NPCC
2017 Québec Balancing Authority Area
Comprehensive Review of
Resource Adequacy

Prepared by
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Approved by the RCC – December 5, 2017

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1. EXECUTIVE SUMMARY

The Québec Balancing Authority Area submits this assessment of resource adequacy to comply with the Reliability Assessment Program established by the Northeast Power Coordinating Council (NPCC). The guidelines for the review are specified in Appendix D of the NPCC Regional Reliability Reference Directory #1, "*Guidelines for Area Review of Resource Adequacy*".

This 2017 Comprehensive Review of Resource Adequacy covers the study period from winter 2017-2018 through winter 2021-2022. Changes in assumptions about facility and system conditions, generation resources availability, load forecast and electricity sector regulations, since the last Comprehensive Review and the impact of these changes on the overall reliability of the Québec electricity system are highlighted therein.

The internal demand forecasts have been revised downward since the last comprehensive review due mainly to a decrease in the expected load from the industrial and the residential sectors. About 2,115 MW of new generation capacity have been added to the system since the filing of the last Comprehensive Review. An additional 1,220 MW is expected to be commissioned over the assessment period.

Results in this comprehensive review show that the loss of load expectation (LOLE) for the Québec area is below the NPCC reliability criterion of not more than 0.1 day per year for all years of this assessment under the base case scenario. For the high case scenario of demand forecast, the area would need additional capacity for the winter peak period 2020-2021 and 2021-2022.

1.1 Major Findings

The 2017 Comprehensive Review results show that the Québec area will meet the NPCC resource adequacy criterion that requires a loss of load expectation (LOLE) value of less than 0.1 days/year for all years of this review. In fact, for the 2021-2022 winter peak period, planned resources (46,331 MW) are above forecasted demand (39,456 MW) by 6,875 MW. This is explained by new resources that are planned to be added to the system.

1.2 Major Assumptions and Results

Major assumptions are summarized in Table 1.1.

Table 1.1   Major Assumptions

ASSUMPTION	DESCRIPTION
Study Period	Winter periods 2017-2018 to 2021-2022.
Adequacy Criterion	NPCC Loss of Load Expectation (LOLE) requirement of not more than 0.1 days/year.
Reliability Model	GE's MARS program.
Load Growth (incl. exports)	Base Case : 0.4% per year High Case : 0.9% per year
Load Model	Hourly loads with forecast uncertainty
Generation Capacity Additions	1,220 MW by the end of 2021, including 700 MW of hydro power generation.
Generation Capacity Retirements	No retirements are scheduled over the period of this review
Internal and Interconnection Transmission Constraints	Transmission system representation and the interface limits are shown in Appendix A, sections A3 and A7.1 of this report.
Emergency Operating Procedures (EOP)	Assumed 2,168 MW of load relief from interruptible load programs (1,918 MW) and voltage reduction (250 MW).
Resource Availability	Forced Outages modeled: Based on Equivalent Demand Forced Outage Rate (EFORd) five - year historical data (2012-2016).
Energy savings	Impact of energy savings programs: Up to 650 MW by 2021-2022.

Table 1.2   **Summary of Results**

Winter Peak	Planned Resources (MW)	BASE CASE		HIGH CASE	
		LOAD (incl. exports) (MW)	LOLE (days / year)	LOAD (MW)	LOLE (days / year)
2017-2018	45,864	38,872	0.000	39,801	0.014
2018-2019	45,980	38,391	0.000	39,453	0.003
2019-2020	46,114	38,862	0.001	40,107	0.027
2020-2021	46,431	39,988	0.055	41,478	0.109
2021-2022	46,331	39,456	0.019	41,279	0.095

All resources are assumed to be in service as planned. Table 1.2 shows that the Québec area meets the LOLE criterion under the base case demand forecast for all years of this review. Under the high case scenario of demand forecast, the area would need additional capacity for the winter 2020-2021.

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3. INTRODUCTION

The Northeast Power Coordinating Council (NPCC) conducts resource adequacy reviews of its member areas to ascertain whether or not each area will have adequate resources to meet the NPCC Resource Reliability Criterion.

Hydro-Québec Distribution (HQD) is the entity responsible for resource planning in the Québec Balancing Authority Area. HQD is also responsible for all activities regarding load forecasting and resource procurement required to supply the internal load. As such, HQD is the reporting entity for this assessment.

The purpose of this report is to present the results of the Québec Balancing Authority Area's comprehensive review of resource adequacy to the NPCC. Results of this resource adequacy review, conducted by HQD and submitted to the NPCC, are documented in accordance with the reporting guidelines specified in Appendix D of the NPCC Regional Reliability Reference Directory #1, "*Guidelines for Area Review of Resource Adequacy*".

This report also includes some information regarding Hydro-Québec Production (HQP) and TransÉnergie (HQT) activities that are required in order to conduct reliability evaluations in this Review.

The information presented in this Comprehensive Review covers the period from November 2017 through October 2022 and is based on the Québec internal demand forecast used in the first Progress Report of the 2017-2026 Supply Plan, which was filed at the Québec Energy Board on November 1, 2017[1].

3.1 Reference to Most Recent NPCC Comprehensive Review

Comparison between this review and the previous Comprehensive Review, submitted in October 2014 and approved by the NPCC Reliability Coordinating Committee (RCC) on December 2, 2014, are included in this report.

3.2 Comparison of this Review and Previous Review

3.2.1. Demand Forecast

The demand forecast presented in this review focuses on winter annual peaks. Two demand scenarios are presented: a base case demand and a high case demand forecasts. Winter peak demand forecasts for this 2017 Comprehensive Review are

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[1] http://www.regie-energie.qc.ca/audiences/TermElecDistrPlansAppro_Suivis.html

presented in Table 3.2.1 and Figure 3.2.1, along with the 2014 Comprehensive Review forecasts.

