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Assessing the value of power interconnections under climate and natural gas price risks

P.-O. Pineau*, D.J. Dupuis, T. Cenesizoglu

HEC Montréal, 3000 Côte-Sainte-Catherine Road, Montréal, Quebec H3T 2A7, Canada

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A B S T R A C T

The value of transmission capacity is hard to assess due to the presence of different issues: physics of power networks, economics of power systems and reliability criteria. Evolving supply and demand trends, however, create interest in increased transmission capacity, especially between jurisdictions with complementarities. Assessing the value of such interconnections is key in analyzing the viability of these projects. Based on a data set containing 10 years of hourly power flows and prices, daily temperature and natural gas prices, as well as climate change forecasts for 2020 and 2050, we simulate export revenues for a DC (direct current) interconnection between Quebec (Canada) and New York (US) under different natural gas price scenarios and extreme heat events. Our innovative approach, combined with an extensive data set, provides a prospective assessment of the value of new transmission projects. Our results suggest that future natural gas prices would be the main driving factor of future revenues on a transmission line, with climate change having a relatively much smaller impact on future revenues.

1. Introduction

Increasing electricity transmission capacity is required but challenging. In North America, for instance, new transmission will be required as part of the solutions to many of the issues identified by the North American Electric Reliability Corporation in its long-term planning assessment [26]: higher level of variable generation, fossil-fired and nuclear generation retirements and continued increase in natural gas-fired generation, among others. Intra and inter-regional transmission projects can indeed provide many benefits in the context of evolving power markets. Similar situations obviously arise in all parts of the world. Investment in transmission, however, is more challenging than ever. With increased competition in power systems, the traditional regulated approach to transmission expansion becomes more difficult to implement as there are less vertically-integrated utilities and increased open access requirements. Benefits of transmission assets are now shared by more players, in different jurisdictions, making the alignment of incentives more difficult to achieve. Merchant transmission has developed as a new approach to transmission investment, but it faces multiple obstacles, such as market power, lumpiness of investment, strategic behavior and difficulties in coordination. See Refs. [8,22] for more on the theory and evidence on merchant transmission.

Benefits of increased transmission capacity are, however, more and more documented. In a Northern European context, [40] underscores transmission expansion benefits, resulting from increased competitiveness, security of energy supply and environmental sustainability. These benefits create a potential for electricity trading. In a North American context, [5] documents eight potential benefits of transmission investments: production cost savings, reliability and resource adequacy benefits, generation capacity cost savings, market benefits (competition and liquidity), environmental benefits, public policy benefits, employment and economic development benefits and other project-specific benefits.

These benefits are often greater for transmission investments between regions where more complementarities can be found, for instance between regions with a large price differential. However, in the absence of common regulators, regulated transmission investments are difficult to justify, often resulting in limited inter-regional transmission links. Merchant transmission has therefore a larger role to play in interconnecting markets, as well as other types of "non-traditional transmission developments". These new approaches are driven by incumbent or new entrants and financed through tariffs or contracts (see Refs. [6,18]). Such initiatives are indeed observed between the province of Quebec (Canada), with

* Corresponding author. Tel.: +1 514 340 6922.
E-mail address: pierre-olivier.pineau@hec.ca (P.-O. Pineau).

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plenty of relatively cheap hydropower, and the US Northeastern region, characterized by a high and growing reliance on natural gas and ambitious RPS (renewable portfolio standards) goals. Three high-voltage direct current transmission projects are indeed being studied, linking Quebec and New York City [41], Quebec and Vermont [39] and Quebec and New Hampshire [28]. These projects can only be completed if the expected commercial benefits, for developers, are large enough to justify their investment. As production costs of renewable power sources from the exporting regions (e.g. Quebec) are fairly stable, uncertainty for these projects is rooted in future demand levels and market prices, in the export market.

This paper proposes a novel approach to assessing the value of an interconnection. Expected revenues generated by such interconnections, under different climatic scenarios (driving demand levels) and natural gas prices (driving market prices) are simulated for 2020 and 2050, using 10 years of hourly trade and market prices, as well as temperature and natural gas prices. The observed data constitute the basis of the simulation, from which distributions with more "extreme heat" days, reaching at least 90° Fahrenheit (°F), equivalent to 32° Celsius (°C), and various levels of natural gas prices (averages of approximately $4, $5.5 and $8 per million British Thermal Units or MMBtu) are created.

In Section 2, a literature review presents the energy economics literature on the value of transmission capacity, providing the context for our approach. It also reviews the evidence on climate change and extreme heat events on electricity demand, and the link between natural gas and electricity prices. Section 3 describes our data sets and methodology. In Section 4, our main results are presented and discussed. Section 5 provides some additional discussion on costs and revenues of such merchant transmission projects, in order to better understand their possible net benefits. Finally, Section 6 concludes.

2. Literature review

2.1. The value of transmission capacity

The potential benefits of transmission investments are well recognized. See for instance [40] and [5], as already mentioned in the introduction. The literature on power system integration, which directly implies transmission links, also considers a series of benefits, as shown in Table 1. See Refs. [4,42,11,45], and also [37] for a discussion.

Beyond recognizing these potential benefits, measuring them is much more challenging. The relatively small literature on the value of transmission capacity can be divided in two groups: papers using network models to simulate a power system with and without a given transmission link, and papers abstracting from power network specificities to focus on the economic modeling of the power market. Such distinctions between economic and engineering considerations have been documented in Ref. [47] and more recently discussed by Refs. [8,19]. We now review some of the main papers on this topic.

Table 1
Potential technical benefits from power sector integration.

