Complément de preuve du Coordonnateur de la fiabilité du Québec Dossier R-4001-2017 – Phase 2

(version anglaise de courtoisie caviardée)

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Additional evidence from the Reliability Coordinator for Québec Application R-4001-2017 – Phase 2

(English courtesy version - redacted)

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1 Executive summary

1.1 Purpose

The Régie de l'énergie (the "Régie") adopted in Decision D-2017-061 new versions of the standards on system operation (the "TOP-IRO Standards"). In Phase 2 of these proceedings, the Reliability Coordinator (the "Coordinator") is requesting the adoption of four TOP-IRO Standards (the "Relevant TOP-IRO Standards") that contain two amendments to the standards adopted in Phase 1. First, it is asking for the removal of the special provisions limiting the scope of certain standards to facilities belonging to the main transmission system (the "RTP"). Second, it is requesting the removal of the special provisions regarding industrial generators (PVIs). These two provisions enable Rio Tinto Alcan (RTA) to circumvent the obligation to submit in real time certain data on generating and transmission facilities (the "Relevant Data").

In requesting the adoption of reliability standards, the Coordinator wishes to ensure fair and reliable operation of the Québec Interconnection.

1.2 Application of the Relevant TOP-IRO Standards to non-RTP facilities

Subsequent to the lessons learned from the 2011 Southwest Blackout, NERC has developed new requirements in the Relevant TOP-IRO Standards in order to include, in enforcing those standards, additional facilities not belonging to the Bulk Electric System (BES) for which certain data is required in order to ensure reliability. The owners of such facilities must now submit specific information to their Transmission Operators (TOPs), Balancing Authorities (BAs) or Reliability Coordinators (RCs). The designation of facilities not belonging to the BES only has effects when enforcing certain requirements of the Relevant TOP-IRO Standards.

In the context of the Québec Interconnection, those facilities newly subject to certain TOP-IRO Standards are referred to as "non-RTP facilities" for the purposes of these proceedings.

In Québec, data about certain non-RTP facilities is necessary to ensure RTP reliability, especially to ensure that tools for real-time system control function adequately. Submitting data from such facilities to the Reliability Coordinator for Québec generally has a modest impact on most owners of non-RTP facilities. In fact, most designated non-RTP facilities belong to Hydro-Québec TransÉnergie (HQT) or Hydro-Québec Production (HQP) and their data is already integrated into the Coordinator's systems. For facilities not belonging to Hydro-Québec, adopting the Relevant TOP-IRO Standards would make it mandatory to submit certain data considered essential for reliability. Regarding application of the Relevant

TOP-IRO Standards to facilities not belonging to the RTP, no entity indicated to the Coordinator during public consultation that implementing those standards had an impact.

1.3 Removal of specific provisions on RTA submitting the Relevant Data

In 2010, the Coordinator had proposed a regulatory relief of certain TOP-IRO Standards with respect to requirements that industrial generators (PVIs) submit the Relevant Data. In 2015, Decision D-2015-059 extended the scope of the regulatory relief granted to RTA.

The North American regulatory context, Québec Interconnection power transmission system and profile of RTA have all evolved substantially since 2010.

In 2012, a new definition of the scope of the reliability standards, the BES, came into effect in North America (except Québec), modifying application of the reliability standards in North America. That definition clarified certain principles regarding the scope of the standards, especially for generators supplying their own loads. Moreover, the requirements, registration, and facilities subject to certain standard and designated under them have been modified in order that the standards support reliability more effectively by clarifying roles and responsibilities.

In light of these changes, the Coordinator submits that the purpose of a facility should no longer be considered in registering it. The impact of a facility on the power system should be the decisive criterion in its registration.

The Québec power transmission system is under increased pressure and its operation must be more tightly and precisely controlled. Over the past few years, the RTA system [redacted]. Furthermore, RTA is now a net exporter in the Québec Interconnection. The figure below illustrates changes in the regulatory context and the profile of RTA.

