Integrating Thermal and Hydro Electricity Markets: Economic and Environmental Costs of not Harmonizing Pricing Rules

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Abstract

The electricity sector is the largest source of GHG emissions in the world, and reducing these emissions would often be costly. However, because electricity markets remain often only integrated at a shallow level (with different pricing regulations), many gains from deeper integration (adoption of marginal cost pricing everywhere) are yet to capture. This paper assesses the benefits of such deep integration between a "hydro" jurisdiction and a "thermal" one. It also underscores the inefficiency of trade when pricing rules differ. Our detailed hourly model, calibrated with real data (from the provinces of Ontario and Quebec, Canada), estimates price, consumption, emissions and welfare changes associated to fully integrating electricity markets, under transmission constraints. A negative abatement cost of \$37/tonne of CO_2 is found (for more than 1 million tonnes), cleary illustrating the untapped potential of wealth creation in carbon reduction initiatives. Furthermore, given the inefficiency of shallow integration between markets, we find that *removing* interconnections between markets is a relatively affordable CO_2-reduction opportunity, at \$21.5/tonne.

J.E.L. Classification: F14, F15, L50, L94, Q52, Q56.
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1 Introduction

While many economic and environmental issues become global, electricity markets, to a large extent, remain local. Many regional integration initiatives are however in place, but a lot of obstacles slow the transformation of local electricity markets. For instance, in the United States, strong state-level political opposition halted in 2005 the plan to implement regional transmission organizations (RTOs), all following a standard market design (FERC, 2005). Even in Europe, where a 1996 European Union directive set the objective to progressively open the electricity market to create a single market, progress has been slow and plans had to be revised. If standard microeconomic theory would justify removing some regulation and barriers to trade, as many natural monopoly features have disappeared in the electricity sector, only a limited number of states have opted to harmonize their electricity market with their neighbours' one. Such integration would indeed lead to various price and quantity adjustments, with the associated political economy challenges. These issues remain poorly documented, as clearly established in a large literature review on regional power sector integration commissioned by the World Bank (ECA, 2010). Our paper contributes to remedy such shortcoming by introducing a model allowing to analyze the impact of trade and of a common market between two jurisdictions: the province of Ontario, Canada where generation is mainly thermal based and the province of Québec, also in Canada, where hydrogeneration provides most of the electricity.

Prices, electricity production, consumption levels and greenhouse gases (GHG) emission levels are estimated under various scenarios, permitting integration outcomes to be clearly illustrated. Our results show that if the hydro jurisdiction keeps its average cost pricing regulation, while the thermal one maintains its competitive market, although trade slightly improves total welfare when ignoring GHG emissions, such emissions *increase* with trade. The welfare improvement amounts to \$21.5 per tonne, which can also be interpreted as the GHG abatement cost associated to transmission capacity removal.

By contrast, we estimate that a *negative* abatement cost of \$37 per tonne could be achieved with more integration, *i.e.* if electricity trade is complemented by the implementation of marginal cost pricing in the hydro jurisdiction. The story is however not the same for producers and consumers in both markets: while consumers in the thermal jurisdiction gain from trade and market harmonization, their counterparts in the hydro jurisdiction lose with the end of price regulation. Producers, on the other hand, lose with trade in the thermal jurisdiction but increase their profit in the hydro one. When transmission capacity increases, all these impacts become greater.

The rest of the paper is divided into four sections. In section 2, we provide a literature review. Section 3 presents the detailed hourly model, empirically calibrated relative to the Canadian electricity markets of Ontario and Quebec. The Ontario market stands for the competitive "thermal" market while the Quebec market stands for the average cost pricing "hydro" market. Results are discussed in section 4 and a conclusion follows.

2 Literature Review

Most of the literature on electricity market reforms is concerned with competition levels, market design, transmission pricing rules and other issues, in a context of isolated electricity markets. See for instance the books of Newbery (2000) or Stoft (2002) and the large literature they refer to. Despite the important potential benefits of regional electricity market integration, the literature

on such harmonization reforms is limited.
Such conclusion is documented in a large literature review made for the World Bank's Energy Sector Management Assistance Program, see ECA (2010). It states that there are "few academic studies which have real theoretical depth [on regional power sector integration]" (ECA, 2010: 2) and also that there is a need for "theoretical analysis of the way in which benefits are distributed" (ECA, 2010: 12). This happens in a context of many initiatives promoting such regional power sector integration, especially in developing countries. See for instance WEC (2005) and UNECA (2006) for perspectives from international organizations on energy integration in Africa. UN (2006) attempts to makes the case for international electric power grid interconnections, while clearly underscoring potential costs and institutional challenges. World Bank (2010) draws lessons from the study of various integration cases, both in developed and developing nations, and from a literature review (ECA, 2010). This literature review summarizes the following expected benefits from regional integration: improved economic efficiency (in a broad sense), reduced costs (in operation and investment), improved supply conditions and various possible social, environmental and even political gains (ECA, 2010: 4-5). There is however no mention of any rigorous analysis of such benefits or subset of benefits. If some assessments have been occasionally made, such as the economic benefits of RTOs in the US (IFC, 2002), they remain at a very general level, with scarce information on the distribution of benefits (among regional producers and consumers) and on environmental impacts. An exception is Finon and Romano (2009), who discuss the impact of market integration on producer's profits, in the lower cost jurisdiction. Yet, welfare remains absent from their analysis.

A key issue in electricity market integration is the protection of "native load", which is associated to "end-use customers that the Load-Serving Entity is obligated to serve" (NERC, 2011). In most cases, such obligation comes with a regulated price based on the local production costs, which can be especially low if large amounts of hydropower are available. In the United States, federal regulation to promote wholesale competition protects such native load by not making generation and transmission capacity planned to meet native load available to non-local purchasers. See in particular the Federal Energy Regulatory Commission (FERC) orders 888 and 890. This limits integration at a shallow level, by only allowing limited transactions, and maintains potentially important price differences between neighbouring markets.

Our paper presents a two-market model to assess "shallow" and "deep" integration, to use the World Bank (2010) terminology. In the first case, the two jurisdictions are interconnected but keep their distinct market organization: one is competitive and the other one follows an average-cost pricing regulation. In the second case, both jurisdictions are competitive: native load commitments are removed. Change in outcomes can clearly be observed from the three integration regimes: no interconnection (autarky), shallow and deep integration.
The contribution of the paper is twofold. First, by proposing a model allowing a straightforward comparison of shallow and deep integration outcomes, with detailed impacts on consumers, producers and emission levels. Second,

by providing empirically-based welfare estimates of GHG abatement costs in the electricity sector. Also, by including transmission constraints and costs, we better captures the influence of transmission and of the cost of transaction in electricity trade.

The paper builds on a stream of papers dealing with associated topics. Billette de Villemeur and Pineau (2010) identifies conditions under which trade between two jurisdictions is environmentally damaging, without, however, looking at any change in market organization. Billette de Villemeur and Pineau (2012) focuses on such market changes (integration regime changes), but from a purely theoretical perspective, and without considering intertemporal arbitrage possibilities in the hydro jurisdiction. In Billette de Villemeur and Pineau (2012), a key result was the decrease in total consumption under deep integration, as compared to shallow integration, while welfare increased. This results is empirically illustrated in this paper, further making the point that deep integration would be beneficial, at least from an environmental perspective.

Intertemporal arbitrage possibilities are studied in Billette de Villemeur and Vinella (2011), but on a single market. The basic model we use, and expand, comes from Førsund (2007). However, in his study of hydropower economics, Førsund does not look at a regulated hydro jurisdiction trading with a competitive one, as we do here. His model has recently been used in Green and Vasilakos (2012), to study wind and hydro trade between Denmark and Norway. These two countries have a competitive market. In this paper, we use the setting of Ontario and Quebec, two neighboring Canadian provinces, engaged in trade, but with very different pricing rules.

3 Trade in Electricity Markets: A Multi-period Analysis

Our model, formally presented in section 3.2, focuses on the role of hydropower, which requires including multiple periods when storage is available. Indeed, thermal electricity is seldom constrained by the available quantity of primary energy (uranium, coal, natural gas or oil). As compared to demand fluctuations, production costs can essentially be considered stationary. Market equilibrium analysis can thus legitimately be performed in a static framework when the whole electricity supply steams from thermal technologies. By contrast, absent water storage, hydropower supply is almost completely inelastic, due to the exogenous character of water provision (*i.e.* water inflow from rainfall). With a dam, hydro production profile can instead be easily modulated to meet a time-varying demand. Indeed, water reserves can be almost freely allocated across time if there is sufficient storage capacity. There is thus room for arbitraging, whatever the objective of the utility. As pointed by Billette de Villemeur and Vinella (2011), this gives hydropower an important role in the working of electricity markets, beyond that attached to its actual market share.

