Cross-Border Trade in Electricity

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Abstract

This paper develops an economic theory of cross-border two-way trade in electricity in which regulated electric utilities engage in profitable trading opportunities when they have sufficient reserve capacity. Electricity demand is stochastic. Two-way trade emerges in similarity to models of 'reciprocal dumping.' Whereas in those models firms engage in rent-seeking reciprocal market access, in the present model electric utilities simply exploit cost variations in order to enhance economic efficiency through 'reciprocal load smoothing.' After deriving estimating equations, the model is tested with cross-border trade data, exports from Canadian provinces to U.S. states. The empirical tests strongly support the theoretical model. Reciprocal load smoothing provides an economically significant rationale for integrating North America's fragmented interconnections into a continental 'supergrid.'

Keywords: electricity, international trade

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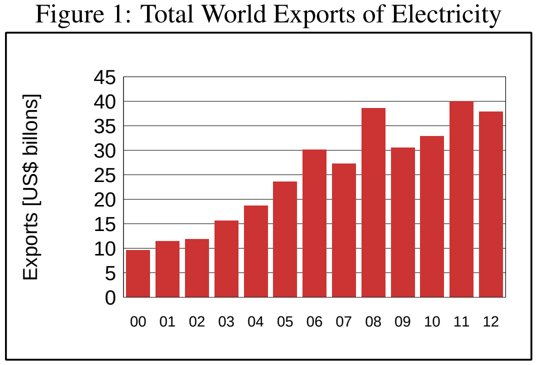
1. Introduction

Cross-border trade in electricity is not quite like international trade in other commodities. Electricity is traded mostly over relatively short distances with neighbouring jurisdictions within an integrated electrical transmission grid. Electricity trade across borders is also two-way in many instances. A jurisdiction may import *and* export electricity over the course of a year, a single day, or even at the same time if there are multiple transmission lines (interties) across a border. The peculiarities of electricity generation and transmission limit the applicability of conventional trade models. There is little scope for Ricardian comparative advantages based on technology differences. There is a limited scope for neoclassical comparative advantage based on factor endowments for hydroelectric power and other renewable energy sources. Modern trade theories based on product differentiation do not apply because electricity is a homogenous good. A new theoretical model is needed that can account for the reality of two-way cross-border trade in electricity. This paper develops such a model and puts it to the test empirically using electricity exports from Canadian provinces to US states.

International trade in electricity is miniscule by the standard of overall trade in good services. In 2011, exports of electricity amounted to barely forty billion US Dollars (and 662 TWh), only about 0.225% of the nearly eighteen trillion US Dollars of worldwide trade. In that year only 87 nations reported positive exports or imports. Yet trade in electricity has become vital for many countries, and as figure 1 shows, in the last decade electricity trade has quadrupled.

Unlike other commodities, electricity cannot be stored; supply must meet demand instantaneously.[2] As a result, self-reliant jurisdictions need to maintain sufficient reserve generation capacity to meet peaks in fluctuating demand. International trade opens up opportunities to reduce excessive reserve capacity as well as import electricity from neighbouring countries that have a comparative ad-

Figure 1: Total World Exports of Electricity



Source: UN Comtrade, HS 271600.

[2]A very small amount of electricity can be stored through hydroelectric reservoir pumping. Currently, there are no economically viable large-scale technological solutions for storing electricity.

vantage in electricity generation due to favourable resource endowments. Technologically, the main barrier to an increase in international trade in electricity has been the problem of long-distance power transmission. High-voltage direct current (HVDC) transmission lines are more economical than alternating current transmission lines and can also be used for undersea links. Still, HVDC losses amount to roughly 3.5% per thousand kilometer (about 6% per 1,000 miles), and constructing new HVDC links remains very expensive. Among the most important HVDC links is the 1,362 km (846 miles) Pacific DC Intertie from northern Oregon to Los Angeles. First completed in 1970, by 2004 it was upgraded to a capacity of 3.1 GW. Significant new construction of HVDC lines is currently under way (particularly in China and Brazil), although very little of the new capacity crosses country borders.

Electricity generation in most jurisdictions is characterized by self-sufficiency mandates and a high level of government control. Because electricity distribution (although not electricity generation) is a natural monopoly, governments often exert control over electricity generation and distribution through government ownership or through other forms of regulation (Everett, 2003). Retail prices for electricity are set by utility commissions that largely amount to cost-plus markup rules. Experiments with privatization (such as in Britain) primarily focused on electricity generation and electricity trading, with the implicit goal of promoting market entry of independent power producers (IPPs) that would compete with the established utilities (Rothwell and Gómez, 2003). The economics of power markets has attracted considerable attention due to the inherent complexities of electricity generation and transmission (Stoft, 2002; Harris, 2006). Because of government-mandated self-sufficiency, trade in electricity across jurisdictional boundaries (both subnational and national) is mostly an afterthought, albeit a very profitable one. For trade economists, it is easy to identify excessive self-sufficiency as autarkic inefficiency.

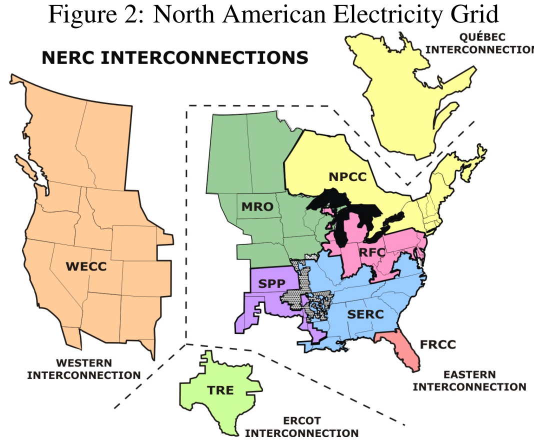
This paper approaches the issue of cross-border trade in electricity both theoretically and empirically. To the best of my knowledge, mine is the first paper to tackle this issue in a rigorous trade-theoretical context by introducing a new model of two-way international trade.

The empirical reality of trade in electricity exhibits a pattern of two-way trade. Two-way trade is well understood within the context of product differentiation, where love-of-variety preferences lead to intra-industry trade where countries simultaneously import and export similar (although not identical) goods. By comparison, trade in a classical or neoclassical model is inter-industry—and thus one-way. While factor endowments clearly plays a role in determining comparative advantage for electricity generation, the neoclassical model alone cannot account for the empirical reality of two-way trade. A new model is needed that can encompass both one-way and two-way trade in electricity.

The theoretical section of this paper adapts the Brander (1981) and Brander and Krugman (1983) model of 'reciprocal dumping' to the context of efficiency-seeking trade in electricity. In addition to conventional comparative advantage, a key driver of trade in electricity is the stochastic variation in electricity demand across jurisdiction coupled with the (often strong) convexity of electricity generation cost. Under fairly general conditions, jurisdictions will engage in two-way trade in electricity. Unlike Brander (1981), the reason for this two-way trade is not strategic and rent-seeking because retail prices are regulated. Instead, two-way trade is primarily efficiency-seeking through 'reciprocal load smoothing.'

Understanding the rationale for electricity trade informs the quantification of the possible gains from trade. How (in)efficient is today's trade regime? What is the potential for additional gains from trade if the North American electric grid was fully integrated? Indeed, a well-known source of inefficiency is the regional separation of electricity grids in North America, illustrated in figure 2.

Figure 2: North American Electricity Grid



Source: North American Electric Reliability Corporation

Transmission of bulk electricity in North America is managed by the *North American Electric Reliability Corporation* (NERC) and in the United States is regulated by the *Federal Energy Regulatory Commission* (FERC). NERC's standards and policies apply throughout the United States and Canada. There is in fact no continent-wide grid. Instead, there are several interconnections (i.e., wide area synchronous grids) that operate mostly separate from each other. The two most important are the Western Interconnection and the Eastern Interconnection. The other three interconnections serving Quebec, Alaska, and Texas are smaller in size. There are also nine NERC regional reliability councils that coordinate activities in their corresponding regions. Transmitting power between interconnections is technically challenging, precluding trade among neighbouring jurisdictions and hampering long-distance east-west trading opportunities. To trade economists, North America's power grid looks like free trade areas separated by tariff walls.

The empirical analysis in this paper makes use of export data from Canadian provinces to US states. The geographic west-east alignment of Canadian provinces along the US border allows for trade with neighbouring provinces as well as trade with many (not merely neighbouring) US states. Sufficiently disaggregated data is available at the monthly level, allowing for the identification of seasonal patterns in electricity trade. There is a limited number of cross-border trading pairs. Among the ten Canadian provinces and 49 landlocked US states (plus DC), there are 500 potential trading pairs. However, there are only 75 actual trading pairs—or 15% of the potential. The extensive margin dominates the trading patterns.

2. Empirical Patterns of Trade in Electricity

Table 1 shows average annual generation and demand of electricity in the ten Canadian provinces and three territories. In most provinces, output and demand match closely. Most provincial utilities operate under a mandate of self-sufficiency. A few provinces export a significant amount of electricity to neighbouring provinces. For example, the province of Newfoundland and Labrador exports most of its electricity to neighbouring Quebec.[3]

Table 2 provides simple correlation statistics for electricity demand in the ten provinces (aligned geographically from west to east). In some instances, demand correlation between neighbouring provinces is relatively high and exceeds 0.8. Interestingly, the correlation between two pairs of large provinces are modest: demand in Alberta and British Columbia is correlated at 0.37, and demand in Ontario and Quebec is correlated at 0.43. The point to take away is that correlations are far less than perfect, and this opens up a source for gains from trade.

Table 3 extends the correlation analysis to the pairs of eight provinces and 32 US states that are engaged in cross-border electricity trade. Actual trading partners are highlighted in boldface, while hypothetical trading partners are shown in italics. Many of the existing trade partners exhibit positively-correlated electricity demand. As the theoretical section will demonstrate later, lower and negative correlations are associated with a higher potential for trade. In the case of British Columbia, trade with California, Nevada, Arizona, New Mexico, and Texas is particularly beneficial because of the negative correlations. As is easily seen, many

[3]The Churchill Falls hydroelectric dam in Labrador, with an installed capacity of 5,428 Megawatt from 11 turbines, delivers electricity to the province of Quebec under a long-term power purchasing agreement that is a highly favourable to Quebec at today's prices.

Table 1: Average Annual Electricity Generation, Consumption, Exports and Imports by Province (2008-2012)

Province	Output [GWh]	Demand [GWh]	Exports CA[%]	Exports US[%]	Imports CA[%]	Imports US[%]
Canada	585,173	550,163		8.9		3.1
Alberta	61,163	64,228	0.3	0.3	4.2	1.2
British Columbia	64,649	64,670	3.4	13.0	0.3	15.6
Manitoba	33,962	24,426	4.1	26.8	2.8	1.0
New Brunswick	11,830	14,511	11.0	9.9	30.1	5.5
Newfoundland and Labrador	41,000	11,423	72.2		0.2	
Nova Scotia	11,333	11,726	0.1	0.1	1.9	1.6
Northwest Territories	671	671				
Nunavut	166	166				
Ontario	145,075	132,535	3.9	9.7	2.6	2.7
Prince Edward Island	216	1,197	23.3		86.2	
Quebec	193,364	202,835	3.6	10.0	17.1	0.5
Saskatchewan	21,334	21,424	5.2	0.5	4.6	1.5
Yukon	411	411				

Note: Output is total generation of electricity in gigawatthours (GWh). Demand is total electricity available for use with the province in gigawatthours (GWh). Exports are the delivery of electricity to other provinces (CA) and the United States (US). Imports are the receipts of electricity from other provinces (CA) and the United States (US). Exports and imports are expressed in percentages of output and demand, respectively. Source: Statistics Canada CANSIM Table 127-0003.

Table 2: Correlation of Monthly Provincial Electricity Demand

	BC	AB	SK	MB	ON	QC	NB	NS	PE	NL
BC		0.37^b	0.58^d	0.91^d	0.49^d	0.91^d	0.87^d	0.80^d	0.42^c	0.87^d
AB	0.37^b		0.58^d	0.48^d	-.05	0.47^d	0.13	0.03	0.41^c	0.40^b
SK	0.58^d	0.58^d		0.76^d	0.07	0.74^d	0.51^d	0.50^d	0.50^d	0.64^d
MB	0.91^d	0.48^d	0.76^d		0.46^c	0.97^d	0.84^d	0.79^d	0.43^c	0.86^d
ON	0.49^d	-.05	0.07	0.46^c		0.43^c	0.59^d	0.61^d	0.38^b	0.32^b
QC	0.91^d	0.47^d	0.74^d	0.97^d	0.43^c		0.86^d	0.81^d	0.45^c	0.91^d
NB	0.87^d	0.13	0.51^d	0.84^d	0.59^d	0.86^d		0.87^d	0.39^b	0.83^d
NS	0.80^d	0.03	0.50^d	0.79^d	0.61^d	0.81^d	0.87^d		0.41^c	0.70^d
PE	0.42^c	0.41^c	0.50^d	0.43^c	0.38^b	0.45^c	0.39^b	0.41^c		0.36^b
NL	0.87^d	0.40^b	0.64^d	0.86^d	0.32^b	0.91^d	0.83^d	0.70^d	0.36^b	

Note: The numbers in the table are Pearson correlation coefficients based on the 60 monthly observations for the 2008-2012 period. Statistical significance at the 95%, 99%, 99.9% and 99.99% confidence levels are indicated by superscripts ^{a}, ^{b}, ^{c}, and ^{d}, respectively. Source: Statistics Canada CANSIM Table 127-0003.