Demand forecast methodology is basically the same as in the previous Comprehensive Review. The Québec peak load forecast is based on normal weather conditions. For this purpose, a 46-year reference period is used to assess average temperatures (1971-2016). The same reference period is used to assess demand uncertainties resulting from weather. More details on forecast methodology are provided in Appendix A.

Load forecasts take into account the impact of energy savings on energy and capacity requirements. The incremental impact of programs to be deployed and those remaining active during the five years covered by this review is estimated to be 650 MW by 2021-2022.

Forecasts also take into account the load shaving resulting from the residential dual energy program, a rate option for residential customers equipped with a dual energy space heating system (electric/fuel oil). When the outside temperature falls below a given level, the space heating system automatically runs on the fuel oil. The impact of this program on peak load demand is about 600 MW.

The average annual growth rate over the entire period of this review is approximately 0.4 percent in the base case scenario. Under the high demand forecast scenario, peak load demand is expected to increase, on average, by 0.9 percent.

Table 3.2.1   Comparison of Demand Forecasts (MW)

Winter Peak	Base case Scenario			High case Scenario		
	2017 Comprehensive Review	2014 Comprehensive Review	Difference	2017 Comprehensive Review	2014 Comprehensive Review	Difference
2017-2018	38,872	39,789	-917	39,801	41,170	-1,370
2018-2019	38,391	39,489	-1098	39,453	41,118	-1,665
2019-2020	38,862			40,107		
2020-2021	39,988			41,478		
2021-2022	39,456			41,279		
5-year Average Growth Rate	0.4%	0.5%		0.9%	1.0%	

Figure 3.2.1   **Comparison of Demand Forecasts**
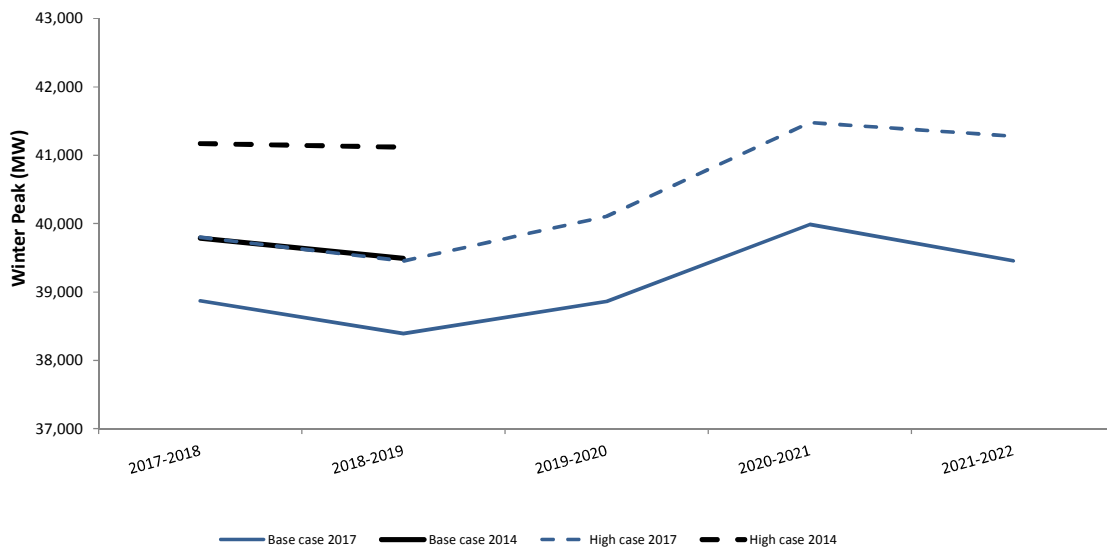
As shown in Table 3.2.1, the demand forecasts for the two next winters of this review in the base case scenario are -917 and -1,098 MW compared to the demand forecasts presented in the 2014 Comprehensive review for the same periods. This shift can be explained by mainly two factors. About two third of the reduction come from the residential sector, where there's been a significant reduction of space heating. An internal survey has shown that after two very cold winters, many customers have reduce the temperature settings of their thermostat (in the Quebec Area, most customers have an electric heating system) while new apartments have been less energy intensive than previously anticipated. Also, decreasing manufacturing activity, especially in the industrial sector is the other key factors driving downward electricity load in the Quebec area.

3.2.2. Planned Resources

Most of resources in the Québec area are hydro power generation owned and operated by Hydro-Québec Production (HQP). HQP also operates one gas turbine generation station (for peaking purposes).

Remaining resources are owned and operated by Independent Power Producers (IPPs) and are under long term power purchase agreements with Hydro-Québec Distribution as well as with Hydro-Québec Production. The purchased energy and capacity originates from wind, small hydro and biomass generation.

New Resource Additions

Since the last comprehensive review, two hydro generating units (La Romaine-2 and La Romaine-1) have been commissioned in 2014 and 2015, adding a total of 910 MW to the system. Work is under way on the La Romaine-3 (395 MW) development which will be fully operational by the end of 2017. The last hydro generating station from the Romaine Complex (La Romaine-4) is expected to be commissioned for the 2020-2021 winter peak period, adding 245 MW of capacity. Also, the integration of small hydro units accounts for about 40 MW of new capacity since the 2014 Comprehensive review and will add 60 MW during the assessment period.

For other renewable resources, about 1,100 MW (330 MW on-peak value) of wind capacity and 65 MW of biomass have been added to the system since the filing of the last Comprehensive review. Additionally, 414 MW (124 MW on-peak value) of wind capacity and 105 MW of biomass are expected to be in service by the end of 2019.