The high investment costs and the low marginal costs attached to hydroelec-

tricity generation make of power plants "natural monopolies", in relatively small and isolated electricity markets. This may explain why, in hydro-dominated electricity markets, the price of electricity is very often regulated. More generally, this calls for specific competition policies in jurisdictions were generation is predominantly hydro-based (see Rangel 2008).
The persistence of price regulation has very important consequences for market integration outcomes. In fact, assuming price regulation in the hydropower jurisdiction (hereafter referred to as H), neither price nor demand should vary in that jurisdiction with the introduction of trade. This says that, absent rationing, the sum of the trade flows should add up to exactly zero (no "loss of resource" for H-consumers). As a result, it must be the case that total production in the thermal jurisdiction (hereafter referred to as Th) is also equal to total consumption is this jurisdiction. This says that, the sole consequences of "shallow integration" go through the intertemporal redistribution of production, thanks to the arbitrage possibility offered by hydropower. Clearly, absent demand fluctuations, there is no place for trade. If instead price happens to vary in Th, intertemporal arbitrage may help to improve upon both efficiency and profitability, even if the H-producer has native load commitments.
The introduction of electricity trade has radically different consequences if there is "deep integration", *i.e.* if, after the introduction of trade, prices are market-based in both jurisdictions. In fact, both the price regulation and the interaction with a trading partner with higher production costs call for a price increase in H. Thus, while total hydropower supply remains unchanged because it is completely independent from the pricing policy in the short run, there is a positive net power outflow from H to Th. It follows that price decrease in Th and thermal electricity now represents a fraction of Th consumption. Importantly, these gross effects add up to the intertemporal arbitrage already evidenced in the case of "shallow integration" that pertains in the case of "deep integration". This makes of importance to adopt a multi-period model, even for the analysis of the later case.

In this paper, we refer to the case of Ontario (a jurisdiction where generation is mostly thermal and prices market-based) and Québec (a jurisdiction which rely essentially on hydropower and where prices are regulated on the basis of average costs). To make the results clearer, we will assume that jurisdiction Th holds *no* hydro storage capacity while H *only* produces hydropower with storage capacity (we ignore multiyear water management possibilities). We focus on this particular case in order to be able to provide figures and to illustrate our previous theoretical results (see Billette de Villemeur and Pineau 2010 and 2012) and their multi-period extension provided here. Yet, our results are of more general interest as the modelled situation is far from being unique: British Columbia, another Canadian province with regulated hydropower and storage capacity, actively trades with Alberta, its competitive thermal neighbor, as well as with its Southern US neighbours. In the US, large hydro provides more than $66,000$ MW of capacity (EPRI, 2007) and with 73% of this hydro owned by federal and non-federal public organizations (Hall and Reeves, 2006), most of this hydropower is sold at average cost, instead of being sold at market price.

We now introduce some brief additional background on Ontario and Québec, before presenting the three trade regimes of interest, along with the formal model. In a third subsection, we present the detailed outcomes of our calibrated model.

3.1 Description of the Two Markets

Ontario and Quebec are two Canadian neighboring provinces. Despite its larger population of 12.8 million (against 7.7 million for Quebec), Ontario has significantly less generation capacity: $31,056$ MW in 2007 (IESO, 2007) compared to $46,220$ MW for Quebec (MRNF, 2009). The structure of the two markets is also very different, notably because Ontario relies on all types of generation capacities (however mostly thermal), while Quebec relies almost exclusively on hydropower (92% of its capacity). Its main hydroproducer has a yearly hydropower production of about 190 TWh, with a storage capacity of 175 TWh (Hydro-Québec, 2008).[1] Ontario has a hourly price set in a competitive spot market (with some share of its generation still sold at a regulated price; see IESO, 2009), which resulted in an average hourly price of $47.81/MWh in 2007 (IESO, 2008a). Electricity is entirely sold at a regulated price in Quebec, close to $27.90/MWh.[2] This price represents the estimated cost of the "heritage pool" of 165 TWh dedicated to Quebec consumers (Hydro-Québec, 2008). Because many suppliers compete in the Ontarian spot market, while Hydro-Québec dominates in Quebec (88% of the overall production), these two markets are a good illustration of the theoretical context we wish to study. Furthermore, electricity is traded over transmission lines that can supply up to 1,295 MW from Quebec to Ontario, and up to 720 MW from Ontario to Quebec (HQ TransÉnergie, 2006). This interconnection only changed in 2010 with the addition of about 1,000 MW of transmission capacity in both directions. The situation between the two provinces represents a "mixed market structure with trade" (or shallow integration): Ontario sells electricity at marginal cost within its border and Quebec at average cost. Exports and imports, are done at the Ontario marginal cost, unless transmission constraints are binding.

We focus on the Ontario-Quebec trade relationship despite many other interconnections (for both jurisdictions) for a variety of reasons: a lot of data from the Ontario market is available, the Quebec hydropower capacity and production are very important (and could have regional implications if managed differently), there is an active and still developping electricity trade history between Ontario and Quebec and, finally, it would probably be easier to harmonize pricing rules within a single country than between jurisdictions in two different countries. Having said this, nothing in our empirical choices is central to the core findings of our paper. We could have used the Quebec-New York or British

[1] BC Hydro, by comparison, produces about 50 TWh of hydropower and usually keeps more than 10 TWh in storage (BC Hydro, 2012).

[2] 165 TWh are sold at this price, and the remaining energy is either produced or purchased at a different cost. The final energy price to consumers is the average procurement cost, which remains close to $27.90/MWh.

Colombia-Alberta situations for illustrative purposes.

3.2 The model

We adopt the multi-period "bathtub" framework introduced in Førsund (2007) for our analysis. The model uses fixed capacity and is not intented to explore dynamic capacity investment issues. The original model provides a simple way to analyze the "optimal" use of hydro and thermal generators over several jurisdiction with varying demand. *Absent externalities, if markets are competitive everywhere*, the constrained optimisation problem that maximizes social welfare gives rise to a solution that also correspond to the market equilibrium outcome. This explains why Førsund's framework is also used as a tool for positive analysis, *e.g.* to analyze the actual effect of competing hydro, thermal and also wind generators on price and demand patterns. See Førsund et al. (2008) and Green and Vasilakos (2012).

Our contribution consists precisely in studying the consequences of having electricity markets that are *not* competitive everywhere. We evidence however that, even in the case where average cost pricing prevails in one market, the framework can easily be adapted for the equilibrium outcome to still correspond to the solution of a (slightly modified) optimisation problem. This allows us to use a unified approach to address the issue of market integration when institutional arrangements differ across jurisdictions.

Generation takes place within two provinces, thermal (Th) and hydro (H) as characterized by their dominant technology. More precisely, in jurisdiction Th, while the nuclear provides the base load, most of the power is generated by generators endowed with a thermal technology (coal, gas).[3] We denote by e_t^{Th} the electricity production within Th at period t. The industry-wide production cost function is denoted $C_{Th}\left(e_t^{Th}\right)$. Since the cost function is considered at the aggregate level and total consumption in the jurisdiction never exceeds the production capacity, there is no need to introduce capacity constraints.[4]

In jurisdiction H, electricity generation almost exclusively steams from hydropower. We denote by e_t^H the electricity production within H at period t. Hydro-generators have a marginal cost of zero. Yet, we introduce the (operations and maintenance) costs C_H attached to production in jurisdiction H. Although they won't play any role in the time distribution of the energy production, they shall account for the (regulated) price in jurisdiction H. Obviously, the yearly production cannot exceed the total available water in reservoir W,

[3] Since Ontario progressively phased-out coal power plants after 2007, coal will not be not used after 2014 in Ontario, see Pineau (2013).