Table 3: Correlation of Monthly Electricity Demand, Canadian Exporter Provinces and US Importer States, 2001–2012

	AB	BC	MB	NB	NS	ON	QC	SK
AK	*0.63*^{d}	**0.84**^{d}	*0.83*^{d}	*0.54*^{d}	*0.62*^{d}	*-.00*	*0.80*^{d}	*0.68*^{d}
AZ	*0.08*	**-.46**^{d}	*-.45*^{d}	*-.68*^{d}	*-.54*^{d}	*-.12*	*-.60*^{d}	*-.20*^{a}
CA	**0.19**^{a}	**-.24**^{b}	*-.30*^{c}	*-.51*^{d}	*-.37*^{d}	*-.01*	*-.41*^{d}	*-.10*
CO	*0.47*^{d}	**-.11**	*0.00*	*-.43*^{d}	*-.27*^{b}	*-.15*	*-.21*^{b}	*0.22*^{b}
IA	**0.46**^{d}	*0.04*	*0.15*	*-.23*^{b}	*-.09*	*0.06*	*-.04*	*0.27*^{b}
ID	**0.31**^{c}	**-.04**	*0.01*	*-.26*^{b}	*-.14*	*0.15*	*-.13*	*0.09*
IL	*0.22*^{b}	*-.09*	*-.02*	*-.22*^{b}	*-.10*	**0.34**^{d}	*-.13*	*0.03*
IN	*0.29*^{c}	**0.08**	*0.14*	*-.07*	*0.09*	**0.39**^{d}	*0.07*	*0.15*
MA	*0.23*^{b}	*0.05*	*0.08*	**-.06**	*0.11*	**0.42**^{d}	**0.05**	*0.09*
MD	*0.01*	*-.05*	*0.05*	**0.04**	*0.14*	*0.52*^{d}	*0.05*	*0.02*
ME	*0.14*	*0.22*^{b}	*0.13*	**0.19**^{a}	**0.25**^{b}	*0.59*^{d}	**0.23**^{b}	*0.10*
MI	*0.07*	*-.13*	*-.15*	*-.22*^{b}	*-.10*	**0.48**^{d}	**-.16**	**-.14**
MN	*0.43*^{d}	*0.11*	**0.17**^{a}	*-.17*^{a}	*0.01*	**0.20**^{a}	*0.02*	**0.23**^{b}
MO	*0.32*^{d}	*0.00*	*0.08*	*-.20*^{a}	*-.06*	**0.20**^{a}	*-.06*	*0.19*^{a}
MT	*0.45*^{d}	**0.67**^{d}	*0.60*^{d}	*0.37*^{d}	*0.51*^{d}	*0.26*^{b}	*0.54*^{d}	*0.40*^{d}
ND	**0.79**^{d}	*0.61*^{d}	**0.79**^{d}	*0.33*^{d}	*0.39*^{d}	*-.19*^{a}	*0.63*^{d}	**0.80**^{d}
NE	*0.45*^{d}	*-.01*	*0.14*	**-.24**^{b}	**-.12**	*0.03*	**-.06**	*0.28*^{c}
NH	*0.28*^{c}	*0.19*^{a}	*0.18*^{a}	**0.06**	*0.21*^{a}	*0.43*^{d}	**0.20**^{a}	*0.14*
NM	*0.40*^{d}	**-.22**^{b}	*-.13*	*-.54*^{d}	*-.39*^{d}	*-.21*^{a}	*-.34*^{d}	*0.12*
NV	*0.12*	**-.40**^{d}	*-.40*^{d}	*-.64*^{d}	*-.50*^{d}	*-.06*	*-.55*^{d}	*-.17*^{a}
NY	*0.08*	*-.19*^{a}	*-.14*	**-.22**^{b}	**-.12**	**0.39**^{d}	**-.21**^{a}	*-.09*
OH	*0.20*^{a}	*0.10*	*0.13*	*0.05*	*0.16*	**0.56**^{d}	*0.10*	*0.06*
OR	**0.44**^{d}	**0.82**^{d}	*0.74*^{d}	*0.67*^{d}	*0.70*^{d}	*0.41*^{d}	*0.79*^{d}	*0.50*^{d}
PA	**0.36**^{d}	*0.30*^{c}	*0.34*^{d}	*0.14*	*0.30*^{c}	**0.40**^{d}	*0.29*^{c}	**0.30**^{c}
TX	*0.15*	**-.48**^{d}	*-.38*^{d}	*-.64*^{d}	*-.53*^{d}	**-.13**	*-.55*^{d}	*-.09*
UT	*0.54*^{d}	**-.00**	*0.10*	*-.35*^{d}	*-.20*^{a}	*-.15*	*-.12*	*0.28*^{c}
VT	*0.36*^{d}	*0.54*^{d}	*0.49*^{d}	*0.41*^{d}	*0.51*^{d}	**0.67**^{d}	**0.50**^{d}	*0.27*^{b}
WA	**0.59**^{d}	**0.73**^{d}	*0.79*^{d}	*0.56*^{d}	*0.60*^{d}	*-.00*	*0.79*^{d}	*0.72*^{d}
WY	*0.69*^{d}	**0.44**^{d}	*0.58*^{d}	*0.07*	*0.21*^{a}	*-.40*^{d}	*0.38*^{d}	*0.68*^{d}

Note: The numbers in the table are Pearson correlation coefficients based on monthly demand data for Canadian provinces that export electricity to the US, and US states that import electricity from Canada. Coefficients in **boldface** are for actual trade partners; all other correlations are shown in *italics*. Statistical significance at the 95%, 99%, 99.9% and 99.99% confidence levels are indicated by superscripts ^{a}, ^{b}, ^{c}, and ^{d}, respectively. Source: Statistics Canada CANSIM Tables 127-001, 127-0002, and 127-0003; US Energy Information Administration, Electricity Browser.

pairs with high negative correlations are not engaging in trade—an indication of unrealized trade potential.

Figure 3 illustrates the time dimension of electricity trade with the example of British Columbia, which has one 500 kV intertie with the neighbouring province Alberta, and two 500 kV and two 230 kV interties with Washington state. This amounts to an export capacity of 3,150 MW to the United States and 1,200 MW to Alberta. For technical reasons, import capacities are slightly lower. As was indicated in table 1, British Columbia's total electricity trade is relatively balanced with a significant amount of imports and exports. On closer inspection, exports and imports exhibit seasonal patterns. Even over the period of a month, British Columbia tends to export and import electricity at the same time. This is in part explained by the fact that there are multiple interties. British Columbia's available generation capacity depends on water levels in the reservoirs of its hydroelectric dams. Thus there is surplus electricity in high-water years. The years 2011 and 2012 exhibited large net exports during the summer months. Electricity trade with Alberta, shown in figure 4, contributes relatively little to the overall trade because of the smaller capacity of the interties. The trading pattern is clearly dominated by exports, indicating that British Columbia has a strong comparative advantage in electricity generation with respect to neighbouring Alberta.

Figure 5 shows the volume of bilateral Canada-US trade over the last decade. Canada runs an electricity surplus with the United States, with US imports of Canadian electricity about twice the volume of US exports to Canada. Prices can fluctuate significantly, as is illustrated in figure 6. Electricity can trade for as little as \$25 per MWh, and as much as \$70 per MWh. Canadian electricity commands an export price premium. Over the twelve-year period in the diagram, Canadian electricity exports to the US cost about 20% more than US electricity exports to Canada (15% volume-weighted, 23% unweighted) despite the apparent comparative advantage of Canada in electricity production suggested in figure 5.

One of the peculiarities of international trade in electricity is that the price does not necessarily reflect resource abundance in a conventional Heckscher-Ohlin sense. The price of traded electricity depends as much on long-term comparative advantage as it does on short-term shortages. The result is that electricity—a homogenous commodity—can be priced rather differently depending on which way the electricity flows through an intertie. The 'law of one price' does not apply. Pricing may even reach absurd levels. During the California electricity crisis in 2000/2001, British Columbia exported electricity to California at peak prices of around \$800/MWh (see also figures TA-1 and TA-2 in the *Technical Appendix*). And in March 2013, Ontario exported electricity to New York and Michigan at

Figure 3: British Columbia Total Trade in Electricity, 2008-2012

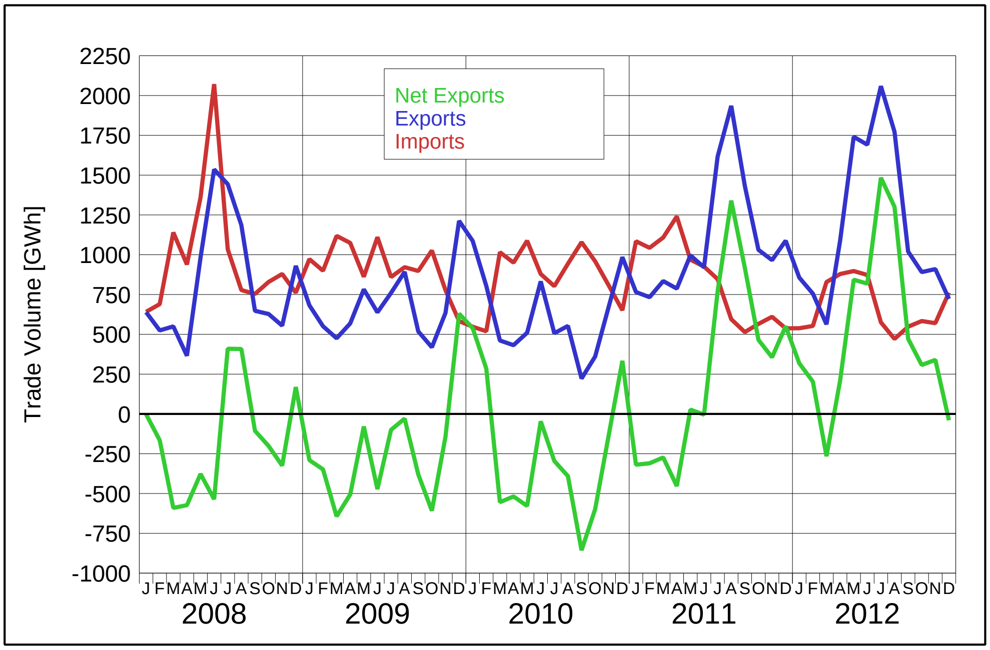
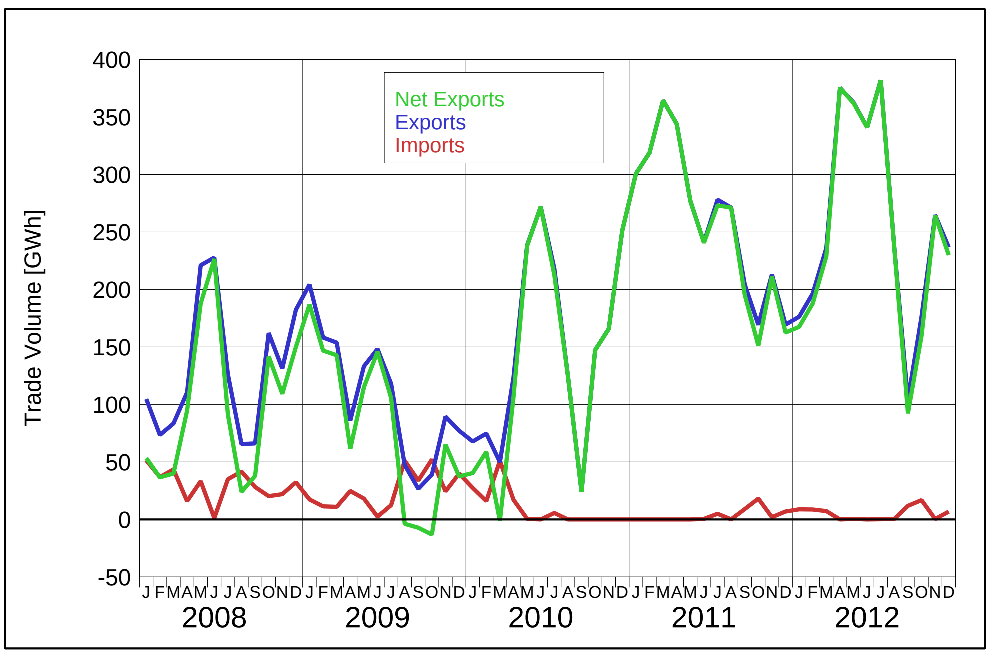


Figure 4: British Columbia Interprovincial Trade in Electricity, 2008-2012



Note: Original data from Statistics Canada CANSIM Table 127-0003.

Figure 5: Canada-US Electricity Exports

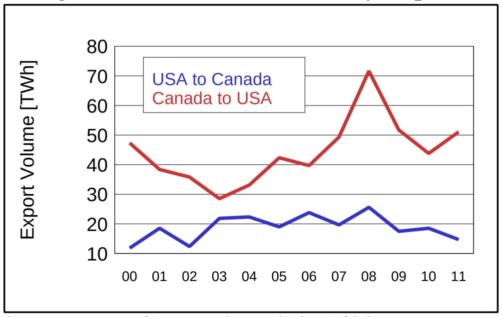
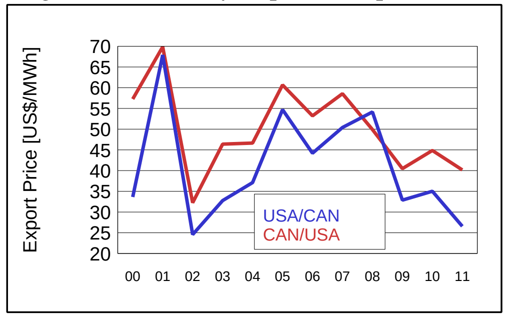


Figure 6: Electricity Export & Import Prices



Source: UN Comtrade, HS 271600

\$–128/MWh: a negative price. Dumping electricity across the border was less costly than ramping down generators.

Building interties between jurisdictions is expensive. A double-circuit 500 kV AC line is estimated to cost over \$2 million per kilometer (Mason et al., 2012), with each circuit able to carry a 2,000 MW load. At the end of each line, additional substations are needed, each costing about \$30 million. However, there are significant economies of scale with respect to the length of the line. High-voltage direct current (HVDC) lines are cheaper for carrying long-distance loads but require more expensive Line Commutated Converters (LCCs) at the end. Recent years have seen many innovations into HVDC technology that will make HVDC technology cheaper and expand its scope of use.[4]

3. Modeling Trade in Electricity

This section develops a model of an electric utility that is regulated with respect to its domestic operation but is not constrained with respect to earning profits from engaging in cross-border trade in electricity with a neighbouring foreign jurisdiction. The first part develops the equilibrium for the purely domestic operation. The second part develops a model for two jurisdictions that engage in trade, and the third part obtains closed-form solutions for the volume of two-way trade. Further parts explore implications of the two-way trade in electricity.