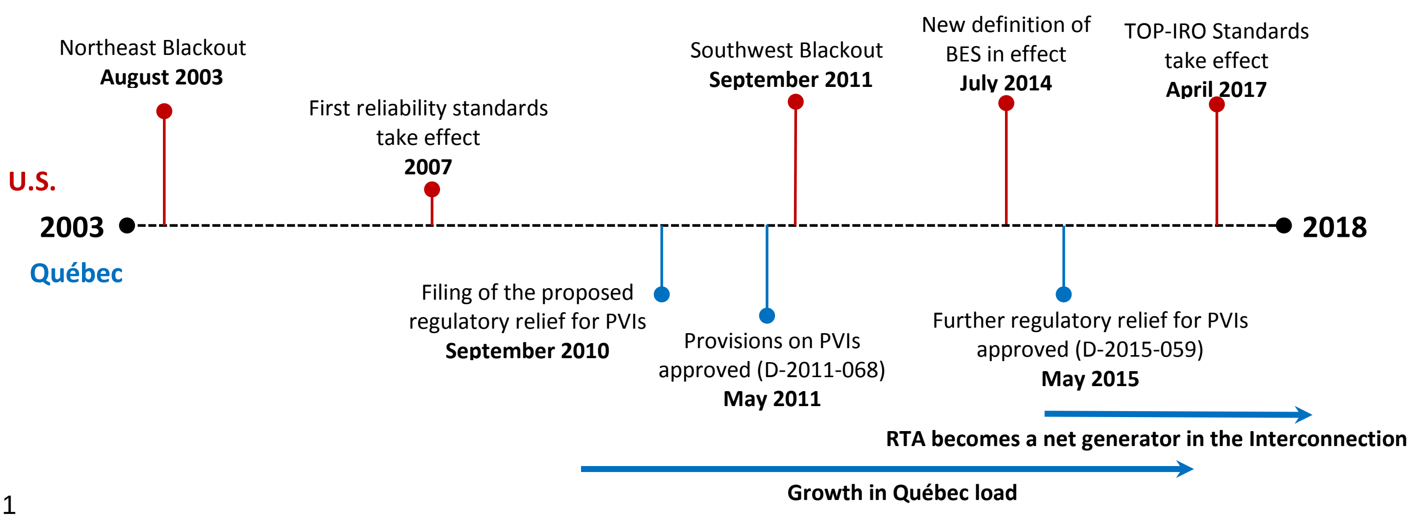

Figure 1: Changes in the regulatory context and profile of RTA

The Relevant Data from RTA is needed for adequate functioning of the Coordinator tools that ensure reliable operation of Québec's RTP. A "black box" like the RTA system in the middle of the Québec Interconnection is unacceptable for fair, reliable operation of the latter; all other North American reliability coordinators have access to such data.

In the Coordinator's view, the effort for entities to submit the data is modest since the data is already available. The data is protected electronically, like all of the Coordinator's operating data, and the *Reliability Coordinator Code of Conduct* governs releasing such data to other Hydro-Québec affiliates. The means by which the data is transmitted can also be implemented by a mutual agreement with the entities. The Coordinator notes that it already obtains confidential information from other Québec industrial entities, it repeats that such data is handled confidentially and it points out that this situation has not raised any issues for those industrial entities.

1.4 Conclusion

The North American context, Québec Interconnection and profile of RTA have all evolved since 2010. Today, the relevance of the TOP-IRO Standards is clear and the impact of implementing them is modest for entities, while the reliability gains are demonstrated by the Coordinator in these proceedings.

The Coordinator submits that adopting the Relevant TOP-IRO Standards will have a beneficial impact for reliability of the Québec Interconnection.

2 Background to Phase 2

2.1 Purpose of the mandatory system of reliability standards

The *Final Report on the August 14, 2003 Blackout in the United States and Canada* concluded that the blackout was avoidable and that the first and foremost lesson learned is that voluntary compliance with reliability standards is no longer acceptable for the U.S. and Canadian governments.[1] The Report thus specifies that "*...actions must be taken in both the United States and Canada... First and foremost, compliance with reliability rules must be made mandatory...*".