Table 3.2.2-1 below summarizes the installed wind capacity and net capacity values at peak for all years of the present review. By 2019-2020, installed capacity is expected to reach 3,923 MW.

Table 3.2.2-1   Installed Wind Capacity and Values at Peak (MW)

Winter Peak	Wind Installed Capacity			Capacity Value at peak
	HQP [1]	HQD [2]	Total	
2017-2018	212	3,668	3,880	1,133
2018-2019	212	3,692	3,904	1,140
2019-2020	212	3,711	3,923	1,146
2020-2021	212	3,711	3,923	1,146
2021-2022	212	3,711	3,923	1,146

[1]: 108 MW with 30% capacity value at peak and 104 MW are derated.
[2]: 30% capacity value at peak of nameplate capacity.

Mothballed, Unavailable and Retired Resources

In this review, TransCanada Energy's combined cycle G.S in Bécancour (547 MW) is mothballed for all years of this review. Also, about 120 MW of hydro generation capacity is planned to be unavailable during winter 2021-2022. There is no unit retirement scheduled during this review.

Summary of Available Resources

Table 3.2.2-2 and Fig 3.2.2 show the available resources in the Québec area. It also includes a comparison with the planned resources from the previous Comprehensive Review.

Table 3.2.2-2   **Comparison of Available Resources 2014 vs 2017 Review (MW)**

Winter Peak	2017 Comprehensive Review	2014 Comprehensive Review	Difference
2017-2018	45,864	45,169	694
2018-2019	45,980	45,268	712
2019-2020	46,114	-	-
2020-2021	46,431	-	-
2021-2022	46,331	-	-

The difference between the two reviews is 694 MW for the 2017-2018 and 712 MW for the 2018-2019 winter peak periods respectively. The main factors explaining these differences are:

- Higher firm capacity import due to a new electricity trade agreement between Québec and Ontario (500 MW for winter 2017-2018 and 2018-2019);
- Higher on-peak capacity contributions from new demand response programs (95 MW in 2017-2018 and 215 MW in 2018-2019);
- Higher on-peak capacity contributions from some hydro units are expected due to higher level of water in reservoirs (142 MW in 2017-2018).

Figure 3.2.2   Comparison between 2017 and 2014 Available Resources
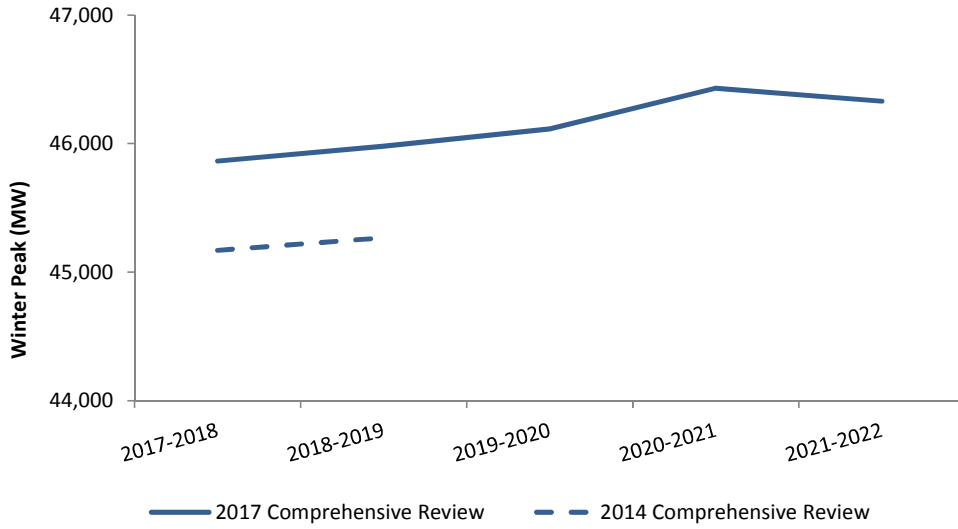
4. RESOURCE ADEQUACY CRITERION

4.1 Statement of Resource Adequacy Criterion

In the Québec Balancing Authority Area, the NPCC resource adequacy criterion from Directory #1– Design and Operation of the Bulk Power System is used to assess resource adequacy. This criterion reads as follows:

« The probability (or risk) of disconnecting firm load due to resource deficiencies shall be, on average, not more than one day in ten years as determined by studies conducted for each Resource Planning and Planning Coordinator Area. Compliance with this criterion shall be evaluated probabilistically, such that the loss of load expectation (LOLE) of disconnecting firm load due to resource deficiencies shall be, on average, no more than 0.1 day per year. This evaluation shall make due allowance for demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Planning Coordinator Areas, transmission transfer capabilities, and capacity and/or load relief from available operating procedures. ».

4.2 Statement of How the Criterion is Applied

The reliability criterion is used to assess the adequacy of available resources to reliably supply the Québec area's electricity needs. Also, it is used to establish the Québec Area Reference Reserve Margin.

Consideration can be given to Québec's interconnections with New Brunswick, Ontario, New York and New England and the resultant potential for capacity purchases which can be assumed. More details on this issue are provided in section 5.1.

Generating unit scheduled and forced outages have been assessed by considering actual historical outage data for the 2012-2016 period.

Before any load disconnection will occur, a series of emergency operating procedures (EOPs) will be invoked. In order to properly represent the system operation, EOPs are modeled considering their dispatching order and the amount of load relief or capacity increase. Table 4.2 summarizes the assumptions regarding the load relief from EOPs used for this study.

