# A Decarbonized Northeast Electricity Sector: The Value of Regional Integration

Northeast Electricity Modelling Project

Scoping Study

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# Executive Summary

The North American Northeast (New York, New England in the Unites States and the Canadian provinces of Ontario, Québec and the Maritimes) is particularly engaged in the fight against climate change. Indeed, except for the relatively small Maritimes provinces, all emissions from the power sector are under a hard, declining cap, either under the Regional Greenhouse Gas Initiative (RGGI) or the Western Climate Initiative (WCI). GHG emissions from the region's power sector currently stand at 74 million tonnes (Mt), and would need to decrease to 30 Mt to be 80% below their 1990 level. Such reduction corresponds to the global 2050 target for all sub-regions of the North American Northeast.

To achieve such ambitious target, each state and province could follow its traditional approach to power sector planning, and decarbonize its sector without coordinating with its neighbours. Alternatively, a regional approach could be adopted, and cost optimal decisions could help decarbonizing the regional power sector at the lowest overall cost. Gains from such a regional approach could in theory be significant, notably due to the large amount of hydropower and reservoirs in Canada, which could help balance renewable generation options, such as wind and solar power.

This scoping study focuses on the economic gains from a North American Northeast power sector integration. An hourly model of the regional power sector is develop and solved to minimize yearly investment and operation costs, under the constraint of reducing GHG by 80%. Two aspects of regional integration are investigated: physical and institutional integration. Physical integration corresponds to transmission capacities (interconnections) between sub-regions. Institutional integration correspond, in our study, to a shared approach in meeting capacity constraints: instead of planning exclusively with the local generation capacity to meet peak demand (as it is currently the case), available regional capacity can also be used to plan for peak capacity requirements.

Our main findings show that both physical and institutional integration would bring significant gains to the region's decarbonization efforts. Without nuclear power, cutting GHG emissions could increase the yearly power sector cost by 50% to 100%, depending on the selected approach. From a yearly cost of $14 billion (without carbon constraints), the yearly cost could jump to $24 billion.

With more integration, the same reductions in GHG could be achieved with a power system costing $20 billion per year – a saving of $4 billion to the region. Gains come from physical integration (about $2 billion) and from institutional integration (about $2 billion). Without such integration, as our results show, the total generation capacity increases by nearly 20% (34 gigawatt, GW) in addition to requiring 4 GW in local energy storage (battery type). Gains from institutional integration come from allowing one sub-region's peak demand to be partly met by its neighbors' installed capacity. This avoids duplicating unnecessary peak capacity, as it is currently the case. Gains from physical integration come from a greater ability to optimize renewable production and by allowing hydropower to balance all sub-regions' demand. In other words, both integration policies are good complements, and it may be valuable to enact both of them.

We also find that if significant energy efficiency gains are achieved in Quebec and deep regional integration materializes, total annual costs of a decarbonized power system could decrease to $16 billion. At this level, the power system costs would be largely equivalent to the ones of a non-decarbonized system.

Deep cuts in GHG emissions will however require increasing installed capacity by at least 40%, because wind and solar generation have low capacity value. From an estimated need of 135 GW to supply the region's total demand without carbon constraints, 217 GW would be required under an 80% GHG reduction constraints, along with 4 GW of battery storage. Gigantic investment in wind (60 GW) and solar (close to 40 GW) would be required, unless regional integration occurs (both physical and institutional). In such case, solar investment are cut to 27 GW and storage can be avoided. More wind capacity can be deployed (65 GW) and wind production is curtailed less often (from 5 to 2 TWh of curtailment).

Such significant gains call for more detailed analysis and more consideration from North American Northeast power planners. We propose a series of areas of investigations, notably on how load profile changes could affect these results, priority transmission corridors and on the specific roles and value of large scale hydropower storage.

## Background and Warnings

In the fall 2017, different participants from the academic, professional and philanthropic sectors (see Appendix 1) agreed to move ahead with a scoping study on the decarbonization of the Northeast North American electricity sector. This scoping study was led by an active working group (from McGill's TISED: François Bouffard and Navdeep Dhaliwal, and from HEC Montreal: Pierre-Olivier Pineau and Sébastien Debia), with an overview committee composed of Mark O'Malley and Greg Brinkman (NREL), Normand Mousseau and Louis Beaumier (IET) and Lorne Trottier.

This scoping study aims at providing some preliminary results on the value of integration in regional grid decarbonization. Its goal is to generate interest in the topic, to foster actions towards grid decarbonisation at the lowest possible cost.

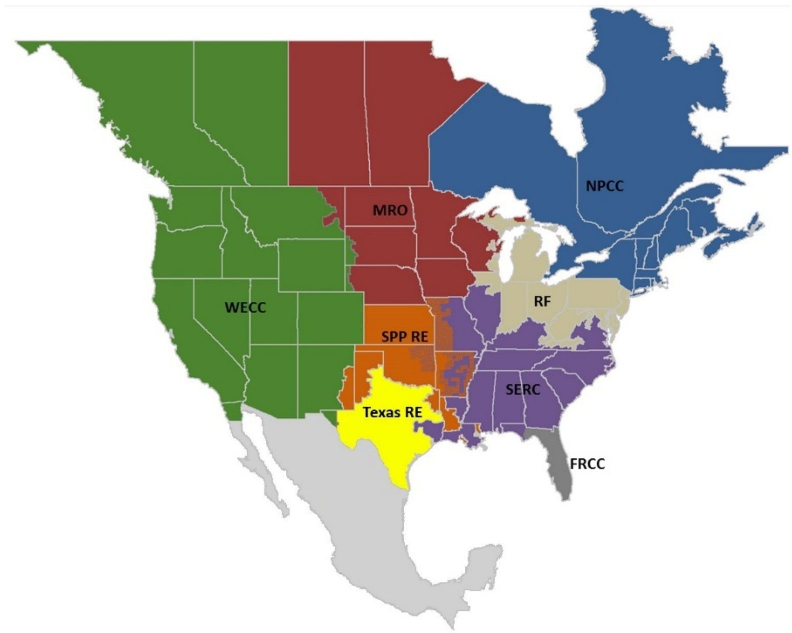
**Warnings: What This Study Is and Is Not**

| | What this study is about | What this study is *not* |
|---|---|---|
| **Research Question** | A preliminary study on required installed capacity, given that ***only existing hydro power would be kept in place***, in the North-American North-East, in a largely decarbonized context. | A detailed study on renewable integration. |
| **Demand / Load** | An analysis based on current hourly loads. | A prospective study on how load levels and profiles can evolve.<br>A reliability study assessing power needs given a combination of load profiles. |
| **Supply** | An analysis based on current technology costs. | A prospective study assuming some trends in technology costs. |
| **Hydropower modelling** | A simplified valley modelling taking into accounts water inflows seasonality and equipment capacity. | A detailed modelling taking into account the impact of water heads on plants productivity and real water flow constraints. |
| **Supply-demand equilibrium** | Deterministic hourly dispatch for a full year. | Intra-hour dispatch with reserve margins. |
| **Capacity expansion** | Minimization of annualized investment and operating costs, to meet hourly demand in all NPCC sub-regions. | A detailed investment analysis with real plants operating constraints. |
| **Transmission network** | Based on nameplate interconnection capacity. | A network simulation, with voltage, transient stability, etc. |
| **Economic analysis** | A sectoral analysis about the impact of carbon mitigation measures on the costs to supply electricity. | A macroeconomic analysis about the impact of carbon mitigation measures on the whole economy. |

## Introduction

Decarbonization of human activites is required to avoid catastrophic climate change impacts. Electrification of most energy uses will be required, but this will imply that power systems are themselves largely decarbonized. This scoping study investigates the value of regional integration to decarbonize the Northeast Power Coordinating Council (NPCC) power systems. The NPCC consists of five sub-regions: Ontario, Quebec, the Maritimes, New York and New England (see Figure 1). The NPCC is characterized by a shared commitment towards achieving the Paris agreement goals among its governments and a unique access to hydropower with important reservoir storage. These two features provide a strong basis to explore how to achieve the deep cuts in GHG emissions at the lowest cost, from a regional perspective.

**Figure 1. The eight regions of the North American Electric Reliability Corporation (NERC)**




The goal of this scoping study is to present a first estimate of the value of regional integration in this context, to trigger more ambitious analysis of such regional power system integration and to foster discussions around its possible implementation.

Two basic scenarios are analyzed: no mandated reduction in greenhouse gases (GHG) and an 80% reduction in GHG emissions (from the 1990 level in the NPCC regional power system). The value of regional integration is explored through the analysis of the impact of two key factors:

- **Physical integration: level of interconnections** (electricity transmission constraints between sub-regions). All scenarios are studied in a hypothesized context of unconstrained transmission capacity between all five NPCC sub-regions, and under their current transmission constraints. Such comparison allows to illustrate the possible value of relieving transmission constraints.
- **Institutional integration: local or regional capacity constraints**. Power systems are usually built to ensure that peak demand can be supplied with local generation capacity – even if this often leads to redundancies in regional generation capacity. We compare in this study the impact of allowing neighboring generation capacity to count under such local capacity constraint. Such comparison illustrates the possible gains made from more regional cooperation in capacity planning.

This scoping study compares the total cost of these scenarios, for one full year (8,760 hours) of operation. A key assumption is that only existing hydropower and reservoirs are used as a starting point (about 64 gigawatt, GW, of installed capacity). No other technology remains, so that investments in the cheapest technologies are sought to meet the hourly demand in each sub-region.

A linear programming model is used to **minimize the annualized investment and operation costs, subject to the constraint of meeting the hourly load in each region.** This document presents the general structure of the model of the NPCC power system, the scenarios and their results. Data used to calibrate the model are presented in Appendix 2.

## Related Studies

This scoping study complements recent decarbonization studies, such as the one published by the Sustainable Development Solutions Network in collaboration with Evolved Energy Research and Hydro-Québec (Williams et al., 2018). It however differs from that study by not pre-selecting any technologies, but by optimizing investment in installed capacity over the whole Northeast region. Furthermore, all Northeastern sub-regions are included in our study.

Our approach is similar to the one adopted by Dolter and Rivers (2018), who study the Canadian electricity sector. Our focus is however on the Northeast and we model hydropower in more details.

Our study is directly aligned with the recommendations of the December 2017 report on *Strategic Electricity Interties* (Standing Committee on Natural Resources, 2017). In particular, our report assesses "the economic opportunities of increased electricity interties in different regions" (recommendation 1), it explores "ways to maximize the value of Canadian electricity exports to the U.S." (recommendation 2) and it examines "opportunities to coordinate interprovincial electricity trade between low-carbon electric-dominant provinces and their neighbouring provinces" (recommendation 3).

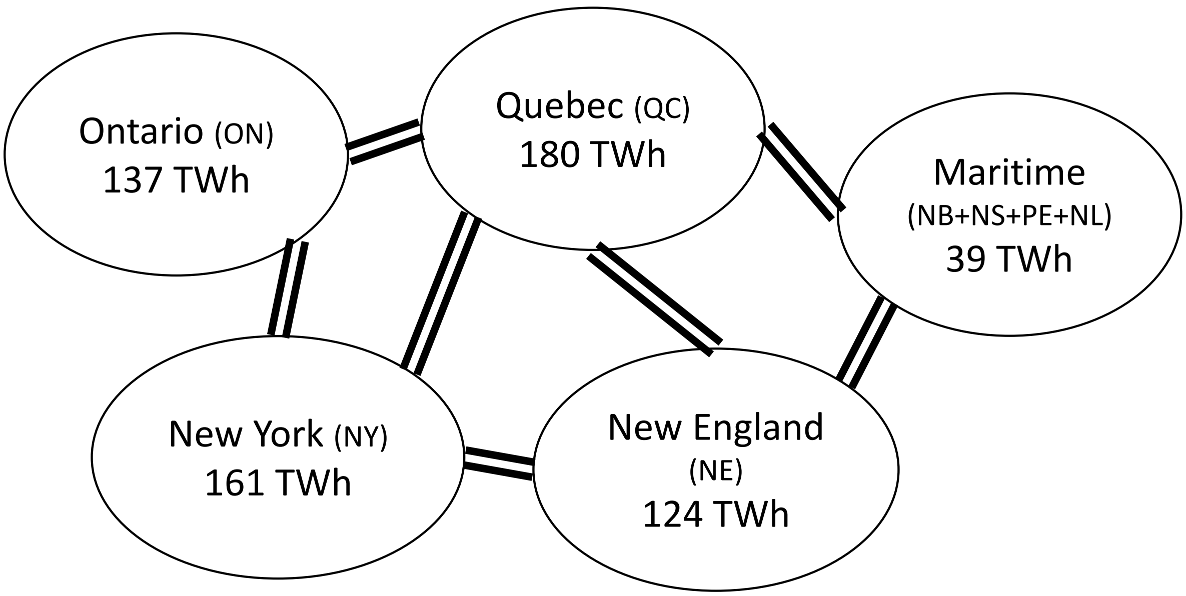
Our findings reinforce conclusions of these related studies, while providing some optimized scenarios and quantitative estimates of gains that can be achieved through increased regional collaboration.

# 1. Scope of the Model and Approach

A simplified hourly transportation model, with investment in generation capacity, minimizes investment and operating cost under the constraint of supplying load in each sub-region. Figure 2 illustrates the five sub-regions, with their 2016 total load and interties (interconnection capacities are shown in Table 2). The model is a linear programming model written in GAMS and solved by CPLEX[1].

Current hydropower (capacity and reservoirs) and interconnections are assumed to be available in the future, while other technologies (solar, wind, incremental hydro, nuclear and natural gas – both combustion turbine and combined-cycle) are added as required to meet the load. Demand response can also be used to reduce load at a cost. Load shedding can also be chosen as the technology of last resort, and so is the addition of some energy storage capacity. All assumptions on costs are presented in Appendix 2.