Canadian provincial governments then addressed the Report's recommendations. The Québec government included in its 2006–2016 energy policy an objective to "*harmonize electricity transmission reliable standards with those of our North American partners*".[2,3]

The Régie recently indicated that it understands that the purpose of the desired harmonization is [translation] "*to establish a system that makes it mandatory to comply with the standards needed to ensure power transmission reliability in Québec and that is consistent with the normative framework in place in adjacent jurisdictions*".[4]

2.2 Reliability Coordinator: Role in requests to adopt reliability standards

The *Act respecting the Régie de l'énergie* (the "Act") states that the Régie is responsible for designating a reliability coordinator on the conditions it determines.

When the Régie designated the Coordinator in 2007, it concluded that the latter has the competence and expertise required to assume its role in Québec.[5]

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[1] *Final Report on the August 14, 2003 Blackout in the United States and Canada, U.S.-Canada Power System Outage Task Force,* page 1, consulted online (in French) on September 15, 2017 at: [http://bibvir1.uqac.ca/archivage/24063935.pdf]

[2] Using Energy to Build the Québec of Tomorrow: Québec Energy Strategy 2006–2015, Ministère des ressources naturelles et de la faune, 2006, Bibliothèque et Archives nationales du Québec, p. 90

[3] This objective comes in response to recommendations in the 2003 Final Report, specifically: "*The interconnected nature of the transmission grid requires that reliability standards be identical or compatible on both sides of the Canadian/U.S. border, Several provincial governments in Canada have already demonstrated support for mandatory and enforceable reliability standards and have either passed legislation or have taken steps to put in place the necessary framework for implementing such standards in Canada. The federal and provincial governments should work together and with appropriate U.S. authorities to complete a framework to ensure that identical or compatible standards apply in both countries, and that means are in place to enforce them in all interconnected jurisdictions.*" (Report referenced in Note 1)

[4] D-2017-031, p. 22, paragraph 62

[5] The Coordinator is the reliability coordinator (RC) for the Québec Interconnection and, to date, is the sole transmission operator (TOP) and balancing authority (BA) in that Interconnection. HQT is the planning coordinator (PC) for the Québec Interconnection and, to date, the sole PC in that Interconnection. It also exercises the functions of transmission owner (TO) and distribution provider (DP).

The Coordinator possesses the competencies required to exercise the RC, BA and TOP functions, and its operating staff is certified by NERC. It masters the tools, systems and technological means needed to exercise its functions and is acknowledged by NERC, NPCC and neighboring reliability coordinators as the reliability coordinator for the Québec Interconnection as defined by NERC. It operates the main transmission system (RTP) around the clock seven days a week.

When designating the Coordinator, the Régie required that the latter adopt a specific code of conduct complementing the *Transmission Provider Code of Conduct*. That code of conduct specifically states that:

> *"4.1 Staff shall act in a manner that gives priority to the reliability of the electric power transmission system for which the Reliability Coordinator is responsible.*
>
> *4.2 Staff shall treat all system users in a fair and non-discriminatory manner."* [6]

The Act also states that the Coordinator must exercise the functions devolved to it by the reliability standards. In addition, the Coordinator has important responsibilities toward all Québec customers and neighboring systems. Per its history, competence, clear accountability and the code of conduct governing its actions, the Coordinator is responsible for reliable operation of the Québec Interconnection in a fair and non-discriminatory manner for all entities using that system.

Moreover, the Act stipulates that the Coordinator must file with the Régie the reliability standards proposed by NERC or NPCC, and an evaluation of the relevance and impact of the standards proposed.[7] Evaluating the relevance of the standards proposed involves determining the importance of the reliability standards for Québec Interconnection reliability, specifically, whether it is necessary or opportune to implement the standards.

The Régie recently confirmed that the burden of the Coordinator is to file an evaluation of the relevance of the standards[8] and when an entity requests a specific provision, it is the requesting party's burden to demonstrate that the provision is necessary and opportune.[9]

The Coordinator points out that the Régie has mandated NERC and NPCC under a formal agreement to develop the reliability standards and, in so doing, to take into account the specific features of the Québec Interconnection. NERC and NPCC are acknowledged by the

[6] The *Reliability Coordinator Code of Conduct* was approved by the Régie in December 2007. It took effect on January 14, 2008 and was subsequently amended by Régie Decision D-2010-126 (September 21, 2010) and Decision D-2011-132 (August 31, 2011).
[7] *Act respecting the Régie de l'énergie*, Section 85.6.
[8] D-2017-031, p. 27, paragraph 84.
[9] D-2017-031, p. 22, paragraph 66.