Table 4.2   **Emergency Operating Procedures**

STEP	PROCEDURE	EFFECT	IMPACT VALUE IN MW
1	Interruptible Load Program	Load Relief	1,918
2	Emergency Purchases	Increase Capacity	Varies [1]
3	30-Minute Reserve Reduction	Allow Operating Reserve to decrease	500
4	Voltage Reduction	Load Relief	250
5	10 Minute Reserve to the minimum of 250 MW of spinning reserve	Allow Operating Reserve to decrease	750
6	Customer Disconnection	Load Relief	As needed

[1] : Winter purchases of 1,600 MW were used for the simulations. See section 5.1 for more details.

4.3   Resource Requirements to Meet Criterion

For the purposes of this study, the adequacy of the area's existing and planned resources is assessed through the calculation of the annual LOLE and compared with the 0.1 days/year criterion established by the NPCC in its Directory #1. The resulting Reserve Margin is therefore set as the Québec Area Reference Reserve Margin. Simulation results show that the Reference Reserve Margin is 12.6 percent for the winter 2017-2018 and will reach 13.4 percent for the winter 2021-2022.

4.4   Comparison of Québec and NPCC Criteria

The Québec Balancing Authority Area reliability criterion for this review is the same as the NPCC criterion, as defined in Section 4.1.

4.5   Resource Adequacy Studies Done Since the 2014 Review

Every year, Hydro-Québec Distribution produces a report on resource adequacy for the Québec Balancing area.

Moreover, every 3 years, Hydro-Québec Distribution submits to the Québec Energy Board, a Supply Plan which outlines, among other things, a resource adequacy evaluation limited to Hydro-Québec Distribution (which is responsible for the internal load supply in the Quebec area) demand and supply positions on a 10-year horizon.

Furthermore, for each of the two years following the Supply Plan, HQD files a Progress Report, which includes updated information on demand forecasts, resource availability and a reliability assessment update.

5. RESOURCE ADEQUACY ASSESSMENT

5.1 Reliability Assessment Based on the Base Case Scenario

Table 5.1.1 shows the LOLE evaluations for the base case demand forecast. According to these results, the Québec area will have adequate resources to meet the NPCC criterion for the entire period of this review. This was achieved with the inclusion of 1,600 MW of winter capacity purchases.

Each year, the Load Serving Entity (HQD), which is responsible for resource adequacy in Québec, will purchase the required amount of capacity on the markets to meet its requirements. In order to secure the appropriate access to capacity located in neighboring areas, HQD has designated the Massena-Châteauguay (1,000 MW) and the Dennison-Langlois (100 MW) interconnections to meet its resource requirements during winter peak period. The Quebec area limits its planned capacity purchases to capacity accessible from summer peaking neighbouring areas having an organized market structure. Also, as part of the electricity trade agreement between Ontario and Quebec, Ontario will supply 500 MW of capacity to Quebec each winter (from December to March) over the assessment period (the current agreement ends in 2023).

Table 5.1.1 also shows both planned and reference reserve margins for each winter until 2021-2022. Reserve margins are expressed in MW or as a percentage of the annual peak load. The planned reserve margin is the difference between planned resources and the forecast annual peak load. The reference reserve margin is the excess capacity (over the forecast annual peak load) needed to meet the NPCC resource adequacy criterion. The reference reserve margins are estimated by removing firm capacity (such as import capacity) from the system until the 0.1 days/year LOLE criteria is obtained.

Table 5.1.1 Planned Resources to meet criteria under Base Case Demand Forecast

Winter Peak	Planned Resources (MW)	Annual peak load (MW)	Planned Reserve MW	Planned Reserve (%)	LOLE (Days / year)	Reference Reserve MW	Reference Reserve (%)	LOLE (Days / year)
2017-2018	45,864	38,872	6,992	18.0%	0.000	4,902	12.6%	0.100
2018-2019	45,980	38,391	7,589	19.8%	0.000	4,944	12.9%	0.100
2019-2020	46,114	38,862	7,252	18.7%	0.001	5,037	13.0%	0.100
2020-2021	46,431	39,988	6,444	16.1%	0.055	5,284	13.2%	0.100
2021-2022	46,331	39,456	6,875	17.4%	0.019	5,275	13.4%	0.100

5.2 High Case Demand Forecast

For the winter peak period 2017-2018, the high case scenario is approximately 930 MW higher than the base case load forecast and the difference reaches about 1,800 MW for the winter period 2021-2022. On average, over the forecast period, the Québec load is expected to increase by about 0.9 percent annually under the high case demand forecast.

The gap between the base case and high case is mostly due to higher population growth and stronger economic activity. This is an extreme level that has an estimated ten percent probability of being exceeded.

5.2.1. LOLE Values, High Case Demand Forecast

Table 5.2.1 shows that under the high case demand forecast, the Québec area will have less than 0.1 days/year of loss of load expectation for all the winter peak periods except for winter 2020-21.The additional resources needed are estimated to be 70 MW. This could be achieved by some additional purchases from neighboring areas.

Table 5.2.1 shows the planned resources, demand forecasts and LOLE under the high case demand forecast.

Table 5.2.1   Planned Resources and LOLE under High Case Demand Forecast

Winter Peak	Planned Resources (MW)	Annual peak load (MW)	Planned Reserve		LOLE (Days/ year)
			MW	(%)	
2017-2018	45,864	39,801	6,063	15.2%	0.014
2018-2019	45,980	39,453	6,526	16.5%	0.003
2019-2020	46,114	40,107	6,006	15.0%	0.027
2020-2021	46,431	41,478	4,954	11.9%	0.109
2021-2022	46,331	41,279	5,052	12.2%	0.095

5.3 Contingency Mechanisms for Managing Demand and Resource Uncertainties

Supply planning involves some uncertainty related to demand as well as resources. Resources could be limited or insufficient in relation to the required quantities.