[4] Indeed, with the so-called "reserve margins requirements" (as imposed for system reliability), there is excess capacity in most power systems, as it is the case in Ontario. In 2013, this reserve margin was 18% - meaning that total capacity was 18% above peak demand (IESO, 2013). Being interested in resources allocation within a given system of two interconnected jurisdictions with no capacity shortage, and not in capacity addition within this system, ignoring capacity constraints for generation has no influence on our results.

measured in MWh (a normalization). This yields the constraint:

$$\sum_{t=1}^{8760} e_t^H \leq W, \tag{1}$$

where, in our data, t indexes the 8,760 hours of the year 2007.

There is a well organised power market in Th so that we assume that all generators in this jurisdiction behave competitively. Power is thus priced at marginal costs and we have

$$p_t^{Th} = C'_{Th}\left(e_t^{Th}\right),$$

where p_t^{Th} stands for the price of power in jurisdiction Th at period t. By contrast, p_t^H, the price of power in jurisdiction H at period t is supposed to be regulated, at least in some scenarios (our regimes 1 and 2). If so, the price p_R^H is assumed to be equal to the average cost and constant over a year, as it is the case in regulated electricity markets.[5]

Exports of Th (into H), x_t^{Th}, and imports into Th (from H), x_t^H are supposed to be traded at price p_t^{Th} on market Th. Yet we allow for transmission costs c^τ so that trade does not occur if the price differential across jurisdiction is not large enough. As usual, we follow the convention that both jurisdictions cannot export at the same time. However, we account for the fact that transmission capacity are direction specific. Moreover, their availability varies across time. We account for both aspects by introducing $\overline{x}_t^{Th}$ and $\overline{x}_t^H$, the time-specific upper-limits of respectively, x_t^{Th} and x_t^H.

There is a (varying) demand in each jurisdiction, $D_t^{Th}\left(p_t^{Th}\right)$ and $D_t^H\left(p_t^H\right)$. We assume that their respective inverse function $p_t^{Th}\left(D_t^{Th}\right)$ and $p_t^H\left(D_t^H\right)$ provide the marginal (social) value of power in each jurisdiction.

This paper is intended to study the effect of "shallow" and "deep" integration of electricity markets on prices, quantities, firms profits and consumer welfare. More precisely, we aim at comparing three different regimes:

- In Regime 1, there is a "mixed" market structure[6] and both jurisdictions are in autarky (no transmission capacity).
- In Regime 2 (shallow integration), there is still the "mixed" market structure but trade is possible, with transmission constraints.

[5] Regulated electricity rates are usually changed once a year, and remain constant otherwise. See for instance the regulated rate pages of two "hydro" power systems: Hydro-Quebec (http://www.hydroquebec.com/residential/understanding-your-bill/rates/residential-rates/rate-d/) and Seattle City Light (http://www.seattle.gov/light/Accounts/Rates/ac5_erps25_1.htm). This is also the case for the nuclear-dominated system in France (http://particuliers.edf.com/offres-d-energie/electricite-47378.html).

[6] Competitive market in jurisdiction Th, while in jurisdiction H, average cost pricing prevails.

- In Regime 3 (deep integration), market are fully integrated, albeit with transmission constraints. These constraints prevent the price across jurisdictions to be always unique, but marginal cost pricing prevails everywhere.

The shift from Regime 2 to Regime 3 corresponds to an institutional change in jurisdiction H that would result in marginal cost pricing. Let us note that such a change does not necessarily require a complete reorganization of the industry (*i.e.* the fragmentation of the monopoly and the creation of a power market). It may simply follow from a change in the regulatory policy.

The two markets are studied as if there were no connections with other neighboring markets. In practice, we considered their commercial exchanges as being part of each jurisdiction. Imports from other jurisdictions are considered produced in the jurisdiction, exports are considered consumed in it.

3.2.1 Optimal water use on a regulated market

For an average cost pricing policy to be implemented meaningfully, it is not sufficient to set the price. Some supply obligations constraints are also to be introduced, or at least considered. This is especially true if energy operators are allowed to trade with other jurisdictions. In fact, producers will privilege markets that offer them better opportunities while restraining (and possibly cutting) their supply to less profitable markets. This explains why, wherever there is price regulation, operators are also subject to other obligations regarding energy provision.

In this paper, we assume that the regulated producer in jurisdiction H has a supply obligation toward all clients within this jurisdiction (see equation 4). It is also assumed that the (regulated) price p_H is set at the average cost of providing energy to all its clients. Thus, in jurisdiction H, price and consumption does not depend on water allocation; moreover, the sole (unregulated) profits of the regulated operator streams from trade.

By definition energy balance in the system requires that, in each moment t

$$D_t^{Th}\left(p_t^{Th}\right) = e_t^{Th} + x_t^H - x_t^{Th}, \tag{2}$$

$$D_t^{H}\left(p_t^{H}\right) = e_t^{H} + x_t^{Th} - x_t^{H}. \tag{3}$$

The pattern of energy production $\left(e_t^{Th}, e_t^H\right)$ and of trade flows $\left(x_t^{Th}, x_t^H\right)$ are chosen by the operators as to maximize their profits. In doing so, however, they are subject to several constraints. There are first constraints attached to the capacity of both the thermal and the hydro generators. As they appear to almost never be binding, due to reliability margins, we choose to ignore them from the outset. For the hydro-production, there are also constraints attached to the replenishment of reservoirs.[7] Again, we choose to ignore them because

[7] Replenishment cannot go beyond reservoir capacity and below a minimum level, generally resulting from environmental considerations. Also, the water level in a reservoir has an influence on the production level, due to height differences.

as long as there is some accessible storage capacity, they become irrelevant to what we want to study. Other constraints however are not purely theoretical. In particular, as already stated in (1), the yearly hydropower production cannot exceed the total amount of available water. We shall denote by λ the shadow value of this constraint, to be interpreted as the (implicit) "price of water". The observation of the trade pattern across jurisdisctions makes it also clear that transmission capacity constraints can be binding. We denote by μ_t their (time-specific) shadow value.[8]

Transmission capacities are small enough for the hydroproducer to be considered as a price-taker provider (or buyer) on the competitive market Th. Water availability and energy provisions obligations make it clear that the hydroproducer may freely trade $x_t = x_t^H - x_t^{Th}$ on Th market provided that

$$\sum_{t=1}^{8760} x_t \leq W - \sum_{t=1}^{8760} D_t^H \left(p_R^H\right), \tag{4}$$

where p_R^H is set by the regulator. It follows that:

Proposition 1 *Computing the equilibrium in Regime 2 amounts to solve the optimization program*

$$\max_{\left\{e_t^{Th}, x_t^{Th}, x_t^H\right\}_{t=1,\dots,8760}} \left\{\sum_{t=1}^{8760} \left[\int_0^{e_t^{Th}+x_t^H-x_t^{Th}} p_t^{Th}(q)\, dq - C_T\left(e_t^{Th}\right) - c^\tau x_t^{Th} - c^\tau x_t^H\right]\right\}$$

$$s.t. \quad \sum_{t=1}^{8760} \left(x_t^H - x_t^{Th}\right) \leq W - \sum_{t=1}^{8760} D_t^H\left(p_R^H\right) \quad and \quad -\overline{x}_t^{Th} \leq x_t^H - x_t^{Th} \leq \overline{x}_t^H,$$

all $t = 1, \dots, 8760$.

This proposition is adapted from Førsund (2007), where we include here a regulated hydroproducer and transmission costs (c^τ). Let's note that to characterize Regime 1, we simply need to set $\overline{x}_t^{Th} = \overline{x}_t^H = 0$.

Absent transmission constraints, price patterns are easily characterised. If $x_t^H > 0$, then $p_t^{Th} = \lambda + c^\tau$; if $x_t^{Th} > 0$, then $p_t^{Th} = \lambda - c^\tau$; if $x_t^{Th} = x_t^H = 0$, then

$$\lambda - c^\tau \leq p_t^{Th} = C'_{Th}\left(e_t^{Th}\right) \leq \lambda + c^\tau.$$

This says that, despite abundant hydro resources, price fluctuations may arise in a power-system as a result of the sole transmission costs. This is consistent with the observation that transmissions constraints are actually rarely binding, while prices are almost never identical even in adjacent periods; see Pineau and Lefebvre (2009).

Limited transmission capacities may explain why the presence of hydropower is not sufficient to prevent extreme prices. We establish the following characterization of Regime 2 prices:

[8] Because we assume that both jurisdictions cannot export at the same time, there is no need to introduce a multiplier for each of the (direction specific) transmission capacity.