Régie as experts in the development of standards. The Coordinator also points out that, as an industry stakeholder, it has contributed to the work in developing the NERC reliability standards. When NERC proposes to the Coordinator that a standard be adopted by the Régie, the standard thus has already undergone a rigorous development process and been approved by the industry. Its relevance is then established and the Coordinator can propose amendments that take into account the specific characteristics of the Québec Interconnection.

Under the agreement[10] between the Régie, NERC and NPCC, NERC and NPCC undertake to ascertain that any standard proposed by the Coordinator, as well as any other variant, are "as stringent as the NERC reliability standards applicable in the rest of North America".

In its role in filing reliability standards, as in its operator role, the Coordinator acts to ensure Québec Interconnection reliability while treating all system users in a fair and non-discriminatory manner.

2.3 Request dealt with in Phase 1

During Phase 1 of these proceedings, the Coordinator filed a request regarding the standards on system operation (the "TOP-IRO Standards"). To enable those standards to be adopted promptly in Phase 1, the Coordinator limited their scope to the main transmission system (RTP) by excluding non-RTP facilities, contrary to what is included in those standards. It also extended the special provisions regarding the industrial generator (PVI). In Decision D-2017-061, the Régie adopted those standards and made them effective.

3 Coordinator's request in Phase 2

In Phase 2 of these proceedings, the Coordinator is requesting two changes to the standards adopted during Phase 1: firstly, the removal of the special provisions limiting the scope of certain standards to facilities belonging to the RTP; and secondly, the removal of the special provisions regarding the industrial generator (PVI).

The Coordinator proposes that the special provisions limiting the scope of IRO-002-4 (R3), IRO-010-2 (R1) and TOP-003-3 (R5) to the RTP be removed. The scope of those standards will then match that of the original standards. Note that TOP-001-3 is not subject to this change. However, the next version that the Coordinator plans to submit in a later filing is subject to similar provisions.[11]

[10] *Agreement on the Development of Electric Power Transmission Reliability Standards and of Procedures and a Program for the Monitoring of the Application of These Standards for Québec*, Section 4.2.

[11] TOP-001-4 is filed for reference purposes as Exhibit HQCF-5, Document 5.

As summarized in Table 1 below, the Coordinator is requesting that the special provisions be amended in four standards (the "Relevant Standards"): TOP-001-3, IRO-002-4, IRO-010-2 and TOP-003-3.

Table 1: Amendments to the special provisions in Phase 2

Requirements	Special provisions in Phase 1	Special provisions desired in Phase 2
IRO-002-4 R3	**Specific provisions applicable to requirement R3 and measure M3:** The Reliability Coordinator is not required to monitor: - Generation facilities for industrial use. However, it shall perform that monitoring at the connection points; - non-RTP facilities.	**Specific provisions applicable to requirement R3 and measure M3:** The expression "non-BES" is replaced by "non-RTP".
IRO-010-2 R1.1 and R3	**Specific provisions applicable to requirement R1 (1.1):** The Reliability Coordinator does not have to include non-RTP data it deems necessary in the data specification. **Specific provisions applicable to requirement R3:** The Generator Operator for industrial use must provide to the Reliability Coordinator data related to: (i) the net power at the connection points of its system in the planning and real time horizon; (ii) the total production of its generation facilities and its system load in the planning time horizon. If the Generator Operator for industrial use receives a data specification document distributed in accordance with requirement R2, it is only required to comply with the provisions relating to the data to be provided.	**Specific provision applicable to requirement R1.1:** The expression "non-BES" is replaced by "non-RTP".
TOP-001-3 R3, R10.1 and R11	**Specific provisions applicable to requirement R3 for Distribution Provider:** If the Operating Instruction issued to the Distribution Provider requires a load shedding, the load shedding required is equivalent to a reduction in net transfer from the Québec's system to the entity's load. Depending on the load shedding required, the Distribution Provider may have to reduce net transfer to zero. **Specific provisions applicable to requirements R10.1 and R11 and measures M10 and M11** The Transmission Operator and Balancing Authority are not required to monitor generation facilities for industrial use. These must be monitored at the connection points.	**Specific provisions applicable to requirement R3 for Distribution Provider:**[12] If the Operating Instruction issued to the Distribution Provider requires a load shedding, the load shedding required is equivalent to a reduction in net transfer from the Québec's system to the entity's load. Depending on the load shedding required, the Distribution Provider may have to reduce net transfer to zero.
TOP-003-3 R1.1 and R5	**Specific provisions applicable to requirement R1 (1.1):** The Transmission Operator does not have to include non-RTP data it deems necessary in the data specification. **Specific provisions applicable to requirement R5:** The Generator Operator for industrial use must provide to the Transmission Operator and the Balancing Authority data related to: (i) the net power at the connection points of its system in the planning and real time horizon; (ii) the total production of its generation facilities and its system load in the planning time horizon. If the Generator Operator for industrial use receives a data specification document distributed in accordance with requirement R3 or R4, it is only required to comply with the provisions relating to the data to be provided.	**Specific provision applicable to requirement R1.1:** The expression "non-BES" is replaced by "non-RTP".