If, in any case, the expected required reserve would fall below critical level, it would be possible to make some additional purchases from neighboring areas.

5.4 Impacts of Major Proposed Changes to Market Rules on Area Reliability

In the Quebec area, there are no structured short term (daily, hourly or real time) electricity markets. Most of new supplies are contracted by HQD through long term PPAs. Neither the quantity of available capacity nor the energy dispatched is based on market ability to react to price signals. There are no expected changes to the actual electricity market structure within the period covered by this review.

6. PROPOSED RESOURCE MIX

6.1 Reliability Impacts of Capacity Mix, Demand Resource Response and Transportation or Environmental Considerations

Table 6.1 and Figure 6.1 show the expected available generation capacity mix at winter peak period for each year of this review. The information regarding existing and future resources as of September 2017 have been used for this evaluation.

Table 6.1   **Québec Available Capacity Mix by Fuel Type (MW)**

Fuel Type	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022
Hydro	40,184	40,042	40,081	40,329	40,208
Thermal	436	436	436	436	436
Biomass	342	324	354	403	403
Wind [1]	3,880	3,904	3,923	3,923	3,923
Total	44,843	44,706	44,793	45,090	44,970

[1]: For wind, the numbers correspond to installed capacity. A 30 percent of nameplate capacity is expected at winter peak.

Figure 6.1   **Québec Available Capacity Mix by Fuel Type (%)**
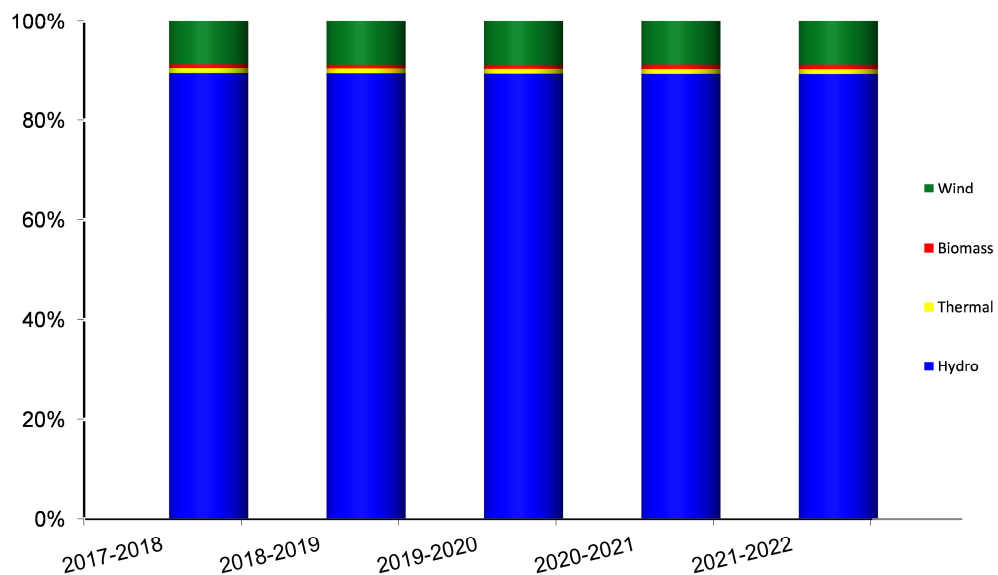
Although wind installed capacity is about 3,900 MW, the area total capacity is still mainly composed of large reservoirs hydro complexes that can react quickly to adjust their generation output and meet the sharp changes in electricity net demand. The forecasted changes to resource mix are not expected to have any impact on reliability.

6.2 Available Mechanisms to Mitigate Reliability Impacts of Capacity Mix, Demand Resource Response, Transportation and/or Environmental Considerations

Québec area's energy requirements are met for the greatest part by hydro generating stations, located on different river systems and scattered over a large territory. The major plants are backed by multiannual reservoirs (water reserves lasting more than one year).

Due to those multi-year reservoirs, a single year of low water inflow cannot adversely impact the reliability of energy supply. However, a series of few consecutive dry years may require some operating measures as the reduction of exports or capacity purchase from neighbouring areas.

To assess its energy reliability, Hydro-Québec has developed an energy criterion stating that sufficient resources should be available to go through a sequence of 2 consecutive years of low water inflows totalling 64 TWh or a sequence of 4 years totalling 98 TWh, and having a 2 percent probability of occurrence. The use of operating measures and the hydro reservoirs should be managed accordingly. Reliability assessments based on this criterion are presented three times a year to the Québec Energy Board. Such documents can be found on the «Régie de l'Énergie du Québec» website[2].

Fuel supply and transportation is not an issue in the Québec area. With the exception of Trans-Canada Energy plant (547 MW) which is presently mothballed, fossil fuel generation (Bécancour, 436 MW) is used for peaking purpose only and adequate fuel supplies are stored nearby. The storage capacity is enough to generate about 60 hours of electricity at maximum power.

No other conditions that would create supply reductions are expected for the period covered by this assessment.

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[2] http://www.regie-energie.qc.ca/audiences/Suivis/Suivi_HQD_D-2011-162_CriteresFiabilite.html

6.3   Reliability Impacts Related to Compliance with Provincial Requirements

As a member of the Western Climate Initiative, the province of Québec has implemented a cap-and-trade system for greenhouse gas (GHG) emission allowances, with the first compliance beginning January 1st, 2013. The carbon market is aimed at companies that emit at least 25,000 metric tons of CO_2 equivalent each year. Regulated companies are required to acquire emission units for each ton they release into the atmosphere. The government sets annual maximum GHG emission unit caps that are progressively lowered over time. As the Québec's electricity generation system is predominantly hydro (about 90 percent) and wind power generation (about 8 percent), there's no impact on reliability.