Improved reliability and pooling reserves	Diversity of generation mix and supply security
Reduced investment in generating capacity	Economic exchange
Improved load factors and increased demand diversity	Environmental dispatch and new plant siting
Economies of scale in new construction	Better coordination of maintenance schedules

[3] uses a model of a simplified version of a two-area interconnected competitive electricity market to develop a tool to assess reliability and economic benefits of transmission expansions. Their tool (REliability and MARKet, REMARK) requires a relatively detailed level of characterization of the network. It optimizes the system under different transmission scenarios and provides some benefit assessments, based on different assumptions for demand, supply and value of lost load. While in principle this approach can be extended for various cases, the modeling effort can be quite large to adjust to a particular situation. While the tool aims at assessing transmission benefits, it focuses on the short and mid-term (1 year of operation), and is not designed to look at longer term trends, such as a shift in demand due to climate change or different price scenarios for fuels (e.g. natural gas). [7], in a similar approach, investigates the economic impacts of connecting Norway and Great Britain. [9] considers the case of Great Britain in light of its interconnections.

[46] considers a real case, very close to the abstract example of [3]: the Alberta (Canada) competitive electricity market, consisting of two interconnected areas, with a highly congested transmission link. Their analysis is centered on various scenarios for additional power plants and transmission capacity, while loads remain inelastic. While such an approach provides valuable estimates on short term benefits for consumers and producers, it is not designed to assess long-term risks affecting the fundamentals of the market. Also, as in Ref. [3], it focuses on a single competitive market, and not on the interconnection of two different markets, where merchant transmission investors are locked-in without regulatory protection.

Still within a single market [2], explores how small investment in transmission capacity can have important competitive impacts, by increasing competition between producers only interconnected with limited transmission capacity.

[8], building on an approach initially developed in Refs. [20,21], moves away from the detailed modeling of power systems to focus on the energy price impacts of increasing transmission between two different competitive markets. Their approach to value electricity transmission consists in assessing, both for the transmission owners and society in general, the impact of the changing market prices due to an increasing transmission capacity between the two markets. Indeed, with increasing transmission capacity, there is an increasing possibility to take advantage of market price differences, but also a declining price difference. For a given level of interconnection, their approach allows one to estimate how much the market benefits from the transmission link, and how much the owner of the link can capture in terms of price differential between the markets. The key assumption in their approach is the value used for the elasticity of supply, which directly affects the price level, as export possibilities grow with the transmission line capacity. The model built under this approach takes advantage of hourly market prices and flows between two markets. Unconstrained and constrained trading hours are characterized and the addition of transmission capacity decreases the number of hours of constrained trade in their simulation. Demand and supply in both markets are held fixed, although responding to price. While this approach is an interesting contribution to the literature on the value of transmission investments, it relies on the availability of market prices from two contiguous (or at least connected) markets. In addition, it is designed to assess the incremental value of transmission, rather than the future value of transmission under different demand and supply scenarios.

Our approach is closer to the economic approach of [8] than to the network simulation one. However, we do not model electricity markets but focus on the possible use and revenues of the transmission line. We take advantage of hourly market prices and flows between two markets, for an extensive period of time (2000–2009) and assume that this pool of data can provide enough evidence of trade patterns to project similar outcomes into the future, but under different demand and price scenarios. These trade outcomes (use of the line and revenues) are used as the main building block to assess the value of an interconnection.

2.2. Electricity, climate change and natural gas

The focus of our analysis is on the use of the transmission line and on price levels which, combined, create an important share of the value of an interconnection. As these two variables are highly dependent on climate conditions and fuel prices, we concentrate on relevant climate and natural gas price scenarios for our analysis of an interconnection's value. Next is a review of the relevance of climate and natural gas price in electricity consumption and price.

The literature on climate change and electricity is abundant. [24] reviews this literature. The link between rising temperature and a greater need for cooling, and hence a higher related electricity demand, is found to be well established. See also [1] on this. [13] looks at electricity demand, hydroelectric production and plant efficiency in relation to climate change. As they study these aspects in Western Europe, interconnections are an implicit component of their research, but not the main focus. This accentuates the finding made by Ref. [24] that transmission issues are one area where further research is needed. Our paper aims at contributing to this area.

In its annual State of the Markets, the US Federal Energy Regulatory Commission emphasizes the relationship between weather, natural gas prices and electricity; see Ref. [12]. Indeed, "since natural gas is often the marginal fuel in electric generation, lower natural gas prices generally [result] in lower electricity prices" [12]. This is particularly the case in New England, where in 2012 "natural gas was the marginal fuel during 81% of all pricing intervals" ([16], page 17). The relationship between natural gas price and electricity price is also strong in the New York market, where "average electricity prices fell substantially from 2011 to 2012, decreasing 20 to 25 percent in most areas. These decreases were consistent with the change in natural gas prices, which fell 28 to 35 percent from 2011 to 2012." [32].

This relationship is indeed what we observed in our data, ranging from 2000 to 2009 (as described in the next section), both under extreme heat events and under normal temperature. Fig. 1 below illustrates a high level of dependence between natural gas and electricity prices.

Table 2
Northeastern Canada-United States electricity market [38] [44] [27].

	Population in 2013 million	Capacity in 2013 MW	Electricity consumption in 2012 TWh
Quebec	8.15	43,534	184.8
New York	19.65	40,001	162.8
Ontario	13.54	36,466	141.3
New England	14.62	35,727	128.1
Maritimes	2.37	7551	23.4

3. Data and methodology

3.1. Context

We use the Northeastern Canada-United States electricity market to provide the context and data to illustrate our approach. This region includes the provinces of Ontario, Quebec and the Maritimes region of Canada, along with New York and New England in the United States. Table 2 provides a basic description of these five areas, in terms of population, capacity and electricity consumption.

The Quebec area, despite its smaller population (except for the Maritimes area), has the biggest power generation capacity and internal load. This is due to the dominance of relatively low-cost hydropower: 88% of the 43,534 MW of total installed capacity [27]. This abundance of relatively cheap, available on-demand, renewable electricity, creates a potential for profitable interconnections between Quebec and its direct neighbors: Ontario, New Brunswick (the Maritime province adjacent to Quebec), New York and New England. Indeed, Hydro-Quebec (the largest electricity producer in Quebec) has 26 large reservoirs providing a combined storage capacity of 175 TWh [14] that could allow this large vertically-integrated power company to potentially offer more than simply energy to its neighbors, for instance wind balancing services. Table 3 provides the four Quebec area interconnections limits.