Proposition 2 *In Regime 2, when Th is exporting, the price in jurisdiction Th is at most $\overline{p_{Th}} = \lambda - c^{\tau}$. When T is importing, the price in jurisdiction T is no less than $\underline{p_{Th}} = \lambda + c^{\tau}$. If $x_t^{Th} = x_t^H = 0$ then*

$$\overline{p_{Th}} < p_t^{Th} = C'_{Th}\left(e_t^{Th}\right) < \underline{p_{Th}}.$$

Proof. *See appendix A.1.* ■

Observe that the shadow price of water $\lambda = (\partial \mathcal{L}/\partial W)$ a priori differs from the regulated price p_R^H. Because the hydro-producer in H is actually arbitraging between high-price and low-price periods in Th, it may well be the case that $x_t^{Th} > 0$ and $p_t^H = p_R^H < p_t^{Th}$. Yet, the values of λ and p_R^H are not completely unrelated. The higher p_R^H, the smaller consumption in H, the larger the propensity to export toward jurisdiction Th, and thus the smaller λ. The environmental impact of trade in Regime 2 depends on many factors, especially demand and supply elasticity as well emission intensity for different levels of production. Such impacts have been studied in Billette de Villemeur and Pineau (2010) and some additional results are presented later in this paper (see in particular Tables 5 and 9).

3.2.2 Comparison of shallow and deep integration

In the deep integration regime (Regime 3), native load commitments are removed in H and both jurisdiction apply marginal pricing policies. This situation was already studied by Førsund (2007) see in particular his problems 6.26 and 6.29. We restate his results to ease the comparison with Regime 2:

Proposition 3 *(Førsund (2007)) - Computing the equilibrium in Regime 3 amounts to solve the optimization program*

$$\max_{\left\{e_t^{Th}, e_t^H, x_t^{Th}, x_t^H\right\}_{t=1,\ldots,8760}} \left\{ \begin{array}{c} \sum_{t=1}^{8760} \left[\int_0^{e_t^{Th}+x_t^H-x_t^{Th}} p_t^{Th}(q)\,dq - C_{Th}\left(e_t^{Th}\right) - c^{\tau} x_t^{Th} - c^{\tau} x_t^H\right] \\ \sum_{t=1}^{8760} \int_0^{e_t^H+x_t^{Th}-x_t^H} p_t^H(q)\,dq - C_H \end{array} \right\}$$

$$s.t. \quad \sum_{t=1}^{8760} e_t^H \leq W \quad and \quad -\overline{x}_t^{Th} \leq x_t^H - x_t^{Th} \leq \overline{x}_t^H,$$

all $t = 1, ..., 8760$.

If welfare comparisons across regimes are to be made, the gross surplus of consumers in jurisdiction H and the costs of hydro-production are to be added to the program presented in Proposition 1 to study shallow integration:

$$\sum_{t=1}^{8760} \int_0^{D_t^H\left(p_R^H\right)} p_t^H(q)\,dq - C_H. \tag{5}$$

This constant term was cut out because it clearly does not affect water allocation.

It should be clear that the overall welfare will be higher in the deep integration regime than in the shallow one, the "augmented" program of Proposition 1 differ from the program of Proposition 3 by the sole addition of constraints, formally

$$e_t^H + x_t^{Th} - x_t^H = D_t^H \left(p_R^H\right).$$

The shift from Regime 2 to Regime 3 may yet meet resistance since the overall improvement that would follow such a change does not mean that all stakeholders would benefit from it.

The structure of the price pattern is identical in both regimes, with the only difference that the "price of water" λ is now equal to the prevailing equilibrium price in jurisdiction H, that we denote by p_e^H. This says that the threshold prices $\overline{p_{Th}}$ and $\underline{p_{Th}}$ *a priori* differ.

Proposition 4 *In Regime 3, when Th is exporting, the price in jurisdiction Th is at most $\overline{p_{Th}} = p_e^H - c^\tau$. When Th is importing, the price in jurisdiction Th is no less than $\underline{p_{Th}} = p_e^H + c^\tau$. If $x_t^{Th} = x_t^H = 0$ then*

$$\overline{p_{Th}} < p_t^{Th} = C'_{Th}\left(e_t^{Th}\right) < \underline{p_{Th}}.$$

Proof. *See appendix A.2.* ∎

It is noteworthy that price in H remains constant even after price regulation is removed. Indeed, price volatility is usually an important characteristic of deregulated electricity markets (see for instance Zareipour et al., 2007). One could thus fear it would be a necessary outcome of deregulation in the H jurisdiction. Our paper shows that this is not so. The intuition behind this result is however straightforward: if price in H was higher during some hours, then (price taker) producers would simply sell more during these hours, driving down the price with additional supply. If on the contrary price was lower during some hours, supply would contract, and the price would increase. This is of course only possible in a hydro system with enough storage and constant production cost, where water power can be freely allocated across time periods. The price in H is the marginal value of water over the entire horizon considered.

3.3 Model Calibration

In the following subsections, we provide details on the model calibration. Real supply and demand data for Ontario and Quebec have been used, along with some necessary assumptions and approximations on production costs and constraints, demand elasticity and emissions.

3.3.1 Demand Data for Ontario and Quebec

Because the Ontario electricity market is open and competitive, hourly demand and price data are publicly available on the Ontario Independent Electricity

System Operator (IESO) website. Hydro-Quebec does not release the hourly demand, but has to share with the North American Electric Reliability Corporation (NERC) monthly data on its peak load and total energy supply (NERC, 2008). Figure 1 illustrates peak demand and total monthly consumption for both markets. It can be observed that peak demand and energy consumption is higher in Quebec during winter, due to heating. This represents a major difference between the Quebec and Ontario electricity systems. This pattern is reversed during the summer, due to air conditioning.

Total power demand was 152.206 TWh in Ontario and 185.828 TWh in Quebec in 2007 (IESO, 2008b, NERC, 2008). As we need hourly data for the Quebec market but don't have them, these data have to be estimated. Knowing the monthly total consumption and peak load for Quebec, knowing also that daily load patterns in Ontario and Quebec are mostly similar due to the proximity of both markets, hourly demand data have been reconstructed for Quebec, based on the Ontario demand pattern. See Appendix B for more details on how this is done. The fact that Quebec has a winter peak and Ontario a summer peak does not represent a problem for such data reconstruction. This is because daily load curves have the same shape: low night loads, morning and evening peaks with a "shoulder" load between them.

Using these hourly price and demand values, $8,760$ hourly linear demand curves are estimated for every hour t and each province:

$$D_t^{Th} = a_t^{Th} - b_t^{Th} p_t^{Th}, \tag{6}$$
$$D_t^{H} = a_t^{H} - b_t^{H} p_t^{H}. \tag{7}$$

In addition to price and quantity data, a price elasticity value of -0.15 is used to compute the values of parameters a_t^j and b_t^j $(j = Th, H)$. This elasticity value reflects the short-term (in)elasticity of electricity consumption. See Lijesen (2007) for a survey of price elasticities in the electricity sector.

3.3.2 Supply and Marginal Cost Data

Table 1 presents the breakdown of the nominal generation capacity in Ontario and Quebec. This capacity is however not always technically available (as indicated by the "capability factor") and even less used (as indicated by the "production factor"). The capability factor reflects maintenance and occasional breakdowns. The production factor reflects the fact that it can be either uneconomical or impossible to produce. Data for the capability and production factors are observed 2007 data for Ontario (IESO, 2007). Nothing is shown for Quebec because there are no available public data.