APPENDIX: DESCRIPTION OF RESOURCE RELIABILITY MODEL

APPENDIX

The GE MARS model is used for the purpose of this review. This model uses a sequential Monte Carlo simulation to assess the reliability of a system comprised of a number of interconnected areas containing generation and load. This Monte Carlo process simulates each targeted year repeatedly (multiple replications) to evaluate the impacts of a wide range of possible random combinations of load and generator outages. The transmission system is modeled in terms of transfer limits (constraints) on the interfaces between interconnected areas.

Chronological system operating margins are developed by combining randomly generated operating states of the generating units and inter-area transfer limits with the hourly chronological loads. The model can compute various reliability measurements, including Loss of Load Expectation (LOLE) which is selected as the principal reliability metric.

For each hour of the year, the program computes the isolated area margins based on the available capacity and demand in each area. GE MARS then uses a transportation algorithm to determine the extent to which areas with negative margin can be assisted by areas having positive (excess) margin, subject to the available transfer constraints between the areas. The program collects the statistics for computing the reliability indices, and proceeds to the next hour. After simulating all of the hours in the year, the program computes the annual indices and tests for convergence. If the simulation has not converged to an acceptable level, it proceeds to another replication of the year under study.

1.   LOAD MODEL

1.1   Description and Basis of Period Load Shapes

GE MARS model employs an 8760 hours chronological subarea load model. The load model currently used relies on an actual year of historical loads of 2010-2011 because it is the most representative of normal weather condition. This model is then scaled up to the winter peak for the future years being analyzed.

The Québec peak load forecast is based on normal weather conditions. First, the energy-sales forecast is built on the forecast from four different consumption sectors–domestic, commercial, small and medium-size industrial and large industrial. The model types used in the forecasting process are different for each sector and are based on end-use and/or econometric models. They consider weather variables, economic-driver forecasts, demographics, energy efficiency, and different information about large industrial customers. This forecast is normalized for weather conditions based on an historical trend weather analysis.

The requirements are obtained by adding transmission and distribution losses to the sales forecasts. The monthly peak demand is then calculated by applying load factors to

each end-use and/or sector sale. The sum of these monthly end-use/sector peak demands is the total monthly peak demand.

1.2   Load Forecast Uncertainty

Load Forecast Uncertainty (LFU) includes weather and load uncertainties. Weather uncertainty is due to variations in weather conditions. It is based on a 46-year temperature database (1971-2016), adjusted by 0.30°C (0.54°F) per decade starting in 1971 to account for climate change. Moreover, each year of historical climatic data is shifted up to ±3 days to gain information on conditions that occurred during either a weekend or a weekday. Such an exercise generates a set of 322 different demand scenarios. The base case scenario is the arithmetical average of the peak hour in each of these 322 scenarios. Load uncertainty is due to the uncertainty in economic and demographic variables affecting demand forecast and to residual errors from the models.

Overall uncertainty is defined as the independent combination of weather uncertainty and load uncertainty. The overall uncertainty is expressed as a percentage of standard deviation over total load.

In the MARS model, load forecast uncertainty is modeled through the load forecast multipliers. These multipliers are directly derived from the distribution of the load. For each multiplier, a probability of the load level occurring is associated. There is a set of seven probability points that allows to adequately represent the distribution of the load. The probability distribution of the load is assumed to follow a skewed distribution. The analysis of the distribution of the load has shown that the probability that the forecast exceeds two standards deviation is very low. Therefore, for load uncertainty modeling purposes, a skewed normal distribution limited to two standards deviations is assumed. The standard deviation range from 1,720 MW for winter peak 2017-2018 to 1,970 MW for winter peak 2021-2022.

1.3   Demand and Energy Projects of Interconnected Entities

The loads and resources of interconnected entities within the area that are not members of the area were not considered.

1.4   Demand-Side Management

The demand forecast presented in section 3.2.1 takes into account the impact of energy savings on sales and capacity requirements. These energy savings consist of the energy efficiency measures to be deployed and those remaining active during the five years covered by this review.

Forecasts also take into account the load shaving resulting from residential dual energy. This program is handled in the same way as energy savings: it is not included as a resource but its impact on peak demand (about 600 MW) is included in demand forecasts.

Other interruptible load programs specifically designed for peak shaving and fully dispatched by the system operator are included as resources (see section 5 of the Appendix).

Table A-1.4   **Incremental Impact of Energy Savings on Forecasted Winter Peak Demand (in MW)**

Winter Peak	Energy savings (MW)
2017-2018	130
2018-2019	260
2019-2020	390
2020-2021	520
2021-2022	650

2. SUPPLY-SIDE RESOURCE REPRESENTATION

The MARS model has the capability to model different types of resources used in the Quebec area: hydroelectric, thermal, wind and demand management resources.

For each generation unit modeled, the installation and retirement dates and planned maintenance requirements must be specified. Other data such as maximum rating, forced outage rates, and net modification of the hourly loads depend on the unit type. The planned outages for all types of units in the MARS model can be specified by the user or automatically scheduled by the program on a weekly basis.

2.1.1. Definitions

For Hydro units with installed capacity larger than 30 MW, Dependable Capacity is calculated as the net output a unit can sustain over a specified period modified for month limitations. The period that a unit can sustain is defined as two consecutive hours per month. This definition may seem optimistic but proper use of the reservoirs usually make this capacity available daily. The Dependable Capacity varies from month to month according to projected reservoirs levels. Beauharnois (1,741 MW), Les Cèdres (104 MW) and Carillon (602 MW) generating stations are not modeled according to this definition. The specific treatment for these power stations will be discussed in section A.4.