We focus on the "Chateauguay-Massena" Quebec-New York interconnection, a DC (direct current) 765 kV (kV) line, with a maximum rated capacity of 1800 MW, most of the time limited to 1500 MW for export (see Ref. [29]). The choice of this line is justified by the availability of data (electricity flows, prices,

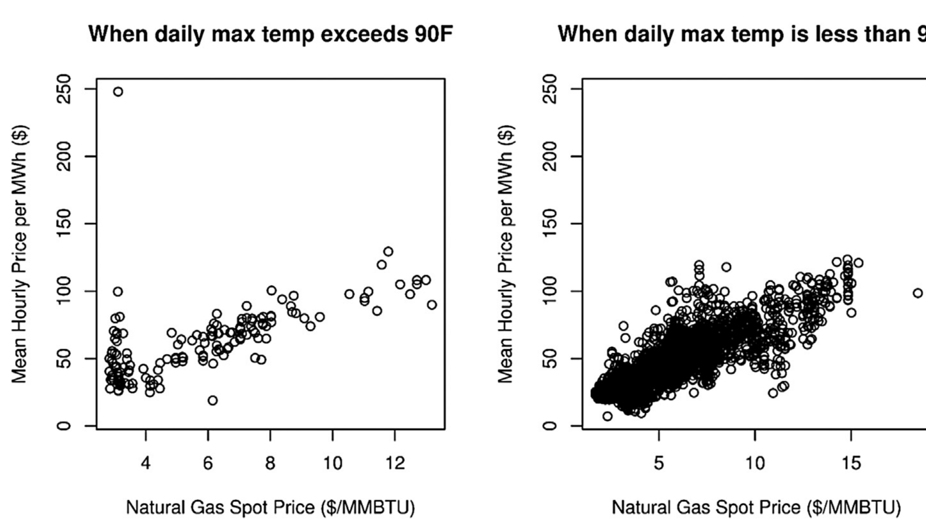

Fig. 1. Daily mean hourly electricity price and natural gas spot price, HQ Zonal price in the New York Control area, 2000–2009.

Table 3
Quebec area interconnections limits, 2011 [30].

Interconnection	Flows out of Quebec (MW)	Flows into Quebec (MW)
New Brunswick	1029	770
Ontario	2795	2055
New England	2255	170[a]
New York	1668	1100

[a] Winter peak period.

temperature and natural gas price), but also due to the fact that the city of New York has compiled forecasts for 2020 and 2050 on the number of days with extreme heat (with a daily maximum temperature of more than 90 °F/32 °C). As these events play a role in electricity demand and transmission use patterns, the availability of such forecasts is a determining reason to focus on the Quebec-New York interconnection. A new 1000 MW high voltage DC line is also planned between Quebec and New York (Transmission Developers, 2014). Our approach can therefore be useful to assess the potential value of this project. Section 5 will provide more information on this case.

3.2. Data

Our main data set covers 87,672 h over the 3653 days of 10 years (2000–2009). Hourly power flows over the interconnection have been retrieved from the WebOASIS website hosted by OATI. Data on electricity flows between New Brunswick, Ontario, New England, New York and their respective neighbors can also be found on the website of their system operator ([25] [15] [17], and [33]). Hourly market prices are also available from these websites. We use the HQ Zonal Price in the New York Control Area, because this is the price obtained for deliveries in this interconnection. This price zone, being in the northern region of the New York State, is far from the densely populated area of NYC (New York City), and has much lower electricity prices than in zones closer to NYC. The daily natural gas price used, as a reference price, is the Henry Hub Natural Gas Spot Price in Dollars per MMBtu, available from Ref. [10]. Finally, the daily maximum temperature in New York City was obtained from the US NOAA's National Climatic Data Center, as a reference temperature for the New York markets.

3.2.1. Daily maximum temperature and temperature forecasts

The NYCPCC (New York City Panel on Climate Change) [31] describes the possible changes in mean temperature according to 16 models using SRES (Special Report on Emissions Scenarios) for 2010 to 2090. In this compilation of results from these 16 models, 1971–2000 data are used as a baseline and (overall) changes are described.

We use 1971–2000 maximum daily temperature data in New York City (as measured at LaGuardia Airport) as our baseline. We simulate every year of daily data from this baseline, but ensure that NYCPCC descriptions of the upper-tail for 2020 and 2050 (i.e. the number of days over 90 °F and the number of days over 100 °F) are respected.

The temperature exceeded 90 °F on 151 days over the 2000–2009 period, i.e. an average of 15.1 times a year. According to forecasts obtained by the NYCPCC, the number of days/year with maximum exceeding 90 °F should be between 19 and 38 in 2020, with a central range (middle 67%) of 23–29 days, from model-based probabilities across global climate models and greenhouse gas emissions scenarios. In 2050, the number of days/year with maximum exceeding 90 °F should be between 23 and 58, with a central range of 29–45 days.

3.3. Observed relationship between line use and temperature

There is a strong observed pattern of increased intensity in the use of the line when the maximum daily temperature rises. Fig. 2 shows the distribution (using box-plots) of line use for different levels of maximum daily temperatures. The daily observation used is the percentage of hours, for that day, where the line has been used above 85% of its capacity. As illustrated in Fig. 2, for all temperature levels below 85 °F, the median observation (bold bar in the box-plot) is close to zero. Beyond 85 °F, it rises quickly to 20% and it reaches 40% after 90 °F. What Fig. 2 illustrates is the greater intensity of line use during days of extreme heat.

As illustrated by Fig. 3, such a relationship is not observed as clearly with electricity price. In Fig. 3, the median observations for different temperature (circles) and mean prices (dots) are shown. These medians are again the percentage of hours, within a day, where the line is used above 85% of its capacity. While the median observation quickly rises after 85 °F (from 0 to 20%), there is no clear increase in the use of the line as a function of the mean daily price (dots). In other words, the use of the line appears to be much more related to the temperature than to the price. This can be explained relatively easily by the fact that temperature forecasts are more reliable than price forecasts. Traders therefore follow temperature, hoping that a high price will follow, as it is more difficult to follow directly high prices and export when they happen.