[4]Notably, ABB's hybrid breakers are considered a 'game changer,' and the voltage-source converter (VSC) technology makes it feasible to use HVDC for lower capacity applications in HVDC 'light' systems. The early 20th-century 'war of the currents' between alternating current (favoured by Tesla and Westinghouse) and direct current (favoured by Edison and General Electric) may well reappear in a new battle over bulk electricity transmission.

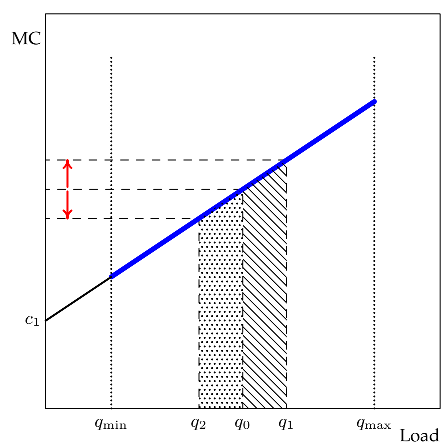
The model of 'reciprocal load smoothing' developed here introduces a novel type of comparative advantage. However, I will continue to use the term 'comparative advantage' to refer to the fixed long-term comparative advantage from factor endowments in the Heckscher-Ohlin sense, and contrast this with the variable short-term comparative advantage from load asymmetries between jurisdictions.

3.1. One Jurisdiction

The most significant starting point for modeling an electric utility is its cost function. Power generation is characterized by a least-cost-first approach to deploying power plants. Base load utilizes power plants with low marginal cost such as hydroelectric dams, or nuclear power plants whose output is difficult to ramp up or down. Peak load utilizes power plants with short ramping times but high fuel costs. A sufficiently general cost function for electricity generation is

$$c(q(t)) = c_0 + c_1 q(t) + \frac{1}{2} c_2 q(t)^2 \tag{1}$$

Figure 7: Load and Cost Variation



This cost function is quadratic in production $q(t)$ over time t and obeys the capacity constraint $q(t) \leq K$. Making use of a quadratic cost function is an essential feature of the model, illustrated in figure 7. In practice, the cost function is not smooth but a sequence of step functions (Mansur, 2008, p 373). Nevertheless, a quadratic function provides a reasonable approximation.

As the load varies between $q_{\min}$ and $q_{\max}$ along the thick (blue) line in the diagram, the marginal cost increases as q rises. There is thus an asymmetry in cost changes. When the load increases from q_0 to q_1, the increase in total cost is equal to the hatched area in the diagram. However, when the load decreases by the same amount from q_0 to q_2, the decrease in total cost is equal to the dotted area, which is less than the hatched area. This directional cost asymmetry is the fundamental driver of the theoretical model.

The use of a quadratic cost function also allows for applying properties of the normal distribution. Appendix A provides a brief discussion of the expected value of linear and quadratic transformations of random variables. The quadratic cost function is particularly suited to exploiting this concept to derive analytically tractable solutions to the utility's profit maximization problem. Nevertheless, key results of this paper—in particular for the problem of electricity trade between two jurisdictions—can also be derived with alternative cost functions. Appendix D discusses a logarithmic cost function that is based on capacity utilization (q/K).

For delivery of electricity within a single jurisdiction, transmission losses are assumed as part of the cost function. When considering cross-jurisdictional delivery of electricity, transmissions costs will be taken into account explicitly.

Demand for electricity is determined long-term and short-term. Average demand $\bar{q}$ over a sufficiently long reference period (assumed to be a year) is governed by a linear demand function

$$\bar{q} = a - b\bar{p} \tag{2}$$

where the utility price $\bar{p}$ is set by a utility commission as described below. Many utilities still opt for a relatively "flat" pricing system, in the simplest case with a single price. Peak-load pricing, although economically optimal, is only slowly gaining ground.[5] Within the reference period, short-term demand is determined stochastically as

$$q(t) \sim \mathcal{N}(\bar{q}, s^2) \tag{3}$$

so that over the integration time period $[0, T]$, or equivalently over the probability distribution of demand $f(q)$ during the time period T, total supply is

$$\int_0^T q(t)\mathrm{d}t = T \int f(q)\,\mathrm{d}q = \bar{q}T \tag{4}$$

Having defined revenues and costs, the utility company's profits over a fiscal year

[5] For example, the province of Ontario now uses time-of-day residential pricing (on-peak, mid-peak, and off-peak during weekdays, and off-peak during weekends) as well as seasonal pricing (mid-peak and on-peak periods are reversed in summer and winter). Peak-load pricing in Ontario leads to significantly different retail rates for electricity. As of May 1, 2013, the prices for off-peak, mid-peak, and on-peak were 6.7, 10.4 and 12.4 cents per kWh, respectively. By comparison, the province of British Columbia uses a two-step system that amounts to de-facto seasonal pricing. As of April 1, 2013, residential rates are set at 6.90 cents per kWh for the first 675 kWh per month, and at 10.34 cents per kWh for electric power above the threshold. As electricity demand in British Columbia peaks in the winter due to heating needs, consumers face a higher marginal price in winter than in summer.

are given by

$$\pi = \int [pq(t) - c(q(t))] \, \mathrm{d}t \tag{5}$$

Because of the natural monopoly in electricity distribution, a utility's profits are usually constrained in some form (see Bernard and Roland, 1997). A common form is the fixed mark-up where the retail price $\bar{p}$ is set in such a way that the utility realizes a fixed percentage mark-up η over the reference period. For a given value of the policy parameter η,

$$\bar{p} = (1+\eta)\frac{\int c(t)\mathrm{d}t}{\int q(t)\mathrm{d}t} = (1+\eta)\left[\frac{c_0 + c_2 s^2}{\bar{q}} + c_1 + c_2\bar{q}\right] \tag{6}$$

The utility's retail price for electricity is a mark-up on marginal cost at average load $(c_1 + c_2\bar{q})$ plus a component for absorbing the fixed cost and the variability of demand that is caused by the asymmetry in costs that was illustrated in figure 7. The retail price increases with the variance s^2. More volatile loads are associated with higher electricity retail prices because of a stronger exposure to the cost asymmetry. Equations (2) and (6) together characterize the long-term equilibrium. For a given η, the two equations identify the equilibrium outcome $\{\bar{p}, \bar{q}\}$.[6]

3.2. Two Jurisdictions

Let there be two jurisdictions, home (h) and foreign (f). Where a distinction between home and foreign needs to be made, corresponding superscripts are used.

At any given time, the home jurisdiction can export a flow of electric power $x(t)$ to the foreign jurisdiction. A negative $x(t)$ constitutes an import of electric power. Transporting electricity across jurisdictional boundaries incurs a transmission cost $g|x|$ that is proportional to the amount (absolute value $|x|$) of electrical power transmitted. The parameter g is a function of the distance D between the jurisdictions.[7] It is assumed that the transmission cost is split equally between

[6] If the utility would use peak-load pricing instead of flat pricing, the demand fluctuations would be dampened by consumers' adjustment to the changing prices. This will change the time path for the actual loads $q(t)$ and reduce its variance s^2.

[7] It may be appealing to model transmission costs in terms of actual electricity losses—reminiscent of 'iceberg transportation costs' in the international trade literature. However, this approach increases algebraic complexity significantly with very little gain in economic insights. Modeling transmission costs as a linear function of exports or imports is a suitable approximation of reality. An alternate logarithmic cost function is explored in Appendix D where the transmis-

exporter and importer.[8] Exports and imports are balanced through a market price p that will fluctuate over time. To manage notation, define the indicator variable[9]

$$\delta \equiv \begin{cases} +1 & \text{when exporting and } x > 0 \\ -1 & \text{when importing and } x < 0 \end{cases} \tag{7}$$

Assume that the utility is unconstrained to maximize profits after satisfying purely domestic demand as described in the previous section. This means that at any time, the under-utilized capacity $K - q(t)$ can be used for export. At any given time, the utility decides whether to import or export electric power. When it exports electricity, it earns revenue px and incurs an additional cost $c(q + x) - c(q)$. Providing this additional electricity will incur extra costs that are increasing progressively because of the quadratic term in (1). When the utility imports electricity, it buys quantity $-x$ of electricity at price p and saves generation costs $c(q) - c(q - |x|)$ by moving down on its marginal cost curve. The utility's export profit function is therefore given by

$$\pi^x = px - [c_1 + c_2(q + x/2)]x - g|x|/2 \geq 0 \tag{8}$$

Time arguments were dropped for expositional simplification. Note that $g|x| = \delta g x$ remains positive both when exporting and importing. The first-order condition for a profit maximum implies that

$$x = \frac{p - c_1 - \delta g/2}{c_2} - q \tag{9}$$

subject to the non-negative profit constraint. Applying the first-order condition, the utility will export electricity when the export price exceeds marginal cost, and import electricity when the import price is lower than marginal cost:

$$p > c_1 + c_2 q + g/2 \qquad \text{export} \tag{10}$$
$$p < c_1 + c_2 q - g/2 \qquad \text{import} \tag{11}$$

sion losses are modeled directly. All of the key results can obtained with the alternate formulation.

[8] This assumption simplifies exposition without changing the allocation results. Defining who pays for the transmission, importer, exporter, or both, merely influences the distribution of profits.

[9] Alternatively, one may use binary indicators $\delta^x \equiv (1 + \delta)/2$ for exporting and $\delta^m \equiv (1 - \delta)/2$ for importing.

In equilibrium, exports and imports must be equal and thus it must hold that $x^h + x^f = 0$. Therefore,

$$p = \frac{(q^f + q^h)c_2^h c_2^f + c_1^h c_2^f + c_2^h c_1^f}{c_2^h + c_2^f} + \frac{g}{2}\left|\frac{c_2^f - c_2^h}{c_2^h + c_2^f}\right| \tag{12}$$

The equilibrium trading price is proportional to the sum of loads $q^f + q^h$. It is highest when capacity utilization is high in both jurisdictions. The trading price is a weighted average of marginal cost. The constant part is a weighted arithmetic average of the linear cost terms c_1, with weights determined by the relative share of the trading partners' quadratic cost terms. The variable part is a harmonic average of the quadratic cost terms, multiplied by the combined load. The price also rises with the transmission cost g, and this cost factor is magnified by the cross-border difference in quadratic cost factors.

Equation (12) also explains how two-way trade can occur at a price differential between two jurisdictions, where exports in one direction occur at higher prices on average than exports in the other direction. Consider the case where Home has little variation in demand (q^h) and where Foreign has high variation in demand (q^f). When demand is high in Foreign, Foreign imports electricity from Home at a high cost. When demand is low in Foreign, Foreign will export electricity to Home at a low cost. The jurisdiction with the larger variation in demand is at a trade disadvantage irrespective of underlying comparative advantage.

With the equilibrium price determined, the amount of electricity exported or imported is

$$x^h = \frac{(c_1^f + c_2^f q^f) - (c_1^h + c_2^h q^h) - \delta g}{c_2^h + c_2^f} \tag{13}$$

The home jurisdiction exports electricity when its marginal cost is lower than the marginal cost of the foreign jurisdiction. The export or import volume is diminished by the transmission cost.

Equation (13) identifies trading opportunities for both jurisdictions if marginal costs are sufficiently close. If one jurisdiction has a large comparative advantage, trade will be unidirectional at all times. This can be the case when one jurisdiction has a particularly cheap source of electric power, such as hydroelectric dams. If the cost parameters c_1 for home and foreign may be sufficiently close, it is just the capacity utilization that determines which jurisdiction has a temporary comparative advantage. If all cost factors are identical, then

$$x^h = \frac{q^f - q^h - \delta g/c_2}{2} \tag{14}$$

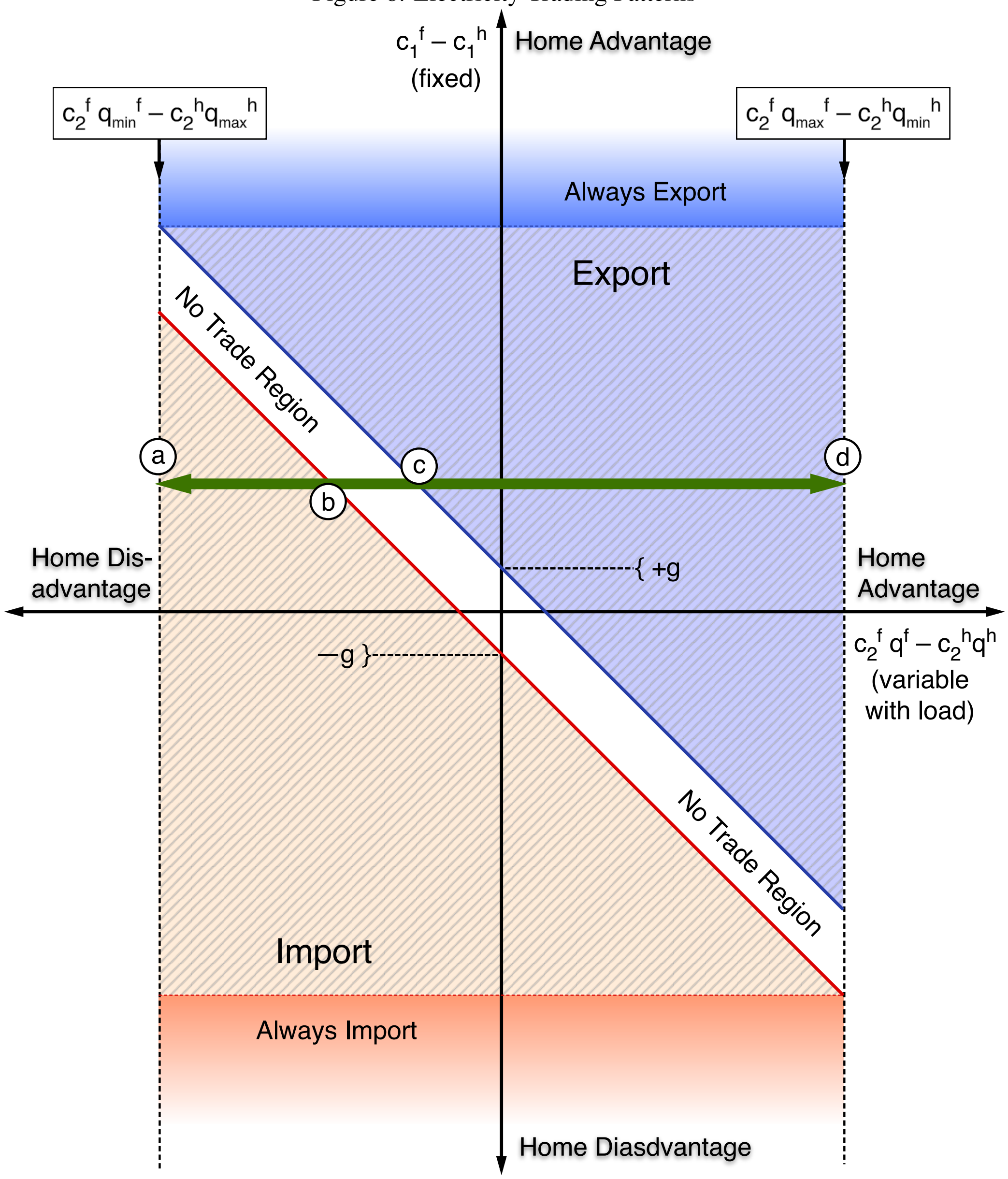
In the absence of transmission losses ($g = 0$), both jurisdictions would simply split the difference in the loads so that both would operate at the same level. In the presence of transmission costs, the volume of trade diminishes in proportion to g (which depends on distance between the jurisdictions) and the convexity of the cost function (c_2). Trade will only occur when g is sufficiently small:

$$g < \delta \left|(c_1^f + q^f c_2^f) - (c_1^h + q^h c_2^h)\right| \tag{15}$$

The difference in marginal costs must be sufficiently large to overcome the transmission cost. More trading opportunities exist when (a) home and foreign demand are wider apart, and when (b) the cost function is more convex. More generally, the condition for exporting and importing are

Figure 8 illustrates the patterns of trade that emerge from the two inequalities (15) when δ is +1 for exporting and –1 for importing. The vertical axis depicts the home-foreign difference of the fixed linear term in the cost function, $c_1^f - c_1^h$. This can be considered the baseline comparative advantage. At the top of the diagram, home has an export advantage. When $c_1^f - c_1^h$ is large enough, home will always export (above the blue dashed line). Conversely, when $c_1^f - c_1^h$ is negative, then home will tend to import, and below a certain threshold (the red dashed line) it will always import electricity. The horizontal axis depicts the variable component of the comparative advantage that depends on the quadratic term in the cost function. This part of the comparative advantage is constrained to the left by $c_2^f q_{\min}^f - c_2^h q_{\max}^h$, which occurs when demand in the foreign jurisdiction is lowest and demand in the home jurisdiction is highest. On the right, this part of the comparative advantage is constrained by $c_2^f q_{\max}^f - c_2^h q_{\min}^h$, which occurs when demand in the foreign jurisdiction is highest and demand in the home jurisdiction is lowest. On the left side of the diagram, the foreign jurisdiction gains a comparative advantage, and on the right side of the diagram, the home jurisdiction gains a comparative advantage. These constraints are shown as vertical dashed lines. The inequalities (15) appear as downward-sloping 45-degree lines. Above the (upper) blue line the home jurisdiction will export electricity (shaded blue area), and below the (lower) red line the home jurisdiction will import electricity (shaded red area). The region between the two diagonal lines is a region where no trade

Figure 8: Electricity Trading Patterns



takes place because the gains from trade do not compensate for the transmission costs. In the diagram the minimum $c_2^f q_{\min}^f - c_2^h q_{\max}^h$ and maximum $c_2^f q_{\max}^f - c_2^h q_{\min}^h$ have been centered around zero for illustration purposes. Depending on the exact parameters, these expressions could be asymmetric, including all positive or all negative.

A particular pair of jurisdictions will operate on a horizontal line, for example the thick green line in the diagram. This particular case illustrates a situation where the home jurisdiction has a slight fixed-part advantage because $c_1^f > c_1^h$. As demand fluctuates, the variable-part advantage moves along the horizontal line between the minimum at point (a) and maximum at point (d). If demand in the foreign jurisdiction is high, and this jurisdiction experiences high marginal costs of production, the home jurisdiction gains an increasing export advantage moving from point (c) right to point (d). On the other hand, as demand at home is high and demand abroad is low, the home jurisdiction will shift further to the left, eventually cross point (b) and start importing electricity. As demand at home grows further, the home jurisdiction will experience increasing disadvantages as it moves towards point (a). Between points (b) and (c), engaging in electricity trade will not be profitable because of the transmission costs.

3.3. *The Volume of Two-Way Trade*

The discussion of the previous section demonstrates that electricity trade can be unidirectional or bidirectional over a sufficiently time period. While at any given point in time (with a single intertie) electricity can only flow one way, over the course of a day, month, or year electricity can flow either direction as demand changes in both jurisdictions. This is particularly the case if demand across both jurisdictions is not perfectly correlated, for example because of different seasonal patterns. For simplicity of exposition, assume that home and foreign demand are distributed bivariate normal with correlation coefficient ρ so that

$$\begin{bmatrix} q^h(t) \\ q^f(t) \end{bmatrix} = \mathcal{N}\left(\begin{bmatrix} \bar{q}^h \\ \bar{q}^f \end{bmatrix}, \begin{bmatrix} (s^h)^2 & \rho s^h s^f \\ \rho s^h s^f & (s^f)^2 \end{bmatrix} \right) \tag{16}$$

Making use of the affine transformation formula for multivariate normal distributions, explained in Appendix B, one obtains:

$$u \equiv \mathcal{E}\{x^h\} = \frac{(c_1^f + c_f^2\bar{q}^f) - (c_1^h + c_2^h\bar{q}^h) - \delta g}{c_2^h + c_2^f} \tag{17}$$

$$v^2 \equiv \mathcal{V}\{x^h\} = \frac{(c_2^h s^h)^2 - 2c_2^h c_2^f s^h s^f \rho + (c_2^f s^f)^2}{(c_2^h + c_2^f)^2} \tag{18}$$

Evaluating the truncated normal distribution as described in Appendix C provides expressions for the total volume of Home's exports X^h and total volume of Home's imports M^h over the reference period. Let u^x denote the version of (17) for exporting when $\delta = +1$, and let u^m denote the version of (17) for importing when $\delta = -1$. Integrating over the reference period yields

$$X^h \equiv \int_{x^h>0} x^h(t)\,\mathrm{d}t = \left[u^x + v\frac{\phi(u^x/v)}{\Phi(u^x/v)}\right]T \tag{19}$$

Analogously, Home's volume of imports is given by

$$M^h \equiv \int_{x^h<0} -x^h(t)\,\mathrm{d}t = \left[-u^m + v\frac{\phi(u^m/v)}{1-\Phi(u^m/v)}\right]T \tag{20}$$

The variance expression v^2 is of crucial importance for determining the volume of exports and imports: there is a positive sign in front of v in the case of exporting *and* importing. By definition, $\phi(\cdot) > 0$ and $\Phi(\cdot) \in]0,1[$, and thus v always has a positive influence on X^h and M^h. The larger the variance v^2, the more bilateral trade. The correlation coefficient ρ plays an important role determining the variance v^2. The derivative of v^2 with respect to ρ is clearly negative, which implies that higher correlation diminishes trade. This is a very intuitive—and essential—feature. If demand is strongly correlated between jurisdictions, they will both experience high demand and low demand simultaneously, and this leaves little room for additional trade. However, when demand in both jurisdictions is correlated negatively, they can benefit from increased trade.

The derivation above gives rise to an expression for the trade intensity, $(X^h + M^h)/Q^h$, where $Q^h \equiv \int q(t)\mathrm{d}t$ is total demand. For expositional simplicity, it is expedient to ignore the transmission costs g so that $u^x = u^m$. Then

$$\frac{X^h + M^h}{Q^h} = \frac{v}{\bar{q}^h}\frac{\phi(u/v)}{\Phi(u/v)\Phi(-u/v)} \tag{21}$$

It is interesting to investigate the case where both jurisdictions are identical (same cost coefficients, $\bar{q}^h = \bar{q}^f$, and $s^h = s^f$). Then $u/v = 0$ and $\phi(0)/\Phi(0) = \sqrt{2/\pi}$. Hence:

$$\left.\frac{X^h + M^h}{Q^h}\right|_{h=f} = \frac{s}{\bar{q}}\sqrt{\frac{4}{\pi}(1-\rho)} \tag{22}$$

The trade intensity increases along with the coefficient of variation $\tau \equiv s/\bar{q}$ and a decreasing coefficient of demand correlation between the two jurisdictions ρ.

Yet another simplification is useful to look at. Consider the case where the two jurisdictions are different in size by a factor of ζ so that $\bar{q}^f = (1+\zeta)\bar{q}^h$ and $s^f = (1+\zeta)s^h$. Both jurisdictions exhibit the same coefficient of variation $\tau \equiv s/\bar{q}$. Further assume that their demand is perfectly correlated ($\rho = 1$). Then

$$\left.\frac{X^h + M^h}{Q^h}\right|_{\rho=1, f/h=1+\zeta} = \frac{\zeta}{2}\frac{\tau\phi(1/\tau)}{\Phi(1/\tau)(1-\Phi(1/\tau))} \approx \frac{\zeta}{2} \tag{23}$$

The approximation improves when $\tau \to 0$ and holds reasonably well for small values of τ (e.g., for $\tau = 1/4$ it is 0.5282ζ). When the size difference between the jurisdictions decreases towards zero ($\zeta \to 0$), the trading opportunity will vanish completely because of the perfect demand correlation ($\rho = 1$).

The case where jurisdictions only differ in size creates an opportunity for trade that is proportional to the size difference ζ. The economic intuition behind this result is that the marginal cost accelerator c_2 works differently in the two jurisdictions. In the larger jurisdiction, demand variations move up and down the marginal cost curve "faster" than in the smaller jurisdiction. The larger jurisdiction thus experiences larger cost variations than the smaller jurisdiction.

3.4. Decomposing One-Way and Two-Way Trade

The model introduced in this paper allows both for one-way trade (driven by comparative advantage in electricity generation) and two-way trade (driven by the benefits of reciprocal load smoothing). Available trade data aggregates both types of trade into one figure. Can they be decomposed?

A conventional measure for measuring the extent of two-way trade is the Grubel and Lloyd (1971) index

$$\mathrm{GL}_t = 1 - \frac{|X_t - M_t|}{X_t + M_t} \tag{24}$$

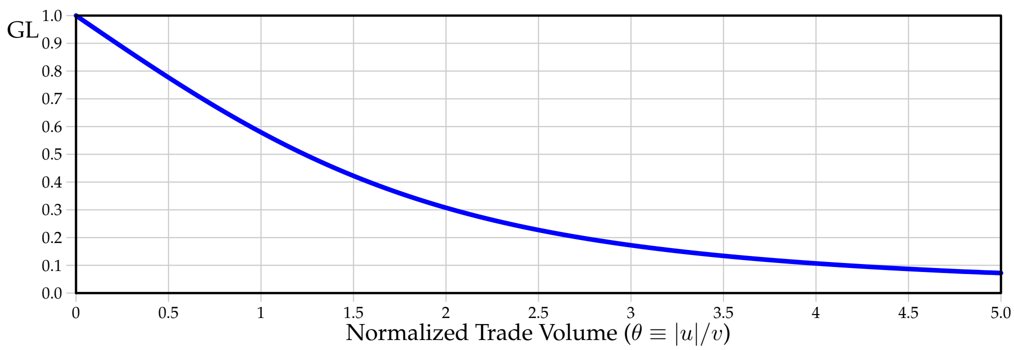
This means that total trade $X + M$ can be decomposed into one-way trade $|X - M|$

and two-way trade $(X + M) - |X - M|$. Thus the GL index captures the share of two-trade trade. Using the expressions for exports (19) and imports (20), ignoring transportation costs g, and defining the ratio $\theta \equiv |u|/v$ as the normalized trade volume, it can be shown that

$$\mathrm{GL}(\theta) = 2\Phi(\theta)\left[1 - \theta\frac{1-\Phi(\theta)}{\phi(\theta)}\right] \tag{25}$$

Figure 9 visualizes (25). When the trade volume is small relative to the variation in trade volume, virtually all trade is two-way. A high GL index indicates that reciprocal load smoothing dominates as the reason for trade. On the other hand, when comparative advantage dominates and the trade volume is large relative to its variation, one-way trade dominates and the GL index approaches zero.

Figure 9: Index of Two-Way Electricity Trade



As the share of two-way trade is computed easily through (24) for a given reference time period, equation (25) provides yet another testable implication of the reciprocal load smoothing model. It needs to be noted, though, that the patterns of one-way and two-way trade do not remain stable over time. The *Technical Appendix* contains figures that depict the share of two-way trade for Ontario, British Columbia and Manitoba during 2003-2012. Over that period, Ontario's two-way trade with the United States has given way to one-way trade, and British Columbia's two-way trade with Alberta has turned into one-way trade.

3.5. Jurisdictional Integration

How much electricity trade would there be if both jurisdictions were fully integrated? The joint capacity limit is $K^\circ \equiv K^h + K^f$, and joint production is $k^\circ \equiv k^h + k^f$, Demand is now $q^\circ \equiv q^h + q^f$ with expected value $\bar{q}^h + \bar{q}^f$, and at any point in time demand must equal supply: $q^\circ = k^\circ$. However, the new variance of demand is $(s^h)^2 + 2\rho s^h s^f + (s^f)^2$. As the coefficient of correlation varies between $[-1, +1]$, the variance is constrained and ranges between $(s^h - s^f)^2$ at the low end and $(s^h + s^f)^2$ at the high end. For simplicity of exposition, the discussion here will ignore the transmission cost g.