For the sake of keeping the model of the supply side simple, the following assumptions are made. Ontario nuclear and hydro capacities are bundled and represent $12,694$ MW of capacity (after capability and production factors are taken into account). This can be justified by the fact that most hydropower

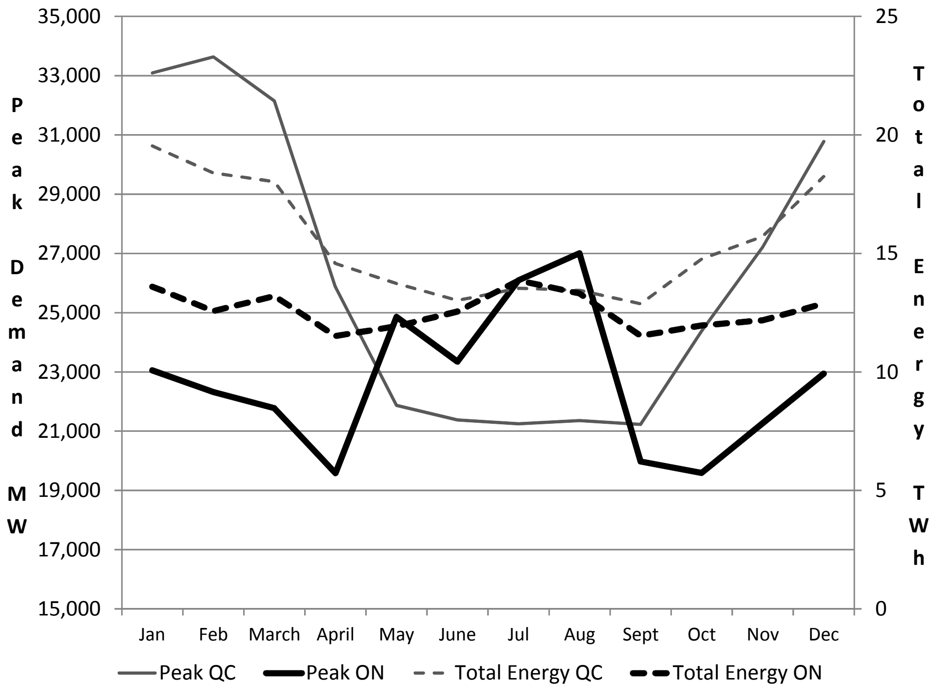

Figure 1: Monthly Peak Demand and Total Monthly Consumption

	ON Capacity (MW)*	Capability Factor	Production Factor	QC Capacity (MW)
Coal	6, 285	68%	42%	0
Natural Gas	2, 766	90%	54%	550
Hydro	7, 906	92%	45%	42, 640
Nuclear	11, 365	81%	75%	675
Oil	2, 100	79%	5%	1, 470
Wind	409	100%	30%	431
Wood Waste	225	81%	48%	454
TOTAL	31, 056			46, 220

*IESO (2007) **MRNF (2009) and Hydro-Québec Production (2009)

Table 1: Generation Capacity in Ontario and Quebec

in Ontario is run-of-river hydro with no storage capacity. Applying again the capability factor to thermal production, we allow only for 4, 265 MW of coal capacity and for 4, 145 MW of combined natural gas and oil capacity. Wind and wood waste are not modelled because they represent only a small share of the capacity in Ontario (2%, and even less of the actual energy production).

For Quebec, no capacity constraint is used, but an energy constraint is defined: 184.705 TWh of hydroelectricity can be produced. This value comes from the 2007 Quebec electricity demand (185.828 TWh, from NERC, 2008) minus net imports from Ontario (1.123 TWh, from HQ TransÉnergie, 2009). This is a realistic constraint, given that the actual peak load in 2007 was less than 35, 000 MW (see Figure 1), for a production capacity of 46, 220 MW. Furthermore, hydropower production in Quebec is limited by water availability, more than by actual plant capacity. We assume away thermal and wind generation, which represent less than 8% of the capacity (and even less of the actual energy production).[9]

Ontario marginal production costs, determining which technology is used on a hourly basis, are modelled in two parts. First, the nuclear marginal production cost is set constant at \$4.6/MWh.[10] This is an estimate of the combined fuel and operation and maintenance (O&M) costs of nuclear production (see for instance EIA, 2007:77 and IEA, 2005:44). Second, the marginal production cost for thermal production is assumed to be increasing linearly as more thermal capacity is used. Real 2007 price data are used to estimate this part of the Ontario marginal cost curve. Figure 2 illustrates price-quantity pairs for the 8, 760 hours of 2007, in Ontario. A simple linear regression of observed prices

[9] The thermal production in Quebec was dominated by the nuclear production (3%) in 2007 and much of the remaining is off-grid to supply remote communities in Northern regions. In 2007, combustion turbines represented less than 2% of the total Quebec dispatched production (Statistics Canada, 2009).

[10] This cost actually covers the combined nuclear and hydro production in Ontario. As already mentioned, there is less flexibility in using hydropower in Ontario compared to Quebec. Due to the lack of water storage capacity, both nuclear and hydro production in Ontario are "must run".

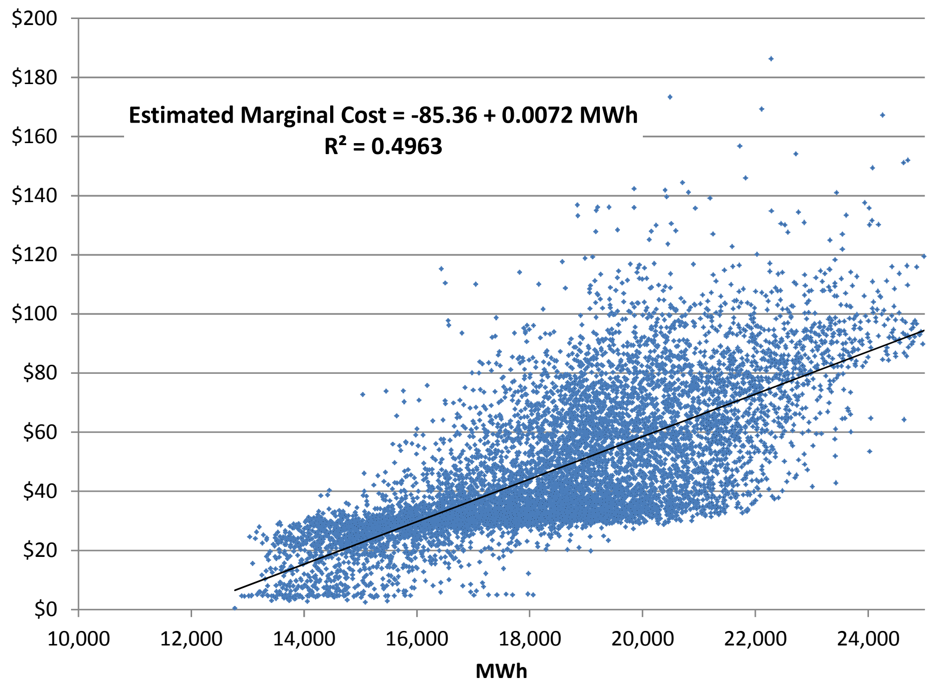

Figure 2: Marginal Production Cost Estimate for Generation in Ontario

and loads in Ontario provides parameters for the second part of the marginal cost function.

In Quebec, the marginal production cost is considered constant at $3.3/MWh, which is the estimated variable operation and maintenance cost for hydropower in EIA (2007:77).

3.3.3 Fixed Cost Data

EIA (2007) provides some estimates of investment and fixed O&M costs for various generation technologies; see Table 2. Using these estimates, the economic lifetime of these technologies and the discount rate of 6%, an annual fixed cost, per MW can be estimated for each technology.

Using the real Ontario and Quebec capacities and the above numbers, the annual fixed cost the Ontario electricity industry faces is estimated at $3.102 billion and $4.219 billion for Quebec.

	Economic Lifetime (Years)	$,000 /MW	Fixed O&M $/MW	Annual Cost $/MW
Coal	40	1,290	25,910	85,735
Natural Gas	25	594	11,010	46,466
Hydro	60	1,500	13,140	92,813
Nuclear	40	2,081	63,880	138,306
Oil	40	420	11,400	27,913
Wind	20	1,202	28,510	104,795
Wood Waste	40	1,869	50,180	124,216

Table 2: Technology Cost Parameters

3.3.4 Transmission Constraints and Cost

In 2007, the operating security limits for exports from Quebec to Ontario was 1,295 MW, while is was 720 MW for Quebec imports from Ontario. Real hourly maximum transmission capacities differ from these numbers. HQ TransÉnergie (2009) provides such capacities for every hour of the year. These can be used to set maximum import and export quantities. However, observed exports and imports show that transmission lines are only used, on average, at 29.9% of the full capacity for Quebec exports (to Ontario) and at 53.2% of the full capacity for Quebec imports (from Ontario). This is likely due to transmission constraints attached to the grid topology which are not modelled here. In order to better calibrate trade in the model and to better reflect real market outcomes, hourly transmission capacities are adjusted by a ratio set such that the aggregated modelled export and import values match the observed ones.