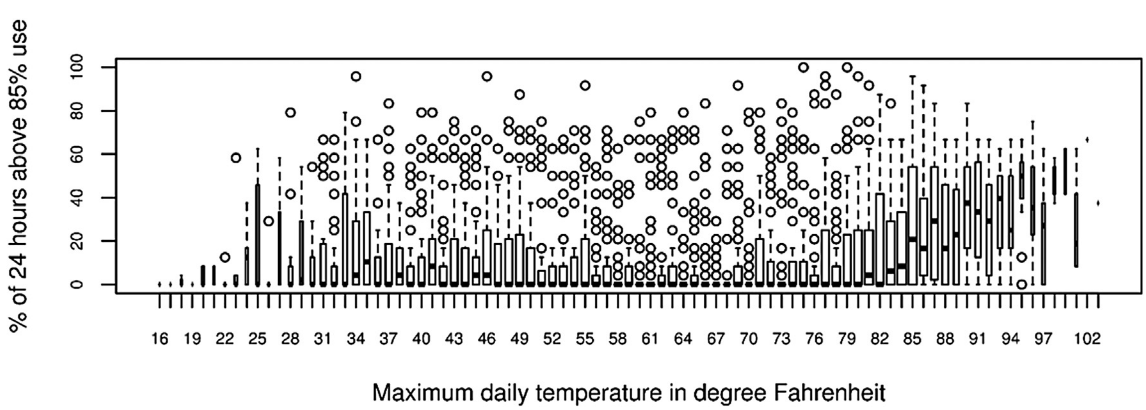

Fig. 2. Use of the line for different observed maximum daily temperature in New York City. Note: Each small box in Fig. 2 represents the central range of values containing 50% of all observations. The bottom and top of the box are the first and third quartiles. The bold bar inside the box is the median. Whiskers, mostly seen above the bars, extend to the most extreme data point which is no more than 1.5 times the interquartile range (= third quartile minus first quartile) from the box. Circles, again mostly seen above the bars, represent individual outliers.

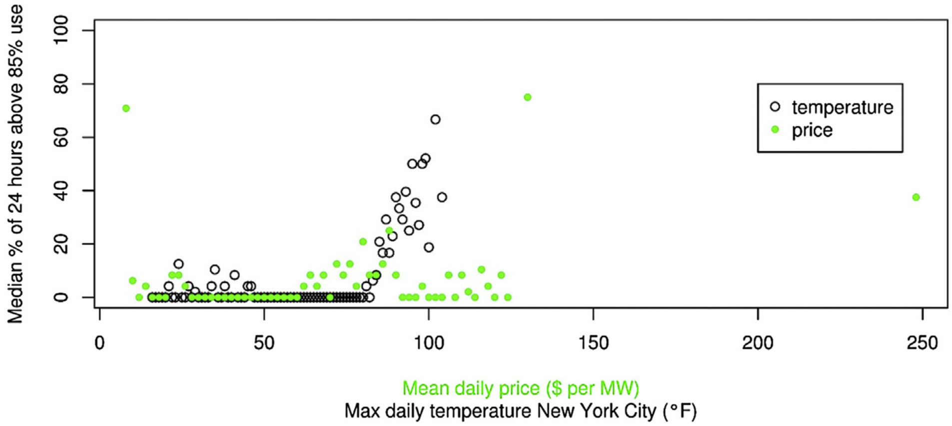

Fig. 3. Use of the line for mean daily price and maximum daily temperature in New York City.

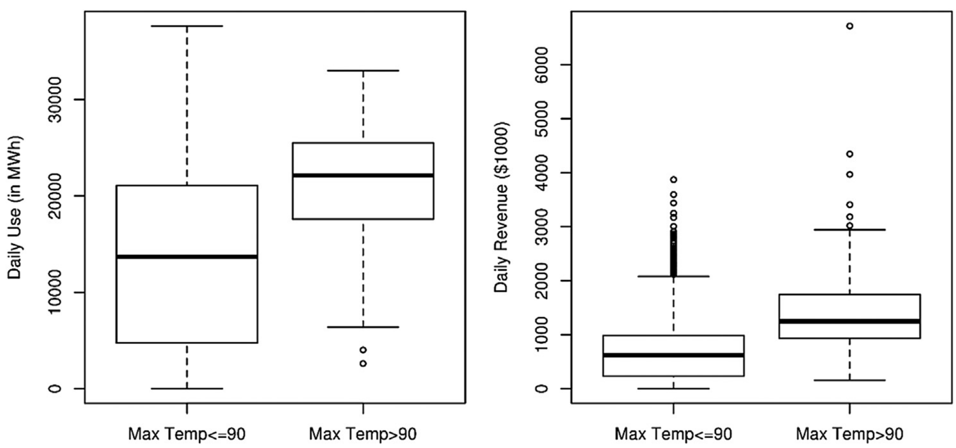

Fig. 4. Distribution of daily use of the line (in MWh, left panel) and daily revenues (in $1,000, right panel) for maximum daily temperature in New York City below and above 90 °F.

Dots in Fig. 3 represent average daily prices, with the corresponding median percentage of hours in a day where the line is used above 85% of its capacity. Such median values do not increase with price, while circles (associated to temperature) clearly increase for maximum daily temperature above 85 °F. In addition, there are three outliers in "mean price − median use above 85%" pairs: the green dots for the lowest daily average price (close to 0$/MWh) and the two highest daily average prices (close to 140$ and 250$/MWh). In the two first cases, the median observations were close to 75% and in the third, close to 40%. These isolated observations illustrate the weak relationship between price and line use.

Fig. 4 further illustrates the relationship between line use and temperature. Fig. 4 shows the distribution of the total daily energy flowing into New York, in MWh, and of revenues (in thousands of $) for days with a maximum temperature below 90 °F and days above this threshold. The median value jumps from about 14,000 MWh in a day to about 22,000 MWh (an increase greater than 50%). Using the usual maximum capacity of 1500 MW for this interconnection, this is equivalent to a daily utilization factor increasing from 39% to 61% (only considering exports). In terms of daily revenues (right panel of Fig. 4), the median value increases from $0.7 million to $1.2 million.