Total cost of the merged utility is determined in such a way that the utility employs the lower cost resources first until it is possible to equate the marginal cost of the original home and foreign resources. Then it employs both resources equally until one of the resources is at full capacity. The remaining capacity, at highest marginal cost, is brought in at the end. The lower and upper thresholds are

$$q_L^\circ \equiv \min\{(c_1^h - c_1^f)/c_2^f, (c_1^f - c_1^h)/c_2^h\} \tag{26}$$
$$q_H^\circ \equiv \min\{(c_1^h - c_1^f + c_2^h K^h)/c_2^f, (c_1^f - c_1^h + c_2^f K^f)/c_2^h\} \tag{27}$$

In the region $[q_L^\circ, q_H^\circ]$, the merged marginal costs will be

$$\frac{\mathrm{d}c^\circ(q^\circ)}{\mathrm{d}q^\circ} = \frac{c_1^h c_2^f + c_1^f c_2^h}{c_2^h + c_2^f} + \frac{c_2^h c_2^f}{c_2^h + c_2^f} q^\circ \tag{28}$$

which is composed of a weighted arithmetic mean of the linear terms c_1 and a harmonic mean for the quadratic terms c_2. When $q^\circ > q_L^\circ$, total supply and individual supply (denoted by k) are related through

$$k^h = \frac{c_1^f - c_1^h + c_2^f q^\circ}{c_2^h + c_2^f} \tag{29}$$
$$k^f = \frac{c_1^h - c_1^f + c_2^h q^\circ}{c_2^h + c_2^f} \tag{30}$$

Implied exports of Home and Foreign are $x^h = k^h - q^h$ and $x^f = k^f - q^f$. It is immediately apparent that x^h is the same as (13) without the transmission cost. Exports and imports are thus the same as (19) and (20) without transmission costs. Therefore, in the absence of other economic frictions, the efficient volume of trade in electricity under jurisdictional separation is the same as under jurisdictional integration. This equivalence theorem is fundamental but not unexpected: it is a property of all neoclassical trade models. Trade brings about full efficiency unless dampened by frictions.

In practice, jurisdictional integration has two advantages over jurisdictional separation. First, integration removes the potential conflict over building sufficient intertie capacity. Integration eliminates the negotiation and contracting issues that may arise otherwise. Second, integration also leads to a new price $\bar{p}$, which—as was shown earlier—is influenced by the variance of the distribution of $q(t)$. If demand in both jurisdictions is less than perfectly correlated, integration will lead to a reduction of the joint variance s^2; it will be lower than $(s^h)^2 + (s^f)^2$. This means that the joint price $\bar{p}$ can be lower than the original $\bar{p}^h$ or $\bar{p}^f$ (unless the original price gap was very large). This 'integration bonus' is a true efficiency gain.

3.6. Building Interties

When is it profitable for two neighbouring utilities to construct an intertie connecting their grids? The capital cost building it must be compensated by the gains from trade. Assume that the amortized capital cost of building an intertie with capacity I is given by κI, where κ is a cost factor that includes the financing cost, maintenance cost, and need for eventual replacement. Implicitly, κ depends on the discount rate. It is expressed on a time scale equivalent to T, the reference time period for evaluating profits. Then an intertie is profitable when

$$\int \pi^x(t)\,\mathrm{d}t > \kappa I \tag{31}$$

The discussion in the previous section had assumed that the flow of electricity across jurisdictions is not constrained by the capacity of the intertie. In practice, the volume of exports and imports may be constrained so that $|x| < I$.

Evaluating the profitability of a proposed intertie is necessarily a much more complex decision problem in the network structure of a power grid. Kleit and Reitzes (2008) provides an analytic economic framework, and Doucet et al. (2013) extends that approach and provides an application to a proposed Montana-Alberta intertie. Encouragingly, they find that the gains to transmission expansion are largely appropriable. Bresestia et al. (2009) shows how a network flow optimization model can be utilized to gauge the economic benefits of network expansion, although such complex optimization models have rather high data requirements. Church et al. (2009) demonstrates the complexity of a weighing costs and benefits for a proposed new intertie in Alberta, in particular the sensitivity of the investment decision to the underlying assumptions.

3.7. Capacity Constraints

The theoretical model developed so far does not take into consideration that intertie capacity is fixed in the short term. A given intertie has a rated MW capacity for export ($\bar{x}$) and import ($\bar{m}$). These two numbers do not have to be identical for a given intertie because of constraints with transformers and other equipment.[10] A jurisdiction will export or import at maximum intertie capacity when

$$
\begin{aligned}
p &> c_1 + c_2(q + \bar{x}/2) + g/2 \equiv c_{\bar{x}} \quad \text{exporting} \qquad (32)\\
p &< c_1 + c_2(q - \bar{m}/2) - g/2 \equiv c_{\bar{m}} \quad \text{importing} \qquad (33)
\end{aligned}
$$

When $c^f_{\bar{m}} < c^h_{\bar{x}}$, the home jurisdiction will export electricity at maximum capacity $\bar{x}^h = \bar{m}^f$. The price must fall in the range $c^f_{\bar{m}} < p < c^h_{\bar{x}}$; it is not unique and subject to bargaining. Maximum intertie use for exporting will therefore occur when

$$
c^f_2 q^f - c^h_2 q^h > c^h_1 - c^f_1 + g + \bar{x}^h(c^f_2 + c^h_2)/2 \qquad (34)
$$

When foreign and domestic cost factors are the same, then this condition simplifies to $q^f - q^h > \bar{x}^h + g/c_2$. Home exports at maximum capacity as soon as the gap between foreign and domestic load is sufficiently large.

A related question is about the utilization rate of the intertie. How often will the intertie operate under full load? It is again possible to employ the equations for affine transformations in Appendix B. Taking expectations on the left-hand side of (34) and abbreviating the term on the right-hand side as $\tilde{c}$, it follows that

$$
\begin{aligned}
\mathcal{E}\{c^f_2 q^f - c^h_2 q^h\} &= c^f_2 \bar{q}^f - c^h_2 \bar{q}^h \equiv \tilde{u} \qquad (35)\\
\mathcal{V}\{c^f_2 q^f - c^h_2 q^h\} &= (c^f_2 s^f)^2 - 2\rho c^h_2 c^f_2 s^f s^h + (c^h_2 s^h)^2 \equiv \tilde{v}^2 \qquad (36)
\end{aligned}
$$

The probability that the capacity is fully utilized in the export direction is thus $1 - \Phi((\tilde{c} - \tilde{u})/\tilde{v})$. When both jurisdictions are cost-identical and have demand correlation ρ, the probability of full intertie utilization is

[10] As a practical example, the *Total Transfer Capability* (TTC) of the Ingledow-Custer intertie (two 500 kV lines) between British Columbia and Washington state is rated at 3,150 MW in the southern direction and 2,000 MW in the norther direction. A figure in the *Technical Appendix* depicts actual utilization hour-by-hour over a few weeks. The frequent reversal of direction is a defining feature of many interties.

$$\text{Prob}(x = \bar{x}^h) = 1 - \Phi\left(\frac{\bar{x}^h + g/c_2}{s\sqrt{2(1-\rho)}}\right) \tag{37}$$

When both jurisdictions are symmetric, the probability in the expression above cannot exceed 50% because imports and exports are symmetric as well. From the above expression it becomes clear that capacity utilization increases with: a decreasing demand correlation (ρ becomes smaller or negative); a decreasing ratio of intertie capacity to demand variation $\bar{x}^h/s$; and decreasing transportation cost g. Conversely, as $\rho \to 1$, utilization drops to zero. Capacity utilization will increase if the intertie's use is driven by comparative advantage rather than demand fluctuations and reciprocal load smoothing. The larger the comparative advantage $|c_1^f - c_1^h|$, the more the intertie will be used.

3.8. Multilateral Resistance and Other Caveats

The theoretical model developed in this section is strictly bilateral. However, in many instances electric utilities are dealing with multiple neighbouring jurisdictions. This complicates the algebra but leaves the economic intuition unchanged. The main adjustment involves the affine transformation for a vector of random variables (electricity demand in multiple jurisdictions). This transformation generalizes to an arbitrary number of jurisdictions, with a more complicated variance-covariance matrix.

Gravity models of international trade allow explicitly for trade barriers to alternative trading partners through inward and outward multilateral resistance (Head and Mayer, 2014). Something similar applies in a model of *multilateral* load smoothing (as opposed to reciprocal load smoothing). Exports to a foreign jurisdiction depend not only on the exporter's and importer's load, but also on the available load of all feasible alternate jurisdictions. For electricity trade, this set of feasible alternatives is limited by available transmission capacity. The empirical analysis would be incomplete without allowing specifically for the available capacity from the alternate jurisdictions. This will be taken into account appropriately in the empirical section below.

An important caveat applies to the time dimension. Demand is correlated differently at different frequencies. The empirics in this paper focuses on monthly data, which captures demand correlations that are mostly attributable to seasonal effects. Monthly data cannot capture intra-day effects. Over long east-west distances, time zone differences can generate negative correlations even when seasonal effects are the same for two jurisdictions.

4. Estimating Electricity Trade

4.1. Principal Estimating Equation

The theory section of this paper has developed a model of two-way trade in electricity. Equation (13) predicts instantaneous exports and equation (19) predicts the volume of exports from Home to Foreign over a reference time period. The latter equation can be turned into an estimating equation for monthly or annual trade in electricity.

Deriving the estimating equation needs to start with a discussion of the identification strategy. Demand in Home and Foreign have time variation. However, variance and correlation are derived from demand data and thus have limited or no time variation, depending on the time horizon for calculating these statistics. For monthly data, the covariance structure is calculated over the entire available sample period, and therefore s_i does not have a time subscript.[11] Without time variation, variance and correlation become a trading-dyad fixed effect. It is therefore necessary to use cross-sectional variation to identify the economic effect of the time-invariant variables, and thus submit the theory to an appropriate test.

In order to make use of cross-sectional variation in the data, it is necessary to impose a crucial identification assumption. The c_2 cost parameters will tend to be different for each jurisdiction. In order to estimate the economic effects through coefficients that are similar for all jurisdictions, one can impose the additional assumption that $c_2^i = \tilde{c}_2/K^i$ for each jurisdiction i. This means that the quadratic cost term varies with $q^i(q^i/K^i)$, the product of actual load and capacity utilization. Then $\tilde{c}_2$ can be assumed to be similar across jurisdictions. With this modification, one can derive the export-to-capacity ratio

$$\frac{x^h}{K^{fh}} = \frac{1}{2}\left[\frac{q^f}{K^f} - \frac{q^h}{K^h} + \frac{c_1^f - c_1^h - g}{\tilde{c}_2}\right] \tag{38}$$

where $K^{fh} \equiv 2K^f K^h/(K^f + K^h)$ is the harmonic average of the generation capacity in both jurisdictions. This identifying assumption also simplifies the variance term

[11] Correlation patterns may be different at different frequencies. The *Technical Appendix* contains figures that illustrate load patterns at the hourly, week-daily, and seasonal level for British Columbia. Seasonal correlation accounts for a large chunk of the cross-jurisdictional variation, whereas week-daily patterns are similar across jurisdictions. Seasonal correlations are influenced by the latitude and climate of jurisdictions. Hourly correlations are relatively high in the north-south direction, but due to time zone shifts drop significantly along with east-west separation. At the extreme, a 12-hour time zone difference would imply a high negative correlation.

so that it depends merely on the correlation coefficient ρ and the two normalized demand standard deviations (s_i/K_i and s_j/K_j).

Econometric estimation of trade models often involves 'gravity' models of the type pioneered by Anderson and van Wincoop (2003, 2004). As discussed in Head and Mayer (2014), state-of-the-art estimation techniques typically make use of extensive dyadic fixed effects, which identify economic effects primarily through the time variation in the trade data. While this approach is necessary because of the presence of multilateral resistance effects in the love-of-variety models of trade in differentiated products, it is not strictly necessary in the case of estimating equation (19). Even though the estimating equation has pair-specific effects, they can be captured through suitable economic variables. Unlike multilateral resistance, these pair-specific effects are generally observable.

Equation (19) is rather nonlinear due to the appearance of the probability density function and cumulative density function of the normal distribution. It is therefore noted that $\partial X/\partial u > 0$ and $\partial X/\partial v > 0$. A log-linearized approximation of equation (19) for exports of electricity from jurisdiction i to jurisdiction j in time period t is given by

$$\begin{aligned} \ln\left(\frac{X_{ijt}}{K_{ij}}\right) &= \mu_{ij} + \alpha_0 + \alpha_1 \ln\left(\frac{\bar{q}_{jt}}{K_j}\right) - \alpha_2 \ln\left(\frac{\bar{q}_{it}}{K_i}\right) - \alpha_3 \ln(D_{ij}) \\ &\quad + \alpha_4 \ln \sqrt{\left(\frac{s_j}{K_j}\right)^2 - 2\rho\frac{s_j s_i}{K_j K_i} + \left(\frac{s_i}{K_i}\right)^2} + \alpha_5 T_t + \epsilon_{ijt} \qquad (39) \end{aligned}$$

where parameters α_1 through α_4 are all positive to be consistent with the theoretical model.

The parameter μ_{ij} captures the comparative advantage differential in the c_1 parameters and can thus be either positive or negative. The parameter α_3 captures the effect of distance D on the trade volume. A time trend (T_t) is added to capture infrastructure changes over time. The error term is ϵ_{ijt}. The normalization of the dependent variable (expressing it as an export-to-capacity ratio) removes much of the potential heterogeneity in the error term.