**Figure 2. NPCC Region with 2016 Total Load**

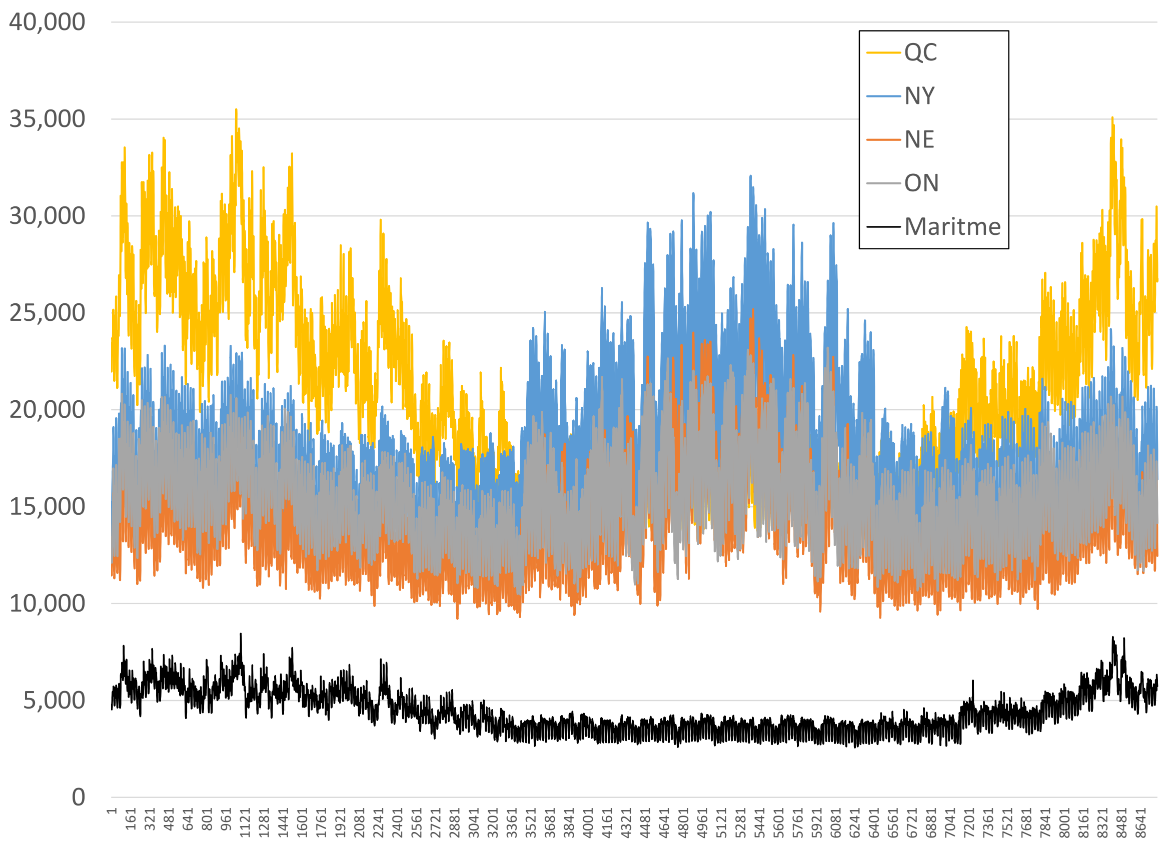



[1] GAMS, which stands for Generalized Algebraic Modeling System, is a modeling language tailored to represent optimization problems. It compiles the models to allow their solution by off-the-shelf solvers. CPLEX is such a solver for linear programming problems.

## Load Data

The total load supplied was 639 TWh for the entire NPCC region in 2016. Figure 3 illustrates the hourly loads of the five regions. The winter-peaking system of Quebec provides some potential integration gains with the summer peaking regions of NY, NE and ON.

**Figure 3. Hourly Load Data for 2016**




Hourly load data for the five regions for 2016 (a leap year with 8,784 hours, but only 8,760 are used in the model) have been compiled from the following sources:

- ON: IESO (Hourly Ontario and Market Demands, 2002-2016)
- QC: HQD (2017)
- NY: NYISO (Integrated Real-Time Actual Load)
- NE: ISO-NE (Hourly wholesale load cost reports for the entire New England system)
- Maritime: Hourly profile calibrated on the New Brunswick hourly profile from NB Power (2017)

Scenarios of different load shapes and levels have not been used in the scoping study – except for one “energy efficiency breakthrough” scenario, presented in Appendix 3, along with other alternative scenarios. Increased electrification of other energy uses (mostly transportation and heat), will however very likely change these loads.

**Table 1. Descriptive Statistics on Regional and Integrated Hourly Loads, 2016 (MWh)**

| | NY | NE | ON | QC | Maritime | Integrated NPCC | Sum of regional peaks |
|---|---|---|---|---|---|---|---|
| Min | 12,023 | 9,215 | 10,461 | 12,734 | 2,569 | 48,250 | |
| Max | 32,076 | 25,192 | 23,213 | 35,504 | 8,455 | 105,422 | 124,440 |
| Day of peak | Aug. 11 | Aug. 12 | Sept. 07 | Feb. 13 | Feb. 15 | Dec. 16 | |
| Average | 18,305 | 14,164 | 15,595 | 20,491 | 4,427 | 72,982 | |
| *Total for 2016 (TWh)* | *160.4* | *124.1* | *136.6* | *179.4* | *38.8* | *639.2* | |

Future loads will have to be analyzed in light of possible trends reshaping demand, as the economy electrifies many processes. NREL's Electrification Futures Study (https://www.nrel.gov/analysis/electrification-futures.html) could be one source of data to build load scenarios.

## Interconnection Capacities

Table 2 provides the current interface limits between regions, used to calibrate the transmission capacity between the five regions.

**Table 2. Transmission Capacities between Nodes**

| Interface Limits (TTC)<br><br>From \ To | ON | QC | Maritime<br><br>NB+NS+PE+NL | NY | NE |
|---|---|---|---|---|---|
| ON | | 1,970 | | 2,000 | |
| QC | 2,705 | | 1,029 | 1,999 | 2,275 |
| Maritime NB+NS+PE+NL | | 785 | | | 700 |
| NY | 1,600 | 1,100 | | | 1,600 |
| NE | | 2,170 | 700 | 1,400 | |
| Source: Hydro Québec (2017c) for all QC interties, NYISO (2017b) for NY interties with ON and NE and NPCC (2016) winter transfer limits for NE-Maritime. | | | | | |

## Installed Capacities

Table 3 below presents the current installed capacities in the NPCC sub-regions.

**Table 3. NPCC Installed Capacity, 2016 for NE and NY (EIA, 2017e) and 2015 for MA, QC and ON (Statistics Canada, 2017a), MW**

| | NE | NY | MA | QC | ON | Total | NPCC share |
|---|---|---|---|---|---|---|---|
| Wind | 1,348 | 1,825 | 852 | 2,174 | 2,763 | 8,962 | |
| Solar PV | 578 | 110 | 0 | 20 | 173 | 881 | |
| Hydro | 1,957 | 4,719 | 8,081 | 40,159 | 8,991 | 63,907 | 47% |
| Biomass | 1,645 | 520 | | | | 2,165 | |
| Solar PV (Distributed) | 1,410 | 728 | | | 2,009 | 4,147 | |
| Nuclear | 4,016 | 5,399 | 705 | | 13,328 | 23,448 | 14% |
| NG CCGT | 12,007 | 8,129 | | 399 | 5,375 | 25,910 | |
| NG CT | 1,086 | 3,180 | 1,210 | 794 | 4,900 | 11,170 | |
| NG (other) | 1,050 | 9,546 | | | | 10,596 | 39% |
| Coal | 1,955 | 1,747 | 3,972 | | | 7,674 | |
| Oil | 6,593 | 3,523 | 63 | 184 | 233 | 10,597 | |
| | 33,645 | 39,426 | 14,883 | 43,731 | 37,771 | 169,457 | |

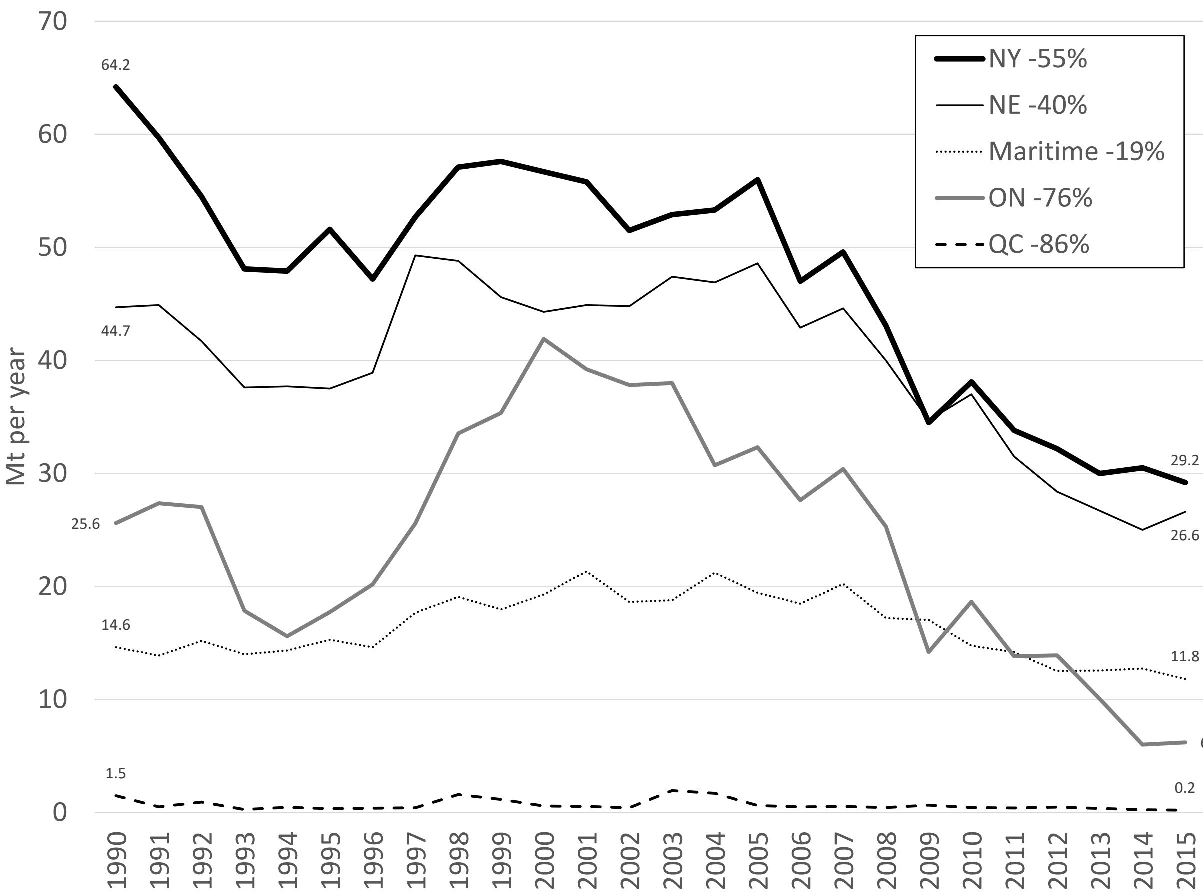
## GHG Emissions from the Electricity Sector

Greenhouse gas (GHG) emissions from the electricity sector have been falling in the NPCC region by 50.8% between 1990 and 2015 due to the retirement of coal power plants. See Table 4 and Figure 4 below. In 2015, they still represented 74 million tons (Mt). An 80% reduction from their 1990 level would place a cap on NPCC electricity emissions at 30.13 Mt.

**Table 4. NPCC GHG Emissions from the Electricity Sector, in Mt (EIA 2017e; ECCC, 2017)**

| | 1990 Mt | 2015 Mt | 1990-2015 change (%) | Level after an 80% reduction from 1990 Mt |
|---|---|---|---|---|
| NE | 44.70 | 26.60 | -40.5% | 8.94 |
| NY | 64.20 | 29.20 | -54.5% | 12.84 |
| Maritime | 14.63 | 11.83 | -19.2% | 2.93 |
| QC | 1.50 | 0.21 | -86.1% | 0.30 |
| ON | 25.62 | 6.21 | -75.8% | 5.12 |
| Total | 150.64 | 74.04 | -50.8% | 30.13 |

**Figure 4. GHG Emissions from Electricity Generation in the five NPCC Regions, 1990-2015, with their Respective Decline during the Period (EIA 2017e; ECCC, 2017)**



## Decarbonization Scenarios

Two main scenarios are been investigated:

1. No cap on $CO_2$ emissions
2. Regional cap on $CO_2$ emissions, corresponding to an 80% decrease in emissions

In the first scenario, investment is made to minimize the annualized investment and operational cost to meet hourly load in all sub-regions. Only currently existing hydropower assets are kept. In the second scenario, a regional 80% reduction in GHG emissions (form the 1990 level) is enforced. Given the limited interest expressed in investing in new nuclear plants in most regions of the north-east, nuclear technology is excluded from these scenarios. We nevertheless include a nuclear scenario in Appendix 3, for the sake of discussion.

Both of these two scenarios come in four different versions, based on these two dimensions:

- **Perfect physical integration**. Unconstrained capacity interconnections are represented by "**Unconstrained T**" (no transmission constraint between sub-regions) while "**Limited T**" represents the case with existing transmission constraints between sub-regions (see Table 2 on interconnection capacities for the value used).
- **Institutional integration.** A "**Business as Usual**" (BAU) and a "**Shared**" versions of the model are run. BAU means that each sub-region has the requirement to invest alone in enough capacity to meet its peak demand (in scenarios 1 and 2). In the shared version, interconnections with neighbouring sub-regions count as eligible capacity. The next sub-section (*Capacity Investment Constraint for scenarios 1 and 2*) provides the explicit constraints that apply in the BAU and shared versions.

The two scenarios are each studied in four different versions, for a total of eight scenarios, as summarized in Table 5.

**Table 5. Summary of the Eight Scenarios**

| 1. No cap on emissions | | 2. Carbon cap | |
|---|---|---|---|
| 1.1 Unconstrained Transmission | 1.2 Limited Transmission | 2.1 Unconstrained Transmission | 2.2 Limited Transmission |
| BAU | BAU | BAU | BAU |
| Shared | Shared | Shared | Shared |

## Capacity Investment Constraint for BAU and Shared Scenarios

The model, for the sake of simplicity, does not include capacity reserve margins. Capacity investment constraints are defined as follows:

**BAU (for each sub-region):**

$$\text{Nameplate Capacity per region (Thermal)} \geq \max_{hours} \{\text{Demand} - \text{DR} - \text{Production(Wind+Solar+Hydro)} - \text{Battery(Discharge - Charge)}\}$$

**Shared-Unconstrained Transmission (at the NPCC region level):**

$$\text{Nameplate Capacity for NPCC (Thermal)} \geq \max_{hours} \{\text{Demand} - \text{DR} - \text{Production(Wind+Solar+Hydro)} - \text{Battery(Discharge - Charge)}\}$$

**Shared-Limited Transmission (for each sub-region) :**

$$\text{Nameplate Capacity per region (Thermal)} \geq \max_{hours} \{\text{Demand} - \text{DR} - \text{Production(Wind+Solar+Hydro)} - \text{Battery(Discharge - Charge)} - \text{Transmission(Imports - Exports)}\}$$

These constraints simply enforce that enough dispatchable capacity[2] is installed locally to meet the sub-region's peak *net* demand. This net demand is the actual maximum hourly load during the year, net of all demand response, renewable energy production and battery net discharge.

In the shared scenarios, when transmission is limited, available net imports from neighboring sub-regions count to reduce the net load, of course under the existing capacity constraints. This therefore reduces the need to invest locally in dispatchable generation capacity.

[2] "Dispatchable capacity" is the installed capacity that can be used on demand (or "dispatched"), while not subject to any natural constraint on access to primary energy sources (wind, sun or water).

# 2. Results

This section presents the results of the eight scenarios. Total yearly costs, installed capacity per technology, emission levels, net quantity traded between sub-regions and prices are provided. In addition, new installed capacity by sub-region is also presented.