The electricity price is not as sensitive to temperature as line use, as the left panel of Fig. 5 shows. The distribution of the mean daily electricity price is higher when the maximum daily temperature is above 90 °F, with the median price moving from close to $50/MWh to $60/MWh, an increase of about 20%. This compares to a 50% increase in the median daily line use (Fig. 4). The right panel of Fig. 5 shows that the distribution of natural gas spot prices is relatively unchanged by temperature.

Lastly, for each of the ten years in our sample, the mean daily use of the line increases when temperature exceeds 90 °F compared to days where the temperature is below this threshold. This can be seen in Fig. 6, where the bold number is systematically above the faded number, sometimes by 10,000 MWh (years 2002, 2003, 2008 and 2009). The smallest increase occurred in 2004, the year with the smallest total exports out of Quebec.

3.4. Methodology: simulating expected revenues from reconstructed distributions

Our methodology consists in estimating revenues generated from the Quebec-New York transmission lines for 2020 and 2050, when a higher number of extreme heat days will be observed. Natural gas prices may also vary from low (first tercile from $1.69 to $4.60/MMBtu) to high (third tercile from $6.47 to $18.48/MMBtu),[1] and can have an important impact on revenues.

From the pool of observations, we have for each of the 3653 days a quantity exported to New York, the price of electricity, the percentage use of the available capacity of the line, the natural gas

[1] Although the maximum observed price is $18.48/MMBtu, most of the observations are much lower, with the 87th percentile being $8.02.

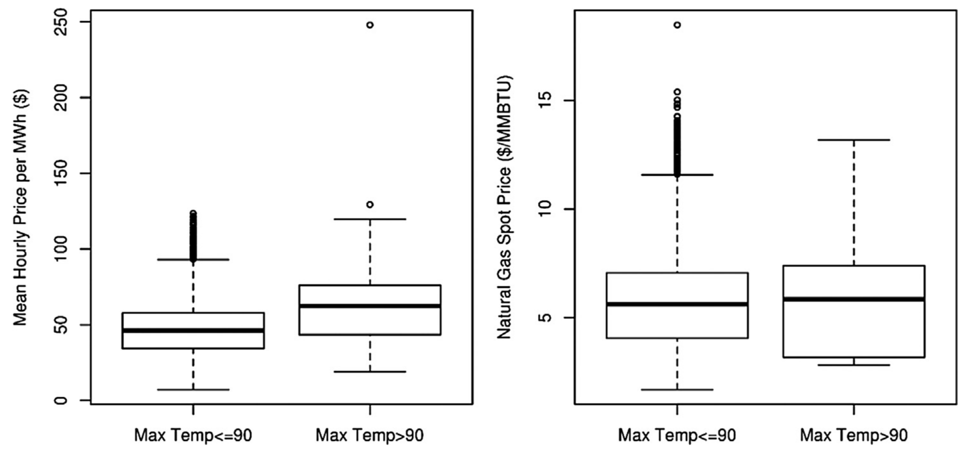

Fig. 5. Distribution of the mean daily electricity price (in $/MWh, left panel) and natural gas spot price (in $/MMBtu, right panel) for maximum daily temperature in New York City below and above 90 °F.

price and the maximum temperature of the day. We simulate a year of exports under NYCPCC extreme heat days scenarios and natural gas price scenarios, to provide estimates for the value of export revenues from the line.

Simulated expected revenues (and line use) are determined by the dependence structure between daily maximum temperature, line use and revenue. To capture properly this dependence structure, without having to model it, we sample from the empirical distribution. More specifically, the 2000–2009 data are used to obtain the empirical (trivariate) distribution of daily maximum temperature, line use and revenue. We have two empirical distributions: one when the daily maximum temperature exceeds 90 °F and one when it does not. We obtain line use and revenue distributions for 2020 and 2050 by simulating typical daily maximum temperatures for these years. We use the NYCPCC anticipated number of days/year with maximum exceeding 90 °F to determine the proportion of samples that will be drawn from each empirical distribution. As daily maximum temperatures exhibit serial correlation, we use a block bootstrap approach with block size equal to 5.[2]

We actually divide the 2000–2009 data into three equal parts according to whether natural gas prices were in the bottom, middle or top third of the prices observed over the 10-year period. For a given natural gas price tercile, we then form our two empirical trivariate distributions, splitting according the temperature variable as described above. We then draw 5000 bootstrap samples, one bootstrap sample being 365 trivariate (temperature, use, revenue) daily realizations from a year that respects the NYCPCC daily maximum temperature forecast for days of extreme heat and the annual temperature distribution. The 2.5% and 97.5% quantiles of the marginal bootstrap distributions for line use and revenues form the 95% bootstrap percentile confidence intervals that are reported in the next section (Tables 4 and 5).

4. Results and discussion

Our simulations provide two important insights into the value and use of the transmission line. First, the number of extreme heat days does not have a large impact on either revenues or exports. Second, the price of natural gas is a key driver for revenues, but has little influence on the exports.

As illustrated in Fig. 7 (from data presented in Table 4), the simulation for 2020 shows that revenues are very stable when the number of extreme heat days increases, but jump with the increase of natural gas prices. Similarly, Fig. 8 shows that total yearly exports are almost insensitive to the number of extreme heat days. Indeed, for 2020, from the 10-year average of 15 extreme heat days to the maximum of 38 days in 2020, revenues would only increase by about 6%, 2% and 3% (low, middle and top natural gas prices respectively), while volumes exported would increase by even lower percentages. These percentages corresponds to the small observable upward shifts in Fig. 7 (revenues) and 8 (exports) between the confidence intervals (illustrated by vertical bars) at the far left and the far right of the two figures. Values for the lower and upper bounds of these interval are presented in Table 4. For instance, in the low natural gas price scenario, the upper bound of the confidence interval for the estimated revenues for 15 extreme heat days is $297.06 million and only increases to $313.51 (a 6% increase) when 38 extreme heat days are assumed.

