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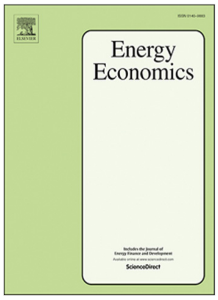

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Energy Transition and the Role of New Natural Gas Turbines for Power Production: The case of GT11N2 M generators

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Abstract

We study General Electric's new combined-cycle natural gas generator called GT11N2 M upgrade and quantify its economic benefits and the environmental implications in Ontario. We propose a structural power supply chain model involving upstream supplier General Electric and downstream power firm TransAlta at Sarnia, construct generation, service and maintenance cost functions, and calibrate different customer demand curves using actual market and firm data in the Ontario market. We solve for Stackelberg equilibrium outcomes, and quantify prices, outputs, and emissions based on efficiency rates of GT11N2 M. We consider two types of cost efficiencies implied by GT11N2 M: upstream service and maintenance cost efficiency experienced by General Electric and downstream fuel cost efficiency experienced by TransAlta. We provide new insights in the realm of technology adoption. We find in equilibrium that there exists a large variation in electricity generation over operational modes of GT11N2 M: the total generation can increase in the range of 5% (under "Lifetime" mode) to 18% (under "Maximum Continuous Load" mode). The output variation is nonlinear and the amount of carbon emissions is largely impacted by operating modes. In particular, the total greenhouse gas emission is expected to increase by 12% in the mixed-mode. Consequently, a policy implication of this research is that clean energy adoption facilitated by GT11N2 M is expected to increase carbon emission due to the "rebound effect".

JEL codes: C13; C72; L94; Q35; Q55

Keywords: Energy transition; Power sector economics; Technology adoption; Natural gas-fired generator; Efficiency; Supply chain; General Electric; TransAlta.

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1 Introduction

In the era of energy transition, developed countries have been shifting away from dirty generation resources to clean energy in their electricity markets (IEA, 2020). In this regard, Ontario, Canada has become the first North American government to eliminate its coal-fired electricity generation and pave the way for a greener electricity system.[1] The closure of coal-fired plants has lead to installment of more natural gas-fired generators and renewable energy, mainly wind and solar in the province. The shift from coal to clean energy is an important structural change in the Ontario electricity market. The province is ambitious to become a leading green energy provider, and the entire country has committed to supply 90% of electricity based on non-emitting energy sources by 2030.[2]

After decommissioning of coal-fired plants (which comprised of about one-quarter of electricity generation), the share of natural gas-fired electricity generation has increased in Ontario. There are two obvious reasons for that. The first is to fill in the large energy gap created by the removal of coal generators. The second is to mitigate intermittency of the newly installed wind and solar generation. Coincidentally, right after coal generation phase-out in the province, General Electric (GE) purchased Alstom's power and grid businesses in 2014. This acquisition included 11N2 gas turbines. They have been manufactured by GE with the nameplate GT11N2 since then. The new technology, called GT11N2 M upgrade, discovered by GE, has the goals of efficiency in output and service and maintenance costs, and of operational mode flexibility. According to GE, the new technology has been providing competitive electricity costs worldwide.[3]

Not only in Ontario, but also in other jurisdictions in the world, natural gas turbines have become an integral part of power generation portfolio by facilitating energy security and reliability to electricity systems and complementing renewable energy. For example, power generation from natural gas-fired generators are the largest source of electricity in the U.S. with the share of 38.3% in 2021 (EIA, 2022). Shale gas production in Bakken and Permian fields has made natural gas power plants a competitive source of electricity generation in the U.S. In the EU in 2020, it was the second largest technology with the share of 20%, after nuclear (with 25%) (Statista.com).

As congruent to the UN Sustainable Development Goals of 7 ("affordable and clean energy") and

[1] https://www.ontario.ca/page/end-coal
[2] https://www.cleanenergycanada.ca
[3] https://www.ge.com/power/services/gas-turbines/upgrades/gt11n2-m

9 ("industry, innovation and infrastructure"), the new discoveries and technological improvements in natural gas generators have been occurring in a constant flux in power industry. The novel production technologies in electricity sector are also required to mitigate the global warming and help tackle climate change issues. In connection with the research and development initiatives in the sector, the new natural gas-fired generation technology designed by GE is a pathway to accelerate green technology diffusion in the world. GE's new technology GT11N2 M upgrade is a superior technology, promising to improve energy efficiency and reducing input costs. Accordingly, this research aims to quantify GT11N2 M's economic benefits and the environmental implications in Ontario. We investigate the efficiency gains of this technology, examine its implications in a power supply chain, and quantify its performance in Stackelberg equilibrium.

In connection with energy transition research, there are a number of topics which have been examined in the literature. The issues include the nexus of energy transition and technological change (Bistline and Blanford, 2020; Sanchez et al., 2015; Mai et al. 2018, Luderer et al. 2017), energy efficiency and direct and indirect rebound effects (Berner et al. 2022; Bruns et al. 2021; Stern, 2020; Colmenares and Loschel, 2020; Yan et al. 2019; Gillingham et al. 2016), and economic and environmental assessments of renewable energy (Genc and Reynolds, 2019; Pietzcker, et al., 2017; Gowrisankaran et al. 2016; Lovering et al. 2016). In a recent review article, Genc and Kosempel (2023) identify active topics and potential research gaps and provide future directions in the area of energy transition. However, different than these papers, this research focuses on adoption of a new and clean generation technology (called GT11N2 M) and examines its economic and environmental contributions in a power supply chain in an important power jurisdiction.

This study contributes to the literature by answering the following crucial questions and their ramifications:

- How can a new technology adoption be assessed in electricity supply chain?
- Are clean energy innovations always good for the environment?
- What does a technological change represented by the innovation of natural gas-fired GT11N2 M generators offer?
- How does the GT11N2 M technology affect the strategies of energy firms (General Electric and TransAlta) and their economic performance in the energy supply chain?

- What are the environmental implications of GT11N2 M? Is it going to help reduce greenhouse gas emissions?
- Are GT11N2 M's cost and output efficiency rates substantial? How do they impact energy supply chain performance and outcomes such as prices, and outputs?

The main novelty of this research is to examine the impact of a technological change in electricity sector represented by the innovation of natural gas-fired GT11N2 M generators and analyze the implications of its cost and output efficiencies on supply chain outcomes and the environment. To our knowledge, an analysis of technology adoption in a power supply chain has not been studied in the literature.

This article also offers methodological contributions and provide new insights in the realm of technology adoption. In terms of the modeling aspect, it embeds a rich set of assumptions into a power supply chain. It explicitly distinguishes upstream firm TransAlta-Sarnia's customers which are residential, small businesses, industrial firms, and the Ontario market participants and formulates their power demand. Also, it constructs downstream firm General Electric's service and maintenance cost function for the GT11N2 M generators. In addition, it specifies TransAlta-Sarnia (TA-Sarnia) plant's power generation cost function involving fuel, emission, and service and maintenance costs. Furthermore, it evaluates GT11N2 M's generation cost and output efficiencies and examines their impacts on supply chain outcomes including prices, outputs, and greenhouse gas emissions.

To examine economic and environmental aspects of GT11N2 M upgrade in power production in Ontario, we propose a vertical relations setting between technology firm GE and power firm TransAlta (TA). GE is the supplier of GT11N2 generators and provides total plant solutions to TA through gas turbine field services, turbine repairs and parts, and rotor life extensions.[4] Therefore, GE affects TA's electricity generation costs.

We focus on the Ontario wholesale electricity market because of data availability and its unique features. The system operator of Ontario market publishes hourly generation data for each generator along with price, load, export, and import data. In addition, Ontario is the financial and manufacturing hub of Canada and its electricity market has unique characteristics in terms of its generation portfolio, market clearing mechanism, and price volatility compared to other jurisdictions in North America.

[4]www.ge.com/power/services/gas-turbines

In calibrations, we construct cost functions for power generation and service and maintenance using actual market and firm data. The investment in GT11N2 generators results in invention of GT11N2 M upgrade and provides different operational modes and efficiency rates. The downstream firm TransAlta's Sarnia plant utilizes this new technology to produce and sell electricity to residential, small business, industrial, and wholesale market customers in Ontario. We formulate electricity demand for each customer type. The cost and demand functions change for each time period based on fuel prices and market conditions. We use daily data as natural gas spot prices are daily. We explicitly focus on 2014 data because *i*) GE gained ownership and management of GT11N2 generators in 2014; *ii*) all coal plants were completely shut down as of 2014; *iii*) gas turbines ramped up production starting 2014. Firms maximize profits in the supply chain: GT optimally chooses its service and maintenance price of GT11N2 M generators and TA-Sarnia optimally chooses outputs for its customer groups. Stackelberg equilibrium solution is used to characterize supply chain outcomes.

We consider two types of cost efficiencies implied by GT11N2 M upgrade: upstream service and maintenance cost efficiency experienced by GE and downstream generation and fuel cost efficiency experienced by TA. We perturb the efficiency rates and then compute the equilibrium upstream prices and downstream outputs and emissions. We also assess the implications of efficiency rates of three operating modes reported by GE. Each operating mode is associated with a different performance rating. However, in reality, it is not known how long and how often these modes are used per period (hour or day). To overcome this, we consider a fourth mode which is a mixture of all modes. So, we consider four scenarios in total. The first scenario assumes that only "Maximum Continuous Load" (MCL) mode is operational; the second scenario supposes that "Performance" (P) mode is utilized for all periods; the third scenario involves "Lifetime" (L) mode only; the fourth scenario, which we coin "Mixed-mode", assumes that each mode is used at equal proportions for each day. In addition, we consider a benchmark scenario that supposes: what if the new technology was not active at all?

After cost and demand functions are constructed and model parameters are calibrated using actual data, we formulate factual and counterfactual efficiency scenarios in upstream and downstream layers of the supply chain. We then run a constrained Stackelberg equilibrium model for every day of 2014 to reveal the impact of GT11N2 M upgrade on prices, outputs, and emissions.