In a nutshell, adding a carbon cap equivalent to an 80% decrease in GHG emissions significantly increases the total regional yearly cost, combining annualized investment and operations costs. From $12-14 billion in the no carbon cap scenarios, decarbonizing raises the cost to more than $20 billion, up to $24 billion. Removing transmission constraints lowers the cost by a yearly $2 billion, while sharing capacity removes another $2 billion.

Installed capacity radically changes by adding the low carbon cap: from 135 GW of mostly natural gas and hydro power plants, generation capacity jumps above 200 GW if GHG emissions are constrained, unless transmission capacity is unconstrained and capacity is shared. In this scenario, installed capacity is limited to 184 GW. A lot of wind and solar completely change the generation profiles in each sub-region. Integration, both physical and institutional, significantly reduces the need for such gigantic investment in renewable technologies.

The following sub-sections provide more details.

## Total Costs

Total costs are the sum of the annualized investment and operation costs of all installed technologies (see Appendix 2). Only investment in already existing hydropower is omitted, as well as the transmission costs.

Table 6 shows the value of physical integration, from Limited to Unconstrained Transmission, and the value of institutional integration, from BAU to Shared. More gains come from physical integration under a carbon cap, as complementary production profiles help avoiding investment in local capacity and storage, which are necessary when one sub-region cannot count on other sub-regions. Perfect physical integration brings up to $3.3 billion in yearly savings under a carbon cap, while at most it results in a $1.1 billion yearly cost reduction without the carbon cap. Local natural gas power plants, used on demand, erase most of the transmission lines' value.

Institutional integration has also more value in the absence of transmission constraints: at least $1.5 billion, compared to at most $0.8 billion when transmission capacity is limited.

**Table 6. Total Yearly Cost for each Scenario, in billion of dollars**

| | No carbon cap | | Carbon cap | |
|---|---|---|---|---|
| | 1.1 Unconstrained Transmission | 1.2 Limited Transmission | 2.1 Unconstrained Transmission | 2.2 Limited Transmission |
| BAU | $14.1 | $14.2 | $21.9 | $24.1 |
| Shared | $12.5 | $13.6 | $20.0 | $23.3 |
| BAU-Shared Difference | $1.5 | $0.6 | $1.9 | $0.8 |
| % | 11.0% | 4.2% | 8.8% | 3.5% |

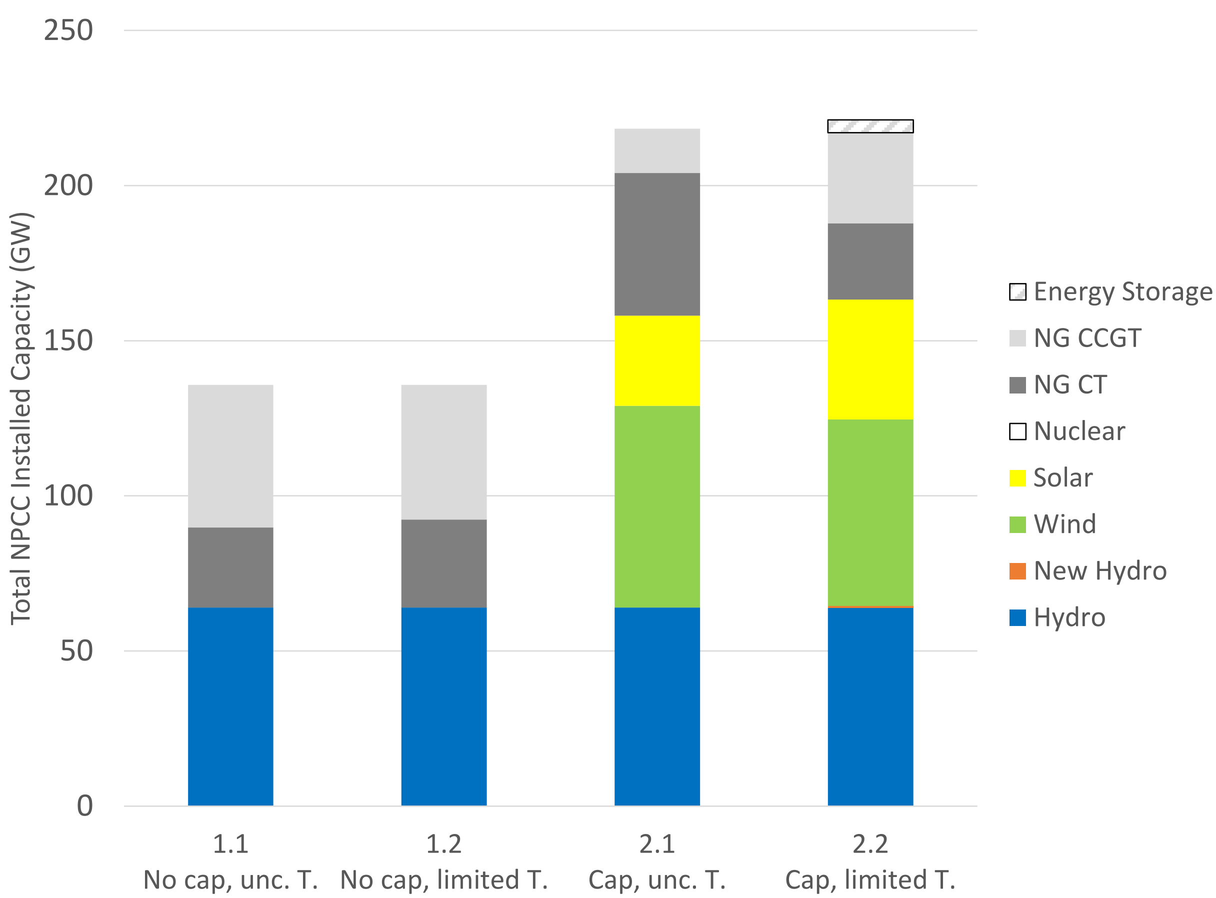
Additional scenarios have been run to investigate these results. One scenario allows nuclear investments, one has no capacity constraint (an "energy only" market), one looks at a hypothetical situation where the relatively high Quebec loads are reduced by 30% (assuming massive energy efficiency programs) and finally one where Quebec exports are limited to 30 TWh. Without discussing in details results from all these additional scenarios, it can be mentioned that the 30% load reduction in Quebec, combined with physical and institutional integration, would result in an annual cost of $15.9 billion, only slightly higher than the no carbon cap scenarios. Given the high electricity consumption level in Quebec, this results illustrates that gains can come from many sources: not only integration, but also energy efficiency.

## Installed Capacity

Obviously, cost patterns reflect investments patterns in installed capacity. In this sub-section we present detailed results on the regional generation capacity by technology.

As illustrated by Figure 5 and Table 7, installed capacity increases by about 75 GW when the carbon cap is implemented. About 60 GW of wind capacity and 30 GW of solar capacity have to be installed. Compared to current levels (about 10 GW of wind and less than 1 GW of solar, see Table 3), the change is major. Beyond the actual economic cost of increasing such generation capacity, multiple social and possibly environmental challenges would arise in expanding wind and solar capacities to these levels. Optimizing these investment becomes particularly important in such context, and significant reduction in generation capacity can be achieved through both physical and institutional integration.

**Figure 5. Total Capacity in BAU Scenarios, in GW**




From a peak of 217 GW plus 4 GW of storage (Table 7, under BAU and limited transmission), total generation capacity could be cut by 16% to 184 GW and no storage (Table 8) by integrating peak capacity constraints and removing limits on interconnections.

The increase in solar and storage capacities in Table 7, under a carbon cap and limited transmission, reflect the key value of transmission to allocate resources. Without such possibility, redundancy has to be built. When transmission is sufficient, a much smaller wind capacity (5 GW, from 60 to 65 GW) can replace about 9 GW of solar and 4 GW of storage – with access to flexible natural gas CT power plants and existing hydro. Natural gas CT plants are used for very brief periods of time (less than 5% of the time), but are required for local capacity constraints and load following.

**Table 7. Total Capacity in BAU Scenarios, in GW**

| | No carbon cap | | Carbon cap | |
|---|---|---|---|---|
| | 1.1 | 1.2 | 2.1 | 2.2 |
| | Unconstrained T | Limited T | Unconstrained T | Limited T |
| Hydro | 64.0 | 64.0 | 64.0 | 64.0 |
| New hydro | 0.0 | 0.0 | 0.0 | 0.5 |
| Wind | 0.0 | 0.0 | 65.0 | 60.1 |
| Solar | 0.0 | 0.0 | 29.1 | 38.7 |
| Nuclear | 0.0 | 0.0 | 0.0 | 0.0 |
| NG CT | 25.8 | 28.4 | 46.0 | 24.5 |
| NG CCGT | 46.0 | 43.4 | 14.3 | 29.2 |
| **Total** | **135.8** | **135.7** | **218.3** | **217.1** |
| Storage | 0.0 | 0.0 | 0.0 | 4.1 |
| DR (GWh) | 197.1 | 198.4 | 258.2 | 222.4 |
| Load Shed | 0 | 0 | 0 | 0 |

With institutional integration, and the possibility to count transmission from neighboring sub-regions in peak capacity constraints, investment in peaking units (natural gas CT) drops by large amounts: from more than 46 GW to about 12.7 GW in the carbon cap-Unconstrained transmission case, and from 24.5 GW to 11.5 GW in the limited transmission case (Tables 7 and 8).

**Figure 5. Total Capacity in Shared Scenarios, in GW**

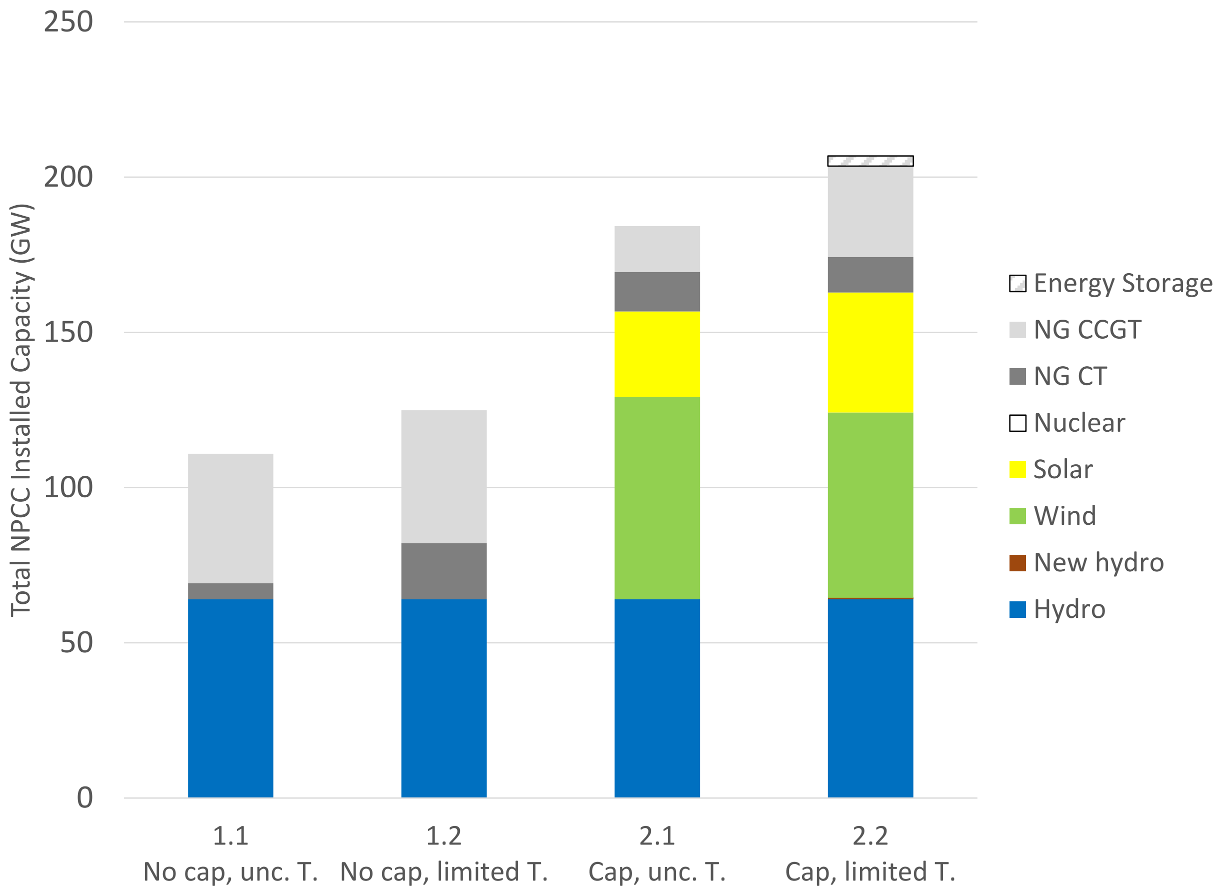



**Table 8. Total Capacity in Shared Scenarios, in GW**

| | No carbon cap | | Carbon cap | |
|---|---|---|---|---|
| | 1.1 | 1.2 | 2.1 | 2.2 |
| | Unconstrained T | Limited T | Unconstrained T | Limited T |
| Hydro | 64.0 | 64.0 | 64.0 | 64.0 |
| New hydro | 0.0 | 0.0 | 0.0 | 0.5 |
| Wind | 0.0 | 0.0 | 65.2 | 59.6 |
| Solar | 0.0 | 0.0 | 27.5 | 38.7 |
| Nuclear | 0.0 | 0.0 | 0.0 | 0.0 |
| NG CT | 5.2 | 18.1 | 12.7 | 11.5 |
| NG CCGT | 41.7 | 42.8 | 14.8 | 29.3 |
| **Total** | **110.9** | **124.9** | **184.2** | **203.5** |
| Storage | 0.0 | 0.0 | 0.0 | 3.2 |
| DR (GWh) | 169.5 | 209.1 | 301.7 | 242.7 |
| Load Shed | 0.0 | 0.0 | 0.0 | 0.0 |

The lower installed generation and storage capacity in the Shared scenarios, compared to the BAU ones, also means that demand response is more often used, unless enough transmission capacity is available for natural gas power plant to supply this demand. Such demand response remains marginal (maximum of 0.3 TWh over a total load of about 640 TWh), but illustrates the fact that demand flexibility will play a bigger role in a low-carbon power sector.

The main driver of the cost reduction in sharing the investment constraints is the reduced need of capacity, especially for peak plants. Comparing the BAU and Shared scenarios, coupling the investment constraint permit to drastically reduce the amount of peak plants (NG CT), especially under the carbon cap (-80% in scenario 1.1, -36% in 1.2, -72% in 2.1 and -53% in 2.2). It is known that coupling investment constraints greatly reduces the need for (often) idle peak capacity, which is illustrated by comparing the BAU and Shared scenario results. The important renewable integration implied by the carbon cap generates a more volatile residual demand, thus increasing the need for low-investment-cost NG CT. But as a CT burns more gas than a CCGT for the same amount of power (and thus more emission per MWh), this capacity is idle in most of the time. Hence, the carbon cap increases the need for peak capacity but allows for less use of it, which is highly inefficient. Coupling the markets' investment constraints allows for a significant improvement in this case (see Tables 9-10 for utilization rates).