Similarly, export volumes remain fairly constant across the various assumptions for the future number of extreme heat days. Fig. 8 illustrates this by having all confidence intervals at similar levels (for the same natural gas price terciles). Only small increases of export volumes are observed. For instance, in the low natural gas

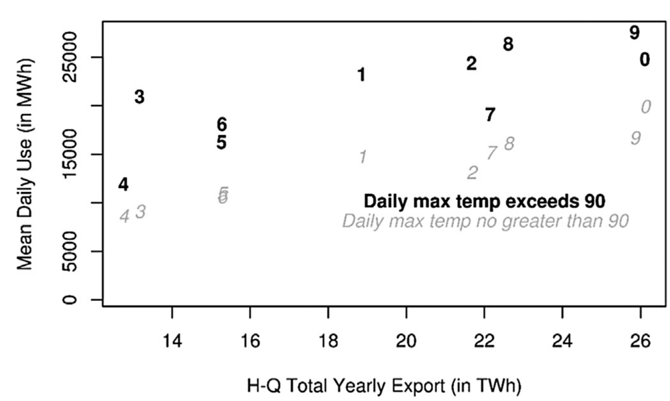

Fig. 6. Mean daily use of the line (in MWh) for days where the maximum temperature in New York City is no greater than and above 90 °F, years 2000–2009 (integers in the graph correspond to the last digit of the year).

[2] Temperature on days more than five days apart can be considered to come for different weather fronts and this guided our block size selection. Our results are robust to a slightly larger block size selection.

Table 4
Estimated 95% confidence interval for 2020 annual revenues (in $ million) and total yearly export (in TWh) for different natural gas price scenarios and different number of days where the daily maximum temperature in New York City is above 90 °F.

		Natural gas prices terciles		
	Number of days with max temp > 90 °F	Low $1.69 to $4.60/MMBtu	Middle $4.60 to $6.47/MMBtu	Top $6.47 to $18.48/MMBtu
Observed 2000-2009	15	[222.92, 297.06] $M [4.68, 6.17] TWh	[271.97, 345.85] $M [5.56, 6.81] TWh	[415.63, 519.33] $M [5.56, 6.69] TWh
Minimum	19	[225.85, 300.21] $M [4.70, 6.18] TWh	[272.76, 347.07] $M [5.58, 6.83] TWh	[417.47, 522.48] $M [5.58, 6.70] TWh
Central range (67%)	23	[228.66, 302.85] $M [4.75, 6.25] TWh	[274.81, 347.59] $M [5.59, 6.84] TWh	[419.90, 523.01] $M [5.60, 6.71] TWh
	29	[232.89, 307.08] $M [4.84, 6.28] TWh	[276.82, 348.89] $M [5.61, 6.85] TWh	[425.89, 526.73] $M [5.63, 6.71] TWh
Maximum	38	[238.26, 313.51] $M [4.93, 6.37] TWh	[279.94, 351.62] $M [5.64, 6.86] TWh	[429.26, 532.48] $M [5.66, 6.76] TWh

Table 5
Estimated 95% confidence interval for 2050 annual revenues (in $ million) and total yearly export (in TWh) for different natural gas price scenario and different number of days where the daily maximum temperature in New York City is above 90 °F.

		Natural gas prices terciles		
	Number of days with max temp > 90 °F	Low $1.69 to $4.60/MMBtu	Middle $4.60 to $6.47/MMBtu	Top $6.47 to $18.48/MMBtu
Minimum	23	[228.66, 302.85] $M [4.75, 6.25] TWh	[274.81, 347.59] $M [5.58, 6.83] TWh	[419.90, 523.01] $M [5.60, 6.71] TWh
Central range (67%)	29	[232.89, 307.08] $M [4.84, 6.28] TWh	[276.82, 348.89] $M [5.61, 6.84] TWh	[425.89, 526.73] $M [5.63, 6.71] TWh
	45	[242.82, 319.55] $M [5.02, 6.42] TWh	[280.76, 354.64] $M [5.63, 6.87] TWh	[434.84, 536.28] $M [5.68, 6.78] TWh
Maximum	58	[249.98, 328.46] $M [5.14, 6.58] TWh	[285.08, 356.44] $M [5.68, 6.87] TWh	[441.14, 545.20] $M [5.72, 6.82] TWh

price scenario, the upper bound of the confidence interval for the estimated exports for 15 extreme heat days is 6.17 TWh (Table 4) and only increases to 6.37 TWh, a 3% increase, when 38 extreme heat days are assumed.

What does make a difference, however, is the price of natural gas. This is the second insight obtained from our simulation results. When natural gas prices reach the top tercile (from $6.47 to $18.48/MMBtu, see Table 4), the upper bound of revenues increases by 50% form the middle tercile ($4.60 to $6.47/MMBtu). This corresponds to the increase of the upper bound from $345.85 million to $519.33 million in the 15 extreme heat days scenario (see Table 4). In Fig. 7, this corresponds to the higher level of the extreme left vertical

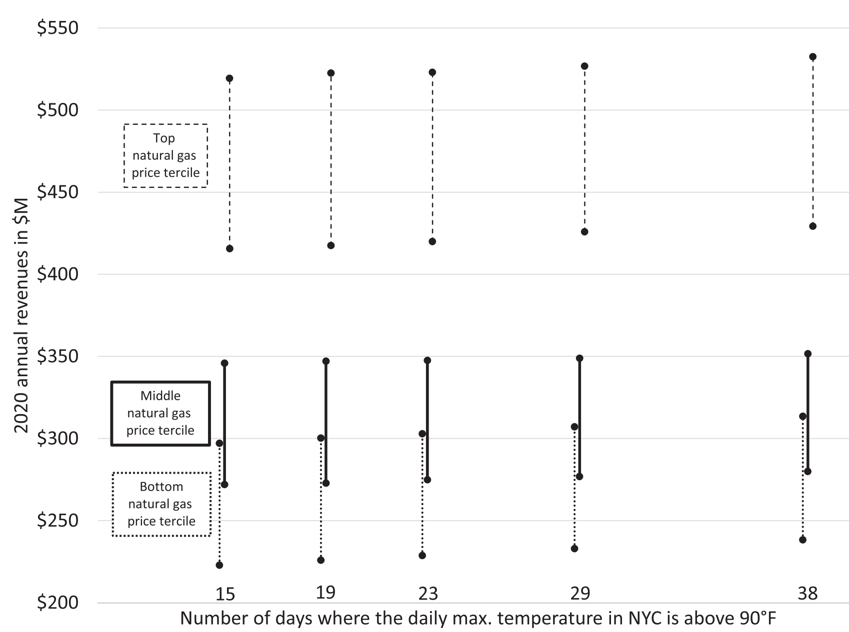

Fig. 7. Estimated 95% confidence interval for 2020 annual revenues (in $ million) for different natural gas price scenarios and different number of days where the daily maximum temperature in New York City is above 90 °F.