We find that GE's dynamic prices decrease in upstream efficiency, while they are intact in downstream efficiency. They are highly volatile because equilibrium price is a function of Hourly Ontario

Energy Price (HOEP). The price distribution is asymmetric and leptokurtic. So, price spikes are significant and prevalent. TransAlta's sales to the Ontario wholesale market increase in efficiency at increasing rates. Moreover, the output expansion is higher under fuel efficiency than under service and maintenance cost efficiency. Compared to the price volatility in upstream, the output volatility in downstream is higher and is about twice the size of output. In some days (and hours), TransAlta does not sell electricity to the wholesale market, but its outputs are always positive in residential and business sectors. This stems from low supply conditions combined with low prices in the wholesale market.

We also run the model for GE's predicted cost and output efficiency rates with the new technology. From TA-Sarnia's point of view, the most efficient generation mode in the short term is MCL. It can sell the highest output to all consumer groups. Compared to the old technology, we expect that the total generation increase should be in the range of 5% (under L-mode) to 18% (under MCL-mode). Because output variation is nonlinear and significant over the modes, the amount of greenhouse gas emissions will be largely impacted by the operating modes and how long they have been used. The simulations show that the total emissions increase in efficiency at an increasing rate, which follows from the nonlinear relationship between output and efficiency rate. The total CO2 emissions go up by 12% under the mixed usage of all modes. While the total NOx emissions are low compared to CO2 emissions, they increase in cost and output efficiency and exhibit similar rates to those of CO2.

The structure of the rest of the paper is as follows. Section 2 briefly reviews the related literature. Section 3 described the mathematical model. Section 4 applies the model to a power supply chain involving the energy firms GE and TA in the Ontario wholesale electricity market, and provides the details of data used for constructing and calibrating cost functions and electricity demand over different customer groups. Section 5 quantifies economic and environmental impacts of GT11N2 M over various cost and output efficiency scenarios. Section 6 concludes with a brief discussion of the findings and future research directions.

2 Related Literature

Although natural gas power plants are not totally clean, they offer numerous benefits including operational flexibility and contributes to power sector with greener just transition objectives (IEA, 2020).

Besides, energy transition models predict co-existence of dirty fossil fuel resources and clean renewable energy (Jin et al. 2021; van der Ploeg and Withagen, 2012).

Aside from infeasibility of total replacement of fossil-based assets with green energy, there is a phenomenon called "just transition" that should be taken into account in the realm of energy justice. In that concept, energy transition should consider equity, justice, and social aspects in energy transformation toward renewables (Jenkins et al. 2017). From energy justice point of view, fossil fuel producing energy nations and fossil fuel burning power firms cannot be alienated based on the claim that fossil fuel is bad and dirty. Their wealth and survival hinge on fossil fuel. In that regard, shutting down all coal-fired generators in Ontario has caused job and wealth losses in addition to creating inequalities and injustices by favoring green energy developers only. However, such issues of energy justice have not been addressed in Ontario.

This work is related to the literature of economics of a generation source such as nuclear, wind, solar. Examples of this research stream include Abdulla et al., 2013; Gowrisankaran et al. 2016; Lovering et al. 2016; Luderer et al. 2017; Pietzcker, et al., 2017. To complement this literature, we focus on a specific generator (an advanced combined cycle natural gas-fired generator) in a micro level, and examine its impact on market outcomes including prices, outputs, and emissions in a specific electricity market covering different customer groups.

This research is also related to the literature of energy transition and technological change in energy sector. New fossil fuel-based advanced technologies can play important roles in mitigating intermittency issues of renewables and meeting emissions targets domestically and internationally (Bistline and Blanford, 2020; Sanchez et al., 2015). The role of technological change and their implications for achieving policy objectives are also well studied (e.g.,Bistline and Blanford, 2020; Mai et al., 2018; Donohoo-Vallett et al., 2017; Luderer et al., 2017; Pietzcker et al., 2017; Kyle et al., 2009). With respect to energy transition, in a recent paper, Jin et al. (2021) and papers cited therein emphasize why both fossil fuel and renewable energy will coexist in a future world. Specifically, Jin et al. (2021) show in a two-sector growth model that both green and fossil energy sectors coexist in equilibrium, and fossil capital grows in parallel with clean capital.

In addition, this paper connects with the studies on energy efficiency and rebound effect. Increasing energy efficiency is considered to be one of the vehicles to reduce greenhouse gas emissions. However, the efficiency gain that reduces the cost of energy often results in increased energy usage. There is a vast literature examining rebound effect in energy sector, measuring either direct or economy-wide rebound effects (e.g., Gillingham et al. 2016; Adetutu et al. 2016; Yan et al. 2019; Colmenares and Loschel, 2020; Stern, 2020; Bruns et al. 2021; Berner et al. 2022). They use computational, accounting, and empirical approaches to show that energy efficiency gains significantly increase energy usage and emissions. For example, in a recent paper, Berner et al. (2022) use an econometric model to study the impact of energy efficiency on consumption and find that efficiency gains resulting in reduction in cost of production lead to economy-wide rebound effects of 78%-101% in select countries. Therefore, they suggest that energy efficiency will not be a cure for tackling carbon emissions.

Moreover, this research is also related to Ontario electricity market studies. Using Ontario market and firm level data, Genc (2016) measured wholesale price elasticity of demand by means of market power indices. Aydemir and Genc (2017) investigated the cross-border electricity trade and its impact on air emissions and welfare in Ontario. Billette and Pineau (2016) estimated market outcomes and welfare changes associated with electricity market integration under transmission constraints using Ontario data. Genc and Reynolds (2019) examined the impact of renewable energy ownership on firm, market, and the environmental performance in Ontario.

3 Model

We consider a vertical relations model in which the upstream firm General Electric invests in natural gas turbines, manufactures combined-cycle natural gas-fired generators called "GT11N2", and sells them to the downstream firm TransAlta. GE also supplies parts and provides maintenance and service of GT11N2 generators. TransAlta has been using these generators in its Sarnia plant (called TA-Sarnia by the Ontario system operator) to produce and sell electricity to a variety of customer groups in Ontario.

There are three types of consumers served by TA-Sarnia. Type 1 (T1) consumers are households and small businesses which buy q_1 MWh electricity from TA-Sarnia at a price of p_1, which is a time-of-use price chosen by the Ontario Energy Board. Type 2 (T2) consumers correspond to industrial customers which are petrochemical companies located in Sarnia, Ontario. They are price responsive and their inverse demand $p_2(q_2)$ is linear which is calibrated below. Type 3 (T3) consumers refer to Ontario wholesale customers. They have a broader access to market and can buy electricity from multiple producers in the wholesale market, including TA-Sarnia which is a competitive fringe. TA-Sarnia sells q_3 MWh at a wholesale market price p_3, which is stochastic and changes over time t. TA-Sarnia has $K = 510$ MW installed capacity and production is constrained by its available capacity: $q_1 + q_2 + q_3 \leq K$.

The upstream firm GE's research and development has led to technological change and resulted in cost and output efficiency, which is described below. The new product invented by GE is named "GT11N2 M upgrade". The objectives of GE are to sell the new gas turbine and provide its service and maintenance. TA-Sarnia's objective is to generate electricity from the new generator and sell it to its customer groups. This supply chain game will be solved by using Stackelberg equilibrium concept due to sequential nature of decision making process between the firms.

Given the cost and demand functions, we write the objective functions of each firm. With the new technology, the downstream firm TA-Sarnia chooses optimal generation quantities to maximize the following profit function subject to production constraints for each time $t = 1, 2, ..., 365$ in 2014:

$$\underset{q_{2,t},q_{3,t}}{max}\,\Pi_{TAS,t}(.) = q_{1,t}p_{1,t} + q_{2,t}p_{2,t}(q_{2,t}) + q_{3,t}p_{3,t} - \lambda_0 w_t(q_{1,t} + q_{2,t} + q_{3,t}) - \lambda_{1,t}c_{1,t}(q_{1,t} + q_{2,t} + q_{3,t})^2 \quad (1)$$

subject to

$$q_{1,t} \;\; given, \quad (2)$$

$$0 \leq q_{2,t} \leq K_{TAS,t}, \quad (3)$$

$$0 \leq q_{3,t} \leq K_{TAS,t}, \quad (4)$$

$$\sum q_{1,t} + q_{2,t} + q_{3,t} \leq K_{TAS,t}, \quad (5)$$

where the total service and maintenance cost is equal to GE's price w times total output ($q_t = q_{1,t} + q_{2,t} + q_{3,t}$), and the total generation cost is equal to the cost parameter $c_{1,t}$ (which will be calibrated) times square of the total output (q_t).

With the new technology, the upstream firm GE optimally chooses its price w_t to maximize its profit function for each time t in 2014:

$$\underset{w_t}{max}\Pi_{GE,t}(.) = (q_{1,t} + q_{2,t}(w_t) + q_{3,t}(w_t))(w_t - f_1) - D(I). \quad (6)$$

where the first term is revenue (total output q_t times its price w) minus the total service and maintenance cost (q_t times f_1). Note that the outputs sold to T2 and T3 markets by TA-Sarnia depend on the GE's price w. This is because in the backward solution of Stackelberg game, the best response functions $q_{2,t}$ and $q_{3,t}$ obtained by solving (1)-(5) change as w changes.

Also, $D(I)$ represents a cost of research and development or it is simply investment expenditure function for the level of investment I, aimed to innovate GT11N2 M technology. This is a sunk cost and the level of investment I is fixed and does not affect the decision variable w. However, in a more complicated model, investment level can affect the production capacity, if it is treated as a capacity investment (see Genc, 2017).

The timing of this Stackelberg game is that GE chooses its price w in the first stage. TA-Sarnia chooses its outputs q_2 and q_3 in the second stage, given GE's price w. As usual, this Stackelberg game is solved backwards (solving for TA-Sarnia's problem first and then solving for GE's problem second) to make sure that strategies are optimal and time consistent.