[12] The Coordinator maintains this interpretation for R3 subsequent to the Régie order in Decision D-2015-059. To date, the interpretation remains valid.

4 Evolution of power systems and the regulatory context

4.1 Evolution of the NERC regulatory context

North America has experienced a number of major blackouts since mandatory reliability standards were implemented. The report following the 2011 Southwest Blackout confirmed the importance of certain standards, including those covered in these proceedings, and provided the impetus making other standards more precise.[13] In general, most NERC standards have evolved considerably since 2009, whence the numerous versions.

In 2012, NERC also revised completely the definition of "Bulk Electric System" (BES),[14] which governs the designation of facilities needed for the reliability of interconnected systems. This new definition led to discarding the concept of "Bulk Power System" (BPS) as the scope in the NPCC region in favor of a bright-line criterion.

Since 2012, a number of NERC functions have been removed[15] and a number of requirements merged or removed during overhauls of reliability standards, always to focus the mandatory North American system on the elements crucial to the reliability of electric power transmission systems.

4.2 Evolution of the regulatory context

The regulatory context has evolved appreciably since the 2003 blackout. Figure 2 illustrates the milestones since 2003 in the development of the categories of facilities having an impact on the reliability of electric power transmission systems.

[13] The report on the U.S. Southwest Blackout is submitted as Exhibit HQCMÉ-2017-1, Document 6.

[14] HQCF-5, Document 5.

[15] The purchasing-selling entity (PSE), interchange authority (IA) and load-serving entity (LSE) functions were removed since not deemed necessary for reliability. A number of requirements had to be rearranged to make it possible to remove those functions, especially that of LSE.