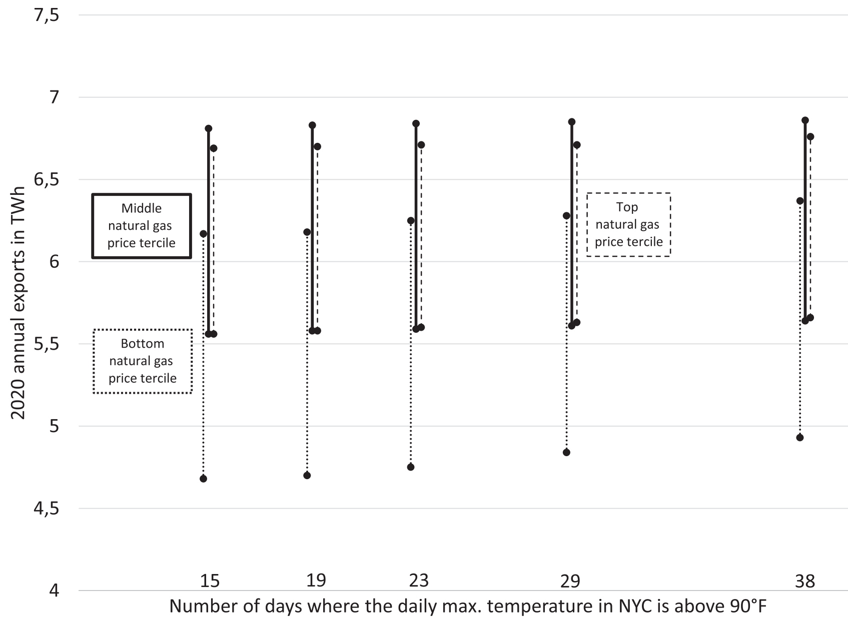

Fig. 8. Estimated 95% confidence interval for 2020 total yearly export (in TWh) for different natural gas price scenarios and different number of days where the daily maximum temperature in New York City is above 90 °F.

dash-bar, compared to the bold bar below. From the bottom tercile to the middle one, the scope of the increase is more modest: only about 16%. This corresponds to the increase of the upper bound of the confidence interval, from $297.06 million to $345.85 million, when the bottom and the middle terciles are compared, in the 15 extreme heat days scenario. Similar increases are observed for all other values of extreme heat days (minimum, 67% middle range and maximum).

These increases in revenues are mostly a price phenomenon. Quantities do not follow prices to the same extent. Export volumes increase only from 10 to 20% (from low to middle natural gas prices), and not at all in the case of top natural gas prices (from the middle range). In Fig. 8, for instance, we observe that the upper bound of confidence intervals are about 10% higher for the middle natural gas tercile compared to the bottom one. For instance, in the 15 extreme heat days scenario, the upper bound moves from 6.17 TWh to 6.81 TWh (see Table 4). From the middle to the top natural gas price, export volumes decrease: from 6.81 TWh to 6.69 TWh, a −2% change. This shows that with higher prices, lower exports are needed to generate profits from the lower cost jurisdiction.

Fig. 9 illustrates the obtained distribution of revenues for 2020, for the lower bound of the central range of the number of days with temperature exceeding 90 °F (23 days). It illustrates how changing

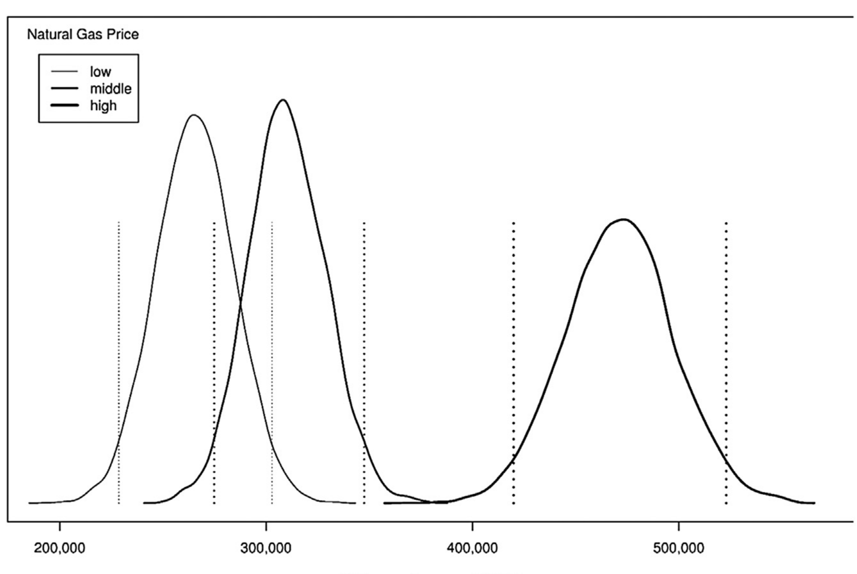

Fig. 9. Distribution of 2020 annual revenue ($1000) under low, middle and top natural gas prices in the case there are 23 days where the maximum temperature in New York City is above 90 °F.