A transaction cost of $2/MWh of traded electricity is applied in the model. This cost, which is not obvious to quantify, is only an estimate. Indeed, electricity sellers in Ontario are not charged any transmission fee: the Ontario Provincial Transmission Service Rate only applies to consumers withdrawing electricity from the network. Exports from Ontario, however, have to pay a $1/MWh "Export Transmission Service Rate". In Quebec, a $8.22/MWh Non-Firm Point-to-Point Transmission Services fee has to be paid to HQ TransEnergie. However, as Hydro-Quebec dominates the markets and is the principal trader, this fee is charged to one division (production) from another one (transmission), but does not affect the overall profitability of the company.

3.3.5 Emission Data and Marginal Damage

Greenhouse gases (GHG) emissions from electricity production in Ontario and Quebec in 2007 were respectively 34 million of tonnes (Mt) and 1.95 Mt (Environment Canada, 2009). On average, coal production in Ontario is responsible for about 0.94 t/MWh, while natural gas production emits about half, 0.43 t/MWh (Environment Canada, 2008).[11] We only report these two number be-

[11]Specific GHG intensity by source of electricity production (in g CO_2 eq/kWh) are not reported for 2007 in Environment Canada (2009). We use instead 2006 Ontario values from

cause emissions from other sources are not significant.

Estimates for the social marginal damage of a ton of GHG greatly vary. IPCC (2007) reports estimates from -\$3 to \$95/t, with an average of \$12/t. Tol (2005) analyses 28 peer-reviewed marginal damage cost estimate studies, and finds an average value of \$93/t, while the median is \$14/t. In both cases, high uncertainty characterizes these values.

To provide an order of magnitude from a Canadian perspective, British Colombia implemented a carbon tax in 2008, which reached the value of \$30/t in 2012 (Province of British Columbia, 2009). In a different continent, GHG credits for December 2009 were trading at €10.05 in the European Climate Exchange, on February 9, 2009. Credits for future years were trading at higher prices, reaching €13.70 for a December 2014 credit. Note that, in our setting, it takes a marginal damage greater than \$56/t for natural gas units to become more economical to operate than coal units, that would then only be used in peak load periods.

3.3.6 Computing Market Equilibria

Given our market model and its calibration to Ontario and Quebec, it is possible to compute hourly market equilibria for our three regimes of interest, as seen in Propositions 1-4. The implementation of the model requires finding the unique value of λ, the Lagrange multiplier associated to the "Total water availability", which is such that all markets balance. Given transaction costs, either exports, imports or no trade happen between the two jurisdictions.

A single constraint binds electricity supply in Quebec: the sum of Quebec hydropower production cannot exceed 184.7 TWh over all hours of the year:

$$\sum_{h=1}^{8760} e_t^H \leq 184,705,000$$

Basic properties of the different cases are used to compute the actual equilibrium: price is equal to marginal cost in Ontario and to average cost in Quebec in the two first regimes (here, average cost is \$27.90/MWh for regime 2, while it is \$29.02/MWh in regime 1, due to the absence of imports from Ontario to Quebec); exports and imports are done at the Ontario marginal cost; under integration, Ontario and Quebec prices are equal, unless transmission capacity becomes binding.

Transmission capacity constraints provide upper and lower bounds on trade, and constrained prices are computed. The challenge consists of finding the single Quebec price that will make use of all the available hydropower while respecting all the (first order) conditions of the problem. As shown in propositions 1 and 3, the problem can be solved by optimization. There is a single price for very hour in Quebec, because the Quebec price is the shadow cost of water, which is unique over the year.

Environment Canada (2008), which reports them.

4 Results for the Three Regimes

4.1 Calibrated Model Results

Our model of the 2007 Ontario (Th) and Quebec (H) markets is calibrated to reflect actual trade between these two jurisdictions operating under a mixed market structure (shallow integration). In 2007, Ontario exported 1.93 TWh to Quebec, and imported 0.807 TWh from Quebec, for a net export total of 1.123 TWh. Our model of shallow integration (R2) exactly replicates such export and import numbers. Ontario prices do not perfectly match, however real 2007 price, as shown in Table 3. Our model R2 (shallow integration) slightly overestimates Ontario prices ($48.52/MWh, on average, against a real average hourly price of $47.81), the Ontario export price to Quebec ($38.84/ MWh against $37.15) and the import price to Ontario ($71/ MWh against $67.20). The Quebec average price is obviously the same, because it is directly taken from the 2007 data.

Average price **$/MWh**	2007 Data*	R1	R2	R3
p^{Th}	47.81	47.96	48.52	46.79
p^{H}	27.90	29.02	27.90	30.91
Export from Th	37.15	–	38.84	22.80
Export from H	67.20	–	71.00	53.88
Min p^{Th}	-0.4**	4.60	4.60	4.60
Max p^{Th}	436.53	167.66	165.39	165.39

*Average Ontario export and Quebec export prices are computed from HQ TransÉnergie (2009) and IESO (2008a).

**This negative price occurred during an August night and are among a few outliers. Figure 2 shows that minimum prices are at about $4

Table 3: Price Results

What is interesting to comment is the difference between the three regimes: autarky (R1), shallow integration (R2) and deep integration (R3). Autarky brings slightly lower average prices to Ontario, as it does not have to produce more to export to Quebec. In Quebec, because there is less available energy, prices are also higher ($29.02/MWh against $27.90). Fully integrating both markets by using marginal cost pricing (with limited transmission capacity) increases the Quebec price by $3/MWh (+10.8%), while the Ontario price goes down to $46.79/MWh (-3.5%), given its access to more imports from Quebec.

Table 4 provides the demand and supply quantities resulting from the prevailing prices. The Ontario demand (using a demand price elasticity of -0.15) slightly increase in autarky (+0.27%, due to lower prices) compared to shallow integration. Under deep integration, demand increases by 0.56%, again due to the lower prices. In Quebec, the opposite happens: -0.6% in autarky and -1.62% under deep integration, compared to shallow integration. On the supply side, relatively important generation reductions happen in Ontario: almost 1 TWh would not be generated in autarky (-0.42%), while 3 TWh (-1.29%) less would be produced under deep integration. Of course, these reductions lead to lower profits for Ontario generators, as shown in Table 5. Obviously, supply from Quebec remains stable at 184.70 TWh. The share of trade increases with shallow integration (from R1 to R2) and again with deep integration (R3). It still remains a small fraction of total consumption.

TWh	2007 Data	R1	R2	R3
$\sum D_t^{Th}$	162.25	162.39	161.94	162.85
$\sum D_t^{H}$	185.82	184.70	185.82	182.823
Total Demand	348.083	347.09	347.77	345.67
$\sum e_t^{Th}$	n.a.	162.39	163.06	160.96
$\sum e_t^{H}$	n.a.	184.70	184.70	184.70
Share of Trade*	n.a.	0%	0.79%	0.83%

*Sum of exports and imports over overall demand.

Table 4: Supply and Demand Results

Million $	2007 Data	R1	R2	R3
Change of Consumer Surplus Th	n.a.	+61	–	+275
Change of Consumer Surplus H	n.a.	−208	–	−554
Change of Profit Th	n.a.	−63	–	−275
Change of Profit H	n.a.	+198	–	+601
Consumer Surplus+Profit	n.a.	−12	–	+47
Coal Emissions (million t)		28.74	29.29	28.60
NG Emissions (million t)		8.86	8.90	8.31
Total Emissions (million t)	34	37.60	38.19	36.92

Table 5: Welfare Impacts

While Ontario consumers marginally increase their surplus in autarky (+$61 million, or $4.76 per capita), they benefit more from integration (+$275 million, or $21.50 per capita); see Table 5. Quebec consumers, on the other hand, lose much more in either case: -$27.05 per capita (-$208 million globally) with autarky, or -$71.97 per capita (-$554 million) with integration, as they lose their regulated access to low-price electricity. However, the limited transmission capacity "protects" them against a further increase. Sharing a similar outcome, Ontario producers see their profit decrease with lower production levels, both in autarky (-$63 million) and integration (-$275 million). It is clear from these results that while consumers in Quebec don't want integration, opposition would also be strong from Ontario producers. Profit for the Quebec producer, however, would increase a lot from higher local prices and additional exports, made at a even higher price (as compared to the local price). In the integrated regime (R3), as compared to shallow integration (R2), additional profits in Quebec (+$601 million) are more than twice the decrease in profits faced by Ontario producers (-\$275 million). Net gains per capita amount to -\$0.62 from regime 2 to 1 and to \$2.31 from regime 2 to 3, without accounting for GHG emissions. As emissions decrease by 1.76 Mt from regime 2 to 3, while welfare increases by \$47 million (see Table 5), we obtain an abatement cost of -\$37.16/t. This result, although expected, is striking as GHG emission reduction efforts are usually associated with a positive cost.