The intercept μ_{ij} in equation (39) captures, primarily, the comparative advantage of the trading partners. It will be treated in different ways. First, it can simply be treated as a noisy intercept. Second, it can be treated as a random effect for each trading pair.[12] Third, it can be treated as fixed effects for each exporter

[12]The usual caveat about trade-offs between efficiency and consistency apply; see for example

and importer (i.e., separate μ_i and μ_j). Fourth, μ_{ij} can be modeled explicitly with determinants of comparative advantage. Specifically, comparative advantage can be approximated by the composition of electricity generation, assuming similar underlying technologies. The composition of generation capacity by type (hydroelectricity, nuclear, coal, natural gas, other fossil fuel, and renewable sources) can be used to capture the underlying comparative advantage. All four empirical strategies are pursued, although with different level of emphasis, and with some results relegated to the *Technical Appendix*.[13]

Lastly, the bilateral identification strategy in equation (39) can be augmented through a a term that mimics 'multilateral resistance' in multilateral models of trade in differentiated goods. In some specification, a variable is included that is the capacity-weighted average of load factors of the alternate jurisdictions. In the absence of intra-US state-level trade data, alternate jurisdictions are identified as states within the same interconnection.

4.2. Estimating Trade Intensity and Export Prices

A more indirect method for estimating cross-border trade in electricity focuses on trade intensity, the ratio of total trade (imports and exports) to demand $\mathrm{TI} \equiv (X+M)/Q$. This ratio was introduced in equation (21) and discussed in simplified versions in equations (22) and (23). The key insights from this discussion can be distilled into an estimating equation for each jurisdiction i in time period t:

$$\mathrm{TI}_{it} = \beta_0 + \sum_{j=1}^{J} \beta_1^j \frac{K_{it}^j}{K_{it}} + \beta_2 \ln(Q_i) + \beta_3 \frac{S_i}{Q_i} + \beta_4 T_t + \epsilon_{it} \tag{40}$$

The J measures K^j/K capture the composition of electricity generation for hydroelectric, nuclear, and renewable-source power. Trade intensity and all shares will be expressed as percentages. The regressor $\ln(Q_i)$ captures the size of the

Greene (2011). Random effects and OLS are able to capture cross-sectional variation, while fixed effects suppress cross-sectional variation and use longitudinal variation to identify the effect of regressors.

[13]There are alternatives to the panel data approach captured by (39). In theory it is possible to estimate equation (19) directly for a given pair of jurisdictions, and use the trade data to recover the five underlying parameters (c_1^h, c_1^f, c_2^h, c_2^f, and g). In practice this approach is not feasible because some of the key parameters would need to be available at sub-monthly frequencies. This micro-level estimation approach is also facing the problem that actual cost curves are not neatly convex. Actual cost functions experience discrete jumps when generator stations are brought online.

jurisdiction, and the coefficient of variation S_i/Q_i captures the demand variability of a jurisdiction. The two measures S_i and Q_i are time-averaged over the sample period. A time trend T_t (time in years before or after 2005.0) is added to capture infrastructure changes that include grid expansion. Note that changes in composition are captured by the time variation in K_{it}^j.

Because states and provinces are of significantly different economic size, it is meaningful to weight the regressions accordingly. The reported results will employ weighted least squares with Q_i as weights. Data from the United States and Canada cannot be pooled. Whereas Canada records electricity imports and exports directly, the US trade intensity is imputed as the absolute difference of demand and supply in a given period. This imputation procedure underestimates actual electricity trade due to aggregation bias.

A further method for testing the model is through the use of the price equation (12). Export prices are influenced positively by increasing load in both exporter and importer jurisdiction. Prices should also increase with distance. Equation (12) can be estimated linearly, but a log-linear version may be more appropriate given that prices often have a long upper tail.

$$\ln(p_{ijt}) = \gamma_0 + \mu_i + \mu_j + \gamma_1 T_t + \gamma_2 \ln\left(\frac{q_{jt}}{K_j}\right) + \gamma_3 \ln\left(\frac{q_{it}}{K_i}\right) + \gamma_4 \ln(D_{ij}) + \epsilon_{ijt} \quad (41)$$

There are indicator variables μ_i and μ_j for all exporters and importers, with one exporter and one importer jurisdiction each excluded as the base. To be consistent with theory, the estimates of γ_2, γ_3, and γ_4 all have to be positive.

4.3. Data

For all data sources, trade in electricity is defined as Harmonized System (HS) commodity code 271600. The main source of bilateral monthly trade between Canadian provinces and US states is the *Canadian International Merchandise Trade* database (CIMT) maintained by Statistics Canada. This database records exports from individual Canadian provinces to individual US states, although imports into Canadian provinces are only accounted for in aggregate for all US states. The CIMT database records trade data since 1988.

Electricity demand and generation as well as inter-provincial trade in electricity has been obtained from Statistics Canada's CANSIM database. The tables used include 172-0003 (electric power generation, receipts, deliveries and availability of electricity, monthly from January 2008 onward) and 127-0008 (corresponding annual data). Profiles of electricity generation by type are available in tables 127-

0002 (monthly) and 127-0007 (annual). Table 127-0001 (terminated) contains monthly electric power statistics from 1950 through 2007. The data reported in these tables originates with Canada's National Energy Board.

Additional international trade in electricity data was obtained from the United Nations COMTRADE database. This database records both volume and value of exports and imports, going back to 1988.[14]

State-level electricity data in the United States are available from the *Electricity Data Browser* of the U.S. Energy Information Administration. State-level data are estimated and aggregated from reporting utilities and power generation facilities. Monthly data are available from January 2001 onwards. Available tables cover generation, consumption, but unfortunately not inter-state deliveries.

Distances between jurisdictions were calculated as population-weighted harmonic averages based on populations and geographic locations of postal codes (United States: ZIP codes; Canada: FSA codes). The *Technical Appendix* contains a table for distances between Canadian provinces and US states.

5. Results

5.1. Testing the Two-Way Model of Electricity Trade

The results for the principal estimating equation are shown in table 4. The selected sample in the three columns involve three Canadian provinces (British Columbia [BC], Ontario [ON], and Manitoba [MB]) exporting electricity to US importer states. The three provinces were selected because they exhibit significant levels of two-way trade. Other provinces have little trade or are subject to re-exporting. For example, the province of Quebec exports large quantities of electricity generated outside its boundaries in Labrador. Including such re-exporters confounds the empirical analysis.

The ordinary least squares (OLS) regressions in table 4 capture about a third of the overall variation in the data. The estimates clearly support the theory: all signs are estimated exactly as expected. An increased load ratio in the importing

[14]Data prior to 2000 appears rather spotty, and there may be serious data quality issues. Whereas the value data appears to be mostly reliable, the volume information is often internally inconsistent. This means that exports reported by an origin country to a destination country are rather different than imports reported by the destination country from the origin country. While in some cases this seems to be a misreported physical units problem (MWh instead of GWh), in other cases there seem to be systematic problems. The volume data in the The COMTRADE database should only be used with considerable caution.

Table 4: Regression Analysis of Exports from Canadian Provinces to US States

Export Province		BC		ON		MB	
Intercept		0.189	(.453)	1.610	(.790)	5.950^{a}	(2.07)
Importer Load Ratio	$\ln(q_j/K_j)$	0.892^{c}	(6.60)	2.460^{c}	(6.34)	1.719^{b}	(3.18)
Exporter Load Ratio	$\ln(q_i/K_i)$	-0.948^{a}	(2.40)	-3.246^{c}	(3.72)	-1.736^{c}	(6.07)
Transmission Distance	$\ln(D_{ij})$	-2.034^{c}	(25.6)	-2.700^{c}	(11.4)	-4.876^{b}	(3.09)
Demand Variability	$\ln(V_{ij})$	0.855^{c}	(7.25)	1.196	(1.69)		
Time trend		−0.001	(.061)	0.062^{a}	(1.97)	0.032^{a}	(2.32)
Observations		1,443		799		138	
R^2		0.358		0.274		0.276	

Note: Statistical significance at the 95%, 99%, and 99.9% confidence levels are indicated by superscripts ^{a}, ^{b}, ^{c}, respectively. Standard scores (unsigned z-values) are shown in parentheses. Dependent variable is $\ln(X_{ijt}/K_{ij})$, the log ratio of electricity exports relative to the bilateral harmonic mean of generating capacity.

jurisdiction raises exports, as does a decreased load ratio in the exporting jurisdiction. The demand variability variable has the expected positive effect, although this effect is not always statistically significant (Ontario) or is not defined (Manitoba) because of an insufficient number of trading partners.[15]

Distance has the expected negative effect, but the magnitude is quite remarkable. The distance elasticity is at least −2 and in one case nearly −5. By comparison, gravity models of merchandise trade estimate the distance elasticity at around −1. Making sense of the observed distance effect is a challenge. Line losses alone cannot possibly (even at large distances) account for the large magnitude of the estimated coefficient. A plausible explanation is that physical distance approximates jurisdictional distance. Crossing more and more jurisdictions (provinces, states, municipalities) impedes the *feasibility* of building transmission capacity considerably, even though right-of-way costs only account for about 10% of total project costs (Mason et al., 2012, p. 2-6). The potential for NIMBY-type opposition increases with increasing length when benefits from a new transmission line accrue in distant locations. Fully accounting for the sources of the large distance effect should be the aim of future research. As the inclusion of the 'multilateral

[15]The variability measure captures seasonal effects that require long time periods for identification. The estimating equation mixes short-term effects (load factor) and long-term factors (demand variability). The within-month variability is unobservable given the constraints of the data set.

resistance' term in the third column in table 6 documents, the large distance effect is not merely an artifact that results from neglecting the multilateral dimension of electricity trade.

Tables 5 and 6 provide further analyses of the estimating equation. Table 5 provides simple estimates of the comparative advantage for all trading pairs and separately for British Columbia (BC) and Ontario (ON). The distance elasticities are again around -2. Comparative advantages are captured by proxies for the composition of generating capacity, for both exporters and importers in the first column, and only for the importer for the second and third column that cover a single exporter jurisdiction. These estimated effects tend to be significant in the 'all' and 'BC' columns. The estimated exporter advantage for hydroelectric power makes immediate sense, although the negative effect for nuclear power less so. Only Ontario has a significant amount of nuclear capacity, and thus the effect may simply capture an Ontario-specific effect. On the importer side, the excluded category for generation capacity is oil-based power plants (typically with high marginal costs). All the importer composition effects are positive in the first two columns. It makes sense that a higher proportion of renewable energy would promote a higher level of electricity imports because of the intermittency of renewable sources. In the case of coal, the effect is negative for Ontario and positive for British Columbia.

Table 6 explores an integrated framework with regressors for comparative advantage *and* reciprocal load smoothing. The first column employs the generation composition variables as proxies for comparative advantage, while the second column uses a full set of exporter and importer indicator variables similar to estimating equation (41). The third column adds a 'multilateral resistance' control variable as defined earlier (as jurisdiction fixed effects do not capture time variation in loads of alternate jurisdictions). The effect from the load ratios of the exporter and importer are fully consistent with the theory, as is the distance estimate. The demand variability regressor is positive but not significant in the first and third columns, and negative and significant in the second column. The latter is not consistent with the theory. However, unlike D_{ij}, the variation in V_{ij} can be captured nearly perfectly with the exporter and importer dummy variables, and thus multicollinearity may interfere with estimating V_{ij} correctly in the second column. The introduction of the 'multilateral resistance' term for the average load ratio of alternate import sources strengthens the effect from the exporter and importer load ratios, and itself is negative. This means that alternate electricity sources compete with the exporter region, just as one might expect in a multilateral setting. The *Technical Appendix* reports additional estimates that employ random effects for

Table 5: Comparative Advantage and Canada-US Electricity Trade

Export Province		All		BC		ON	
Intercept		-6.495^c	(8.49)	-14.23^c	(9.53)	0.671	(.337)
Transmission Distance	$\ln(D_{ij})$	-2.213^c	(36.6)	-2.157^c	(17.6)	-1.789^c	(11.0)
Importer coal share	%	0.039^c	(5.01)	0.116^c	(8.56)	-0.054^b	(2.61)
Importer natural gas share	%	0.054^c	(6.26)	0.144^c	(9.65)	−0.041	(1.84)
Importer hydro share	%	0.028^c	(3.68)	0.112^c	(7.57)	0.003	(.130)
Importer nuclear share	%	0.070^c	(9.03)	0.174^c	(13.0)	−0.032	(1.59)
Importer renewables share	%	0.104^c	(10.9)	0.193^c	(13.7)	0.041	(1.39)
Exporter hydro share	%	0.008^c	(6.48)				
Exporter nuclear share	%	-0.011^c	(5.11)				
Exporter renewables share	%	−0.000	(.839)				
Time trend		-0.023^a	(2.07)	−0.024	(1.69)	0.100^c	(3.86)
Observations		3,482		1,443		799	
R^2		0.533		0.511		0.384	

Note: Statistical significance at the 95%, 99%, and 99.9% confidence levels are indicated by superscripts ^{a}, ^{b}, ^{c}, respectively. Standard scores (unsigned z-values) are shown in parentheses.

Table 6: Full Trade Model

Export Province		All		All		All	
Intercept		-5.240^c	(6.11)	-8.589^c	(4.25)	-4.947^c	(5.74)
Importer Load Ratio	$\ln(q_j/K_j)$	0.767^c	(7.19)	1.345^c	(6.08)	0.806^c	(7.52)
Exporter Load Ratio	$\ln(q_i/K_i)$	-2.978^c	(15.3)	-0.779^c	(4.22)	-3.053^c	(15.6)
Alternates Load Ratio	$\ln(q^-/K^-)$					-0.833^b	(3.16)
Transmission Distance	$\ln(D_{ij})$	-2.240^c	(36.9)	-1.911^c	(13.5)	-2.241^c	(37.0)
Demand Variability	$\ln(V_{ij})$	0.161	(1.55)	-3.224^c	(4.04)	0.061	(.560)
Importer coal share	%	0.029^c	(3.82)			0.021^a	(2.54)
Importer natural gas share	%	0.040^c	(4.75)			0.033^c	(3.70)
Importer hydro share	%	0.019^a	(2.53)			0.009	(1.14)
Importer nuclear share	%	0.060^c	(7.74)			0.052^c	(6.33)
Importer renewables share	%	0.082^c	(8.19)			0.070^c	(6.57)
Exporter hydro share	%	0.005^c	(3.70)			0.005^c	(3.50)
Exporter nuclear share	%	-0.015^c	(6.05)			-0.015^c	(6.22)
Exporter renewables share	%	-0.000^c	(3.58)			-0.000^c	(3.85)
Time trend		−0.004	(.400)	0.023^b	(3.01)	0.009	(.772)
Observations		3,482		3,482		3,482	
Exporter & Importer F.E.		no		yes		no	
R^2		0.570		0.737		0.571	

Note: Statistical significance at the 95%, 99%, and 99.9% confidence levels are indicated by superscripts ^{a}, ^{b}, ^{c}, respectively. Standard scores (unsigned z-values) are shown in parentheses.

the full panel. Qualitatively, the results are highly similar to those reported here.