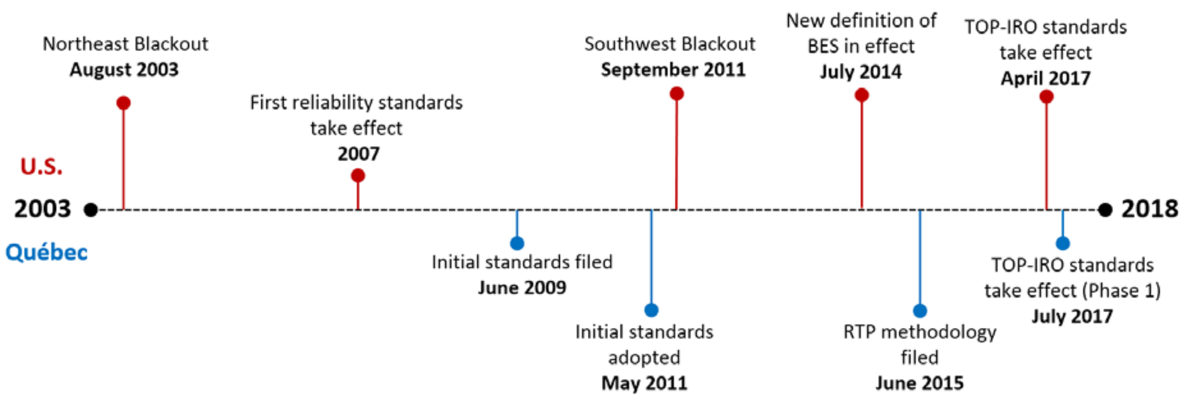

Figure 2: U.S. and Québec regulatory milestones since 2003

4.2.1 Evolution in Québec Interconnection operation from 2009 to 2017

The Coordinator notes that the Québec electric power transmission system has changed significantly since Application R-3699-2009 was filed. In Procedural Decision D-2017-050, the Régie asked the Coordinator to elaborate further regarding:

- Changes to transmission system infrastructure impacting Québec power transmission reliability;
- Changes to the categories of systems subject to the reliability standards needed for Québec power transmission reliability before and after implementing the mandatory system of reliability standards;
- Justification of the pertinence of such changes in the Québec context.

In 2017, the Coordinator notes that the transmission system in the Québec Interconnection is under greater pressure than in 2009, the year that reliability standards were initially filed with the Régie, particularly due to the growth in Québec load, the integration of new generation like the Romaine generating stations and the addition of new wind farms. The Québec peak and average system use have increased from 2009 to 2016, by 10.8% and 7.7% respectively.[16]

The system is also under greater pressure during non-peak periods.[17] The operator's safety margin has become tighter. In particular, increasingly hot summer periods mean that the capacity of transmission system facilities is further reduced by thermal constraints, as are the associated transmission limits. In addition, more and more equipment maintenance

[16] Information from Exhibit HQT-9, Document 1 for the 2010 and 2017 rate applications (R-3738-2010 and R-4012-2017).

outages are required as the system ages. Due to these factors, transmission system power flows are more closely approaching stability and thermal limits in summer.

The system and its use have thus changed. Moreover, operating the system is more demanding for the operator today than in 2009, requiring tighter and more precise control. The Coordinator must consider additional factors to determine operating limits, must manage outages more optimally and must produce more precise weather forecasts.

4.2.2 Evolution in the categories of facilities in Québec from 2009 to 2017

In 2009, there were three types of facilities in Québec:

- The Coordinator's system control centre (CCR) managed Bulk Power System (BPS) facilities as determined by NPCC Criterion A-10,[18] as well as a large number of additional elements belonging to Hydro-Québec and needed for reliable management of the Québec Interconnection;
- Hydro-Québec facilities that were not managed by the CCR were governed by regional system criteria and managed by regional telecontrol centres (CTs);
- Facilities not belonging to Hydro-Québec were governed by connection requirements, operating procedures, common operating instructions and other contracts.

Today in Québec, the Coordinator classifies facilities into the following three categories according to their impact based on a number of criteria (see Figure 3 and Table 2):

- Bulk power system (BPS) facilities based on NPCC Criterion A-10 are critical for reliability of the Québec Interconnection. A serious problem affecting a single element of the BPS can impair the reliability of the Québec Interconnection and neighboring systems, even in the case of an "ideal system", meaning one with all of its elements in service. All BPS facilities are RTP facilities.
- Non-BPS RTP facilities are needed for Québec system reliability. A problem affecting a single non-BPS RTP facility cannot impair the reliability of the Québec Interconnection and neighboring systems under "noble" or ideal system conditions (no line or equipment outage). However, the system is never "ideal" in practice: non-BPS RTP facilities are those that may cause problems for Québec system reliability when the system is degraded or multiple contingencies occur.

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[17] R-3981-2016, HQT-1, Document 1, page 5, lines 23 to 25.

[18] Criterion A-10 is a regional criterion developed by NPCC in order to identify the facilities critical to system reliability in northeastern North America.

- Non-RTP facilities are those that have only a local impact. There is thus no risk that the Québec Interconnection will collapse due to their loss. However, information on some such facilities may be important for reliability. In that case, those facilities are designated when applying the relevant standards and that information is used for the purpose of maintaining RTP reliability. This request covers that category of facilities.