T1 customer's price $p_{1,t}$ is chosen by the energy regulator and their demand is stable, as explained below. TA-Sarnia plant provides on average 95 MWh electricity to the residential consumers (T1) for each period of 2014. So $q_{1,t} = 95$ holds. In addition, total output never exceeds the available production capacity of TA-Sarnia plant, which changes almost every hour in 2014. The outputs $q_{2,t}$ and $q_{3,t}$ are optimized and obey the non-negativity and maximum production constraints. TA-Sarnia is obliged to serve to its core customers (T1 and T2) in its jurisdiction. That is, T1 consumers are served first, T2 customers served next, and the remaining output is sold to the wholesale market T3 at the market price p_3.[5]

As a power producer, TransAlta has a small installed capacity in the Ontario market and is treated as a competitive fringe (Genc and Reynolds, 2019). However, GE is a dominant producer of gas turbines in North American power industry and has a market power in setting its price.

Consequently, given the nature of vertical relations between GE and TransAlta, pricing practices in the industry, complementary feature of products in the supply chain, the role of GE in generator manufacturing in the upstream, and TransAlta's status as a power producer, Stackelberg equilibrium

[5]As pointed out by a referee that the main results of the paper (in Tables 5-8) would not change if the order in which T1 and T2 customers served would change. The order that they are served is intrinsically an exogenous constraint. The least flexible customers are T1 type who have no choice but to purchase electricity from TA-Sarnia. The most flexible customers are T3 who can buy from any power producer in the Ontario market. T2 consumers have some flexibility as they can respond to TA-Sarnia's prices by shifting their production over time or use their own generators, if needed.

concept is used to characterize and compute market outcomes.

In the literature, there are alternative models which examine competition between power firms in the wholesale electricity markets.[6] A prominent one is a supply function equilibrium (SFE) approach in which power firms submit price-quantity pairs, formed by a (step or continuous) function, to electricity action for each time period (5-minutes, 15-minutes, 30-minutes or 60-minutes, depending on electricity market rules) during a day or a day-ahead (Klemperer and Meyer, 1989; Newbery, 1998; Baldick, Grant and Kahn, 2004; Genc and Reynolds, 2011). These functions indicate willingness to sell prices at the associated supply quantities (MWh). An independent system operator aggregates the supply functions submitted by the firms and matches with market demand to find the SFE price at each time. Every firm is paid either at the market price (called uniform SFE price) or at its bidding price (called discriminatory SFE price), if the firm is called to dispatch its power (Genc, 2009). The SFE concept has been commonly implemented to analyze bidding behavior in electricity auctions. Another approach to analyze market power issues is Cournot model in which production quantity is a strategy for each firm. Cournot approach allows different-sized asymmetric strategic firms with competitive fringe firms (Genc and Sen, 2008; Acemoglu, et al., 2017; Genc and Reynolds, 2019). Market outcomes predicted by SFE and Cournot models are sensitive to cost and market demand specifications (Genc and Reynolds, 2011; Genc and Reynolds, 2019). However, these alternative modeling approaches are not suitable in our study. This is because we do not examine the entire market and do not have an intention to model competition between power producers in Ontario. Instead, we focus on a supply chain relation between an upstream firm which is a component supplier (i.e., General Electric) and a downstream power producer (TransAlta) which uses the component to produce and sell a final product (i.e., electricity). For such vertical relations, Stackelberg equilibrium concept is a proper approach (Genc and DeGiovanni, 2020; Genc, 2021).

Before we examine the model, we will briefly provide the details about firms in the supply chain and explain the features of the Ontario market.

3.1 The Downstream Firm: TransAlta Sarnia Plant

The power producer TransAlta (www.TransAlta.com) has the holdings of a variety of power generators in North America. In Ontario, TransAlta operates several wind farms and natural gas-fired plants with

[6] This issue was pointed out by a referee.

total installed production capacity of less than 1,000 MW. This study focuses on its largest natural gas-fired plant, which is in Sarnia. Sarnia is the largest city on Lake Huron and in Lambton County. TransAlta's Sarnia Regional Cogeneration Plant has been producing electricity since 2003. The plant is located on a large 268-acre land and this generation facility is registered as TA-Sarnia in the IESO's list of generators. The Sarnia plant initially had three Alstom 11N2 gas turbines. General Electric (GE) acquired Alstom's power and grid businesses, and 11N2 type generators have been produced by GE with the nameplate GT11N2. Each GT11N2 is capable of generating electricity in the range of 102 to 118 MWh. In addition, TA-Sarnia operates condensing steam turbines that can produce 120 MWh, and has back-pressure steam turbines capable of generating 56 MWh electricity. Its total installed production capacity in 2020 was 499 MW.[7]

The electricity produced by TA-Sarnia is sold to three demand segments: residential and small business, industrial, and wholesale market customers. Specifically, the Sarnia plant has long term contracts to supply steam and electricity to industrial customers such as ArLanxeo, Styrolution, Suncor Energy and Nova. The industrial customers are charged "behind the fence" electricity prices, which are private and are only known by TA-Sarnia and buyers. The remainder of generation is sold to other demand segments.

The Sarnia plant is highly efficient because it is a cogeneration facility producing electricity and steam simultaneously by burning natural gas. Steam can be used for industrial processes or to generate additional electricity through a steam turbine. Specifically, at the Sarnia plant, efficiency rates of the most efficient generator are 6707 kJ/kWh of heat rate, 0.07 g/MJ of NOx rate, and 0 g/MJ of SO2 rate. This is reported by the Environment Canada's Module Unit List.[8]

Table 1 displays descriptive statistics of TA-Sarnia's hourly outputs and available production capacities in 2014. There was no plant outage, and output variability was with the minimum of 100 MWh and the maximum of 436 MWh. Distribution of outputs over hours shows that there were output spikes and the likelihood of extreme outputs was significant. In particular, a positive skewness indicates that the distribution is asymmetric and the probability of larger outputs is higher than the probability of smaller outputs. The value of kurtosis is positive and larger than one, and indicates that distribution is leptokurtic (fat-tailed) and the likelihood of extreme outputs lying far away from

[7] See https://transalta.com/facilities/plants-operation/sarnia/

[8] The Canadian module unit list shows the inventory of electric generating units (EGUs) and planned/committed units and their relevant characteristics. The web-link is http://www.ec.gc.ca/air/default.asp?lang=En&n=D6C16D01-1.

Table 1: Hourly TA-Sarnia Output-Available Capacity in 2014

TA-Sarnia	mean	stdev	min	max	skew	kurtosis
output	187.19	73.62	100	436	1.32	1.03
avail_Capacity	436.29	54.12	225	510	-0.53	0.18

the mean is significant. On the other hand, distribution of available production capacities resembles a standard normal distribution and the variability of available production capacity is low.

3.2 The Upstream Supplier: General Electric

In the supply chain, the upstream firm GE manufactures generators and provides after-sale total power plant solutions including parts, service, and maintenance of its generators. Its primary product is the generator GT11N2 M and its secondary products are service, maintenance, and parts. TransAlta, as a downstream firm, once buys GE's GT11N2 M generators and starts producing electricity, it understands that it also commits to purchase parts, service, and maintenance from GE. This vertical relation implies that GE essentially sells TransAlta "complementary products", which are composed of primary and secondary products.

There are, of course, third-party parts, service, and maintenance suppliers in the marketplace, which are competitors of GE in the secondary product market. In this case, would TransAlta choose a third-party supplier over GE? Given that gas-fired plants are marginal generators, clear the market and operate during high-priced peak-times, TransAlta would not risk failures in its generators because of, say, cheap parts and/or lousy service provided by a third party. Therefore, the common sense is that it should choose GE's ancillary after-sale service. In addition, it may be that GE engages in tie-in sales and its contract enforces TransAlta to buy the secondary product when it buys the primary product. In exchange, TransAlta could be offered a favorable "bundle price" for both products which would eliminate a need for a third-party supplier solution. Note that, tie-in sales and bundling are common sales practices in the power sector.

The purchase of Alstom's power assets including its generators was GE's largest-ever industrial acquisition.[9] GE implemented the latest available technologies to upgrade GT11N2 generators. The implementation of upgrades aimed increasing engine power output, reducing costs of operations and management, and facilitating flexible operation modes. All these goals meant cost and productive

[9]https://www.ge.com/news/press-releases/ge-completes-acquisition-alstom-power-and-grid-businesses

efficiency. To meet its goals, the upgrade package comprised of redesigning turbine blade, retrofitting for higher engine performance, and extending lifetime. In addition to the new turbine blades, GT11N2 M upgrade provided *i*) flexibility which translated into three switchable operating modes for maximum extended lifetime, extra power output, and efficiency; ii) reduced maintenance costs through extended service intervals of up to 48,000 equivalent operating hours; iii) better performance with up to 14 MW more power output and up to 1.9% gas turbine efficiency. GE reports that the new upgrade has been operational and providing competitive electricity costs worldwide.[10] The specifications of GT11N2 M upgrade will be presented in detail below.

3.3 The Market: Ontario

Ontario is the manufacturing hub of Canada. Its power market has distinct features, compared to the neighboring jurisdictions of regulated power markets in Manitoba and Quebec and restructured electricity markets in New York and Michigan, in several aspects such as its portfolio of production technologies, market clearing mechanism, and price volatility (Aydemir and Genc, 2017). For example, the Ontario market price volatility is the largest in North America. The Independent Electricity System Operator (IESO) is the clearing-house of wholesale electricity market and manages electricity flow in its transmission network. The IESO runs a pool-type real-time auction for every 5 minutes and matches demand with supply to determine real-time prices. However, power transactions are based on hourly price called Ontario Hourly Energy Price (HOEP), which is the average of 5-minute auction prices. Distribution companies and large industrial consumers are subjected to HOEP. There is no day-ahead forward market and the share of bilateral contracts is tiny because of its market design.