5.2. *The Extensive Margin of Trade*

Cross-border trade in electricity exhibits different extensive margins. First is the margin of exporting and importing on a jurisdictional level: which province-state dyads trade, and which do not. This type of margin is quite dominant as each exporting province only has a relatively small number of import partners in the United States. A logistic regression was used to explore the first type of margin. The results are reported in the *Technical Appendix* because they shed little additional light on cross-border trade in electricity. This analysis looks at all possible trading dyads (all provinces times all states); only about 5% of them trade. This analysis is purely cross-sectional and does not include a time dimension. Only the distance effect is estimated significantly along with a negative effect from a higher share or renewables in the exporter jurisdiction. As can be expected, distance and availability of transmission infrastructure determine trading capability. The separation into different interconnections is, of course, a nearly perfect predictor of who can trade with whom.

Another type of margin is within the group of trading dyads. Some dyads do not always trade. There may be significant periods of zero trade for a given trading pair. These may indicate periods when trading is not profitable despite the fact that transmission capacity exists. This type of extensive margin is related to economic rather than physical constraints. This type of margin is consistent with two-way trade in electricity and the no-trade gap in figure 8. However, this margin is difficult to identify in monthly data. Aggregation may obscure what may be episodes of zero trade throughout a month. If trade is more one-way (driven by comparative advantage) than two-way (driven by reciprocal load smoothing), transmission capacity will also tend to be more utilized.

5.3. *Trade Intensity*

The theory of reciprocal load smoothing can also be tested through estimating equation (40) for trade intensity. Tables 7 and 8 report the results of this approach for Canada and the United States, respectively. Because of the vastly different size of jurisdictions (especially in Canada), weighted least squares were used to obtain estimates, with average jurisdictional demand as the weight. The first column in both tables includes all jurisdictions. As a robustness check, the second column suppresses observations with trade intensities in excess of 120%, which is indicative of jurisdictions that produce electricity primarily for export. The third column suppresses observations where the trade intensity is zero (Canada) or miniscule (United States, less than 1%). The panel used in both instances comprises all jurisdictions in Canada and the United States and monthly data since 2001.

Table 7: Trade Intensity Regressions—Canada

Sample Selection		All		TI<120%		TI>0%	
Estimation Method		WLS		WLS		WLS	
Intercept		112.24^c	(15.2)	41.468^c	(17.0)	121.41^c	(14.5)
Share of Hydro	%	0.495^c	(15.6)	0.254^c	(24.5)	0.513^c	(14.4)
Share of Nuclear	%	0.344^c	(9.01)	0.199^c	(16.1)	0.355^c	(8.34)
Share of Renewables	%	0.000	(1.17)	0.001^c	(7.92)	0.000	(.853)
Demand Coeff. of Var.	–	0.591^a	(2.09)	1.280^c	(14.1)	0.438	(1.38)
Log Average Demand		-13.57^c	(21.7)	-5.808^c	(27.7)	-14.43^c	(20.3)
Time Trend	a^{-1}	0.031	(.235)	0.124^b	(2.86)	0.028	(.187)
Observations		2,081		1,931		1,629	
Weights		Avg. Demand		Avg. Demand		Avg. Demand	
R^2		0.404		0.697		0.418	

Table 8: Trade Intensity Regressions—United States

Sample Selection		All		TI<120%		TI>1%	
Estimation Method		WLS		WLS		WLS	
Intercept		136.85^c	(35.6)	65.860^c	(24.4)	139.25^c	(35.8)
Share of Hydro	%	-0.067^b	(3.07)	0.069^c	(4.70)	-0.071^b	(3.24)
Share of Nuclear	%	0.007	(.346)	0.225^c	(15.8)	−0.003	(.158)
Share of Renewables	%	0.256^b	(2.97)	0.300^c	(5.12)	0.204^a	(2.34)
Demand Coeff. of Var.	–	1.077^c	(9.74)	0.779^c	(10.4)	1.045^c	(9.29)
Log Average Demand		-13.96^c	(34.5)	-6.668^c	(23.5)	-14.05^c	(34.3)
Time Trend	a^{-1}	0.026	(.286)	0.168^b	(2.69)	0.026	(.281)
Observations		7,344		6,862		7,123	
Weights		Avg. Demand		Avg. Demand		Avg. Demand	
R^2		0.147		0.115		0.149	

Note: Statistical significance at the 95%, 99%, and 99.9% confidence levels are indicated by superscripts ^{a}, ^{b}, ^{c}, respectively. TI stands for trade intensity. Standard scores (unsigned z-values) are shown in parentheses.

The estimating equation (40) predicts a positive effect from the coefficient of variation of electricity demand. The results in tables 7 and 8 confirm this prediction, thus providing another crucial piece of evidence in support of the reciprocal load smoothing hypothesis. Jurisdictions with more volatile demand are more eagerly engaging in electricity trade. The results also indicate an interesting size effect. Larger jurisdictions rely much less on trade than smaller jurisdictions. This makes intuitive sense. Larger jurisdictions tend to be more diversified in terms of generating capacity and may be better able to balance load in different regions. Smaller jurisdictions need to rely more on their neighbours to compensate for fluctuating demand, or simply import electricity from their bigger neighbours.

In Canada, jurisdictions with a higher proportion of hydroelectric and nuclear power tend to increase their trade intensity. This may be an indication of the comparative advantage of these technologies, or the higher reliability and availability for satisfying base loads. In the United States, these two power sources do not seem to have a large influence on the trade intensity. However, a larger share of renewable energy is clearly associated with an increase in electricity trade.

5.4. Export Prices

The *Canadian International Merchandise Trade* (CIMT) database records both volume and value of exports and imports. It is therefore possible to analyze the price dimension of exports. Summary data appear in the *Technical Appendix*. There is significant variation in prices along with occasional price spikes such as those during the 2000-2001 California electricity crisis.[16] Price spikes in excess of $200/MWh were purposefully excluded from the analysis in this section.

Table 9 reports results for the price estimating equation (41), which includes fixed effects for exporter provinces and importer states. It may be interesting to look at these numbers as they indicate idiosyncratic price premia and discounts. In the table the importer states are prefixed M, and the exporter provinces ar prefixed X. The base exporter province is Ontario, and the base importer state is New York; all price premia are relative to this base-pair.

The first column in table 9 reports simple OLS estimates. The second column (QREG) reports results from a quantile regression of the median to allow for the long tail of the price distribution. The dependent variable in both columns is expressed in dollars per MWh. The third—and preferred—estimation approach corresponds directly to the log-linear estimating equation (41). The estimated coefficients of the exporter and importer load ratios are both positive, fully consistent with theory. The effect of distance cannot be estimated significantly in the preferred specification, although it points in the right direction. Other specifications suggests that the distance effect is indeed positive as predicted.[17] There is also a

[16]See Borenstein (2002) for a discussion of the factors that contributed to the California electricity crisis.

[17]The *Technical Appendix* contains a table with robustness checks where the distance effect is estimated significantly with a positive sign when the importer dummies are excluded and only

Table 9: Export Prices

Estimation Method	OLS		QREG		OLS	
Price Variable	Mean		Median		Log	
Intercept	-13.01^{a}	(2.33)	0.564	(.120)	4.119^{c}	(70.2)
Load Ratio Exporter	30.014^{c}	(8.21)	26.005^{c}	(7.76)		
Load Ratio Importer	53.108^{c}	(10.6)	45.318^{c}	(11.3)		
Log Load Ratio Exporter					0.442^{c}	(9.30)
Log Load Ratio Importer					0.603^{c}	(10.5)
Log Distance	1.700	(.878)	−2.004	(1.02)	0.051	(1.51)
M: Alaska	18.445^{c}	(3.60)	21.089^{c}	(3.73)	0.342^{c}	(3.85)
M: Arizona	25.117^{c}	(4.68)	24.129^{c}	(3.46)	0.501^{c}	(5.32)
M: California	−1.960	(.388)	1.699	(.278)	0.030	(.347)
M: Colorado	11.645^{a}	(2.09)	10.706	(1.46)	0.225^{a}	(2.32)
M: Iowa	-49.69^{a}	(2.40)	−47.97	(.280)	-1.342^{c}	(3.75)
M: Idaho	1.575	(.299)	3.327	(.551)	0.078	(.855)
M: Illinois	13.267^{b}	(3.08)	12.781^{b}	(3.00)	0.232^{b}	(3.12)
M: Indiana	16.728^{c}	(5.00)	14.544^{c}	(5.47)	0.271^{c}	(4.68)
M: Massachusetts	4.194	(1.47)	8.910^{a}	(2.15)	0.101^{a}	(2.06)
M: Maryland	-106.0^{c}	(5.20)	−103.5	(.467)	-4.344^{c}	(12.3)
M: Maine	10.050^{c}	(3.56)	1.827	(.550)	0.233^{c}	(4.67)
M: Michigan	2.563	(1.25)	2.232	(1.31)	0.046	(1.28)
M: Minnesota	-6.144^{a}	(2.09)	−3.525	(1.43)	−0.072	(1.45)
M: Missouri	9.955^{a}	(2.54)	6.102	(1.42)	0.131	(1.93)
M: Montana	18.391^{c}	(3.32)	13.247^{a}	(2.23)	0.403^{c}	(4.10)
M: North Dakota	25.681^{c}	(3.38)	23.826^{b}	(2.83)	0.608^{c}	(4.43)
M: Nebraska	30.907^{a}	(2.56)	36.731	(1.15)	0.390	(1.86)
M: New Hampshire	27.989^{c}	(8.87)	21.360^{c}	(6.56)	0.584^{c}	(9.87)
M: New Mexico	30.068^{c}	(5.55)	27.219^{c}	(4.64)	0.579^{c}	(6.11)
M: Nevada	17.495^{c}	(3.41)	17.985^{b}	(3.11)	0.336^{c}	(3.77)
M: Ohio	13.106^{b}	(3.18)	9.268^{c}	(3.50)	0.232^{b}	(3.25)
M: Oregon	7.006	(1.31)	2.316	(.385)	0.149	(1.62)
M: Pennsylvania	21.714^{c}	(8.06)	20.053^{c}	(9.44)	0.401^{c}	(8.58)
M: Texas	7.960	(1.70)	13.589^{b}	(2.85)	0.077	(.950)
M: Utah	32.609^{c}	(6.09)	29.505^{c}	(5.03)	0.616^{c}	(6.59)
M: Vermont	17.642^{c}	(8.48)	16.427^{c}	(8.50)	0.325^{c}	(9.07)
M: Washington	1.539	(.260)	−4.882	(.697)	0.004	(.037)
M: Wyoming	48.936^{c}	(8.45)	43.063^{c}	(6.97)	1.061^{c}	(9.63)
X: Alberta	4.919	(.802)	9.378	(1.18)	0.058	(.547)
X: British Columbia	8.276	(1.68)	11.461	(1.85)	0.074	(.867)
X: Manitoba	3.876	(1.38)	−0.503	(.242)	0.107^{a}	(2.17)
X: New Brunswick	32.359^{c}	(11.2)	36.406^{c}	(8.55)	0.599^{c}	(11.8)
X: Nova Scotia	12.513^{c}	(3.77)	16.004^{c}	(4.16)	0.176^{b}	(3.07)
X: Quebec	15.808^{c}	(10.3)	15.981^{c}	(10.1)	0.246^{c}	(9.29)
X: Saskatchewan	10.648	(1.45)	9.041	(1.07)	0.217	(1.71)
Time Trend	-2.848^{c}	(25.2)	-2.768^{c}	(23.3)	-0.053^{c}	(26.7)
Observations	3,424		3,424		3,424	
R^2	0.331				0.367	

Note: Regression methods are Ordinary Least Squares (OLS) and quantile regressions for the median (QREG). Statistical significance at the 95%, 99%, and 99.9% confidence levels are indicated by superscripts ^{a}, ^{b}, ^{c}, respectively. Standard scores (unsigned z-values) are shown in parentheses. The excluded groups for the export and importer jurisdiction indicator variables are Ontario and New York. Importers are prefixed 'M'; exporters are prefixed 'X.'

negative time trend in the data. Electricity exports tend to get cheaper over time, despite the rising cost of generation. Perhaps power markets in North America are becoming more efficient in dispatching electricity.

6. The Gains from Electricity Trade

Having laid out a new theory that leads to gains from trade, the obvious question to ask is about the size of these gains from trade. Does 'reciprocal load smoothing' generate economically meaningful welfare gains? Fundamentally, these gains come from trading off generation capacity and transmission capacity. Underinvestment in transmission capacity equals overinvestment in generation capacity, and this is economically inefficient. Do potential welfare gains make a case for pursuing policy changes towards building a North American 'supergrid'?

The case for increased integration of the North American is gaining significant momentum (Bowman et al., 2009a,b; Carr, 2010; Goodman, 2010; Baker et al., 2011; Bahar and Sauvage, 2013; Canadian Electricity Association, 2013). There are many technical reasons that promote the notion of building a continent-wide supergrid. Chief among them is the integration of renewable energy; see Ambec and Crampes (2012) and van Kooten et al. (2013) for a discussion of many of the related issues. A supergrid may also provide greater reliability and redundancy. There are numerous institutional issues and economic frictions that hold back the construction of more transmission infrastructure. The most obvious is the division of the North American transmission system into separate and mostly self-contained interconnections: a world akin to free trade areas with high tariff walls between them. Neighbouring states cannot exploit trading opportunities if they belong to different interconnections, and more distant states cannot exploit efficiencies from cross-continental delivery of power.