When damages from emissions are accounted for, as illustrated in Table 6, regime 2 is clearly the worse in terms of total welfare. Indeed, total emissions (especially from coal power plants) increase from R1 to R2 (+1.5%). The damage is therefore lower in autarky, as shown in Table 5. This comes from Quebec imports from Ontario in off-peak periods, in part re-exported during peak periods. Under integration, total emissions decrease by 3.34%, as power plants in Ontario are used less often. Let us again emphasize that these reductions in GHG emissions come with an overall welfare improvement, as illustrated in Table 6.

Change in Million \$	R1	R2	R3
Th CS + Profit	−2.41	–	+0.30
H CS + Profit	−10.28	–	+47.12
Total CS+Profit	−12.70	–	+47.42
Marginal Damage Th (@20\$/t)	−11.80	–	−25.52
Marginal Damage H (@20\$/t)	−11.80	–	−25.52
Total Damage (@40\$/t)	−23.61	–	−51.05
Total Welfare (CS+Profit-Damage)	+10.91	–	+98.47

Table 6: Total Welfare Impacts

Only if the damage cost was lower than \$21.5/t would trade gains made under shallow integration (R2) be greater than the environmental cost resulting from higher emissions. Interpreted differently, removing transmission (going from R2 to R1) would lead to lower emissions and a lower welfare, equivalent to an abatement cost of \$21.5/t.

4.2 Doubling Transmission Capacity

In the previous section, all results were presented for transmission capacities between 93 and 451 MW for Quebec to Ontario flows and 92 to 391 MW for Ontario to Quebec flows. These transmission capacities were adjusted from reported maximum transmission capacities to better model real 2007 power exchange between the two provinces. It is interesting to analyze the impact of an increase in transmission capacity between the two jurisdictions, as indeed it happened in 2010, with the addition of about 1,000 MW of transmission capacity. This was an initiative of the Quebec producer. In this section, we provide results for twice the initial modelled transmission capacity.

In Table 7, doubling the transmission capacity under shallow integration (R2 x2) and deep integration (R3 x2) further decreases the price in Ontario, compared to the initial outcome (reproduced in Table 7). In Quebec, the price increase only happens under deep integration (as average cost is not used anymore), and is significantly higher than previously ($32.48/MWh compared to $30.91 with half the transmission capacity). More transmission capacity also reduces export and import prices, except under integration for the Ontario export price: it grows from $22.80/MWh to $24.97. There are actually two price effects. The increase in arbitrage across periods that follow from the increase in trade capacities tend to reduce the price gap between import and export periods in Ontario.[12] On top of this, there is an average price effect that follow from changes in net traded volume. In particular, under deep integration, Quebec becomes a net exporter of electricity (from a net importer situation under shallow integration), because more hydropower is available for exports as a result of the lower Quebec consumption.

Average price **$/MWh**	R2	R3	R2 x2	R3 x2
p^{Th}	48.52	46.79	48.41	45.80
p^{H}	27.90	30.91	27.90	32.48
Export from Th	38.84	22.80	37.60	24.97
Export from H	71.00	53.88	65.24	52.91
Min p^{Th}	4.60	4.60	4.60	4.60
Max p^{Th}	165.39	165.39	163.12	163.12

Table 7: Price Results for Twice the Transmission Capacity

Trends already observed in terms of consumption and production (in Table 4) are again observed in Table 8. One exception, however, is worth mentioning: total consumption in Ontario goes down with more transmission (-0.08%), despite lower (unweighted) average price[13] (-0.22%; Table 7). This is due to the fact that hourly patterns lead to some price increase and some price decrease. On a hourly basis, changes are consistent with the price-quantity relationship, but on the aggregate, a smaller average price and a smaller total consumption are observed. Quebec consumption decreases by 0.86% in the R3 x2 case, as compared to R3. This is 2.46% less than consumption under shallow integration (R2 x2 or R2 - Since price is regulated in Regime 2, Québec consumption is identical in both cases). Overall total demand decreases by 0.95% in R3 x2 as compared to R2.

Table 9 displays losses and gains similar to those of Table 5. Additional transmission capacity further increases consumer surplus in Ontario, while it further reduces the consumer surplus in Quebec (except under R2 x2, where price remains constant for consumers despite more access to the Ontario market). Profits of the Ontario producers continue to shrink, while the Quebec

[12] The Quebec producer imports as much as possible during low-price periods, to re-export at higher price. These additional Quebec imports from Ontario increase the Ontario (export) price, while re-exporting this energy decreases the (Ontario) import price.

[13] A weighted average price would weigh hourly price by the hourly consumption.

TWh	R2	R3	R2 x2	R3 x2
$\sum D_t^{Th}$	161.94	162.85	161.81	163.20
$\sum D_t^{H}$	185.82	182.823	185.82	181.25
Total Demand	347.77	345.67	347.64	344.46
$\sum e_t^{Th}$	163.06	160.96	162.93	159.75
$\sum e_t^{H}$	184.70	184.70	184.70	184.70
Share of Trade*	0.79%	0.83%	1.53%	1.62%

*Sum of exports and imports over overall demand.

Table 8: Supply and Demand Results for Twice the Transmission Capacity

producer continues to increase its own profit. This is an important driver for the addition of transmission capacity. Export revenues grow in all cases, as would be expected with more trade opportunities. Emissions are made worse under shallow integration with more transmission capacity (+0.39%), especially from the more intense imports made in off-peak periods. There are more coal emissions, while natural gas emissions go down. In the R3 x2 case, emissions decrease even more (-1.52%), as compared to R3. The abatement cost for the additional emissions is -$91.86/t, as a result of the high profits made on some hydropower replacing natural gas. This value comes from the welfare and emission differences between R3 x2 and R3, as shown in Table 9 .

Million $	R2	R3	R2 x2	R3 x2
Change of Consumer Surplus Th	–	+275	+54	+466
Change of Consumer Surplus H	–	−554	0	−840
Change of Profit Th	–	−275	−84	−458
Change of Profit H	–	601	32	931
Consumer Surplus+Profit	–	+47	+2	+99
Coal Emissions (million t)	29.29	28.60	29.67	28.53
NG Emissions (million t)	8.90	8.31	8.62	7.82
Total Emissions (million t)	38.19	36.92	38.34	36.36

Table 9: Welfare Impacts for Twice the Transmission Capacity

Table 10, the last one, shows that more trade (through more integration and/or more transmission capacity) increases welfare, before accounting for environmental damages. As shown by Billette de Villemeur and Pineau (2012), this was not completely obvious as price regulation may result in trade being inefficient. As a matter of facts, in Regime 2, the welfare gains that follow from doubling the capacity are very low. Beyond this, we illustrate with this example that increasing trade under shallow integration can be welfare-damaging, even if the Quebec producer increases its profits. After accounting for emission damages, the net gain from trade might indeed be negative. Only if the total damage per tonne is lower than $17.40 would the trade gain be greater than the additional damages. Another interpretation for this value of $17.40/t is that it represents the abatement cost of emissions through *reducing* the transmission capacity between the two markets (under shallow integration).

Note also that additional transmission investment costs are not accounted for in these regimes. A more thorough analysis should include them.

Change in Million $	R2	R3	R2 x2	R3 x2
Th CS + Profit (Billion)	–	+0.30	−29.39	+8.02
H CS + Profit (Billion)	–	+47.12	+32.00	+90.94
Total CS+Profit (Billion)	–	+47.42	+2.61	+98.96
Marginal Damage Th (@20$/t, Billion)	–	−25.52	+3.00	−36.75
Marginal Damage H (@20$/t, Billion)	–	−25.52	+3.00	−36.75
Total Damage (40$/t, Billion)	–	−51.05	+6.00	−73.5
Total Welfare (CS+Profit-Damage)	–	+98.47	−3.38	+172.45

Table 10: Total Welfare Impacts for Twice the Transmission Capacity

5 Conclusion

This paper offers both a theoretical and an empirical perspective on welfare impacts of electricity market integration, taking generating capacity as given. Integration is on the policy agenda of many governments and institutions, but is seldom analyzed theoretically or empirically. We propose a multi-period two-jurisdiction electricity market model to study integration impacts in terms of welfare implications and emissions, with insights on their distribution. This model involves a competitive thermal jurisdiction with a marginal pricing policy and a hydro one with an average-cost pricing regulation. A detailed calibration is made using Ontario and Quebec (Canada) production and demand data.