The IESO publishes actual hourly production and available capacity data for all generators and they are available at its website (www.ieso.ca). The size of power producers is asymmetric and there are a few strategic firms facing competitive fringe suppliers. The firms with large capacities include Ontario Power Generation Inc (OPG), Bruce Nuclear Inc (Bruce), and Brookfield Renewable Energy Inc (Brookfield). They are considered dominant firms with market power. Other firms including TransAlta are considered fringe suppliers (Genc and Reynolds, 2019).

To give a glimpse of Ontario wholesale prices, we plot daily prices in 2014 in Figure 1. The wholesale electricity prices in the first quarter were high and volatile compared to the prices in later

[10]https://www.ge.com/power/services/gas-turbines/upgrades/gt11n2-m

quarters. The polar vortex trapped cold air throughout Northeast resulted in cold temperatures and caused households and businesses to ramp up their electricity consumption. In addition, natural gas reserves in storage depleted due to strong withdrawals that considerably high natural gas prices. Gas inventories in Northeast America hit the lowest levels in the past 5 years, so gas prices soared record levels. Therefore, the higher gas prices caused the higher electricity prices. In the figure, we observe some negative electricity prices which stem from excess supply, caused by wind power generation.

<< Figure 1>>

Because TransAlta Sarnia plant runs gas-fired generators, natural gas prices are input costs for its electricity generation. For gas prices, we use Henry Hub natural gas spot prices as they are the benchmark prices for natural gas transactions in North America. Henry Hub spot prices are published daily. Between January and March, residential and commercial demand for natural gas increased due to low temperatures. High demand combined with pipeline constraints and low gas reserves contributed to record-high prices. In summer of 2014, the need for air conditioning went down because of mild temperatures. This led to reduced natural gas demand for the electricity producers. So natural gas storage increased from April through November and caused lower natural gas prices overall.

4 Model Calibrations

In order to apply the vertical relations model described above to the firms operating in electric power supply chain in Ontario, we will calibrate cost and demand functions using actual firm and market data, and run simulations with respect to factual and counterfactual production cost, output, and service and maintenance cost efficiency scenarios to investigate economic and environmental implications of the new technology GT11N2 M.

4.1 Data Specification

We employ market and firm-level data provided by the Independent Electricity System Operator (IESO), the Environment Canada, Statistics Canada, and a number of web sources (such as GE and TransAlta websites). The market level data incorporates hourly actual generation and available capacity for each active generator selling power to the Ontario wholesale electricity market. It also includes hourly market clearing prices called "Hourly Ontario Energy Price" (HOEP) and hourly demand quantity (Ontario demand plus export demand). Firm level data includes technical features of generators owned by each power firm and financial data such as fuel and emission prices. For each generator registered in Ontario, we have their efficiency rates incorporating energy content and heat rate, and NOx, SO2, CO2, and greenhouse gas emission rates. Along with generator efficiency rates, permit and emission prices are used to construct the marginal production cost of the generators.

In addition, the dataset includes demand and price projections including one-hour, two-hour and three-hour ahead pre-dispatch prices and quantities which are the IESO's estimates before the market clears. The raw data obtained from the IESO, Statistics Canada and the Environment Canada was converted into a workable database.

Moreover, we obtain data for GE's GT11N2 M generator characteristics, operational modes and its efficiency rates from GE's webpage. TransAlta-Sarnia sells power to a number of customer types whose demand profiles are also obtained from a number of websites which are also explained in detail below.

Although we have data for multiple years, we mainly focus on 2014 because of the following reasons. First, as of 2014 all coal plants have been completely shut down and replaced by natural gas-fired generators and renewables. Second, gas turbines ramped up production starting 2014 to mitigate intermittent wind and solar energy and fill in the absence of coal generators. The actual production data in the Ontario market shows that the share of natural gas generated electricity is one of the largest in its generation portfolio compared to the previous years. Third, GE purchased Alstom's power and grid businesses in 2014. Fourth, the upgrade package of GT11N2 M was operational in 2014.

All of this data is used to estimate demand by consumer types, power generation cost functions, and maintenance and service cost functions which are described in the following subsections in detail.

4.2 Demand by Consumer Types

Electricity customers are heterogeneous. Residential, small business, industrial, and wholesale market consumers exhibit diverse consumption behaviors and their demand elasticities are different: residential consumers show the least price response while industrial consumers have the highest price response in general (Genc, 2016). These demand groups are also subjected to different prices. In the Ontario market, TransAlta exercises second and third degree price discrimination to its customers.

To be able to assess economic and environmental implications of a supply-side structural change,

Table 2: Type 1 Consumer Prices (cents/kWh)

Effective date	Off-peak price	Mid-peak price	On-peak price
Nov 1, 2013	7.2	10.9	12.9
May 1, 2014	7.5	11.2	13.5
Nov 1, 2014	7.7	11.4	14.0
May 1, 2015	8.0	12.2	16.1
Nov 1, 2015	8.3	12.8	17.5
May 1, 2016	8.7	13.2	18.0
Nov 1, 2016	8.7	13.2	18.0
May 1, 2017	7.7	11.3	15.7
Nov 1, 2017	6.5	9.5	13.2
May 1, 2018	6.5	9.4	13.2

Source: https://www.oeb.ca/rates-and-your-bill/electricity-rates/historical-electricity-rates

which is the diffusion of a new production technology GT11N2 M upgrade, on market outcomes, one has to specify demand in detail and take different demand elasticities and price discrimination applied to different demand segments into account.

Type 1 consumers:

Type 1 (T1) consumers are comprised of households and small businesses, including farms. They pay time-of-use (TOU) rates which are set by the energy regulator Ontario Energy Board (OEB). TOU rates have been implemented in the province since 2005.[11] Table 2 shows the rates (which correspond to p_1 in the model) and their evolution over years. They are charged to T1 consumers over the periods of day (on-peak, off-peak, mid-peak). The rates change twice a year. In summer (May 1-October 31), off-peak time covers 7pm-7am, on-peak corresponds to 11am-5pm, and the rest denotes mid-peak. In winter (Nov 1-April 30), off-peak time covers 7pm-7am, mid-peak corresponds to 11am-5pm, and the rest is on-peak. All weekends and statutory holidays are treated as off-peak period. In 2014, residential and small business customers paid 10.75 cents/kWh on average (Table 2).

Based on this table, the following daily average prices (p_1) will be used in our simulations for T1 consumers: during Jan 1-Apr 30, \$103.33 and \$72 per MWh are used for weekdays and weekends, respectively; \$107.33 and \$75 are assumed during May 1-Oct 31, and \$110.33 and \$77 are assumed for Nov 1-Dec 31 in 2014.

An Ontarion household uses about 9,500 kWh of electricity per year, which implies 1.08 kWh average consumption per hour. In 2014, the average Canadian household consumed 11,135 kWh of

[11]See https://www.oeb.ca/rates-and-your-bill/electricity-rates/historical-electricity-rates

electricity per year, corresponding to about 1.27 kWh per hour.[12]

We are interested in electricity consumption in the City of Sarnia, as TA-Sarnia provides electricity to residential and commercial customers in Sarnia. It is the largest city on Lake Huron and is a part of Lambton County in southwestern Ontario with a population of 71,594, according to 2016 census.[13] The total population of Lambton County was 123,399 in 2016.[14] The total installed generation capacity in Lambton County is 2,662 MW, including TA-Sarnia's capacity.[15] There are two utilities providing power to Lampton County. The first one is BlueWater Distribution Company, owned and operated by TransAlta, serving Sarnia and adjacent small towns (Alvinston with population 2548, Oil Springs with population 648, Petrolia with population 5742, Point Edward with 2037 people and Warwick Township with 3692 inhabitants). The second utility is HydroOne Networks Company, serving the rest of Lambton County.

Given that the BlueWater serves 86,261 residences and the average consumption figure in Ontario is 1.08 kWh, the total consumption of T1 consumers in Sarnia should be around 95 MWh. This is lower than the average production quantity (187 MWh in 2014) of TA-Sarnia plant.

Type 2 consumers:

Type 2 (T2) consumers correspond to industrial consumers of TA-Sarnia. Their demand is price responsive as they may use alternative energy sources and have the flexibility to shift production over periods. Their inverse demand is assumed to be linear: $p_2 = a - bq_2$, where the coefficients (a, b) are to be calibrated using actual data. Sarnia houses 62 industrial facilities and refineries. The industrial customers are petrochemical companies and refineries including ArLanxeo, Styrolution, Shell Canada, Imperial Oil, Suncor Energy and Nova. They are charged negotiated and confidential "behind the fence" electricity prices by TA-Sarnia.[16] Because of the nature of confidentiality of industrial customer prices, we have a little information to estimate their demand coefficients. However, we will apply the following procedure proposed by Genc et al. (2007).

Given that inverse demand is $p_2 = a - bq_2$, demand becomes $q_2 = a/b - p_2/b$. At the lowest level

[12] https://energyrates.ca/residential-electricity-natural-gas/

[13] Note that population surveys are conducted in every 5 years, and 2016 survey is the closest measure of 2014 population.

[14] https://en.wikipedia.org/wiki/Sarnia

[15] TransAlta Energy Corporation – 506 MW Co-generation (natural gas) Greenfield Energy – 1,005 MW (natural gas) St. Clair Energy Centre – 577 MW (natural gas) Green Electron Power Project – 289 MW (natural gas – under construction) Photo-voltaic Solar Farms – 120 MW, and Wind – over 165 MW. This information is available at https://www.sarnialambton.on.ca/infrastructure/utilities

[16] https://www.sarnialambton.on.ca/infrastructure/utilities

of price (i.e., $p_2 = 0$), the maximum demand quantity becomes $q_{2,max} = a/b$. That is, a/b corresponds to the maximum quantity that can be sold to T2 customers. Based on actual data, the maximum production in TA-Sarnia plant in 2014 was 430.75 MWh. Because T1 customers' demand is stable at 95 MWh, the maximum production at TA-Sarnia less of T1 demand becomes the maximum quantity sold to T2 customers (i.e., 430.75-95=335.75). Note that TA-Sarnia is obligated to first meet T1 and T2 customer demands and then sell the remaining output to T3 customers because of its contractual obligations to T1 and T2 customers. Therefore, the maximum demand quantity of T2 customers becomes a/b=335.75 MWh. Next we write $\bar{q}_2 = a/b - \bar{p}_2/b$, where $\bar{q}_2$ and $\bar{p}_2$ are the average demand quantity and the average price, respectively. Alternatively, $\bar{q}_2$ and $\bar{p}_2$ would correspond to the expected values if demand was stochastic with a white noise. Because of data confidentiality we do not know how much power is actually sold to the industrial customers by TA-Sarnia for each hour or day. However, we can estimate them. According to the U.S. Energy Information Administration Survey of 2010, the petroleum refining industry uses around one third of total electricity production in a town similar to Sarnia.[17]. Based on this survey data, the average consumption of T2 customers becomes one-third of the actual average production at the TA-Sarnia plant. The actual average output is 187 MWh in 2014 and its one-third is about 62 MWh. Therefore, $\bar{q}_2 = 62$.