## New Installed Capacity Results by Sub-Region (MW) and Utilization Factors

Tables 9 and 10 provide the breakdown of new installed capacity by sub-region. Under limited transmission, the location of generation capacity is obviously closer to the load, and is consequently better distributed.

With Unconstrained transmission, in the Shared scenario (without local capacity constraints), new investment can freely be concentrated in some sub-regions. This is why we observe, for instance, all natural gas capacity is located in NY in the scenario with no carbon cap, unconstrained transmission-shared. Similarly, in the same scenario, all solar investments end up in Québec.

Beyond the regional distribution of investment, what Tables 9 and 10 show is the twin capacity impacts of both physical and institutional integration:

- Lowering the amount of required capacity,
- Increasing the utilization factor of the remaining capacity.

Reading Tables 9 and 10 from right to left (Limited to Unconstrained transmission), or from top to bottom (BAU to Shared), as integration levels increase, total capacity usually decreases and utilization factors usually increase. This explains why costs decrease with integration. There are some exceptions to this pattern. For instance wind capacity increases in scenarios 2 (carbon cap), when transmission becomes unconstrained. Integration leads to more wind investment. This comes from the fact that removing the local capacity constraint from the BAU opens up some additional cost effective opportunities for wind.

### Table 9. Regional Investments in Scenarios 1 (No Carbon Cap)

| | **No Carbon Cap 1.1 Unconstrained Transmission** | | | | | | | | **No Carbon Cap 1.2 Limited Transmission** | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| *BAU* | NG CT | NG CCGT | Nuclear | Wind | Solar | New H | Storage | DR (MWh) | NG CT | NG CCGT | Nuclear | Wind | Solar | New H | Storage | DR (MWh) |
| QC | 0 | 0 | | | | | | 0 | | | | | | | | 0 |
| ON | 0 | 18,025 | | | | | | 46,712 | 7,426 | 10,589 | | | | | | 47,560 |
| MA | 0 | 6,825 | | | | | | 20,818 | 3,428 | 3,397 | | | | | | 20,818 |
| NY | 14,265 | 10,742 | | | | | | 62,390 | 8,429 | 16,572 | | | | | | 62,783 |
| NE | 11,525 | 10,368 | | | | | | 67,219 | 9,077 | 12,816 | | | | | | 67,227 |
| **Total** | **25,790** | **45,960** | **0** | **0** | **0** | **0** | **0** | **197,140** | **28,361** | **43,374** | **0** | **0** | **0** | **0** | **0** | **198,387** |
| *Utilization factor* | *0.13%* | *90.54%* | | | | | | | *4.03%* | *93.49%* | | | | | | |
| *Shared* | NG CT | NG CCGT | Nuclear | Wind | Solar | New H | Storage | DR (MWh) | NG CT | NG CCGT | Nuclear | Wind | Solar | New H | Storage | DR (MWh) |
| QC | 0 | 0 | | | | | | 45,692 | | | | | | | | 0 |
| ON | 0 | 0 | | | | | | 34,201 | 4,898 | 10,475 | | | | | | 71,675 |
| MA | 0 | 0 | | | | | | 13,764 | 1,738 | 3,358 | | | | | | 20,818 |
| NY | 5,168 | 41,735 | | | | | | 45,961 | 6,128 | 16,299 | | | | | | 73,556 |
| NE | 0 | 0 | | | | | | 29,893 | 5,339 | 12,680 | | | | | | 43,903 |
| **Total** | **5,168** | **41,735** | **0** | **0** | **0** | **0** | **0** | **169,511** | **18,104** | **42,812** | **0** | **0** | **0** | **0** | **0** | **209,953** |
| *Utilization factor* | *3.18%* | *99.50%* | | | | | | | *6.87%* | *94.48%* | | | | | | |

### Table 10. Regional Investments in Scenarios 2 (Carbon Cap)

| | **Carbon Cap 2.1 Unconstrained Transmission** | | | | | | | | **Carbon Cap 2.2 Limited Transmission** | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| *BAU* | NG CT | NG CCGT | Nuclear | Wind | Solar | New H | Storage | DR (MWh) | NG CT | NG CCGT | Nuclear | Wind | Solar | New H | Storage | DR (MWh) |
| QC | | | | 20,000 | 7,443 | | 0 | 0 | 0 | 0 | | 8,890 | 0 | | 0 | 0 |
| ON | 12,455 | 2,814 | | 10,000 | 7,944 | | 0 | 63,659 | 5,026 | 7,124 | | 10,957 | 14,632 | | 3,413 | 51,342 |
| MA | 2,583 | 3,521 | | 15,000 | 4,918 | | 0 | 8,933 | 3,603 | 2,738 | | 6,017 | 1,733 | | 243 | 8,218 |
| NY | 18,337 | 2,326 | | 10,000 | 5,458 | | 0 | 96,436 | 8,172 | 11,025 | | 16,370 | 14,146 | 533 | 214 | 74,352 |
| NE | 12,585 | 5,658 | | 10,000 | 3,297 | | 0 | 89,143 | 7,719 | 8,360 | | 17,823 | 8,190 | | 247 | 88,530 |
| **Total** | **45,960** | **14,318** | **0** | **65,000** | **29,059** | **0** | **0** | **258,171** | **24,520** | **29,247** | **0** | **60,057** | **38,701** | **533** | **4,117** | **222,442** |
| *Utilization factor* | *1.10%* | *66.35%* | | *40.1%* | *19.3%* | | | | *0.97%* | *33.91%* | | *40.3%* | *18.7%* | | | |
| *Shared* | NG CT | NG CCGT | Nuclear | Wind | Solar | New H | Storage | DR (MWh) | NG CT | NG CCGT | Nuclear | Wind | Solar | New H | Storage | DR (MWh) |
| QC | 0 | 0 | | 20,000 | 27,535 | | 0 | 91,087 | 0 | 0 | | 8,119 | 0 | | 0 | 0 |
| ON | 0 | 0 | | 10,000 | 0 | | 0 | 58,317 | 1,315 | 7,144 | | 10,868 | 14,924 | | 3,016 | 76,654 |
| MA | 0 | 0 | | 15,000 | 0 | | 0 | 23,219 | 1,914 | 2,712 | | 5,996 | 1,896 | | 210 | 9,091 |
| NY | 12,663 | 14,819 | | 10,000 | 0 | | 0 | 72,095 | 3,820 | 11,083 | | 16,887 | 13,534 | 533 | 0 | 93,441 |
| NE | 0 | 0 | | 10,224 | 0 | | 0 | 57,006 | 4,415 | 8,336 | | 17,746 | 8,302 | | 23 | 63,502 |
| **Total** | **12,663** | **14,819** | **0** | **65,224** | **27,535** | **0** | **0** | **301,723** | **11,465** | **29,275** | **0** | **59,616** | **38,656** | **533** | **3,248** | **242,688** |
| *Utilization factor* | *3.65%* | *64.58%* | | *40.1%* | *20.0%* | | | | *2.23%* | *33.79%* | | *40.6%* | *18.7%* | | | |

## Emissions and Trade

Under the carbon cap, the GHG emission level is at 30.1 Mt (see Table 4). In scenario 1, emissions are above the 1990 level (of 150 Mt, see Table 4) because natural gas replaces all nuclear production.

With the carbon cap (scenarios 2), net trade patterns change and Québec becomes a much more important net exporter. Without transmission constraints, net trade from Québec is multiplied by more than three (Tables 11 and 12), as a lot of wind and solar investment happen in that province (see Table 10 for the capacity details by sub-region). Let's however emphasize that if Québec benefits from marginal competitive advantage in wind in our model (see Table A2.4), solar investments in Québec in the integrated case could almost be placed anywhere – as solar profile are not significantly different between sub-regions.

**Table 11. Emission (Mt) and trade (TWh) in the BAU Scenarios**

| | No carbon cap | | Carbon cap | |
|---|---|---|---|---|
| | 1.1 | 1.2 | 2.1 | 2.2 |
| | Unconstrained T | Limited T | Unconstrained T | Limited T |
| $CO_2$ (Mt) | 122.0 | 123.9 | 30.1 | 30.1 |
| **Net export (TWh)** | | | | |
| QC | 21.48 | 23.58 | 102.10 | 53.06 |
| ON | 42.24 | -9.38 | -36.12 | -17.06 |
| MA | -65.36 | -4.84 | 49.09 | -4.21 |
| NY | -50.15 | 3.08 | -72.57 | -17.55 |
| NE | -112.55 | -12.44 | -39.93 | -14.25 |

**Table 12. Emission (Mt) and trade (TWh) in the Integrated Scenarios**

| | No carbon cap | | Carbon cap | |
|---|---|---|---|---|
| | 1.1 | 1.2 | 2.1 | 2.2 |
| | Unconstrained T | Limited T | Unconstrained T | Limited T |
| $CO_2$ (Mt) | 122.4 | 124.1 | 30.1 | 30.1 |
| **Net export (TWh)** | | | | |
| QC | 23.46 | 23.57 | 137.14 | 50.49 |
| ON | -101.79 | -10.08 | -67.42 | -16.82 |
| MA | -34.52 | -5.18 | 19.27 | -3.84 |
| NY | 232.71 | 3.49 | -8.33 | -16.22 |
| NE | -118.21 | -11.81 | -78.20 | -13.61 |

## Energy Prices

Prices shown in this section come from the hourly marginal value of electricity, given the production costs (operating costs), capacity constraints and marginal value of water. Table 13 shows average hourly prices for the NPCC region (a single price when there are no transmission constraints) and for each sub-region when transmission capacity limits trade. Levelized cost of electricity for the various technologies are shown in Table 16.

Reflecting the higher total cost of the carbon cap scenario, prices in this scenario are much higher than in the no carbon cap one. Indeed, the hourly marginal value of electricity (with its various components mixing operating cost but also marginal capacity and water costs) jumps from around \$25/MWh to above \$80. Only Québec, under limited transmission, is protected from such high prices.

We should also remark that prices are slightly higher under integration than under BAU, due to the smaller (and hence more limited) capacity in such context.

**Table 13. Average hourly prices in the different scenarios (\$/MWh)**

| | | No carbon cap | | Carbon cap | |
|---|---|---|---|---|---|
| | | 1.1 | 1.2 | 2.1 | 2.2 |
| | | Unconstrained T | Limited T | Unconstrained T | Limited T |
| BAU | QC | \$24.81 | \$21.24 | \$69.39 | \$43.45 |
| | ON | | \$24.81 | | \$93.06 |
| | MA | | \$24.81 | | \$79.26 |
| | NY | | \$24.81 | | \$93.35 |
| | NE | | \$24.81 | | \$87.42 |
| Shared | QC | \$29.26 | \$20.83 | \$74.02 | \$46.58 |
| | ON | | \$28.86 | | \$92.80 |
| | MA | | \$28.99 | | \$81.89 |
| | NY | | \$28.87 | | \$96.94 |
| | NE | | \$27.75 | | \$91.19 |

While integration lowers the total cost in all cases, institutional integration slightly raises the price and increases volatility in most sub-regions. Indeed, as measured by the standard deviation (and also illustrated by the maximum and minimum values, see Table 14), price fluctuations are always larger in the integrated cases than in the BAU, except for Québec. This is a consequence of having fewer installed capacity in the integrated cases.

When lot of intermittent renewable capacity is invested in, for example in scenarios 2, price volatility dramatically increases at the level of the average prices, except for Québec in which price volatility and level remain reasonable. Comparing the cases with limited and unconstrained transmission (tables 14-15), one can see the value of Québec hydropower at the operational level. When Québec's hydro is not bounded for its export, the price volatility in other regions drops by approximately 50%.

**Table 14. Unconstrained Transmission Versions: Maximum, Average, Median and Minimum hourly prices in the different scenarios ($/MWh), with the number of hours with negative prices and Standard Deviation**

| | | Max | **Average** | Median | Min | # of hours <0 | *Stand.Dev* |
|---|---|---|---|---|---|---|---|
| 1.1 | BAU | $40.03 | **$24.81** | $20.89 | $20.89 | 0 | *$5.05* |
| | Shared | $1,000.00 | **$29.26** | $23.79 | $20.89 | 0 | *$54.75* |
| 2.1 | BAU | $113.45 | **$69.39** | $68.09 | $5.90 | 0 | *$17.91* |
| | Shared | $1,000.00 | **$74.02** | $68.99 | $5.90 | 0 | *$55.61* |

**Table 15. Limited Transmission Versions: Maximum, Average, Median and Minimum hourly prices in the different scenarios ($/MWh), with the number of hours with negative prices and Standard Deviation**

| | | | Max | **Average** | Median | Min | # of hours <0 | *Stand.Dev* |
|---|---|---|---|---|---|---|---|---|
| 1.2 | BAU | QC | $40.03 | **$21.52** | $21.78 | $20.89 | 0 | *$1.67* |
| | | ON | $40.03 | **$24.81** | $21.78 | $20.89 | 0 | *$7.23* |
| | | MA | $40.03 | **$24.81** | $21.78 | $20.89 | 0 | *$7.32* |
| | | NY | $40.03 | **$24.81** | $21.78 | $20.89 | 0 | *$7.21* |
| | | NE | $40.03 | **$24.81** | $21.78 | $20.89 | 0 | *$7.24* |
| | Shared | QC | $40.03 | **$20.83** | $20.89 | $16.24 | 0 | *$1.91* |
| | | ON | $1,000.00 | **$28.86** | $20.89 | $20.89 | 0 | *$56.84* |
| | | MA | $10,000.00 | **$28.99** | $20.89 | $20.89 | 0 | *$118.25* |
| | | NY | $1,000.00 | **$28.87** | $20.89 | $20.89 | 0 | *$55.68* |
| | | NE | $1,000.00 | **$27.75** | $20.89 | $20.89 | 0 | *$48.52* |
| 2.2 | BAU | QC | $55.57 | **$43.45** | $46.33 | $5.90 | 0 | *$10.45* |
| | | ON | $174.31 | **$93.06** | $107.22 | $4.78 | 0 | *$36.86* |
| | | MA | $174.31 | **$79.26** | $107.22 | $5.90 | 0 | *$45.13* |
| | | NY | $174.31 | **$93.35** | $107.22 | $5.90 | 0 | *$37.80* |
| | | NE | $174.31 | **$87.42** | $107.22 | $5.90 | 0 | *$40.95* |
| | Shared | QC | $58.65 | **$46.58** | $46.76 | $5.90 | 0 | *$3.42* |
| | | ON | $1,300.00 | **$92.80** | $104.59 | $2.46 | 0 | *$44.76* |
| | | MA | $10,000.00 | **$81.89** | $104.59 | $5.90 | 0 | *$122.00* |
| | | NY | $10,000.00 | **$96.94** | $104.59 | $5.90 | 0 | *$127.41* |
| | | NE | $10,000.00 | **$91.19** | $104.59 | $5.90 | 0 | *$126.04* |

**Table 16. Levelized Cost of Electricity ($/MWh)**

| | | No carbon cap | | Carbon cap | |
|---|---|---|---|---|---|
| | | 1.1 Unconstrained T | 1.2 Limited T | 2.1 Unconstrained T | 2.2 Limited T |
| BAU | CT | $4,988.48 | $199.66 | $624.85 | $703.22 |
| | CCGT | $32.32 | $31.96 | $36.49 | $51.42 |
| | Wind1 | | | $44.06 | $43.87 |
| | Wind2 | | | $61.49 | $61.22 |
| | Wind3 | | | $102.88 | $102.40 |
| | Solar | | | $67.06 | $69.21 |
| Shared | CT | $242.33 | $133.67 | $216.28 | $328.50 |
| | CCGT | $31.29 | $31.85 | $36.92 | $51.52 |
| | Wind1 | | | $44.06 | $43.59 |
| | Wind2 | | | $61.49 | $60.81 |
| | Wind3 | | | $102.88 | $101.69 |
| | Solar | | | $64.71 | $69.21 |

## Capacity and GHG Marginal Values

From the solution of the cost minimization problems, we can find the marginal value of capacity and GHG, as presented in Table 17.