This section cannot provide a concise answer about the current and potential gains from cross-border electricity trade. Many of the current gains are realized at the sub-monthly level, and potential future gains from trade are contingent on modeling increased transmission capacity. However, it is possible to sketch out the economic extremes of a fully unified grid with pooled supply and zero transmission cost, and an autarkic grid where each province or state is self-sufficient.[18] In a fully integrated continental grid, local demand would be added up nationally

exporter dummies are used.

[18] A rigorous welfare analysis requires hourly mirco data and a sophisticated simulation-optimization model in which additional long-distance bulk transmission capacity can be studied.

and divided in proportion to generation capacity across states or provinces. This would smooth the ups and downs in the capacity utilization because the unified load would vary more smoothly than the sum of local variations—the familiar portfolio effect. With the covariances of demand σ_{ij} and variance $\sigma_{ii} \equiv \sigma_i^2$, the sum of standard deviations $\bar{\sigma}$ is larger than the pooled standard deviation $\bar{\bar{\sigma}}$ when demand is not perfectly correlated:

$$\bar{\sigma} \equiv \sum_i \sigma_i \quad > \quad \sqrt{\sum_i \sum_j \sigma_{ij}} \equiv \bar{\bar{\sigma}} \tag{42}$$

The difference in standard deviations $\bar{\sigma} - \bar{\bar{\sigma}}$ between unpooled and pooled portfolio, multiplied by the desired safety margins $\bar{m}$ and $\bar{\bar{m}}$, identifies the benefit from pooling. The difference between autarky and friction-less pooled trade is $\bar{\sigma}\bar{m} - \bar{\bar{\sigma}}\bar{\bar{m}}$.

Table 10: Load Pooling in Canada (Monthly Scope)

Province	Demand	Std.Dv.	Supply	Surplus	To U.S.	Margin
Newfoundland	968	175	3,459	2,491	0	1.892
Prince Edward Is.	98	7	11	-87	0	2.208
Nova Scotia	998	134	983	-15	-8	2.106
New Brunswick	1,246	285	1,301	55	105	3.372
Quebec	17,015	2,718	15,536	-1,479	1,105	2.375
Ontario	11,924	1,341	12,551	627	472	2.212
Manitoba	1,931	323	2,700	769	678	2.489
Saskatchewan	1,682	216	1,681	-1	-15	4.799
Alberta	5,163	377	5,001	-161	-35	3.649
British Columbia	5,414	659	5,409	-5	-69	2.272
All Canada	46,440	6,236	48,633	2,193	2,234	2.566
(pooled)		5,062				2.272

Note: Analysis is based on 2003-2012 period using monthly data. All but the last columns report figures in GWh per month. The column 'Margin' reports the difference between maximum load and average load in units of standard deviations.

Table 10 backs out the pooling potential for Canada; for space considerations the much longer table for the United States appears in the *Technical Appendix*. For each province the table shows the average demand, standard deviation of demand, supply (generation), and surplus. For example, during the 2003-2012 averaging period, the province of Newfoundland and Labrador generated an average monthly surplus of 2.5 TWh. Quebec's generation deficit of 1.5 TWh was balanced by importing electricity from Labrador, leaving roughly 1.1 TWh for export to the United States. Canada's nation-wide surplus of 2.2 TWh was exported to the United States. The last column shows the safety margin for each province, defined as the difference between maximum and average demand expressed in standard deviations. For example, British Columbia's required safety margin was 2.3 times its standard deviation of 659 GWh; these 1,497 GWh amount to 28% of the province's generating capacity.

The last two lines in table 10 identify the benefits from a nationally pooled grid. A pooled grid would reduce the standard deviation from $\bar{\sigma}$=6,236 GWh to $\bar{\bar{\sigma}}$=5,062 GWh per month, a remarkable 19% drop. The pooled safety margin is also a bit smaller than the weighted average of the individual safety margins. The required contingent capacity is therefore 11.5 TWh instead of 16.0 TWh per month. On a nationwide level, the 4.5 TWh/month difference is equivalent in size to about seven modern nuclear reactors or a dozen large hydroelectric dams.[19] But just how much more trade—and intertie capacity—would a nationally-integrated grid entail? Would the cost of building this intertie capacity come at a lower cost than building seven nuclear reactors (about $50 billion) or a dozen new dams (about $96 billion)?[20] Of course, we are clearly not at the point of a fully autarkic system as most jurisdictions indeed trade with one or more of their neighbouring jurisdictions. On the other hand, the cost of building new transmission capacity diminishes the potential for grid integration at the other end of the spectrum.

The equivalent gains from grid integration are significantly larger in the United States. The pooled standard deviation of demand is 29,567 GWh, compared to 35,257 GWh unpooled. After applying the safety margins (2.286 pooled and 2.565 unpooled), the efficiency gap is 22.8 TWh/month in reduced contingent capacity—the equivalent of 28 nuclear reactors or 65 Hoover dams! Of course, the existing grid already realizes some of these gains. Careful analysis is needed to quantify the remaining gap and the competing costs of building more transmission capacity versus more generating capacity. The 22.8 TWh/month figure underestimates the gains from trade because the available monthly data only captures seasonal effects in the north-south direction. Over long distances, east-west

[19]Figures are based on the Westinghouse AP1000 design, rated at about 600 GWh/month, and the Hoover dam, which generates about 350 GWh/month.

[20]This is based on projected costs for the Vogtle plant expansion in Georgia: $14 billion for two AP 1000 reactors. By comparison, a new hydroelectric dam in British Columbia, Site C, is expected to cost about $8 billion and is expected to generate 380 GWh/month.

timezone shifts could provide significant additional intra-day gains from trade.

A supergrid can provide several other economic and environmental benefits. In the long term, jurisdictions with a comparative advantage in electricity production could build up generation capacity if they can deliver their electricity to more distant markets. Renewable energy sources such as wind also require complementarities in generating capacity to make up for their intermittency. Hydro power (which can accelerate or decelerate use of reservoirs) are a natural complement to wind and solar energy. Greater integration can also improve overall system reliability. More importantly, integration may also provide an opportunity for retiring polluting generating capacity. The 22.8 TWh/month efficiency gap in the United States translates into a significant potential for climate change mitigation. At a carbon dioxide intensity of about 1 tonne per MWh,[21] an annual efficiency gap of 273 TWh translates into a potential for reducing carbon dioxide emissions by 273 million tonnes, or 5.2% of 2012's annual total of 5.3 billion tonnes.

7. Conclusions

This paper has developed a theoretical model of two-way trade in electricity. The set-up shares a common root in the trade-theoretical 'reciprocal dumping' model, which provided a foundation for two-way trade in identical commodities. However, the underlying economic logic is fundamentally different for electricity trade. The 'reciprocal dumping' model relies on reciprocal market access of oligopolistic competitors in two countries. While this model of two-way trade is driven by market structure, the two-way trade in electricity is caused by stochastic demand that shifts electricity generation up and down on an upward-sloping marginal cost curve as electric utilities deploy their generation assets on a least-cost-first basis. Neighbouring jurisdictions engage in 'reciprocal load smoothing.' The theory developed in this paper has identified several key features of two-way trade in electricity:

- Trade is one-way in the presence of strong (conventional) comparative advantage in electricity production, and trade tends to become more two-way when comparative advantages between trading partners are more closely matched.

[21] Source: Environmental Protection Agency. 2,249 lbs/MWh for coal-fired power stations in the United States.

- Trade is two-way in the presence of fluctuating demand where exports and imports follow the load difference between two jurisdictions. Trading opportunities increase with the variability of electricity demand over time (due to seasonal or intra-day effects) and lower (or negative) correlation in demand. Jurisdictional size differences also promote cross-border trade.

The empirical investigation of Canada-US cross-border trade in electricity lends strong support to the theoretical model developed in this paper. Conventional comparative advantage *and* reciprocal load smoothing work in tandem to explain the observed patterns of cross-border trade in electricity.

Empirically, the volume of trade in electricity is subject to a much steeper decline over distance than trade in merchandise goods. Whereas the distance elasticity for the latter is typically around (negative) unity, it is roughly twice as high for electricity. Doubling the distance reduces electricity trade by one-fourth. Perhaps physical distance captures 'jurisdictional' distance: the legal and administrative difficulties of building long-distance interties.

Whether the current level of electricity trade and continental integration of the electricity grid is sufficient remains a rather important policy question. Rough calculations of the trade potential—the difference between autarky and complete frictionless integration—suggest an efficiency gap equivalent to 65 Hoover dams in the United States and a dozen hydro dams in Canada. Even if only half or a third of this efficiency gap remains to be closed, the potential gains from more electricity trade across jurisdictions are impressive. With long-distance transmission costs falling through the development of high-voltage direct current (HVDC) transmission lines, combined with the need to accommodate increasing volumes of intermittent power from renewable sources, the quadrupling of cross-border trade in electricity over the last decade (illustrated in figure 1) is making very good economic sense.

The theory of 'reciprocal load smoothing' introduced in this paper constitutes a new mechanism for gains from trade that may transcend electricity. In principle, the mechanism can apply to any homogenous product provided that there is (a) non-perfect correlation in stochastic demand across trading partners and (b) strongly upward-sloping marginal costs in production.

Appendix A. Expectation of Quadratic Sum

Let $f(x)$ be a normal probability density function of the random variable x with mean μ and variance σ^2. Then the expectation of a function $g(x)$ is

$$\mathcal{E}\{g(x)\} = \int_{-\infty}^{+\infty} g(x)f(x)dx \tag{A.1}$$

where $f(x) = \exp[-(x-\mu)^2/(2\sigma^2)]/[\sigma\sqrt{2\pi}]$ is the normal density function. For a quadratic function $g(x)$ with arbitrary parameters a and b,

$$\mathcal{E}\{ax + bx^2\} = \int_{-\infty}^{+\infty} (ax + bx^2)f(x)dx = a\mu + b(\mu^2 + \sigma^2) \tag{A.2}$$

Appendix B. Multivariate Normal Affine Transformation

Assume the $\mathbf{x}$ is a vector of random variables which are distribute multivariate normal so that $\mathbf{x} \sim \mathrm{N}(\boldsymbol{\mu}, \boldsymbol{\Sigma})$. Further assume that $\mathbf{b}$ is a vector of constants of the same size a $\mathbf{x}$. The product $z = \mathbf{b}^\intercal\mathbf{x}$ is then univariate normal with $z \sim \mathrm{N}(\mathbf{b}^\intercal\boldsymbol{\mu}, \mathbf{b}^\intercal\boldsymbol{\Sigma}\mathbf{b})$. Consider the bivariate case with vector elements $+b_1$ and $-b_2$. Then z is distributed univariate normal with mean $b_1\mu_1 - b_2\mu_2$ and variance $b_1^2\sigma_1^2 + b_2^2\sigma_2^2 - 2b_1b_2\rho\sigma_1\sigma_2$. The variance will decrease if the two random variables are positively correlated, and will increase if the two random variables are negatively correlated.

Appendix C. Truncated Normal Distribution

If a random variable z is distributed normally with mean μ and variance σ^2, then the expected values of the left-truncated and right-truncated distribution with truncation point a are:

$$\mathcal{E}\{z|z > a\} = \mu + \sigma\frac{\phi((\mu - a)/\sigma)}{\Phi((\mu - a)/\sigma)} \tag{C.1}$$

$$\mathcal{E}\{z|z < a\} = \mu - \sigma\frac{\phi((a - \mu)/\sigma)}{\Phi((a - \mu)/\sigma)} \tag{C.2}$$

The functions $\phi(\cdot)$ and $\Phi(\cdot)$ denote the standard normal probability density function and standard normal probability cumulative density function, respectively. Further note that $\phi(x) = \phi(-x)$ and $1 - \Phi(x) = \Phi(-x)$.

Appendix D. Alternative Cost Function

An alternative to the quadratic cost function that was used primarily in this paper, it is possible to employ a logarithmic cost function

$$c(q) = -\gamma \ln\left(1 - \frac{q}{K}\right) \tag{D.1}$$

that depends on the capacity utilization rate q/K. This cost function has a single parameter $\gamma > 0$, and the cost function itself is convex with monotonically increasing marginal cost, i.e., $c'(q) = \gamma/(K - q) > 0$ and $c''(q) = \gamma/(K - q)^2 > 0$, and $\lim_{q\to K} c(q) = \infty$. Instead of transmission costs, exporting incurs transmission losses so that exporting the amount x requires $x(1 + \xi)$ of extra generation, with $\xi > 0$. Thus the profit function can be written as

$$\pi^x = px - [C(q + x(1 + \delta^x \xi)) - C(q)] \tag{D.2}$$

where δ^x and δ^m are binary indicators for export and import status, respectively. The utility will export and import when

$$p > \frac{\gamma(1 + \xi)}{K - q} \quad \text{for exporting} \tag{D.3}$$

$$p < \frac{\gamma}{K - q} \quad \text{for importing} \tag{D.4}$$

The trading price for electricity is

$$p = \frac{(1 + \xi)(\gamma^h + \gamma^f)}{(K^f - q^f)(1 + \delta^x \xi) + (K^h - q^h)(1 + \delta^m \xi)} \tag{D.5}$$

and the export volume is

$$x^h = \frac{\gamma^f (K^h - q^h)}{(\gamma^h + \gamma^f)(1 + \delta^x \xi)} - \frac{\gamma^h (K^f - q^f)}{(\gamma^h + \gamma^f)(1 + \delta^m \xi)} \tag{D.6}$$

Exports and imports will occur when

$$\xi < \frac{\gamma^f (K^h - q^h)}{\gamma^h (K^f - q^f)} \quad \text{for exporting} \tag{D.7}$$

$$\xi < \frac{\gamma^h (K^f - q^f)}{\gamma^f (K^h - q^h)} \quad \text{for importing} \tag{D.8}$$

From the above it is clear that x^h is a linear function of q^h and q^f, and thus the integration over the reference time period to find X^h and M^h proceeds in the same fashion as discussed in the paper and Appendix B and Appendix C.

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