To estimate $\bar{p}_2$. which is unknown and confidential, we assume that the average wholesale market price (which is the Hourly Ontario Energy Price) represents a proxy to the "behind the fence" pricing applied to the industrial customers. The average hourly market price in 2014 was \$32.4/MWh. Therefore, the price paid by industrial customers should be $\bar{p}_2 = 32.4$. We can now solve for the slope $(1/b)$ given the values for a/b, $\bar{q}_2$ and $\bar{p}_2$. That is, we use the equation $62 = 335.75 - 32.4/b$ to solve for b and obtain that $b = 0.11836$. Because $a/b = 335.75$, then we obtain that $a = 39.74$ holds.

Consequently, the calibrated inverse demand for T2 customers is $p_2 = 39.74 - 0.11836q_2$. In model simulations, we find that this demand estimate along with other assumptions leads to equilibrium outcomes close to the actual ones.

Type 3 consumers:

When TransAlta's production in Sarnia exceeds total demand quantity in T1 and T2 markets, it can sell the remaining quantity to the Ontario wholesale electricity market (i.e, T3 customers) through transmission lines. Because TransAlta is a small producer compared to others in the wholesale market,

[17] https://www.eia.gov/totalenergy/data/monthly/pdf/flow/css_2019_energy.pdf

it is treated as a price-taker (see Aydemir and Genc, 2017).

Let q_t denote the total output of TA-Sarnia at time t. It is less than or equal to available capacity: $q_t \leq K_t$. The output sold to wholesale customers (T3) becomes $q_{3,t} = q_t - q_{1,t} - q_{2,t}$, where $q_{1,t}$ is the quantity sold to T1 consumers, and $q_{2,t}$ is the output sold to T2 consumers. The output $q_{3,t}$ is priced at $p_{3,t}$, which is equal to the actual hourly Ontario energy price (HOEP).

To see the relationship between HOEP, load (Ontario market demand including exports), and TA-Sarnia output, we run the following OLS regression using the actual hourly data. This regression is in the spirit of Genc and Reynolds (2019) who examined the effects of wind generation on market price and emissions.

$$p_{3,h} = \alpha_0 + \alpha_1 L_h + \alpha_2 TAS_h + \epsilon_h, \tag{7}$$

where $p_{3,h}$ corresponds to HOEP, L_h denotes load, TAS_h is the TA-Sarnia output, h refers to hour in 2014, and $h = 1, ..., 8760$.

Note that TA-Sarnia sells most of its output to its local customers and load is very large compared to TA-Sarnia output. The OLS estimation in (7) yields,

$p_{3,h} = -131.681 + 0.00718 L_h + 0.1839 TAS_h$, where all coefficients are significant with p-value less than 0.01. The positive sign in front of TA-Sarnia output shows that TA-Sarnia sells power to the wholesale market when HOEP prices increase. Note that while this regression is not used in model calibrations in the following sections its main purpose is to expose the correlation between the variables and their marginal impacts. This specification is in line with Genc and Reynolds (2019) who use "Load" and "Wind output" as the right hand side variables in their price equation (4). Similar to their model, we use load and a supply variable (i.e., TransAlta production) as explanatory variables. In their case, the supply data was comprised of wind output, because they intended to measure the marginal impact of wind generation on price. In this case, the coefficient α_2 serves to the same purpose. Simultaneity and endogeneity are not an issue in this price equation, similar to theirs, because of the price-taking fringe status of TransAlta.

4.3 Electricity Generation Cost Function

TA-Sarnia's electricity production cost function is assumed to be quadratic in output (Aydemir and Genc, 2017; Genc and Reynolds, 2019).[18]

$$C(q_1, q_2, q_3) = w(q_1 + q_2 + q_3) + c_0(q_1 + q_2 + q_3)^2 \tag{8}$$

However, we will rescale and calibrate the following quadratic cost function so as to obtain cost figures close to actual cost of power production in Ontario.

With a slight modification we redefine it as

$$C(q_1, q_2, q_3) = \lambda_0 w(q_1 + q_2 + q_3) + \ \lambda_1 c_0(q_1 + q_2 + q_3)^2. \tag{9}$$

The coefficients λ_0 and λ_1 are scalars and can be chosen based on market and generator specific conditions.

In this cost function, w corresponds to a unit variable cost of maintenance, service and/or parts, provided by the upstream generator maker GE. This is because GE not only sells GT11N2 generators to TA-Sarnia, but also provides generation service, maintenance and parts.[19] The cost coefficient c_0 includes input (i.e., natural gas) cost plus emissions costs, which will be specified next.

In (8) the marginal cost of electricity production is $MC(q) = w + 2c_0 q$ for each unit of output q before the upgrade. The actual average output of TA-Sarnia is 187 MWh in 2014. Taking into account of maintenance, service, parts, fuel, and emissions costs, the marginal cost at the average production $MC(q = 187)$ becomes a large number, which is not meaningful. Therefore, we resort to rescale (8) to obtain (9). This operation will result in a reasonable marginal cost figure representing the actual cost of generation from a natural gas-fired generator.

For the Ontario market and firms GE and TA-Sarnia, we assume that $\lambda_1 = 1/2K$. The term one-half is to remove the effect of quadratic term when the derivative is taken. K corresponds to available capacity at a given time, which can vary every hour. It is usually lower than the installed capacity of

[18] Marginal cost of power generation from natural gas-fired generators is not constant due to generator characteristics such as heat rate, emission rate, ramp-up/down rate. Using generator characteristics, fuel price data and production capacities, Aydemir and Genc (2017) constructed actual cost functions for power production from a variety of generation sources. They obtained that the aggregate power cost function is polynomial and can be approximated by a quadratic function.

[19] www.ge.com/power/services/gas-turbines

510 MW, and the average available capacity in 2014 was 436 MW (Table 1). λ_0 can be chosen based on actual cost figures. For several values of $\lambda_0 > 0$, we run the model and obtain the average equilibrium outputs. For $\lambda_0 \in (0, 10)$ we find that equilibrium outputs are in the same neighborhood and are close to the actual sales to customer groups. So, without loss of generality, we choose an average of this interval and assume $\lambda_0 = 5$.

In (9) we compute the marginal cost of electricity production at Sarnia plant and find that $\overline{MC}(q = 187) = \$33.44$/MWh at the average output ($\overline{q}$) of 187 MWh, the average available capacity ($\overline{K}$) of 436 MW, the average unit fuel and emissions cost ($\overline{c_0}$) of \$43/MWh, the maintenance service price ($\overline{w}$) of \$3/MWh, and λ_0 equals 5. This is a reasonable cost estimate for an efficient combined-cycle natural gas-fired generator in Ontario (Genc and Sen, 2008).

On 10/1/2014, TA-Sarnia plant hit its lowest production of 100 MWh while its available capacity was 435 MW. At this output-capacity pair, the marginal cost of production would be 24.88 \$/MWh. On the other hand, the maximum output of 436 MWh with available capacity of 510 was recorded on 1/22/2014. At this production-capacity level, the marginal cost of electricity would be 51.83 \$/MWh. Therefore, based on this methodology, the marginal production cost of GT11N2 generators should fall into the interval of [\$24.88, \$51.83] per MWh. The variation in marginal costs depends on several factors including output level. Furthermore, GT11N2 generators can be run at different modes, each with its own efficiency rate that impacts cost of generation significantly. We will explain these issues in detail in Section 6.

Next we will compute c_0 from available cost data. The marginal cost coefficient c_0 changes as time t changes and is formulated as follows.

$$c_0(t) = c_{fuel}(t) + c_{SO_2} + c_{NOx} + c_{CO_2}, \tag{10}$$

where the unit cost of fuel is calculated as

$$c_{fuel}(t) = p_{HenryHub}(t) HR_{GT11N2} CR, \tag{11}$$

where CR refers to energy conversion rate. The heat rate HR_{GT11N2} can change from generator to generator.[20]

[20] Also see https://netl.doe.gov/sites/default/files/gas-turbine-handbook/1-1.pdf

Table 3: TA-Sarnia Plant Generator Characteristics

Electric Generating Unit Name	Plant Type	Heat Rate (kJ/kWh)	NOx Rate (g/MJ)
Sarnia Regional: Generator 1	Cogen - C_Cycle	6,707	0.0688
Sarnia: Generator 1	Cogen - C_Cycle	9,187	0.0688
Sarnia: Generator 2	Cogen - C_Cycle	9,187	0.0688
Sarnia/Clearwater:Boiler1-Gen 1	Cogen - Gas	9,648	0.103
Sarnia/Clearwater:Boiler2-Gen 2	Cogen - Gas	9,648	0.103
Sarnia/Clearwater:Boiler3-Gen 3	Cogen - Gas	9,648	0.103
Sarnia/Clearwater:Boiler4-Gen 4	Cogen - Gas	9,648	0.103

Source: Canadian Module Unit List published by the Environment Canada

The unit costs of emissions are

$$c_{SO_2} = p_{SO_2} HR_{GT11N2} E_{SO_2}, \tag{12}$$

$$c_{NO_x} = p_{NOx} HR_{GT11N2} E_{NOx}, \tag{13}$$

$$c_{CO_2} = p_{CO_2} HR_{GT11N2} E_{CO_2}, \tag{14}$$

where E_{SO_2} refers to SO2 emission rate of a gas generator and p_{SO_2} stands for SO2 permit price. Similar notation is employed for NOx and CO2 emission rates and prices.