In the integrated cases, compared to the BAU, the marginal value of capacity drops for a very natural reason: less capacity is required in each sub-region.

**Table 17. Marginal Value of Capacity ($/MW)**

| | | No carbon cap | | Carbon cap | |
|---|---|---|---|---|---|
| | | 1.1 Unconstrained T | 1.2 Limited T | 2.1 Unconstrained T | 2.2 Limited T |
| BAU | QC | $50,275 | $3,725 | $4,344 | $25,739 |
| | ON | $56,427 | $56,427 | $56,427 | $56,427 |
| | MA | $56,500 | $56,500 | $56,500 | $56,500 |
| | NY | $56,353 | $56,353 | $56,353 | $56,353 |
| | NE | $56,574 | $56,574 | $56,574 | $56,574 |
| Shared | QC | | $2,117 | | $0 |
| | ON | | $20,890 | | $48,189 |
| | MA | $17,365 | $19,901 | $24,057 | $26,547 |
| | NY | | $20,814 | | $11,531 |
| | NE | | $30,803 | | $16,057 |

Another telling way of illustrating the significance of our results is by observing the marginal value of a tonne of GHG. Obviously, without any constraint on emissions, the economic marginal value of GHG is zero. With the carbon cap and limited transmission, it jumps over $250/t. Removing transmission constraints lowers this carbon price to about $140/t. Institutional integration has a much lower impact on the carbon price: a reduction in the $3-$8 range per tonne.

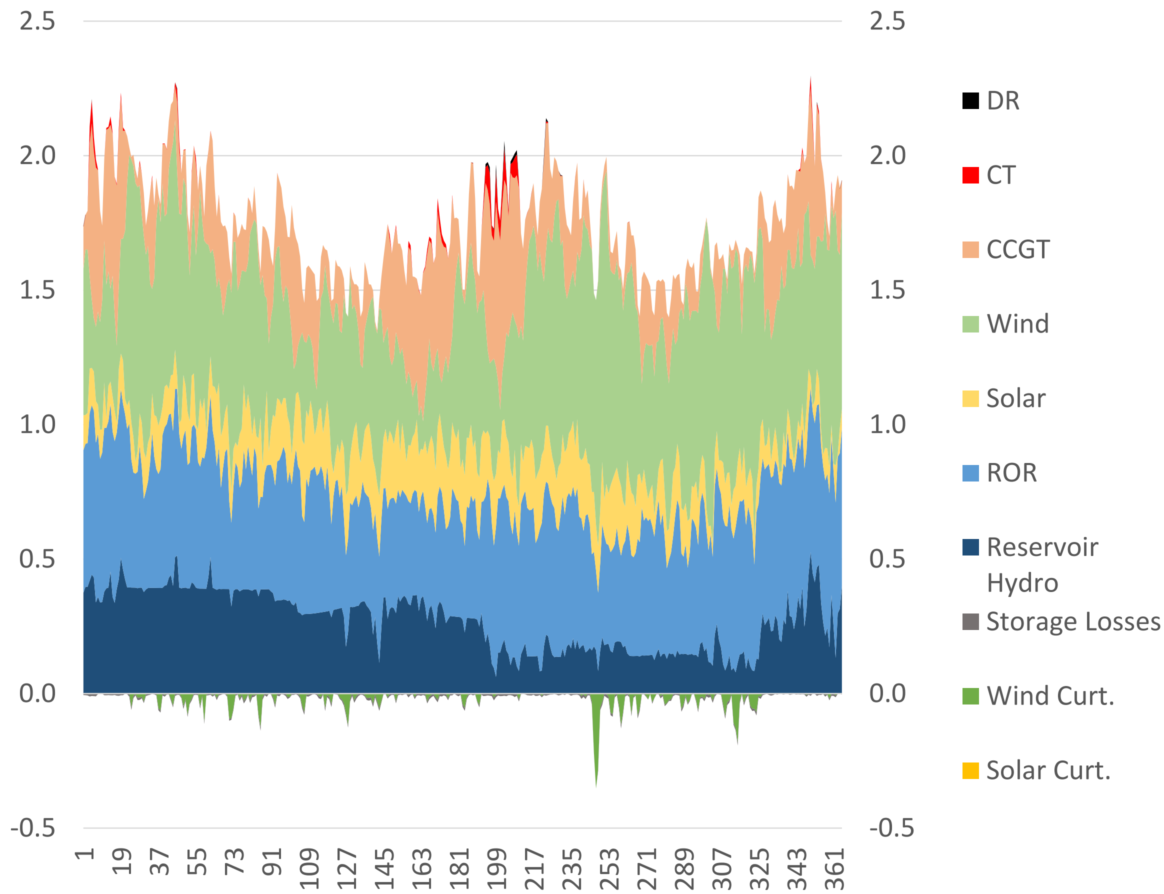
**Table 18. Marginal Value of GHG ($/t)**

| | No carbon cap | | Carbon cap | |
|---|---|---|---|---|
| | 1.1 Unconstrained T | 1.2 Limited T | 2.1 Unconstrained T | 2.2 Limited T |
| BAU | $0 | $0 | $141 | $258 |
| Shared | $0 | $0 | $144 | $250 |

## Production Profiles

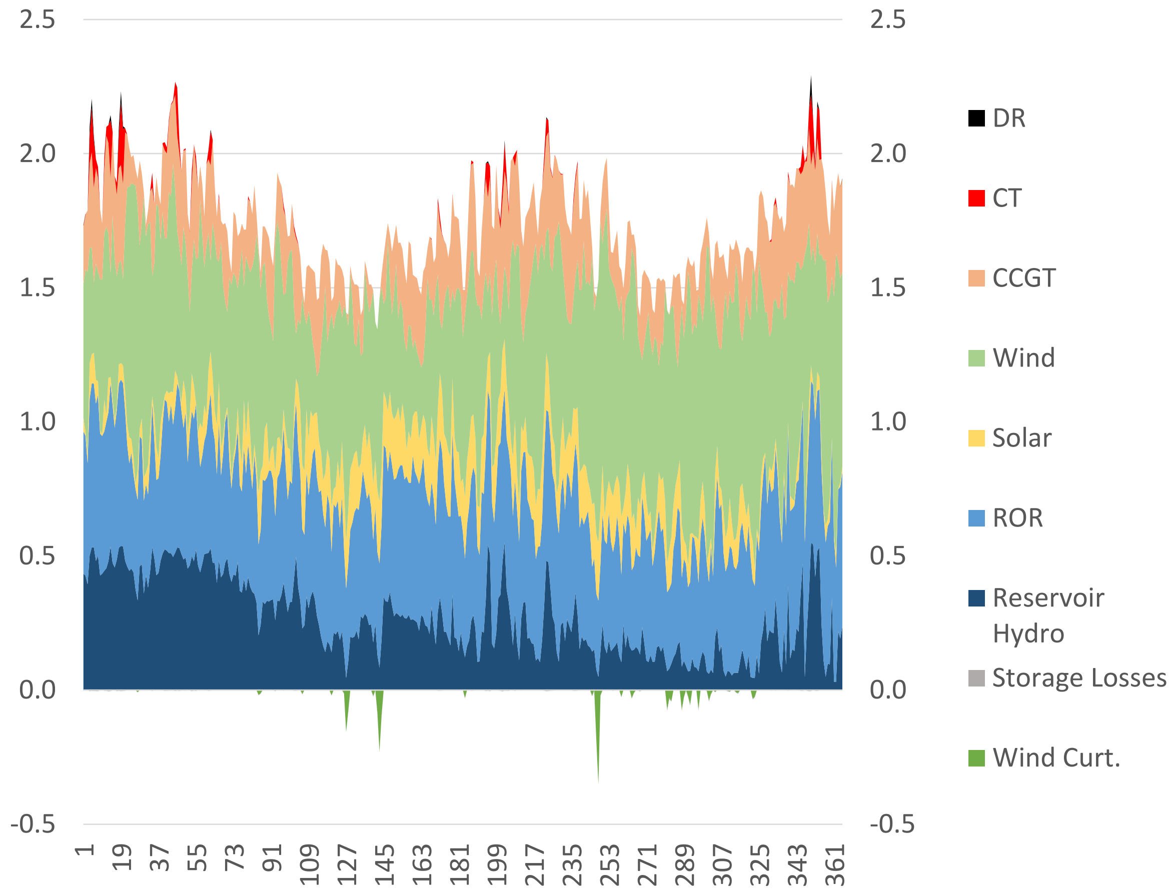
Figures 6 and 7 illustrate the production profiles of each technology, for two different carbon cap scenarios. Figure 6 illustrates production under the BAU and limited transmission scenario, while Figure 7 shows the same production when physical and institutional integration are implemented (scenario unconstrained and shared).

**Figure 6. Daily Production by Technology in Scenario 2 BAU-Limited Transmission, in TWh**




A few observations can be made. First, the amount a curtailed wind and solar production (negative production in both Figures) is much lower when there is more integration. It actually drops from 5.7 TWh to 2.0 TWh. Second, hydropower from reservoirs can be used to follow load more closely. This can be seen by the more frequent peaks in production from reservoir hydro in Figure 7 compared to Figure 6. Correlation between reservoir hydro and actual total hourly load jumps from 0.41 in Figure 6 to 0.62 in Figure 7. Removing transmission constraints allows the flexibility of reservoir hydro to be fully used.

**Figure 7. Daily Production by Technology in Scenario 2 Shared-Unconstrained Transmission, in TWh**




## Discussions: Distributed Generation and Transmission Costs

Our study does not explicitly discuss distributed generation (DG). However, it does not exclude the possibility to have significant penetration of DG. Indeed, our modelling choice for solar technology can be interpreted as being either rooftop or utility scale solar. The only assumption we make is that solar production can be explicitly tracked, instead of erasing some power demand.

One limitation in our study is the absence of transmission investment cost. However, using Dolter and Rivers (2018) cost estimates for new transmission lines, an 800 km 345 kv line with a capacity of 1,500 MW would cost around $2 billion. Given the longevity of transmission lines (40 years or more), yearly savings estimated from our study ($2-3 billion per year) would more than justify the construction of many new transmission lines, effectively removing transmission constraints between regions.

## 3. Major Takeaways and Further Studies

In summary, the main findings of our study are:

- Reducing by 80% GHG emissions from their 1990 level is a costly process: it can add $10 billion/year in investment and operation costs. Integration could reduce this regional cost by up to $4 billion per year.
- Such significant cost reduction comes from both physical and institutional integration gains:
  - Increasing the interconnection capacity allows flexible hydro to hedge the inherent volatility of intermittent renewables and demand. While transmission investment costs have not been considered, the range of gains ($2-3 billion per year) is clearly greater than the actual investment cost of new lines (on the order of $2 billion each, for an economic lifetime of 40 years).
  - Promoting institutional integration by sharing capacity constraints among sub-regions is a good complement to an increase in transmission capacity: it permits to avoid investment in idle peak plants.

### Next steps

Results from this scoping studies are encouraging. They also raise a number of further questions and highlight areas where more depth is needed. In the next paragraphs, we discuss areas where additional work and modelling improvement could be carried out.

#### Optimal asset in transmission capacity

The current incarnation of the investment model does not consider explicit transmission investment variables. Insofar, transmission has been parametrized as part of the scenarios (unconstrained transmission capacity and limited transmission capacity). It is well established from Dolter & Rivers (2018) that significant transmission investments will be essential when moving forward with most credible deep decarbonization scenarios.

The addition of transmission investment decisions will have a computational cost in terms of model optimization run time. In order to pre-empt some of these difficulties through limiting the size of the search space, parametric studies should be run to identify good investment candidates. For example, given the results of the scoping study, we see that New England-Québec links have probably the most value. We can therefore look at specific investment scenarios for this interconnection at 2x, 3x, etc. capacity increments to establish where further transmission increments start to lose intrinsic value.

#### Impact of load profile changes: increased electricity demand and higher peaks

The current scoping study did not consider any change in the electricity consumption across the NPCC as we move to 2050. Given the expected shift from gas to electricity for heating in New England, New York and Ontario as well as an overall electrification of transportation and industry, annual peaks and overall levels of electrical energy consumption are set to shift dramatically across the region. One significant possibility is the shifting of the peak from summertime to winter in all sub-regions of the NPCC (except Québec). Various scenarios, implementing several levels of energy source shifts between fossil fuels and electricity, need to be run to find how sensitive the investment decisions are to these changes.

#### Energy efficiency investments and load reductions

At the same time, knowing the energy efficiency potential of the building stock in Québec—with some estimates reaching close to 30% potential savings—we have to investigate how this potentially freed-up energy could be reallocated elsewhere in the region. In fact, the key question to be answered also is how the freed-up resources would affect investments in both generation and transmission inside and outside Québec.

To a lesser extent, we need to assess the value of efficiency measures in other sub-regions of the NPCC. These runs will be essential in establishing bounds on substitution values for generation and grid investments.

### Sensitivity: technology costs & renewable production profiles

Given the important lead time to 2050, there is significant uncertainty regarding the relative costs of the competing technologies considered in the model. For example, the cost of developing off-shore wind off the coast of New England is difficult to establish, even for today. Therefore, we need to explore parametrically if technology cost changes can lead to radically different investment outcomes or not. If so, we need to identify the fundamental reasons why these radical shifts happen. In addition, it will be worthwhile to determine how robust the optimal investments are to these cost uncertainties.

Production profiles of renewable sources such as wind and solar vary more than what we have implemented in this study. In particular, specific onshore and offshore wind production profiles have not been used here. Wind energy potential will also be affected by climate change, see Ouranos (2018). More sensitivity analysis to these profiles and their possible evolution should be performed.

### Lower emission caps

Likewise, it would be relevant from a public policy perspective to estimate the incremental cost of implementing those more ambitious emission reduction goals: 90% or even 95% cuts in GHG emissions. At the same time, this will allow us to see if these more ambitious targets lead to radically different technology mixes or not. The application of these more aggressive targets could also be subject to the other variations entailed here.

