inst. Cap. (K)
	Expected Market Share per Firm (%)					
0=4.04-05	45.4	15.5	7.3	24.8	7	30,501
1=4.05-06	42.4	14.5	10.1	23.1	9.9	32,670
2=4.06-07	42.1	14.4	10.3	23	10.2	32,890
3=4.07-08	42.1	14.4	10.3	23	10.2	32,890
4=4.08-09	42.1	14.4	10.3	23	10.2	32,890
5=4.09-10	42.1	14.4	10.3	23	10.2	32,890

$(\upsilon,r)=(0.9,\ 1/30)$

Period	OPG	Bruce	NUGA	Firm 4	Firm 5	Exp. Total Inst. Cap. (K)
	Expected Market Share per Firm (%)					
0=4.04-05	45.4	15.5	7.3	24.8	7	30,501
1=4.05-06	40.8	15.5	10.8	22.3	10.6	32,802
2=4.06-07	40.2	15.8	11.1	22	10.9	32,156
3=4.07-08	39.7	16.1	11.3	21.7	11.2	31,480
4=4.08-09	39.2	16	11.8	21.4	11.6	30,855
5=4.09-10	38.9	15.9	12	21.3	11.9	30,011

$(\upsilon,r)=(0.95,\ 1/30)$

Period	OPG	Bruce	NUGA	Firm 4	Firm 5	Exp. Total Inst. Cap. (K)
	Expected Market Share per Firm (%)					
0=4.04-05	45.4	15.5	7.3	24.8	7	30,501
1=4.05-06	40.8	15.5	10.8	22.3	10.6	32,802
2=4.06-07	40.2	15.8	11.1	22	10.9	32,155
3=4.07-08	39.7	16.1	11.3	21.7	11.2	31,490
4=4.08-09	39.1	16.5	11.6	21.3	11.5	30,962
5=4.09-10	38.5	16.5	12	21.1	11.9	30,322

5. Concluding Remarks

In this paper we have examined the implications of market restructuring in the Ontario Electricity Market. We have mainly focused on independent generators (Bruce and NUGA) in the Ontario wholesale electricity market and have explored their capacity investment incentives as the uncertain electric demand has evolved over time. This study is interesting since under the policy *ii*) Market Power Mitigation Agreement of Ontario was on the verge of divesting the largest supplier OPG and was aiming to increase the number of independent suppliers in Ontario. As our model predicts, if the Ontario Market were organized with five dominant suppliers instead of three suppliers (the current situation), the yearly average prices would drop about 25% and yearly average price volatility would reduce approximately 29%. Higher prices in the three-player case may be attributed to the low number of suppliers and high capacity investments. On the other hand, in the five-player market, players make 23% less capital investment (on average) than the ones in the three-player market. Over investments in the current setting (three-player case) may be attributed to low initial capacities of NUGA and Bruce relative to the massive OPG capacity. Also, in the three-player market total capacity installation and market prices are higher than the ones in the five-player market. That is higher capacity may not necessarily alleviate exercise of market power. Our model also predicts that increasing the number of suppliers from three to five may fulfill the objective of National Energy Board's Market Power Mitigation (2001). In particular we would expect OPG's market share to reduce to 38.5% in six periods.

Admittedly, some of our modeling assumptions are simplistic. This partly stems from paucity of fine-grain data because of confidentiality, and institutional non-transparency of the market, rules and the players. But the methodology we apply is general and could apply more general settings, given that oligopolistic dynamic models are not very common in the electricity literature, because of complexity and intractability.

After the completion of this paper, we have been informed that on 10 February 2006, the government directed OPG (with a private sector partner) to build a new natural-gas fuelled generation unit. Further, OPG may build new nuclear capacity, depending on the Ontario Power Authority's integrated system plan and subsequent capacity procurement processes and targets. In October 2005, the government agreed to a fixed-price contract with Bruce Nuclear. A number of long term contracts for renewable energy have been signed. The Market Power Mitigation Agreement was replaced in February 2005, and the Ontario government placed fixed prices for OPG's hydro-electric and nuclear output while placing revenue caps on the most of its remaining output. All of these seem to imply a return to a central planning model and away from competitive, decentralized market for Ontario. However deregulation/restructuring of electricity industry, at least supply side, promises significant welfare improvements and solves reliability issues, as observed in some successful markets such as the England and Wales market, the New Zealand market, the PJM and Texas markets. We hope that the current study will provide Ontario the basis to consider policies that lead to a deregulated/restructured electricity market.

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