Note that there was no carbon pricing in Canada up until 2018. A cap-and trade program was initiated in 2018 with a minimum price of \$10 per tonne of CO2. Therefore, the carbon cost does not show up in our cost formulation. That is, $p_{CO_2} = 0$ holds in 2014.

TransAlta's Sarnia plant consists of three Alstom gas turbines (called GT11N2 after acquisition) and three Nooter-Eriksen supplementary-fired heat recovery steam generators (HRSGs), two Alstom and one Westinghouse steam turbines. Accordingly, we form Table 3 to list the TA-Sarnia plant characteristics provided by the Environment Canada.

Given the different heat rates in the table, we calculate the average heat rate and assign it to HR_{GT11N2}. This is a reasonable assumption because i) not all generators are GT11N2 nameplate; ii) most importantly, only the total electricity production at the Sarnia plant, but not the output from each generator, is observed. Therefore, $HR_{GT11N2} = 9,096$ kJ/kWh is assumed.

Because natural gas is the main fuel for TA-Sarnia generators, we use daily Henry Hub natural gas spot prices to calculate fuel costs. In 2014, the average daily natural gas spot price was US \$4.35 MMBtu, corresponding to CA \$4.80 MMBtu at the average daily exchange rate of 1 CAD=0.90609

USD. The conversion rate CR in the cost formula reflects the relationship between energy units so that 1 kJ = $0.947817 * 10^{-6}$ MMBtu.

Therefore, given the average heat rate, natural gas price, conversion rate, exchange rate, and 1000 kwh=1MWh, we calculate the average fuel cost in 2014 as

$c_{fuel,2014} = (9096kJ/kWh)(\$4.80/MMBtu)(0.947817 * 10^{-6}MMBtu) = \$41.38/MWh.$

The sulfur-dioxide (SO2) emission cost per output is

$c_{SO_2} = p_{SO_2} HR_{GT11N2} E_{SO_2}.$

Because SO_2 emission rates of TA-Sarnia generators are zero, reported by the Environment Canada, the unit SO2 cost will be zero. That is, $c_{SO_2} = 0$. Similarly, because $p_{CO_2} = 0$ in 2014 $c_{CO_2} = 0$ holds.

However, NOx emission cost is positive. Aydemir and Genc (2017) use the average NOx permit price of CA\$2000 per ton for the Ontario market. At the duration of their study period, emissions were neither capped nor traded in Ontario and fossil fuel-based generation firms purchased permits, which intended to cover externality-environmental and social-costs of electricity generation. Given this permit price, the average heat rate (of 9096) and the average NOx rate (of 0.08834) in the above table, we calculate that the average unit cost of emitting NOx per MWh electricity generation should be \$1.61/MWh in 2014. It is specifically calculated as follows.

$c_{NOx} = p_{NOx} HR_{GT11N2} E_{NOx} = (\$2000/ton)(9096kJ/kWh)(0.08834g/MJ) = \$1.61/MWh.$

Then our estimate of average cost coefficient in 2014 is

$\overline{c_0} = c_{fuel} + c_{SO_2} + c_{CO_2} + c_{NOx} = \$41.38/MWh + 0 + 0 + \$1.61/MWh = \$42.99/MWh.$

In model simulations, the variable c_0 will vary daily as c_{fuel} changes daily. Figure 2 plots this variable in 2014.

<< Figure 2>>

The invention of the new technology (GT11N2 M upgrade) results in better performance and cost reduction. Because c_1 is the cost coefficient after the product upgrade and c_0 is the cost coefficient before the upgrade, $c_1 < c_0$ should hold and $c \equiv c_0 - c_1 > 0$ denotes the generation cost efficiency. Specifically, the total cost function with the new technology turns out to be

$$C(q_1, q_2, q_3) = \lambda_0 w(q_1 + q_2 + q_3) + \lambda_1 c_1 (q_1 + q_2 + q_3)^2. \tag{15}$$

This equation represents the total generation cost function after the new technology. It is different

Table 4: GT11N2 M Upgrade Modes and Efficiency

Benefits	MCL-Mode	P-Mode	L-Mode
Power output increase (MW)	14.3	10.2	4.2
Efficiency increase (add.) [%]	1.9	1.8	1.6
Interval extension [keOH]	0	12	24

Source: General Electric (www.ge.com/power)

than equation (9), as the coefficients (c_0 and c_1) are different and equilibrium strategies (w and q_2 and q_3) change with the new technology. In Section 6, we will examine how different cost efficiency rates will impact market outcomes.

4.4 Maintenance and Service Cost Function

The upstream generator maker GE provides service and maintenance of GT11N2 generators to power producers. The cost of maintenance and service is assumed to be linear; $C_s(q_s) = f_0 q_s$, where $f_0 > 0$ is the marginal cost of service per MWh output before the GT11N2 upgrade. The service and maintenance cost function after the upgrade is $C_s(q_s) = f_1 q_s$, where $0 < f_1 < f_0$ and $f \equiv f_0 - f_1 > 0$ is the service and maintenance cost reduction per unit due to efficiency of the new technology. According to California ISO (CAISO) 2018 report of "Variable Operations and Maintenance Cost", a default value for the variable operation and maintenance cost for natural gas-fired combined cycle and steam units is around \$2.80/MWh. We assume the same cost figure for Ontario as labor and service costs are similar in both countries. Therefore, our estimate of unit service cost is $f_0 = \$2.80$/MWh. Next we will explain how we choose the efficiency rate f for service and maintenance cost in model simulations.

4.5 Efficiency Rates of GT11N2 M

GE has redesigned turbine blades and come up with state-of-the-art turbine aerodynamics and cooling for GT11N2 M upgrade. This new technology provides switchable operating modes for maximum extended lifetime, extra power output, and efficiency. It reduces variable service and maintenance costs and production costs. Table 4 displays the operating modes and efficiency rates.[21]

Maximum Continuous Load (MCL) mode is optimized for peak demands, provides inspection (of hot gas path casing-the core) for intervals of 24,000 equivalent operations hours (EOH), and exhibits significantly increased combined-cycle power and efficiency. Performance (P) mode is optimized

[21]https://www.ge.com/power/services/gas-turbines/upgrades/gt11n2-m

for performance and lifetime, leads to inspection intervals of 36,000 EOH, and showcases increased combined-cycle power and efficiency. Lifetime (L) mode is optimized for simple cycle applications, which are suitable for low energy demand situations, corresponds to significantly extended inspection intervals of 48,000 EOH and provides gas turbine power and efficiency.

Table 4 shows that the new upgrade is intended to reduce service and maintenance costs at TA-Sarnia plant and decrease cost of electricity generation. However, neither GE nor Alstom specifically stated how much cost savings would materialize for fuel (represented by c_{fuel}) and service and maintenance (represented by f) per MWh electricity generation. In reality, the actual cost efficiency rates should depend on factors such as age of GT11N2 generator, mode, time, ramp-up and -down rates, outages, and actual output quantity. However, we do not have such a detailed information. Consequently, we will arbitrarily assume several efficiency rates in model simulations to investigate how outcomes will vary with respect to these rates. Specifically, we will assume the efficiency rates of $f = 0\%, 5\%, 10\%, 15\%, 20\%, 25\%$ and $c = 0\%, 5\%, 10\%, 15\%, 20\%, 25\%$. In addition, we will make use of the data in Table 4 when we run alternative scenarios for predicting model outcomes under these operational modes.

5 Simulations and Results

We solve the model formulated by the expressions (1)-(6) for Stackelberg outcomes under efficiency scenarios to determine the impact of GT11N2 M upgrade on prices, outputs, and emissions. Based on the model calibrations in Section 4, we use the following parameter values for all simulations: $a = 39.74$, $b = 0.11835$, $\lambda_0 = 5$, and $f_0 = 2.8$.

5.1 Simulations for Upstream and Downstream Cost Efficiency

We perturb upstream cost efficiency rates at $f = 0\%, 5\%, 10\%, 15\%, 20\%, 25\%$, and downstream cost efficiency with the same rates of $c = 0\%, 5\%, 10\%, 15\%, 20\%, 25\%$.

We run the equilibrium model for each day of 2014 and report GE's dynamic prices (w) with respect to a cost efficiency rate. In Table 5, w-f0 represents a benchmark case in which there is no cost saving from service and maintenance (f0) and GE's endogenous price is w; w-f5 corresponds to GE's price when 5% service and maintenance (S&M) cost efficiency is achieved; w-f10 refers to GE's price in the

Table 5: GE's equilibrium price distribution with respect to upstream efficiency

	w-f0	w-f5	w-f10	w-f15	w-f20	w-f25
mean(w)	4.64	4.57	4.50	4.43	4.36	4.29
stdev(w)	3.59	3.59	3.59	3.59	3.59	3.59
min(w)	0.53	0.46	0.39	0.32	0.25	0.18
max(w)	28.91	28.84	28.77	28.67	28.63	28.56
skew(w)	3.25	3.25	3.25	3.25	3.25	3.25
kurt(w)	14.06	14.06	14.06	14.06	14.06	14.06

case of 10% efficiency in S&M, similarly other efficiency scenarios follow.

Note that the marginal cost of service and maintenance is represented by f_0, which is estimated to be \$2.8 in Subsection 4.4. Due to efficiency brought by the new technology, 5% reduction in this cost implies \$2.66 which is represented by the notation f5 (in Table 5), and therefore f5 takes the value of \$2.66 (i.e., f5=2.66). Similarly, 10% reduction in the marginal cost implies the cost of \$2.52 which is represented by the notation f10, and therefore f10=2.52. Likewise, 15% reduction implies the cost of \$2.38, 20% cost reduction implies \$2.24, and 25% cost efficiency implies \$2.1. Therefore, these cost efficiencies are illustrated by the notation f15=2.38, f20=2.24, and f25=2.1 in Table 5.