### Assessment of the operational value of hydropower in deep decarbonization scenarios

In a deeply-decarbonized and integrated NPCC, we expect that Québec's reservoir hydro will be operated in a radically different fashion than how it is today. Since this scoping study was concentrating its attention on capacity planning, several simplifying assumptions were made with respect to the mode of operation of reservoir hydro and other energy storage technologies. Further investigations are warranted to uncover changes in the hydropower operational philosophy which may arise from decarbonization. We expect to see the inherent flexibility of hydropower being used to balance variable renewables like wind and solar power. In fact, we expect to see a shift from the pure energy generation mission to one where flexibility provision takes on an ever more prominent role.

To do so, we may have to relax some of the traditional constraints and update the operational objectives on Québec's hydro resources. For example, we should investigate alternative short-term hydro planning approaches which are not strictly limited to maximizing the water value.

At the same time, it would be necessary to assess how changes in key hydro system parameters could affect investments in other technologies and the operations of hydro. Specifically, we could perform different analysis:

- System value of reservoir storage—this could be done by increasing significantly the proportion of run-of-river generation against reservoir hydro.
- Sensitivity to the amount of water storage availability—questions remain regarding the optimal size of the energy storage infrastructure.
- Sensitivity to the amount of water available in a given year

### Representation of intra-region transmission bottlenecks and higher fidelity transmission system modeling (DC power flow) and security

It could be interesting to better capture how electricity travels in the upcoming context. First, we need to consider moving away from the transportation model representation to one where the DC power flow is also governed by both KCL and KVL.

Moreover, network contingencies to obtain better bounds on the actual cost and limitations of decarbonisation could be included in the analysis.

### Modeling of the energy transition over the years to capture the effects of policy decisions

It is equally important to elaborate narratives for the transition from now to 2050. Key milestones in terms of how investments could be deployed could be studied, in light of the existing stock of power plants and their planned retirement. Transitional measures could be identified, as may be needed in earlier years.

### Additional possible areas of research

- Climate change and meteorological phenomenon impacts on the energy generated by renewable energy (high wind, icing, shear wind, snow on solar panel, high temperature and solar panel)
- Demand-side flexibility allowed by smart meters and smart grid.
- Endogenous investment in demand-side technologies (energy efficiency, demand-side management)

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## Appendix 1. List of Participants in Scoping Study Meetings

Four meetings took place to shape this scoping study through comments of various stakeholders. These meeting took place on August 30th, 2017 at HEC Montréal, on October 2nd, 2017 at McGill (TISED), on December 11th, 2017 at Polytechnique Montréal (IET) and on February 28th, 2018 at HEC Montréal.

Here is the list of people attending one or more of these meetings:

| | |
|---|---|
| Pierre-Olivier Pineau | HEC Montréal |
| Sébastien Debia | HEC Montréal |
| Johanne Whitmore | HEC Montréal |
| Gary Sutherland | Hydro-Québec |
| Gregory Emiel | Hydro-Québec Production |
| Guillaume Tarel | Hydro-Québec Production |
| Sylvie Ouellet | Hydro-Québec Production |
| André Dagenais | Hydro-Québec TransÉnergie |
| Benoît Delourme | Hydro-Québec TransÉnergie |
| Louis Beaumier | IET |
| Normand Mousseau | IET |
| Alain Forcione | IREQ |
| Innocent Kamwa | IREQ |
| Francois Bouffard | McGill TISED |
| Navdeep Dhaliwal | McGill TISED |
| Laxmi Sushama | McGill TISED |
| Aaron Bloom | National Renewable Energy Laboratory (NREL) |
| Dan Bilello | NREL |
| Greg Brinkman | NREL |
| Laurent Da Silva | Ouranos |
| René Roy | Ouranos |
| Katherine Pineault | Ouranos |
| Keyhan Sheshyekan | Polytechnique Montréal |
| Nazak Soleimanpour | Polytechnique Montréal |
| Ryan Kilpatrick | Natural Resources Canada |
| Bradley Little | Natural Resources Canada |
| Humayun Soomro | Natural Resources Canada |
| Cédric Arbez | Nergica (TechnoCentre éolien) |
| Eric St-Pierre | Trottier Family Foundation |
| Lorne Trottier | Trottier Family Foundation |
| Mark O'Malley | NREL, University College Dublin / McGill TISED |
| Daniel Levie | University College Dublin / McGill TISED |

# Appendix 2. Data Used in the Scoping Study

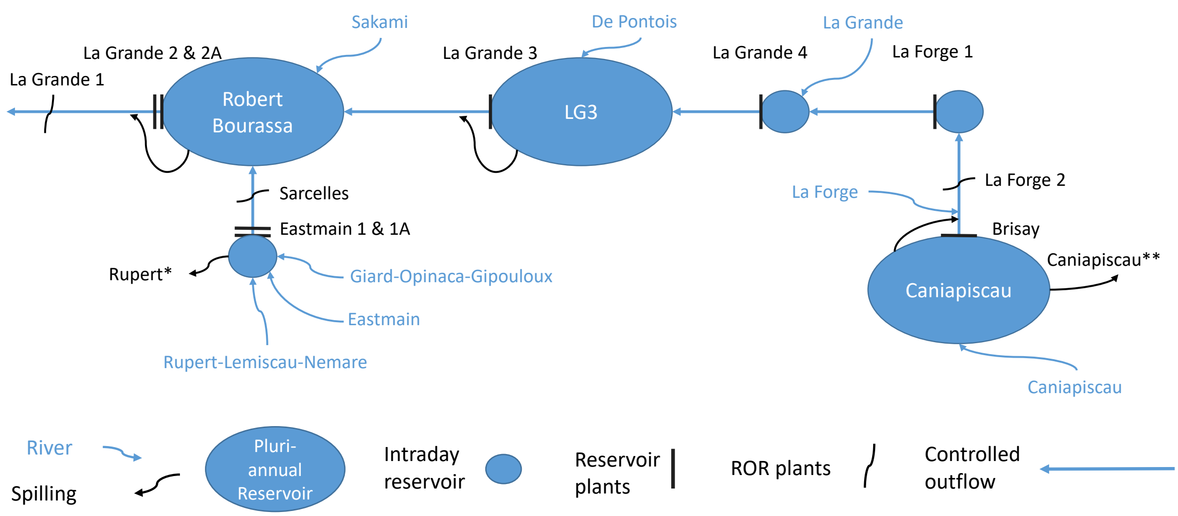
## Existing Hydro

This section provides a general overview of the hydropower modelling approach. More details can be found in Debia (2018).

### Modelling assumptions for the hydro systems

- Hydropower in ON, NY, NE and the Maritime, as well as 29% of Québec's and Churchill Falls, is aggregated by sub-region and assumed to be run-of-river (ROR).
- The remaining 71% of Québec hydro is modelled in more details, as illustrated in Figures A2.1 and A2.2, and following these assumptions:
    - Hydropower is modelled as three "valleys" or systems (or supply chains) (La Grande, Manicouagan and Outarde), where upstream plants' outflow is an inflow to downstream plants.
    - Rivers are exogenous inflows
    - Multiannual reservoirs are the five biggest reservoirs in Quebec, for which public data on maximum and minimum volume is available.
    - All other reservoir, for which no public data on the minimum volume is available, are considered for intraday arbitrage only
    - All other plants are ROR. To avoid some difficult operational constraints, we assume no bound on their spilling.

**Figure A2.1 La Grande System**




* There are strong environmental constraints on the management of the Rupert river
**This spilling mechanism (Duplanter) has never been used since the Brisay plant is in service

**Figure A2.2. Manicouagan and Outardes**

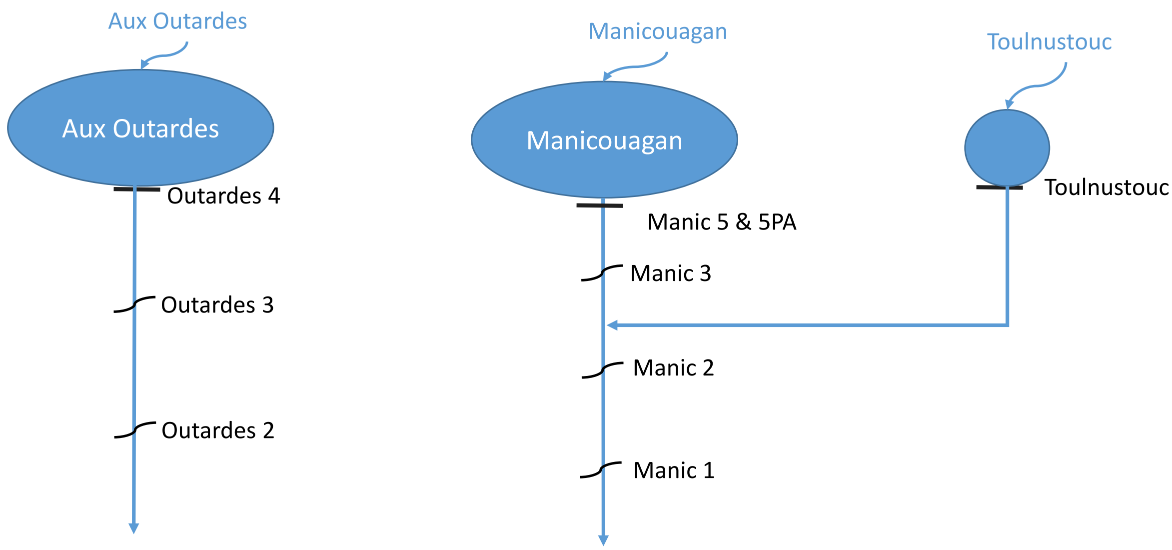



**Table A2.1 Quebec Hydropower Plants**

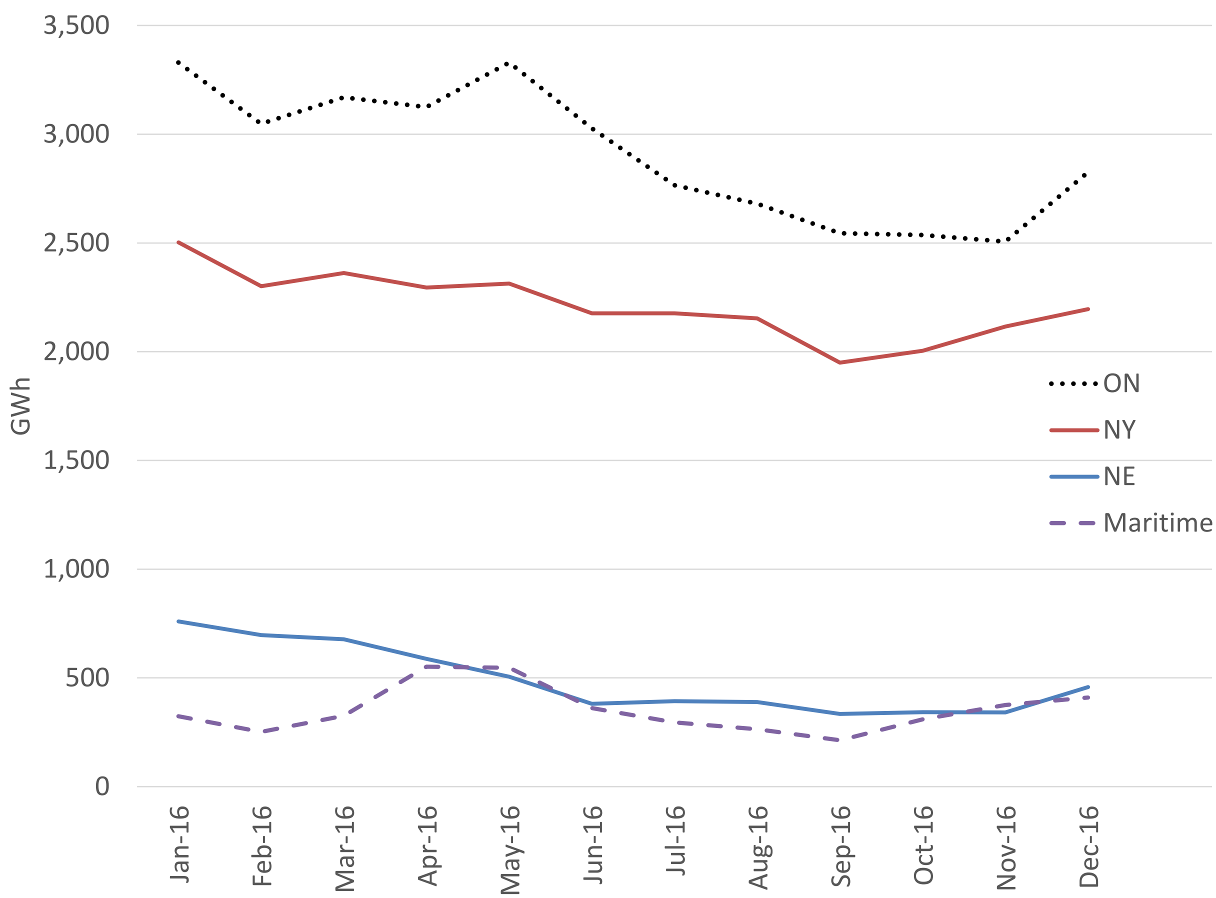
| Name | Drainage basin | River | Type | Installed Capacity (MW) | # of groups (turbines) | Head (m) | Year | Maximum flow rate ($m^3/s$) | Estimated flow rate ($m^3/s$) |
|---|---|---|---|---|---|---|---|---|---|
| Robert-Bourassa | La Grande | La Grande | RES | 5,616 | 16 | 137.16 | 1981 | 4,300 | - |
| La Grande-4 | La Grande | La Grande | RES | 2,779 | 9 | 116.7 | 1986 | | 2,783 |
| La Grande-3 | La Grande | La Grande | RES | 2,417 | 12 | 79 | 1984 | | 3,439 |
| La Grande-2-A | La Grande | La Grande | RES | 2,106 | 6 | 138.5 | 1992 | 1,620 | - |
| Manic-5 | Manicouagan | Manicouagan | RES | 1,596 | 8 | 141.8 | 1971 | | 717 |
| La Grande-1 | La Grande | La Grande | ROR | 1,436 | 12 | 27.5 | 1995 | 5,950 | - |
| René-Lévesque (Manic-3) | Manicouagan | Manicouagan | ROR | 1,326 | 6 | 94.19 | 1976 | | 1,590 |
| Jean-Lesage (Manic-2) | Manicouagan | Manicouagan | ROR | 1,229 | 8 | 70.11 | 1967 | | 2,016 |
| Manic-5-PA | Manicouagan | Manicouagan | RES | 1,064 | 4 | 144.5 | 1990 | | 671 |
| Outardes-3 | Aux Outardes | aux Outardes | ROR | 1,026 | 4 | 143.57 | 1969 | | 633 |
| Laforge-1 | La Grande | Laforge | RES | 878 | 6 | 57.3 | 1994 | | 1,693 |
| Outardes-4 | Aux Outardes | aux Outardes | RES | 785 | 4 | 120.55 | 1969 | | 605 |
| Eastmain-1-A | La Grande | Eastmain | RES | 768 | 3 | 63 | 2012 | 1,344 | - |
| Toulnustouc | Manicouagan | Toulnustouc | RES | 526 | 2 | 152 | 2005 | 330 | - |
| Outardes-2 | Aux Outardes | aux Outardes | ROR | 523 | 3 | 82.3 | 1978 | | 724 |
| Eastmain-1 | La Grande | Eastmain | RES | 480 | 3 | 63 | 2006 | 840 | - |
| Brisay | La Grande | Caniapiscau | RES | 469 | 2 | 37.5 | 1993 | 1,130 | - |
| Laforge-2 | La Grande | Laforge | ROR | 319 | 2 | 27.4 | 1996 | | 784 |
| McCormick | Manicouagan | Manicouagan | ROR | 235 | 7 | 37.8 | 1952 | | 1,373 |
| Manic-1 | Manicouagan | Manicouagan | ROR | 184 | 3 | 36.58 | 1967 | | 708 |
| Sarcelle | La Grande | Eastmain | ROR | 150 | 3 | 16.1 | 2013 | 1,290 | - |