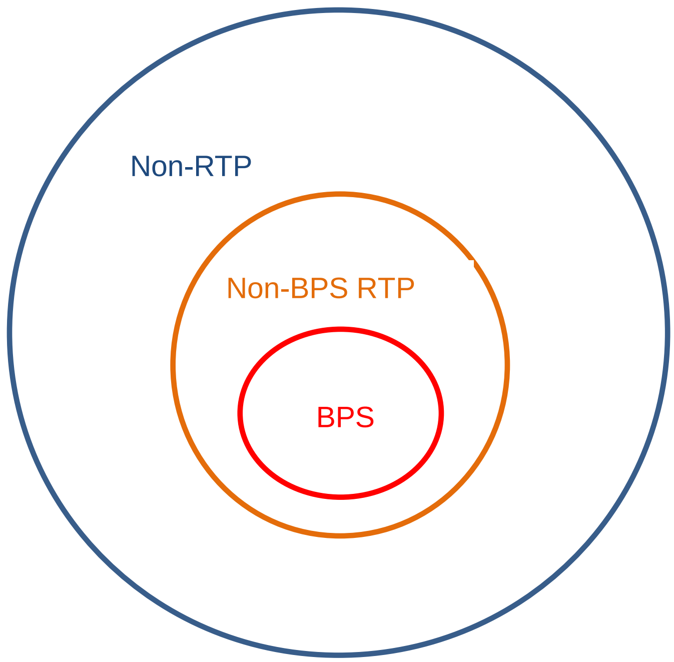

Figure 3: Categories of Québec Interconnection facilities

Table 2: Generating stations and substations categorized as BPS, RTP and non-RTP in Québec

Category	**Number of facilities**	**Percent** (%)
BPS	41	6
Non-BPS RTP	186	25
Non-RTP	510	69

Recently, as part of Application R-3952-2015, the Coordinator proposed raising the threshold for including generation from 50 to 75 MVA,[19] removing the load-serving entity (LSE) function, raising the threshold for including distribution providers (DPs) from 50 to 75 MW and designating an additional number of lines as belonging to the BPS.

The higher threshold in both cases reflects changes to the definition of BES in North America.[20] Designation of lines as part of the BPS stemmed from a change in the definition of NPCC Criterion A-10, which determines BPS elements.

In putting into effect the mandatory North American system, changes in the categories of systems have followed and reflected the lessons from the 2003 blackout. Since 2009, those changes have been fairly minor in substance and are dealt with in Application R-3952-2015. In 2012, NERC clarified the definition of BES and changed the thresholds in order to bright-line them; this is addressed in several sections herein, notably in sections 5 and 7. The concept of “non-BES” was added to a number of NERC standards based on lessons learned by the industry, particularly after the 2011 U.S. Southwest Blackout, as explained in Section 7.1.

5 Industrial generators in Québec

Table 3 lists the entities designated as “industrial generators” (PVIs) in 2012.

Table 3: Industrial generators (PVIs) in 2012

Entity	Total capacity	Capacity per facility
Domtar Inc. (Lebel-sur-Quevillon mill)	55 MW	55 MW
Hydro-Saguenay (Resolute Forest Products)	118 MW	63 and 55 MW
Rio Tinto Alcan	3,568 MW	240, 250, 300, 300, 462, 940 and 1,076 MVA

Domtar operations have been suspended since 2012 and Hydro-Saguenay generating station output is now beneath the new 75-MVA threshold proposed in Application R-3952-

[19] In Application R-3952-2015, the Coordinator proposed that certain generating stations between 50 and 75 MW needed to ensure Québec Interconnection reliability, specifically, that meet a reliability criterion, remain subject to the reliability standards.

[20] The NERC definition of BES in effect is filed for reference purposes as Exhibit HQCF-5, Document 5.

2015. Following the suspension granted in decisions D-2015-213 and D-2016-109, RTA is the sole remaining PVI entity with Québec facilities subject to the standards.

Elsewhere in North America, the definition of BES does not include “industrial generation”. Exclusion E2 in the definition of BES is the means chosen by NERC to take into account generators that supply their own load.[21] Exclusion E2 does not take into account the purpose of facilities, only their impact on the power system and only with regards to a net capacity threshold[22] of 75 MVA.