In Table 5, we report equilibrium price distribution (mean, standard deviation, minimum, maximum, and third and fourth moments) of GE across various efficiency levels. In reality, GE can exercise either dynamic daily prices based on changing market conditions or simply charge the average price, depending on the terms of its contract with TA-Sarnia. Table 5 shows that GE's equilibrium average price decreases in upstream efficiency (S&M cost savings). This is because operational cost reductions facilitated by more efficient new technology will reduce GE's prices charged to TA-Sarnia. In the base case of marginal cost equals \$ 2.8, that is when there is no innovation, the average price that GE charges is \$ 4.64, which corresponds to relative price-cost markup of 40%. On the other hand, at the minimum efficiency level (i.e., f5=2.66) the relative price-cost markup increases to 42%, and at the maximum efficiency level (i.e., f25=2.1) the relative price-cost markup further increases to 51%. This shows that GE's profitability nonlinearly increases due to its new technology. This provides benefits to the downstream producer TA-Sarnia as it experiences lower input costs, thanks to the upstream innovation.

Note that GE's prices will be intact even when TransAlta experiences downstream efficiency leading to fuel and emission cost savings. GE's prices are highly volatile because its equilibrium price is a function of the Hourly Ontario Energy Price (HOEP), which can even take negative values especially at night times. Price distribution is asymmetric and most prices are higher than the average price which is quantified by skewness of 3.25. The tails of price distribution are thick, so price spikes are significant and prevalent which are represented by the kurtosis of 14.06. Observe that standard deviation, skewness, and kurtosis values do not change and therefore are robust to the upstream efficiency rates. Because upstream prices go down in efficiency, TA-Sarnia's electricity production goes up. The rate of increase in output is small because upstream price reductions are small. However, the output expansion will be higher under fuel efficiency than under service and maintenance cost efficiency as we show below.

Table 6 focuses on T3 market and reports TA-Sarnia's sales ("q3") to the Ontario wholesale electricity market. It shows equilibrium output distribution simulated over different upstream and downstream efficiency rates. In this table, "q3" refers to equilibrium output (which comes from the solution of Stackelberg equilibrium model formulated in equations 1-6), sold to T3 market at various combinations of service and maintenance efficiency levels (f=0%, 5%, 10%, 15%, 20%, 25%) and of cost efficiency levels (c=0%, 5%, 10%, 15%, 20%, 25%). These efficiency rates are exogenously chosen. The first part of the table assesses how equilibrium outputs change given the new technology and its assumed efficiency in the upstream. Similarly, in the second part of the table, the "q/c" combinations refer to equilibrium outputs in the case of downstream fuel efficiency resulting from the GT11N2 M technology.

For the sake of brevity, we do not report the outputs for other customer types. This is because their consumption is stable compared to the sales at T3 market.[22]Due to high variability of the Ontario wholesale prices, we find that T3 market sales are the most volatile compared to the sales to T1 and T2 customers.

The first part of Table 6 displays how equilibrium outputs in T3 market change with respect to upstream cost efficiency. In the table, q3-f0 indicates the benchmark case when there is no cost saving from service and maintenance (f0) and TA-Sarnia's output in T3 market is q3; q3-f5 corresponds to sales in T3 market in the case of 5% service and maintenance (S&M) cost saving; q3-f10 refers to output when 10% efficiency in S&M happens; etc. Equilibrium downstream outputs are volatile-the standard deviation is more than 2 times the average output-due to supply conditions, represented by

[22]However, the results are available upon request.

Table 6: T3 market output distribution over different efficiency types

	q3-f0	q3-f5	q3-f10	q3-f15	q3-f20	q3-f25
mean(q3)	56.283	56.875	57.464	58.055	58.638	59.229
stdev(q3)	126	126.389	126.765	127.146	127.521	127.896
min(q3)	0	0	0	0	0	0
max(q3)	415	415	415	415	415	415
skew(q3)	2.177	2.16	2.143	2.126	2.109	2.091
kurt(q3)	3.186	3.115	3.044	2.973	2.902	2.833
	q3-c0	q3-c5	q3-c10	q3-c15	q3-c20	q3-c25
mean(q3)	56.283	57.839	59.518	61.282	63.273	65.578
stdev(q3)	126	127.387	128.871	130.272	131.831	133.6
min(q3)	0	0	0	0	0	0
max(q3)	415	415	415	415	415	415
skew(q3)	2.177	2.131	2.083	2.029	1.97	1.906
kurt(q3)	3.186	2.984	2.778	2.553	2.311	2.054

variability in available capacity, input cost, and wholesale price. The minimum output sold to the T3 market is 0 and the maximum is 415 MWh. On the other hand, the output volatility slightly increases in upstream cost efficiency. TA-Sarnia increases its output to T3 market linearly as the upstream cost efficiency rate rises linearly. The output distribution is right-skewed and the output spikes are widespread. Furthermore, the distribution of total output for TA-Sarnia plant is almost identical to that of output sold to the T3 market. Detailed figures for its total output will be presented in Table 8 under the assumed efficiency scenarios reported by GE.

The second part of Table 6 exhibits the distribution of T3 market outputs with respect to downstream cost efficiency. Observe that, in equilibrium, the outputs increase in fuel cost efficiency at an increasing rate. However, compared to price volatility in the upstream, output volatility in the downstream is much higher and is as much as twice the output. The minimum output takes 0 (the lowest output possible) and the maximum gets 415 (the highest output possible). The main reason for this wide output variation stems from significant changes in wholesale prices in the Ontario market, which is the most volatile power market in North America.

Table 7 considers upstream and downstream cost efficiencies simultaneously. It shows the distribution of TA-Sarnia's output sold in T3 market when both upstream and downstream firms experience efficiency due to GT11M2 M. This is a more realistic case than the one considered in Table 6. However, Table 6 is useful to see the marginal impact of one type of efficiency on the outcomes. In Table 7, q3-fc0% is the benchmark case when cost efficiencies are not experienced in the supply chain; q3-fc5%

Table 7: Output distribution in T3 market under both efficiency types

	q3-fc0%	q3-fc5%	q3-fc10%	q3-fc15%	q3-fc20%	q3-fc25%
mean(q3)	56.283	58.449	60.793	63.405	66.487	70.136
stdev(q3)	126	127.768	129.648	131.485	133.538	136.064
min(q3)	0	0	0	0	0	0
max(q3)	415	415	415	415	415	415
skew(q3)	2.177	2.114	2.046	1.97	1.887	1.799
kurt(q3)	3.186	2.913	2.631	2.324	1.997	1.66

refers to output level when 5% upstream cost efficiency (f=5%) and 5% downstream cost efficiency (c=5%) take place. An extreme case involves q3-fc25%, where f=25% and c=25% cost reductions occur in the entire supply chain. At the highest efficiency gain (f=25% and c=25%) TA-Sarnia can sell about 14 MWh more electricity to the Ontario wholesale market, corresponding to 25% more output compared to the benchmark output. On the other hand, at the lowest efficiency gain (f=5% and c=5%) TA-Sarnia can sell about 2.2 MWh more electricity to the market, corresponding to 4% output increase relative to the benchmark. The outputs increase in efficiency rates at increasing rates, which is unsurprising. However, as we observe in other efficiency scenarios, higher efficiency brings about more volatility in outputs. In some days (and hours), TA-Sarnia does not sell electricity to the wholesale market. Its output is zero in T3 market, but it is positive for T1 and T2 customers. This stems from low supply conditions observed at the Sarnia plant along with low prices in the wholesale market.

5.2 Simulations for GE's Reported Cost and Output Efficiency

Table 4 presented operating modes and performance ratings of GT11N2 M upgrade combined-cycle generators predicted by GE. Each operating mode is associated with a different efficiency rate. However, market implications of these modes are unknown. To quantify impacts of the new switchable operating modes, we consider four scenarios. The first scenario assumes that only MCL-mode is used at all times; the second scenario supposes that only P-mode is utilized; the third scenario involves L-mode only; the fourth scenario, which we coin "Mixed-mode", assumes that each mode is used at equal proportions during the study period. The reason we propose the Mixed-mode is that it is not known how long each of the reported three modes is implemented in real time by TA-Sarnia. Furthermore, we consider a benchmark scenario under which the new technology is assumed to be inactive (i.e., either

Table 8: Descriptive Statistics of Equilibrium Outcomes

	Without GT11N2 M	With GT11N2 M			
Operation Mode		MLC-Mode	P-Mode	L-Mode	Mixed
Total output (MWh):					
Q	220.80	260.34	249.20	232.78	247.46
$stdev(Q)$	104.32	94.24	97.30	101.56	97.75
GE's price (\$/MWh):					
w	4.64	4.64	4.64	4.64	4.64
$stdev(w)$	3.59	3.59	3.59	3.59	3.59
Total Emissions (ton):					
NO_x	1,554	1,833	1,754	1,639	1,742
CO_2	1,108,621	1,307, 121	1,251,188	1,168,746	1,242,493
d (days)	365	365	365	365	365

it is not implemented or old generators are in place).

Based on Table 4, there is no service and maintenance cost efficiency in 2014 so that $f = 0$ holds. One justification for this assumption is that the inspection intervals of these modes are 24,000 equivalent operations hours (EOH) for MCL-mode, 36,000 EOH for P-mode, and 48,000 EOH for L-mode. These long operation hours together with the fact that there are only 8760 hours in 2014 should imply that service and maintenance cost during the study period should be zero.

What follows next is the specification of output efficiency. TA-Sarnia has three GT11N2 generators. Given that its expected output increase in MCL mode is 14.3 MWh per generator, we expect additional 42.9 MWh power increase in total. Similarly, the extra expected power supply in P and L modes should be 30.6 MWh and 12.6 MWh, respectively. For the mixed-mode, it should be 28.7 MWh, which is the average figure from the three modes. These numbers represent output efficiency gains for having flexible operation modes offered by the new technology.