**Table A2.2 Existing Hydropower Capacity and Operating Costs**

| | ON | QC | NB+NS+PE+NL | NY | NE |
|---|---|---|---|---|---|
| Installed capacity-ROR (MW) | 8,991 | 5,659 (HQ)<br>5,063 (non HQ) | 1,322 | 4,672 | 1,857 |
| Installed capacity-dam (MW) | | 29,436 (HQ) | 6,759.0 | | |
| Reservoir capacity (TWh) | | 176 | 28 | | |
| Year | 2015 | 2015 | 2015 | 2015 | 2015 |
| Source | Statistics Canada (2017a) | Debia (2018), HQ (2017) Statistics Canada (2017a) | Statistics Canada (2017a) | EIA (2017a) | |
| Fixed O&M Costs ($/MW) | 14,850 | | | | |
| Variable O&M Costs ($/MWh) | 2.46 | | | | |
| Source | Median value of OpenEI (2017) | | | | |

For ROR, monthly energy requirements reflect the natural water flows and some physical constraints. For instance, Figure 5 shows the actual hydropower monthly production levels in NY and NE.

**Figure A2.3 ON, NY, NE and Maritime Monthly Hydropower Generation in 2016, except for Maritime, where it's the monthly average over 2008-2015 (EIA, 2017c; IESOb, 2017 and Statistics Canada, 2017b).**



Data related to Quebec water inflows have been collected from Environmental and natural ressources Canada Portal (ENS Canada, 2017) and Quebec's Hydrometric Network Portal (MDDELCC, 2017). Data series from 1994 to the early 2000s have been converted to average inflows per day.

## Pumped storage (PS)

PS is only modeled in New York, where 1,400 MW of capacity are installed. No incremental investment is allowed for this technology. PS generation (psg) and pumping (psp) is lower than capacity. Everything that is pumped, times an efficiency coefficient of 0.73, must be generated within a day. The efficiency coefficient is an estimate for the Bleinheim-Gilboa plant (Wong et al., 2009).

In the simplest possible notation:

$$psg \leq \text{Capacity}$$
$$psp \leq \text{Capacity}$$
$$\sum_{hours\ of\ a\ day}(psg - 0.73psp) = 0$$

Energy storage capacity is Unconstrained, but since arbitrage only happens within a day, it limits the potential for multiple-day arbitrage. Such modelling approach permits to have a simple mathematical problem, without a state variable on the amount of stored energy, which would increase the computing time.

## Energy Storage

Energy Storage (ESS) is modeled as pumped storage, but with investment allowed in all sub-regions. Hence investment accounts for the capacity to charge and discharge the battery, not for the size of the storage capacity.

Again, since batteries are for short-term arbitrage, such a modeling permit to avoid state variables following the amount of energy stored, which would have computational implications.

The total (i.e. not annualized) capital cost for investment in energy storage is $935 per kW.

## Solar Supply Data

Actual solar PV production from Ontario is used for the Canadian solar profile. 196 MW of solar PV capacity was installed in 2016. Figure A2.4 shows the production for the first week of January 2016. For the whole year, the solar capacity factor was 20%.

**Figure A2.4 Actual solar PV production in Ontario, 1st week of 2016 (IESO, 2017)**


Alternatively, we could use Natural Ressources Canada's Municipality database of photovoltaic (PV) potential and insolation (NRCan, 2017), from which hourly production profiles could be derived, using monthly insolation profile for each region. It covers 3,500 municipalities across Canada.

Solar profile for NY and NE are provided by NREL.

US solar profile can be generated from NREL's Solar Power Data for Integration Studies (NREL, 2017) See https://www.nrel.gov/grid/solar-power-data.html.

**Table A2.3 Solar Potential, Capacity and Operating Costs**

| | ON | QC | NB+NS+PE+NL | NY | NE |
|---|---|---|---|---|---|
| Potential (MW) | No maximum required at this stage | | | | |
| Cost ($/kW) | 1,200 | | | | |
| Fixed O&M Costs ($/MW) | 24,813 | | | | |
| Variable O&M Costs ($/MWh) | 0 | | | | |
| Source | Cost per kW is the minimum value for large ground-mounted solar PV generation in IEA (2015), other costs are median costs (Table 6.6, p. 112) | | | | |

It is assumed that solar production can be curtailed, so that actual production in a given hour is less than what is technically feasible given the installed capacity and the solar profile.

## Wind Supply Data

Wind potential capital costs are estimated for three blocks, with increasing value. Regions vary depending on the amount of potential MW available at each cost level. To differentiate between regions, some marginal differences are introduced, for computational reasons (limit degeneracy issues).

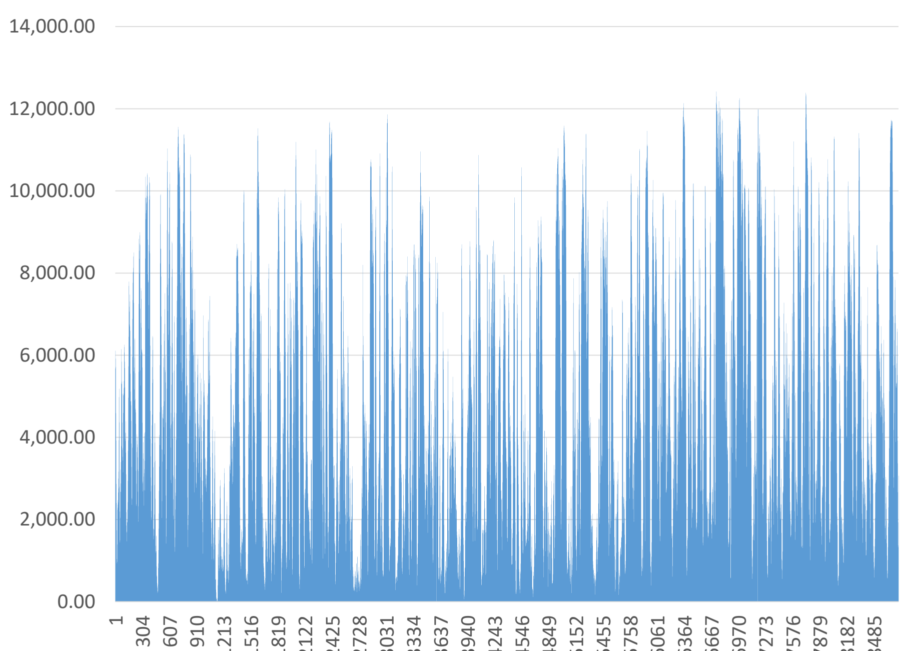
**Table A2.4 Wind Potential, Capacity and Operating Costs**

| | ON | QC | NB+NS+PE+NL | NY | NE |
|---|---|---|---|---|---|
| Block 1 (MW) | 5,000 | 10,000 | 5,000 | 5,000 | 5,000 |
| Block 2 | 5,000 | 10,000 | 10,000 | 5,000 | 5,000 |
| Block 3 | 50,000 | 50,000 | 50,000 | 10,000 | 10,000 |
| Marginal difference | +2 | | +1 | +3 | +4 |
| Cost 1 ($/kW) | 1,200 | | | | |
| Cost 2 | 1,911 | | | | |
| Cost 3 | 2,999 | | | | |
| Fixed O&M Costs ($/MW) | 45,475 | | | | |
| Variable O&M Costs ($/MWh) | 5.9 | | | | |
| Source | Costs per kW correspond to the minimum (1), median (2) and maximum (3) values of IEA (2015; Table 6.7, p. 113). The median value is taken for the Fixed O&M cost and for Variable O&M cost | | | | |

It is assumed that wind production can be curtailed, so that actual production in a given hour may be less than what is technically feasible given the installed capacity and the wind profile.

A “typical” wind profile based on different wind sites per region captures intra-regional geographical diversity. ON, QC and Maritime wind profiles are generated from CanWEA data (GE, 2016), from respectively 49, 53 and 11 real wind sites. See Figure A2.5 for QC (capacity factor of 37.83%).

**Figure A2.5 Combined Hourly wind profile for 53 QC potential sites, totalling a capacity of 12,496 MW (35TRGT scenario), year 2010 (GE, 2016)**




For NY and NE, wind profile come from NREL (2017b) *Wind Integration National Dataset Toolkit*.

Another potential source could be the Global Modelling and Assimilation Office (GMAO) (2016) Modern-Era Retrospective analysis for Research and Applications (MERRA) – see Dolter and Rivers (2018).

## Incremental Hydropower Data

New hydropower capacity, associated to additional amounts of water, has not been modelled at this stage. Only incremental capacity is modelled. Incremental hydropower is additional capacity added to existing hydropower plants. No new inflow of water is associated to these capacity additions.

**Table A2.5 Incremental Hydro Potential, Capacity and Operating Costs**

<table>
<tr><th></th><th>ON</th><th>QC</th><th>NB+NS+PE+NL</th><th>NY</th><th>NE</th></tr>
<tr><td>Block 1 (% of existing hydro)</td><td>10%</td><td>10%</td><td>10%</td><td>10%</td><td>10%</td></tr>
<tr><td>Cost ($/kW)</td><td colspan="5">8,000</td></tr>
<tr><td>Source</td><td colspan="5">440 MW for Quebec corresponds to the available incremental capacity at the Sainte-Marguerite hydropower plant (Official HQ document?)<br>Cost (1) is based on approximate cost for La Romaine and cost (2) is a conjecture based on cost of recent new projects (Keeyask and Site C)</td></tr>
</table>

## Nuclear Data

Although the possibility to have nuclear power plants remains uncertain, mostly due to social acceptability, the option is still included in this project.

**Table A2.6 Nuclear Potential, Capacity and Operating Costs**

| | ON | QC | NB+NS+PE+NL | NY | NE |
|---|---|---|---|---|---|
| Potential (MW) | No maximum required at this stage | | | | |
| Cost ($/kW) | 4,162 | | | | |
| Fuel Cost ($/MWh) | 9.33 | | | | |
| Fixed O&M Costs ($/MW) | 68,800 | | | | |
| Variable O&M Costs ($/MWh) | 6.91 | | | | |
| Source | IEA (2015) Median value of Table 6.3: Overview of data for nuclear generation (p. 112) | | | | |

It is assumed that nuclear production can only be partially curtailed, so that actual production in a given hour is at least 80% of the installed capacity.

## Thermal Power Data

Natural gas combustion (CT) and combined-cycle gas turbine (CCGT) are used as representative thermal technologies. Biomass could fuel these power plants, but this is not modelled.

**Table A2.7 Thermal Potential, Capacity and Operating Costs**

| | ON | QC | NB+NS+PE+NL | NY | NE |
|---|---|---|---|---|---|
| Potential (MW) | No maximum required at this stage | | | | |
| Cost ($/kW) | 672 (CT) / 1,094 (CCGT) | | | | |
| Marginal difference | +1 | +4 | +2 | | +3 |
| Fuel Cost ($/MWh) | CT: 29.4 (heat rate of 9,800 btu/kWh and $3/MBtu)<br>CCGT: 18.9 (heat rate of 6,300 btu/kWh and $3/MBtu) | | | | |
| Fixed O&M Costs ($/MW) | 6,760 (CT) / 9,940 (CCGT) | | | | |
| Variable O&M Costs ($/MWh) | 10.63 (CT) / 1.99 (CCGT) | | | | |
| Carbon Dioxide Emissions (t/MBtu) | 0.05307 t/MBtu | | | | |
| Source | EIA (2017b) Table 8.2. Cost and performance characteristics of new central station electricity generating technologies and EIA (2017d) for $CO_2$ coefficient | | | | |

No ramp-up and ramp-down considerations have been modelled: thermal production can therefore be anything between 0 and the installed capacity at any given hour.

## Demand Response Data and Load Shedding

Demand response (DR) potential is modelled as a percentage of each sub-region hourly load. There are three available block of DR, corresponding to 5% of the sub-region's hourly load that can be removed at an increasing cost.

**Table A2.8 Demand Response Potential, Capacity and Operating Costs**

| | ON | QC | NB+NS+PE+NL | NY | NE |
|---|---|---|---|---|---|
| Block 1 (MW) | 5% of the hourly load | | | | |
| Block 2 | An additional 5% of the hourly load | | | | |
| Block 3 | An additional 5% of the hourly load | | | | |
| Cost 1 ($/MWh) | 700 | | | | |
| Cost 2 | 1,000 | | | | |
| Cost 3 | 1,300 | | | | |
| Source | Cost 1 ($700/MWh) is based on Hydro-Québec (2017b) | | | | |

The current Hydro-Québec demand response program for commercial consumers pays participants a fixed price of $70/kW for each kW of load reduced, during some morning or evening "peak" events. Consumers will not be called for reduction for more than 100 hours during the program's life, typically a winter (Hydro-Québec, 2017b). The price of $700/MWh is derived from this program's parameters.

Load shedding, or non-served energy, is valued at $10,000/MWh. This is the value of lost load (VOLL).

## Transmission Cost

Transmission costs are not modelled in this scoping study. They could be however be included in a next version. Dolter and Rivers (2018), based on GE (2016), use the following transmission investment cost. The cost is based on a double circuit 345 kilovolt line (kv), at a cost of $2.4 million CAD/kilometer, a maximum capacity of 1,500 MW, and amortized over 25 years.

**Table A2.9 Transmission Capacity Costs**

| | ON | QC | NB+NS+PE+NL | NY | NE |
|---|---|---|---|---|---|
| $/MW/km/yr | 184 | | | | |
| Source | Dolter and Rivers (2018) | | | | |

The possibility to build new transmission lines is assumed. Representative distances between regions are shown in Table A12, major cities being also major load centers.