For Hydro units with installed capacity less than 30 MW, Dependable Capacity is defined as the average power based on operational historical generation.

For thermal units, Maximum Capacity is defined as the net output a unit can sustain over a two consecutive hour period. Maximum Capacity varies from one month to another subject to ambient temperature changes.

2.1.2. Procedure for Verifying Ratings

Ratings of generating unit are revised periodically. Hydro unit ratings are based on operational historical values and are reviewed at least annually. At the time of this ratings revision, if needed, the new data on turbine efficiency measurements, the updated operating water head and the temperature of generator cooling water are taken into account. Unit testing are performed as needed.

Thermal Unit Ratings are reevaluated at each unit performance test.

2.2 Unavailability Factors Represented

2.2.1. Type of Unavailability Factors Represented

Planned maintenance was modeled on a unit basis. Typical monthly percentage maintenance for Hydro units is used. The percentage is applied on the total hydro capacity available (except Beauharnois and Les Cèdres units). Thermal power plants are on maintenance during summer and each plant has its own maintenance schedule.

2.2.2. Source of Unavailability Factors Represented

Equivalent Demand Forced Outage Rate (EFORd) for existing generators are based on actual outage data reflecting historical evolution over the period 2012-2016.

New generators EFORd are based on similar generators with historical data as well as on the data provided by the manufacturer and with the conjunction with averages compiled by the Canadian Electricity Association (CEA) and NERC GADS.

2.2.3. Maturity Considerations and In-Service Date Uncertainty

The reliability model accounts for maturing units. Forced outage rates of new units are higher for the first operational years.

No uncertainty is modeled over the commissioning date of the planned generating units.

Regarding the new hydro units over 30 MW to be commissioned during the period under review, all government permits have been received and the construction is in progress at most of them. No construction delays are expected so there is no uncertainty related to the in-service date. Available capacities of each station are modeled with latest available data. Maintenance, restrictions and outages are taken into account.

Regarding small renewable projects, most of them didn't receive all required government permits. However, the likelihood that these projects receive all required permits is high. Data on these projects are continuously updated to reflect the day to day evolution.

2.2.4. Tabulation of Typical Unavailability Factors

The weighted average EFORds used in this evaluation are presented in Table A-2.2.4. These forced outages rates values are computed over the period 2012-2016.

Table A-2.2.4   Québec Area Forced Outages Rates

Unit Type	Weighted Average EFORd (%)	
	2017 Comprehensive Review	2014 Comprehensive Review
Hydro	1.9	1.8
Thermal	4.7	4.5
Biomass	7.5	N/A

2.3   Purchase and Sale Representation

The capacity purchase from Newfoundland and Labrador is represented according to the contract between Hydro-Québec and CFLCo. The expected planned on-peak value is 4,765 MW for all years of this review. Other short term purchases (UCAP) are expected to come from neighboring areas.

The area's sales are long term contract sales with Cornwal (Ontario) and New England including new commitments on the Forward Capacity Market.

2.4   Retirements

No unit generation is expected to be retired over the period of this review.

3. REPRESENTATION OF INTERCONNECTED SYSTEMS

The Québec Area is a separate Interconnection from the Eastern Interconnection, into which the other NPCC Areas are interconnected. TransÉnergie, the main Transmission Owner and Operator in Québec, has interconnections with Ontario, New York, New England and the Maritimes.

There are back to back DC links with New Brunswick at Madawaska and Eel River (in New Brunswick), with New England at Highgate (in New England) and with New York at Châteauguay. The Radisson – Nicolet – Sandy Pond HVDC line ties Québec with New England. Radial load can be picked up in the Maritimes by Québec at Madawaska and at Eel River and at Stanstead feeding Citizen's Utilities in New England. Moreover, in addition to the Châteauguay HVDC back to back interconnection to New York, radial generation can be connected to the New York system through Line 7040. The Variable Frequency Transformer (VFT) at Langlois substation connects into the Cedar Rapids Transmission system, down to New York State at Dennison. The Outaouais HVDC back to back converters and accompanying transmission to the Ottawa, Ontario area are now in service. Other ties between Québec and Ontario consist of radial generation and load to be switched on either system.

Interconnection capacities are established by inter-Area and intra-Area studies as deemed necessary. Table A-3 below shows interconnection limits.

Table A-3   Québec Area Interconnections Limits

Interconnection	Flows Out of Québec (MW)	Flows Into Québec (MW)
New Brunswick	1,029	785
Ontario	2,545	1,945
New England	2,275	170 *
New York	2,125	1,100

*: Transfer capability at Québec area winter peak time.

For the purpose of this review, the import capability of HVDC Sandy Pond – Nicolet interconnection has been excluded due to its none availability during peak period. Moreover, these limits do not correspond to TTC or ATC values posted on the OASIS; they are only intended to offer a global picture of transfer capabilities to the readers of this assessment.

4. MODELING OF VARIABLE AND LIMITED ENERGY RESOURCES

For most hydro units, energy limitations are considered by using a different value of dependable capacity for each month accounting the reservoir variation effect on the net head and the generator cooling water temperature. Unlike reservoir hydro units, the run-of-river Beauharnois and Les Cèdres units are operated in parallel on the St. Lawrence river. Their capability depends on water availability and varies according to seasons. Also, during ice cover formation, capacity output must be reduced. Additionally, generation is affected by navigation constraints on the St. Lawrence river. Available water can be channeled through either Les Cèdres or Beauharnois. As the latter station is more efficient, priority is then given to generation at Beauharnois, leaving less water available for Les Cèdres.