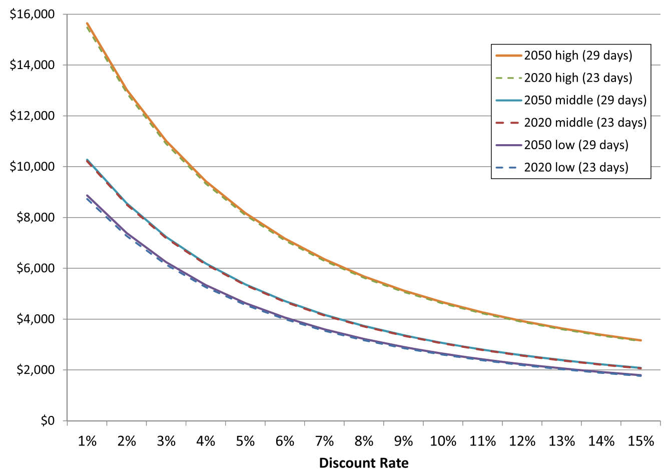

Fig. 10. Present value of revenues (in $M) if 2020 and 2050 annual revenues were constant over 40 years, for different discount rates.

from one tercile of natural gas prices to another makes the distribution of results shift from a revenue centered around $260 million (low), to slightly more than $300 million (middle) to $470 million (top).

Although the higher number of extreme heat days does not appear to have a huge impact on revenues, compared to natural gas price levels, the relative impact of climate change is not the same within each tercile. In the low natural gas price terciles, in 2020, moving from 15 days of extreme heat to the maximum (38) would increase revenues by more than $15 million, while in the other terciles the revenue increase would be lower, especially in the middle tercile (about $6 million). This pattern is also observed in 2050.

The total quantity of energy transported, remains relatively stable: from 4.7 to 6.9 TWh. It is noteworthy to mention that the highest exports do not happen in the top natural gas price tercile, but in the middle one.

5. Transmission costs and net benefits

Assuming a 40-year horizon and a discount rate of 7%, the simulated annual revenues presented in Tables 4 and 5 for 2020 and 2050 respectively (for the lower bound of the central range) have a present value of about $3.6, $4.2 and $6.3 billion under the low, middle and top natural gas price scenarios. The difference between the 2020 and 2050 values are barely noticeable, as illustrated in Fig. 10, for various discount rates. Using a 15% discount rate, closer to what merchant transmission investors would use, the present value of the transmission line is cut by half.

These simulated revenues, along with the simulated export volumes, imply average electricity prices of $48, $50 and $76/MWh for low, middle and top natural gas prices respectively. In order to be profitable, energy exports should be fueled by energy sources having lower production costs. With Hydro-Quebec having access to about 200 TWh/year of energy at an average cost of $20.9/MWh (2012 data; Hydro-Quebec, 2013), any natural gas price scenario looks favorable on this aspect.

Additional considerations, however, have to be included in the analysis, especially if new transmission capacity is considered. Indeed, construction costs and other potential sources of revenues, such as capacity payments and the sale of renewable attributes, are also important. For illustrative purposes, we use the 1000 MW Champlain Hudson Power Express project between Quebec and New York City (Transmission Developers, 2014). First, with a construction cost of $2.2 billion, a 40-year horizon and a 90% utilization rate,[3] a revenue of $42/MWh using a 15% discount rate ($20.9/MWh using a 7% discount rate) is required to break even. Even if enough low-cost ($20.9/MWh) energy is available from Quebec, adding the transmission charge of $42/MWh, for a total of $62.9/MWh (using a 15% discount rate), would only make the project profitable under the top natural gas price scenario, where the average price is $76/MWh. Using the 7% discount rate, the combined energy-transmission cost of $41.8/MWh is attractive under all natural gas price scenarios.

Additional capacity payments and revenues from renewable energy attributes, potentially associated to the electricity delivered from the line, could increase the value of the transmission project. In New York City, indeed, capacity payments average about $20/MWh [36]. Renewable energy attributes in the state of New York have been rewarded at rate ranging from $14.75 to $34.95/MWh between 2005 and 2013 ("aggregate MWh weighted average award price"; see Ref. [34]). Megawatt-hours delivered through the transmission line could therefore generate, in principle, between $35 to $55/MWh in combined capacity and renewable attributes payments. With such additional revenues, the profitability of the new transmission line would be achieved under any natural gas price scenario, even using the discount rate of 15%. This would allow more expensive renewable energy from Quebec (produced above the current cost $20.9/MWh) to be exported profitably.

Capacity payments, however, would unlikely be given for the full capacity of the transmission line. [23] assumes that only 500 MW could be eligible for such payments. In addition, renewable attributes from imported energy sources are not always recognized and/or rewarded, leaving much uncertainty on the actual payments that could come from such sources. The state of New York indeed bans out-of-state renewable sources from renewable energy attributes awards; see Ref. [35]. Although these rules could change, especially given the high goals of renewable penetration in the power system and the current problems in meeting such goals [34], there is no guarantee that Quebec renewable energy would receive such payments for its attributes.

6. Conclusion

We develop in this paper an approach to assess the value of transmission lines, based on the anticipated revenues generated from exports. Using 10 years of export data from Quebec (Canada) to New York (United States), we can simulate the distribution of line use under two driving factors behind power markets: climate and natural gas prices. Our results show that despite important anticipated increases in the number of extreme heat days (from 15 per year to up to 38 in 2020 and 58 in 2050), there will not be much change in the use of the transmission lines, nor in revenue generated. What creates a huge impact is the price level of natural gas. High natural gas prices can almost double revenues on a transmission line. Although such high prices will provide intensives to shifts towards other fuels, GHG emissions constraints will likely limit the extent to which coal power plants will be used instead. Other alternatives (nuclear, wind, solar) cannot react to high gas prices and become available, due to their operational constraints. This means that natural gas prices will have a significant impact on the value of interconnections.

Our main contribution, beyond exploring the sensitivity of one aspect of power markets to climate change and natural gas prices, is

[3] This is the capacity factor used by Ref. [23] in its impact analysis of the project. An even greater energy availability factor of 95% is assumed in the project Environmental Impact Statement ([43], page 34).

to approach the value of a transmission line through its past use, and to simulate various scenarios. We believe that it can provide insights unattainable through alternative methodologies, not as rooted in the history of the line as well as in influential market trends and climate change.

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