Under various integration regimes (autarky, shallow integration and deep integration), we are able to obtain results showing how production, price and emissions evolve. This modelling effort represents the first contribution of the paper, as the literature so far has not focussed on comparable detailed integration outcomes. The second contribution comes from estimates of GHG abatement costs in the electricity sector, resulting from integration. With electricity being an important contributor to world GHG emissions, abatement opportunities with negative cost (as we find in this paper) should be contemplated.

Numerical results show that increasingly lower prices would be observed in the thermal jurisdiction if deep integration would be implemented (-3.5%) and transmission capacity doubled (a further -2.1%). This benefits consumers, but not producers in the thermal jurisdiction. On the contrary, in the hydro jurisdiction, consumers face higher prices (and therefore lose some surplus) with deep integration (+10.8%) and more transmission capacity (+5.1%), while profit significantly increase for the hydro producer. Emissions follow the thermal producers's fate: they decrease as integration develops. Remarkably in a world where GHG emissions reduction are often associated with a cost, a negative abatement cost is obtained: -$37.16/t under deep integration, jumping to -

\$91.86/t for the additional reduction that would follow doubling the additional transmission capacity.

This paper also offer an important warning. Under shallow integration, (*i.e.* when the hydro jurisdiction stick to its average pricing policy), any additional trading leads to *higher* emission levels. In other words, if the institutional settings continue to be overlooked when proceeding to electricity market integration, integrating an hydro-jurisdiction to a thermal one is actually likely to be environmentally damaging.

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A Proofs

A.1 Proof of Proposition 2

Proposition 2: In Regime 2, when Th is exporting, the price in jurisdiction Th is at most $\overline{p_{Th}} = \lambda - c^{\tau}$. When T is importing, the price in jurisdiction Th is no less than $\underline{p_{Th}} = \lambda + c^{\tau}$. If $x_t^{Th} = x_t^H = 0$ then

$$\overline{p_{Th}} < p_t^{Th} = C'_{Th}\left(e_t^{Th}\right) < \underline{p_{Th}}.$$

The proof of Proposition **2** is based upon the following intermediate result:

Proposition 5 ***1****Computing the equilibrium in Regime 2 amounts to solve the optimization program*

$$\max_{\left\{e_t^{Th}, x_t^{Th}, x_t^H\right\}_{t=1,\ldots,8760}} \left\{\sum_{t=1}^{8760}\left[\int_0^{e_t^{Th}+x_t^H-x_t^{Th}} p_t^{Th}(q)\,dq - C_T\left(e_t^{Th}\right) - c^{\tau}x_t^{Th} - c^{\tau}x_t^H\right]\right\}$$

$$s.t. \quad \sum_{t=1}^{8760}\left(x_t^H - x_t^{Th}\right) \leq W - \sum_{t=1}^{8760} D_t^H\left(p_R^H\right) \quad and \quad -\overline{x}_t^{Th} \leq x_t^H - x_t^{Th} \leq \overline{x}_t^H,$$

all $t = 1, ..., 8760$.

Let $\mathcal{L}$ denote the Lagrangian associated with the optimization problem of Proposition **1**. We have:

$$\begin{aligned}\mathcal{L} &= \sum_{t=1}^{8760}\left[\int_0^{e_t^{Th}+x_t^H-x_t^{Th}} p_t^{Th}(q)\,dq - C_T\left(e_t^{Th}\right) - c^{\tau}x_t^{Th} - c^{\tau}x_t^H\right] \\ &\quad +\lambda\left\{W - \sum_{t=1}^{8760}\left[D_t^H\left(p_R^H\right) + x_t^H - x_t^{Th}\right]\right\} + \sum_{t=1}^{8760}\left[\mu_t^H\left(\overline{x}_t^H - x_t^H + x_t^{Th}\right) + \mu_t^{Th}\left(\overline{x}_t^{Th} - x_t^{Th} + x_t^H\right)\right].\end{aligned}$$

Absent transmission constraints, price patterns are easily characterised. The FOC $\left(\partial\mathcal{L}/\partial e_t^{Th}\right) = 0$ implies that $p_t^{Th} = C'_{Th}\left(e_t^{Th}\right)$.
If $x_t^H > 0$, then $\left(\partial\mathcal{L}/\partial x_t^H\right) = 0$ yields $p_t^{Th} = \lambda + c^{\tau}$; if $x_t^{Th} > 0$, then $\left(\partial\mathcal{L}/\partial x_t^{Th}\right) = 0$ yields $p_t^{Th} = \lambda - c^{\tau}$; if $x_t^{Th} = x_t^H = 0$, then we have:

$$\lambda - c^{\tau} \leq p_t^{Th} = C'_{Th}\left(e_t^{Th}\right) \leq \lambda + c^{\tau}.$$

$>$From the optimization program of Proposition **1** and by definition of the hourly Lagrange multipliers of the transmission constraint μ_t^H and μ_t^{Th}, when H is exporting, that is $x_t^H > 0$, but the transmission constraint is binding, we have[14]

$$p_t^{Th} = \lambda + c^{\tau} + \mu_t,$$

[14] This is the first-order condition obtained by derivation of the Lagrangian with respect to the variable x_t^H.

with $\mu_t = \mu_t^H \geq 0$ (and $\mu_t^{Th} = 0$). Thus $p_t^{Th} \geq \underline{p_{Th}}$.
Similarly, when Th is exporting, that is $x_t^{Th} > 0$, but the transmission constraint is binding, then[15]

$$p_t^{Th} = \lambda - c^\tau - \mu_t,$$

with $\mu_t = \mu_t^{Th} \geq 0$ (and $\mu_t^H = 0$). Thus $p_t^{Th} \leq \overline{p_{Th}}$.

If $\overline{p_{Th}} < p_t^{Th} < \underline{p_{Th}}$ the marginal benefits from trade are strictly lower than the transmission costs c^τ. It is both welfare- and profit-maximising to restrain from trading. Clearly, we still have $p_t^{Th} = C'_{Th}\left(e_t^{Th}\right)$.

A.2 Proof of Proposition 4

Proposition 4: In Regime 3, when Th is exporting, the price in jurisdiction Th is at most $\overline{p_{Th}} = p_e^H - c^\tau$. When Th is importing, the price in jurisdiction Th is no less than $\underline{p_{Th}} = p_e^H + c^\tau$. If $x_t^{Th} = x_t^H = 0$ then

$$\overline{p_{Th}} < p_t^{Th} = C'_{Th}\left(e_t^{Th}\right) < \underline{p_{Th}}.$$

The equality $p_t^H = p_e^H = \lambda$ is obtained from the first-order condition associated to the choice of e_t^H in the optimization program of Proposition **3.** The demonstration is then identical to that of Proposition 2 above.

B Estimating Quebec hourly demand

For a hour t (in a month m), the Quebec demand D_t^H is estimated by an affine transformation of the Ontario demand (D_t^{Th}):

$$D_t^H = \gamma_m D_t^{Th} + \delta_m.$$

In order to compute γ_m and δ_m, we use for every month the observed ratio between Quebec and Ontario peak demands (r_m^{peak}) and total consumptions (r_m^{total}), as illustrated in Figure 1:

$$r_m^{peak} = \frac{D_{peak}^H}{D_{peak}^{Th}} \text{ and } r_m^{total} = \frac{\sum D_t^H}{\sum D_t^{Th}}.$$

This results in

$$\begin{aligned} \gamma_m &= \frac{\sum D_t^H - N_m D_{peak}^H}{\sum D_t^{Th} - N_m D_{peak}^{Th}} \\ \delta_m &= \left(r_m^{peak} - \gamma_m\right) D_{peak}^{Th} \end{aligned}$$

where N_m is the number of hours in month m.

[15] This is the first-order condition obtained by derivation of the Lagrangian with respect to the variable x_t^{Th}.

To summarize, we observe hourly Ontario prices from IESO (2008a) and hourly Ontario demands from IESO (2008b). With NERC (2008) and the above affine transformation, we estimate hourly Quebec demands. Quebec energy price is fixed at \$27.90/MWh.