In terms of downstream cost efficiency, we know from Table 4 that the fuel cost should go down by 1.9%, 1.8%, 1.6%, and 1.77% for MCL, P, L, and the mixed modes, respectively. Given these output and downstream cost efficiencies, we run the model for all days of 2014. We report our findings in Table 8, where Q denotes TA-Sarnia's total output, w denotes GE's price, and NOx and CO_2 refer to the total emissions in the year.

From TA-Sarnia's point of view, the most efficient generation mode in the short term is MCL. It can sell the most output to both T2 and T3 markets. Compared to the benchmark, which is the old technology, we find that the total generation increase should be in the range of 5% (under L mode) to 18% (under MCL-mode). However, a more realistic figure should come from the mixed-mode. The reason is that all modes should be used interchangeably because of electricity demand variation over periods. In the mixed-mode, we find 12% generation expansion from TA-Sarnia. Observe that GE's price is stable under these modes, because there is no upstream cost efficiency reported by GE.

Since the output variation is nonlinear and significant, the amount of greenhouse gas emissions will be largely impacted by the operating modes and how long they have been used. Table 8 presents equilibrium CO2 and NOx emissions in tons across GT11N2 M modes. Using heat and NOx emission rates of Sarnia generators reported in Table 3, we calculate that the average heat rate is 9,096 kj/kwh and the average NOx rate is 0.08834 g/MJ. For each operational mode, we multiply equilibrium total output with the average heat and emission rates, add them up over all time periods, and report the total NOx emissions released in 2014. For CO2 emission rate, we use 1265.26 lb/MWh for natural gas generators, reported by Aydemir and Genc (2017). We multiply the CO2 rate with output for each time and add them up to obtain the total CO2 emissions.

We find that the new technology results in more air pollution. This result is obtained when the total emissions before and after GT11N2 M in the table are compared. This is a direct "rebound effect", so efficiency leads to higher consumption and hence higher emissions. More importantly, the total emissions increase in efficiency at an increasing rate, which follows from the nonlinear relationship between output and efficiency rate. The total CO2 emissions rise between 5% and 18%, depending on operation modes, and go up by 12% under the mixed usage of all modes. While total NOx emissions are low compared to CO2 emissions, they increase in cost and output efficiency and exhibit similar rates to those of CO2 in 2014.

6 Conclusions

Energy transition in electricity sector requires new natural gas generators with improved efficiency rating and flexible operation modes to mitigate intermittency of renewables and help tackle climate warming issues. In that regard, we examine the impact of a technological change involving innovation of natural gas-fired GT11N2 M generators in a power supply chain. An assessment of GT11N2 M generators in a power supply chain is novel and has not been studied before. We mainly investigate economic benefits and environmental implications of this new technology that brings about efficiency, operational flexibility, and durability. Specifically, we study the upstream efficiency leading to cost reductions in service and maintenance experienced by General Electric, and the downstream efficiency resulting in cost reductions and output expansion in electricity generation experienced by TransAlta's Sarnia plant in Ontario. We quantify the impact of different efficiency rates, including GE's estimated efficiency rates, on equilibrium prices, outputs, and emissions.

To measure the efficiency gains in service, maintenance, and generation, we construct cost functions in detail using actual market and firm data in Ontario. As TransAlta exercises price discrimination over consumer groups, which is a common practice in electricity sector, we identify three customer groups and formulate their demand for electricity. We examine GT11N2 M's three switchable operation modes that offer flexibility in power production, and compare it to the old technology lacking efficiency, performance, and flexibility features. Given these ingredients, we formulate a vertical relations model between General Electric, TransAlta-Sarnia, and consumer groups, and then quantify Stackelberg equilibrium outcomes.

Qualitatively, we find that GE's equilibrium prices are linear in upstream service and maintenance cost efficiency, and are intact with respect to downstream fuel cost efficiency. GE's prices decrease in upstream efficiency, but become more volatile. However, TA-Sarnia's total outputs and its sales to the wholesale market nonlinearly increase in both upstream and downstream efficiency. While outputs become more volatile in efficiency rates, the price spikes and asymmetry subside in efficiency. Quantitatively, we determine equilibrium outcomes based on GE's actual generation modes. While the most efficient combined cycle mode is MCL which facilitates extra 18% output increase, the least efficient operation mode which is single cycle L mode provides extra 5% output expansion. Because output variation is nonlinear and significant over the modes, the amount of greenhouse gas emissions are largely impacted by the operating modes and how long they have been used. The simulations show that the total emissions increase in efficiency at an increasing rate. The total CO2 emissions go up by 12% under the mixed usage of all modes. While the total NOx emissions are low, they increase in cost and output efficiency and exhibit similar rates to those of CO2. Consequently, we observe a significant direct rebound effect of energy efficiency on output and emission. Of course, the actual impact of GT11N2 M's operational modes on supply chain performance would also depend on other factors such as network constraints that were assumed away.

As a future research direction, the paper could be extended in a number of ways. First, a sophisticated supply chain involving a downstream competition in which TransAlta's competitors such as Northland Power, Ontario Power Generation, and Brookfield Renewable could be introduced. Currently, TransAlta is the only power producer in the proposed model and it is a competitive fringe in the Ontario market. In imperfectly competitive downstream, which reflects the actual structure of the Ontario market, a dominant firm's (such as Ontario Power Generation's) supply strategies would definitely affect the wholesale prices and therefore TransAlta's output decisions. In such a case, it would be interesting to see how GT11N2 M would affect the supply chain performance. Second, in the current setting the wholesale market demand is exogenous to the output decisions of TransAlta, because it is a fringe supplier. In a competitive downstream industry one would need to formulate Ontario wholesale demand. In such a setting, TransAlta should optimize all of its outputs sold to all customer groups. Third, one could easily add uncertainty to cost and/or demand functions to the current supply chain setting and examine its impacts on the outcomes. However, uncertainty would complicate the equilibrium predictions in a supply chain with downstream competition. Fourth, one could assume an alternative competing technology to GT11N2 M. In that case, it would be interesting to know which technology would be chosen by TransAlta in equilibrium.

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Declaration of Competing Interest None.

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Figure 1: Daily Ontario Prices in 2014

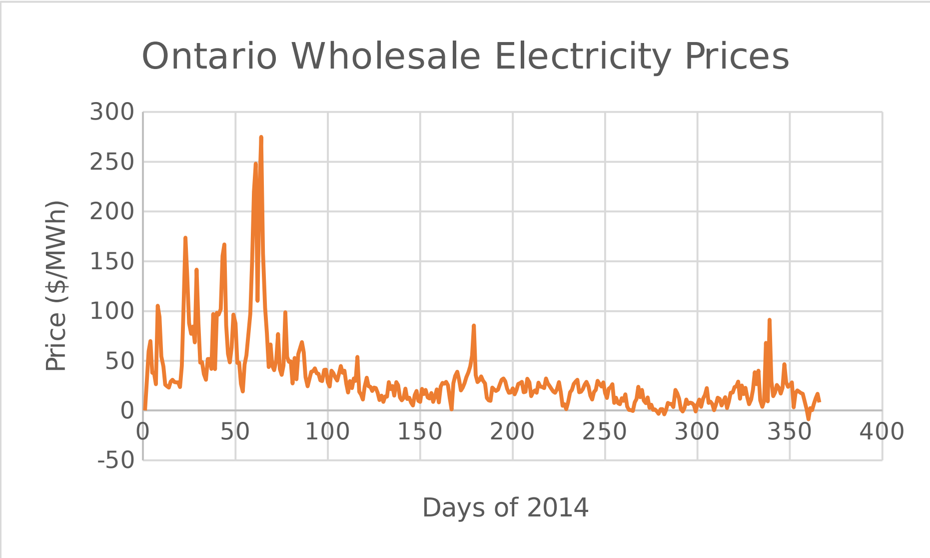
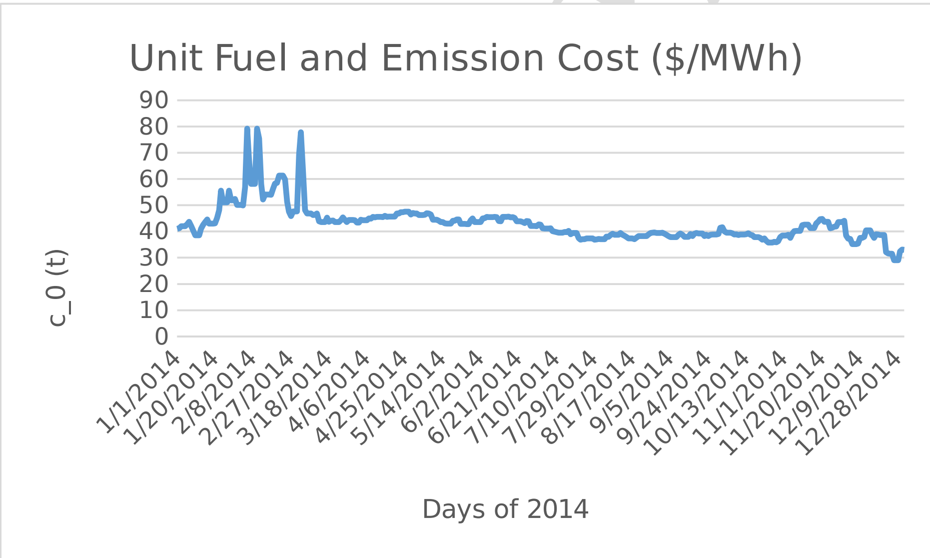


Figure 2: Estimated unit cost of fuel and emissions in 2014. Corresponding to equation 10.



Highlights

- Technological change represented by GT11N2 M generators offer cost and output efficiency.
- General Electric and TransAlta can increase their profitability in the energy supply chain.
- Clean energy adoption may not facilitate carbon emission reduction.

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