Beauharnois and Les Cèdres are modeled in a separate tool designed for this specific purpose. It takes into account a probability distribution based on operational historical generation. This model accounts not only for water restrictions but also for maintenance and forced outages. The results are then transposed in the MARS model which is used for unforced outages simulations.

All wind generation units were considered available to meet daily and monthly peak loads except when they are on planned maintenance or forced outages. The estimated contribution value of wind units at peak time is 30 percent of nameplate capacity. Some amount of wind generation (104 MW) is completely derated.

5. MODELING OF DEMAND SIDE RESOURCES AND DEMAND RESPONSE PROGRAMS

For the resource adequacy assessment, MARS runs were modeled with the most updated demand response capacity. Forecasted demand takes into account the impact of energy savings and dual energy programs, as described in section 1.4 of the Appendix.

Demand response programs fully dispatched by the system operator are included as resources. The Québec area has various types of demand response resources specifically designed for peak shaving during winter operating periods. The first type of demand response resource is the interruptible load program, mainly designed for large industrial customers, with an impact of 1,748 MW during the peak. The second type of demand response resource consists of a voltage reduction scheme with 250 MW of demand reduction at peak. The area is also developing some additional programs, including direct control load management. A recent program, consisting of mostly interruptible charges in commercial buildings, has an anticipated impact of 270 MW in 2017-2018 and up to 540 MW by 2020-2021.

All these demand response programs are modeled as emergency operation procedures.

6. MODELING OF ALL RESOURCES

Modeling of resources was as described in the above sections.

7. OTHER ASSUMPTIONS

7.1 Internal Transmission Limitations

The Hydro-Québec Transmission System has five major interfaces where operating limits are defined. For the purpose of this Resource Adequacy Review, the system has been modeled (through the MARS software) into six sub-areas. The areas are each connected by a single line which represents an actual interface. Figure A-7.2 below shows this model and Table A-7 shows the internal transmission limits used in the model. Actual transmission limits vary continuously as system conditions change over time.

Table A-7 **Internal Transmission Limits**

Sub area		2014 Comprehensive Review	2017 Comprehensive Review	
From	To		2017-18 winter peak period	2021-22 winter peak period
Churchill Falls	Manicouagan	5,200	5,200	5,200
Manicouagan	Québec Centre	13,200	12,500	12,500
Québec Centre	Montréal	23,200	21,300	23,500
Baie James	Québec Centre	15,000	15,000	15,000
Baie James	Nicolet (CC)	2,250	2,250	2,250
Nicolet (CC)	Montréal	2,138	2,138	2,138

Figure A-7.2   Québec's Internal Interfaces and Interconnections (2017-2018)
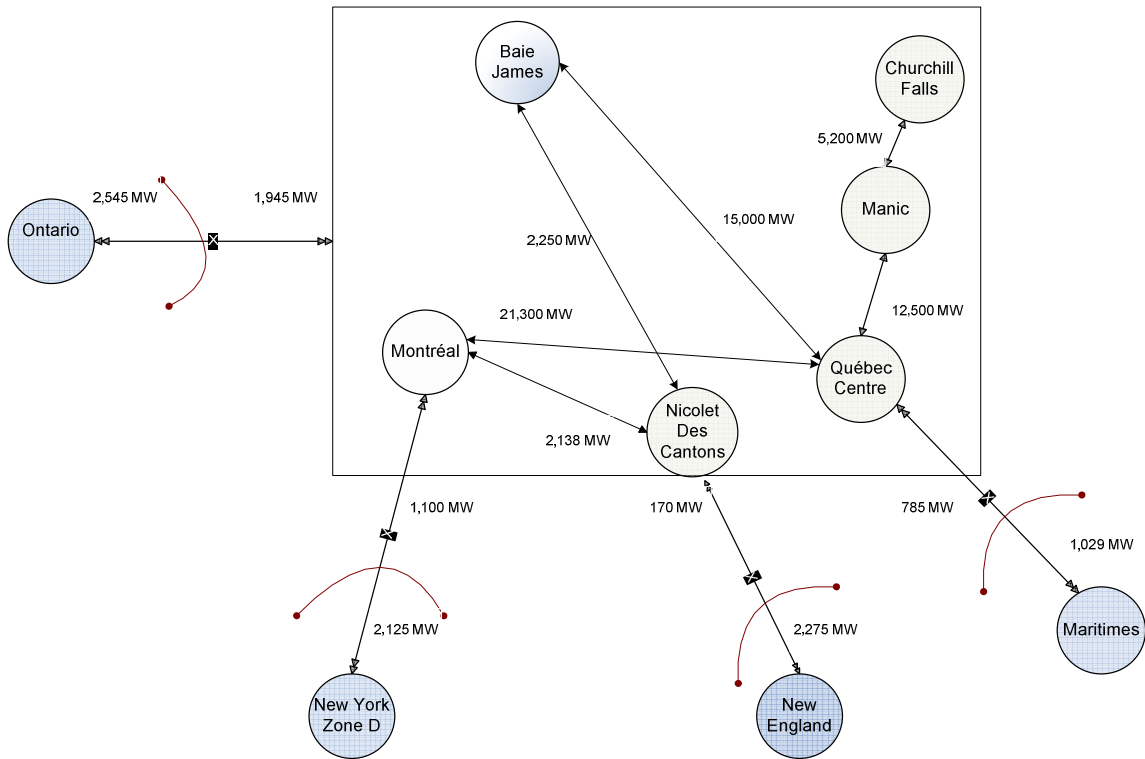
8. RELIABILITY IMPACTS OF MARKET RULES

No reliability impacts due to market rules are anticipated in this review (see section 5.4).