**Table A2.10 Flying Distance between Major NPCC Cities (in km)**

| km | ON | QC | Maritime NB+NS+PE+NL | NY | NE |
|---|---|---|---|---|---|
| ON (Toronto) | | | | 551 | |
| QC (Montreal) | 505 | | 791 | 534 | 403 |
| Maritime (Halifax) | | 791 | | | 655 |
| NY (New York City) | 551 | 534 | | | 306 |
| NE (Boston) | | 403 | 655 | 306 | |
| Source: Air (flying) distance “great circle distance” from https://www.distancecalculator.net/. | | | | | |

Another source is B&V (2014), used in Google Research (2017). We could also add a second block of transmission capacity with lower cost representing some economy of scale if large amounts of transmission were added.

## Annualized Capital Costs

Capital cost are annualized using a discount rate of 6%. Using such discount rate and the lifetime of each technology (see for instance IEA, 2015:30), the table below shows the annualized cost used in the model for investment in each technology.

**Table A2.11 Annualized Cost of Investment and Lifetime by technology**

| | Capital Cost (/MW) | Lifetime | Annualized Cost (/MW) |
|---|---|---|---|
| Hydro | $8,000,000 | 75 | $458,631 |
| Nuclear | $4,162,000 | 40 | $260,956 |
| CT | $672,000 | 25 | $49,593 |
| CCGT | $1,094,000 | 25 | $80,736 |
| Wind 1 | $1,200,000 | 25 | $88,559 |
| Wind 2 | $2,030,000 | 25 | $149,812 |
| Wind 3 | $4,000,000 | 25 | $295,195 |
| Solar | $1,200,000 | 25 | $88,559 |
| Storage | $935,000 | 10 | $119,846 |

# Appendix 3. Alternative Scenarios

## Four additional scenarios

To complement the analysis, four additional scenarios have been explored. The next paragraphs present these scenarios.

- **Nuclear**. In this scenario, the nuclear option is available, at the reported official cost stated in IEA (2015).
- **Energy only** (no capacity constraint). Capacity constraints are removed from the problem. The only requirement is therefore to meet hourly load in each sub-region, or to use demand response (or shed load, ultimately). In such scenario, the distinction between "BAU" and "Integrated" (institutional integration) cannot be made, as there is no capacity constraint.
- **30% load decrease in Québec – "Energy efficiency breakthrough in Québec"**. Given the fact that energy consumption is particularly high in Québec, due to its generous access to relatively cheap hydropower resources, this scenario explores the impact of a possible large gain in energy efficiency in this province: a reduction of 30% of its consumption. This very bold assumption translated in a 30% decrease of Québec's hourly load, while all other parameters are similar to the carbon cap scenario (2).
- **30 TWh limit on Québec's net trade**. In this scenario, also based on the carbon cap scenario (2), net trade from Quebec is limited to 30 TWh.

## Results

Tables A3.1 to A3.9 provide all the results presented for scenarios 1 (no carbon cap) and 2 (carbon cap). As can be seen in Table A3.1, adding nuclear to the possible available technologies, at the official costs (see Appendix 2), significantly reduces the cost of decarbonization, and destroys almost all gains of integration, as local capacity can be installed to meet each sub-region's needs.

The 30% load decrease scenario reduces overall costs only when transmission infrastructures are available to share the saved energy. Otherwise, energy efficiency in Quebec has no regional value at all.

**Table A3.1 Total Yearly Cost for each Scenario, in billions of dollars**

| | Carbon cap with nuclear | | Energy Only | | 30% load decrease | | 30TWh |
|---|---|---|---|---|---|---|---|
| | Unconstrained T | Limited T | Unconstrained T | Limited T | Unconstrained T | Limited T | Limited T |
| BAU | $19.6 | $20.0 | | | $18.3 | $22.6 | $25.1 |
| Shared | $18.0 | $19.3 | $20.0 | $23.3 | $15.9 | $21.8 | $24.0 |
| BAU-Shared Difference | $1.6 | $0.7 | | | $2.3 | $0.8 | $1.1 |
| % | 8.3% | 3.4% | | | 12.8% | 3.4% | 4.3% |

**Table A3.2 Total Capacity in BAU Scenarios, in GW**

| | Carbon cap with nuclear | | Energy Only | | 30% load decrease | | 30TWh |
|---|---|---|---|---|---|---|---|
| | Uncon. T | Limited T | Uncon. T | Limited T | Uncon. T | Limited T | Limited T |
| Hydro | 64.0 | 64.0 | | | 64.0 | 64.0 | 64.0 |
| New hydro | 0.0 | 0.0 | | | 0.0 | 0.5 | 0.0 |
| Wind | 30.0 | 19.8 | | | 55.6 | 49.2 | 60.4 |
| Solar | 0.0 | 0.6 | | | 14.6 | 41.1 | 41.1 |
| Nuclear | 19.4 | 23.5 | | | 0.0 | 0.0 | 0.0 |
| NG CT | 35.9 | 26.9 | | | 50.9 | 22.1 | 30.0 |
| NG CCGT | 11.3 | 16.1 | | | 10.4 | 29.7 | 28.1 |
| **Total** | **160.7** | **150.9** | | | **195.5** | **206.6** | **223.5** |
| Storage | 0.0 | 0.0 | | | 0.0 | 6.3 | 2.8 |
| DR (GWh) | 233.5 | 234.2 | | | 277.8 | 233.4 | 210.0 |
| Load Shed | 0 | 0 | | | 0 | 0 | 0 |

**Table A3.3 Total Capacity in Shared Scenarios, in GW**

| | Carbon cap with nuclear | | Energy Only | | 30% load decrease | | 30TWh |
|---|---|---|---|---|---|---|---|
| | Uncon. T | Limited T | Uncon. T | Limited T | Uncon. T | Limited T | Limited T |
| Hydro | 64.0 | 64.0 | 64.0 | 64.0 | 64.0 | 64.0 | 64.0 |
| New hydro | 0.0 | 0.0 | 0.0 | 0.5 | 0.0 | 0.5 | 0.0 |
| Wind | 30.0 | 19.8 | 65.2 | 59.6 | 56.4 | 49.1 | 60.2 |
| Solar | 0.0 | 1.6 | 27.5 | 38.7 | 12.7 | 41.0 | 41.1 |
| Nuclear | 19.5 | 23.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| NG CT | 9.1 | 15.5 | 12.7 | 11.0 | 11.0 | 8.2 | 13.3 |
| NG CCGT | 10.1 | 15.9 | 14.8 | 29.3 | 10.5 | 29.6 | 28.3 |
| **Total** | **132.7** | **140.0** | **184.2** | **203.2** | **154.6** | **192.4** | **206.9** |
| Storage | | | 0.0 | 3.2 | 0.0 | 6.6 | 1.7 |
| DR (GWh) | 194.5 | 227.1 | 301.7 | 265.8 | 244.4 | 248.6 | 242.8 |
| Load Shed | 0.0 | 0.0 | 0 | 0 | 0.0 | 0.0 | 0.0 |

**Table A3.4 Emission (Mt) and trade (TWh) in BAU Scenarios**

| | Carbon cap with nuclear | | Energy Only | | 30% load decrease | | 30TWh |
|---|---|---|---|---|---|---|---|
| | Uncon. T | Limited T | Uncon. T | Limited T | Uncon. T | Limited T | Limited T |
| $CO_2$ (Mt) | 30.1 | 30.1 | 30.1 | 30.1 | 30.1 | 30.1 | 30.1 |
| **Net export (TWh)** | | | | | | | |
| QC | 56.6 | 23.6 | | | 112.3 | 70.0 | 30.0 |
| ON | -45.1 | -4.5 | | | -31.5 | -20.3 | -8.6 |
| MA | 19.0 | -2.4 | | | 78.0 | -8.1 | -1.3 |
| NY | -106.9 | -12.5 | | | -81.7 | -19.4 | -13.4 |
| NE | 78.0 | -4.1 | | | -75.0 | -22.2 | -6.7 |

**Table A3.5 Emission (Mt) and trade (TWh) in Shared Scenarios**

| | Carbon cap with nuclear | | Energy Only | | 30% load decrease | | 30TWh |
|---|---|---|---|---|---|---|---|
| | Uncon. T | Limited T | Uncon. T | Limited T | Uncon. T | Limited T | Limited T |
| $CO_2$ (Mt) | 30.1 | 30.1 | 30.1 | 30.1 | 30.1 | 30.1 | 30.1 |
| **Net export (TWh)** | | | | | | | |
| QC | 56.4 | 23.6 | 137.1 | 50.4 | 137.0 | 69.9 | 30.0 |
| ON | -84.5 | -6.6 | -67.5 | -16.8 | -67.3 | -20.7 | -9.0 |
| MA | -16.4 | -2.7 | 19.4 | -3.8 | 19.8 | -8.0 | -1.0 |
| NY | -114.6 | -8.2 | -8.4 | -16.2 | -8.5 | -19.0 | -13.1 |
| NE | 72.2 | -6.1 | -78.3 | -13.6 | -78.9 | -22.2 | -6.9 |

**Table A3.6 Average hourly prices in the different scenarios ($/MWh)**

| | | Carbon cap with nuclear | | Energy Only | | 30% load decrease | | 30TWh |
|---|---|---|---|---|---|---|---|---|
| | | Uncon. T | Limited T | Uncon. T | Limited T | Uncon. T | Limited T | Limited T |
| BAU | QC | | $43.63 | | | | $2.47 | $39.88 |
| | ON | | $47.43 | | | | $97.68 | $90.52 |
| | MA | $47.42 | $47.14 | | | $64.32 | $83.74 | $78.25 |
| | NY | | $47.44 | | | | $98.11 | $90.50 |
| | NE | | $47.41 | | | | $92.06 | $86.70 |
| Integrated | QC | | $42.40 | | $46.58 | | $2.47 | $46.36 |
| | ON | | $51.10 | | $98.33 | | $98.22 | $90.65 |
| | MA | $50.64 | $49.26 | $76.76 | $84.89 | $66.04 | $87.79 | $81.37 |
| | NY | | $50.49 | | $98.31 | | $102.45 | $93.55 |
| | NE | | $50.76 | | $93.05 | | $96.48 | $90.51 |

**Table A3.7 Marginal Value of Capacity ($/MW)**

| | | Carbon cap with nuclear | | Energy Only | | 30% load decrease | | 30TWh |
|---|---|---|---|---|---|---|---|---|
| | | Uncon. T | Limited T | Uncon. T | Limited T | Uncon. T | Limited T | Limited T |
| BAU | QC | $9,333 | $17,037 | | | $3,390 | $0 | $56,648 |
| | ON | $56,427 | $56,427 | | | $56,427 | $56,427 | $56,427 |
| | MA | $56,500 | $56,500 | | | $56,500 | $56,500 | $56,500 |
| | NY | $56,353 | $56,353 | | | $56,353 | $56,353 | $56,353 |
| | NE | $56,574 | $56,574 | | | $56,574 | $56,574 | $56,574 |
| Integrated | QC | | $12,329 | | | | $0 | $0 |
| | ON | | $24,411 | | | | $44,509 | $43,917 |
| | MA | $28,363 | $32,635 | | | $22,256 | $17,756 | $24,394 |
| | NY | | $29,756 | | | | $10,922 | $16,256 |
| | NE | | $27,382 | | | | $14,143 | $10,760 |

## Table A3.8 Marginal Value of GHG ($/t)

| | Carbon cap with nuclear | | Energy Only | | 30% load decrease | | 30TWh |
|---|---|---|---|---|---|---|---|
| | Uncon. T | Limited T | Uncon. T | Limited T | Uncon. T | Limited T | Limited T |
| BAU | $69 | $74 | | | $121 | $297 | $230 |
| Integrated | $68 | $68 | $144 | $251 | $115 | $293 | $221 |

## Table A3.9 New Installed Capacity Results by Sub-Region, Nuclear Scenario

| | Cap+Nuclear Unconstrained Transmission | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| *BAU* | NG CT | NG CCGT | Nuclear | Wind | Solar | New H | Storage | DR (MWh) |
| QC | 0 | 0 | 0 | 10,000 | 0 | | | 0 |
| ON | 12,071 | 5,007 | 0 | 5,000 | 0 | | | 60,964 |
| MA | 2,154 | 4,598 | 0 | 5,000 | 0 | | | 8,969 |
| NY | 21,716 | 897 | 0 | 5,000 | 0 | | | 83,835 |
| NE | 0 | 835 | 19,439 | 5,000 | 0 | | | 79,780 |
| **Total** | **35,941** | **11,338** | **19,439** | **30,000** | **0** | **0** | **0** | **233,549** |
| *Utilization factor* | *0.73%* | *87.16%* | *99.9%* | *40.4%* | | | | |
| | | | | | | | | |
| *Shared* | NG CT | NG CCGT | Nuclear | Wind | Solar | New H | Storage | DR (MWh) |
| QC | 0 | 0 | 0 | 10,000 | 0 | | | 40,904 |
| ON | 0 | 0 | 0 | 5,000 | 0 | | | 40,072 |
| MA | 0 | 0 | 0 | 5,000 | 0 | | | 14,130 |
| NY | 9,147 | 10,086 | 0 | 5,000 | 0 | | | 50,396 |
| NE | 0 | 0 | 19,496 | 5,000 | 0 | | | 48,997 |
| **Total** | **9,147** | **10,086** | **19,496** | **30,000** | **0** | **0** | **0** | **194,498** |
| *Utilization factor* | *3.68%* | *96.82%* | *100.0%* | *40.4%* | | | | |

| | Cap+Nuclear Limited Transmission | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| *BAU* | NG CT | NG CCGT | Nuclear | Wind | Solar | New H | Storage | DR (MWh) |
| QC | 0 | 0 | 0 | 0 | 0 | | | 0 |
| ON | 6,910 | 2,867 | 7,082 | 5,000 | 592 | | | 58,066 |
| MA | 4,153 | 2,601 | 0 | 4,835 | 0 | | | 9,115 |
| NY | 7,032 | 8,801 | 6,744 | 5,000 | 0 | | | 86,715 |
| NE | 8,774 | 1,801 | 9,691 | 5,000 | 0 | | | 80,340 |
| **Total** | **26,870** | **16,070** | **23,517** | **19,835** | **592** | **0** | **0** | **234,237** |
| *Utilization factor* | *2.44%* | *57.69%* | *99.3%* | *41.5%* | *20.0%* | | | |
| | | | | | | | | |
| *Shared* | NG CT | NG CCGT | Nuclear | Wind | Solar | New H | Storage | DR (MWh) |
| QC | 0 | 0 | | 0 | 0 | | | 0 |
| ON | 3,359 | 3,358 | 6,291 | 5,000 | 1,611 | | | 68,793 |
| MA | 2,451 | 2,575 | | 4,821 | 0 | | | 9,128 |
| NY | 4,686 | 7,505 | 7,918 | 5,000 | 0 | | | 85,379 |
| NE | 5,024 | 2,447 | 8,993 | 5,000 | 0 | | | 63,770 |
| **Total** | **15,519** | **15,885** | **23,203** | **19,821** | **1,611** | **0** | **0** | **227,070** |
| *Utilization factor* | *4.34%* | *58.18%* | *99.7%* | *41.6%* | *20.0%* | | | |