However, using net capacity alone was disputed when FERC reviewed this exclusion. In response to the concern raised by ISO-NE that a 400-MW generator impacting local reliability but having less than 75 MVA of net generation would be excluded from the NERC Register, FERC replied that the generator could be registered by means of an exception process.[23]

In order that generators in Québec be treated in a manner consistent with those elsewhere in North America, the Coordinator, in a later application, will incorporate the concept of excluded generators into a revision of its methodology for determining RTP elements. It considers that the concept of PVI is no longer necessary or appropriate in applying reliability standard in Québec.

6 The RTA system and its impact on the Québec Interconnection

6.1 Profile of entity RTA

RTA is Québec’s second-largest generator with 3,500 MVA of installed capacity listed in the Register, about 7% of Québec’s installed generation. Its historical peak real generation in 2015 was [redacted] MW. [24] In addition, RTA manages its own reserves.[25]

RTA also operates an electric power transmission system, which connects its seven RTP generating stations to its aluminum smelters, as well as other generators and industrial

[21] “E2. A generating unit or multiple generating units on the customer’s side of the retail meter that serve all or part of the retail customer Load with electric energy on the customer’s side of the retail meter if: (i) the net capacity provided to the BES does not exceed 75 MVA…”

[22] Net capacity is the net flow to the BES over the most recent 12 month period. Bulk Electric System Definition Reference Document, January 2014, p. 50. (Exhibit HQCF-05, Document 9).

[23] FERC Order 773, pp. 108–109.

[24] R-3947-2015, Exhibit C-RTA-0035, p. 5.

[25] R-3699-2009, Answers to Régie Information Request No. 1 to RTA, p. 30.

loads. Its transmission system comprises 345-, 240- and 161-kV high-voltage lines, and also has four connections with the adjacent HQT RTP,[26] as listed in Table 4.

In addition, the RTA system offers HQT an auxiliary transmission service whereby energy is delivered to Hydro-Québec Distribution (HQD) for various industrial and residential customers.

Table 4: Tie lines between the adjacent HQT RTP and RTA

Line and voltage	**HQT substation**	**RTA substation**
One 345-kV RTP line operated at 315 kV	[redacted]	[redacted]
One 240-kV RTP line	[redacted]	[redacted]
Two 161-kV RTP lines	[redacted]	[redacted]

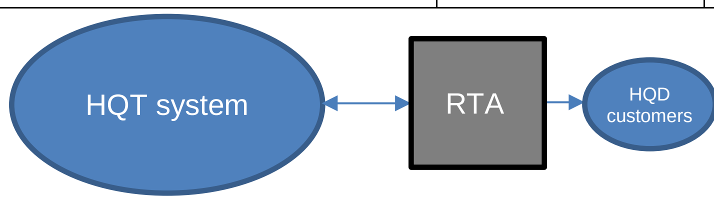

Figure 4: Black box – auxiliary carrier model

The data used in this section is based on the "black box – auxiliary carrier" model to represent the RTA system. That model corresponds to RTA's net interchange with the other entities to which it is connected (see Figure 4).

As summarized in Table 5, RTA was a net generator during the last three peaks in Québec.

Table 5: Contribution of RTA during the last three peaks in Québec[27]

Date of peak	**Number of peak hours**	**Net interchange from RTA to HQ (MW) (Black box – auxiliary carrier)**
January 9, 2017	8	[redacted]
February 15, 2016	7	[redacted]
January 8, 2015	8	[redacted]

[26] The RTP understood as a continuous system of RTP elements.

[27] Hydro-Québec annual reports for 2014 to 2016, consulted on the French-language web page on September 15, 2017 at: [http://www.hydroquebec.com/publications/fr/documents-entreprise/rapport-annuel.html]. The net interchange is based on data from the Coordinator's System Control Centre (SCC).

In Table 6, the Coordinator presents the power flows between the RTA system and the Hydro-Québec system since 2009.[28] Large net generation occurred in 2012 due to a six-month strike that year. RTA did not consume its own generation during the strike. That situation demonstrates that RTA industrial generation is not typical of that in North America since RTA can generate electricity without consuming it. Typical outputs of industrial generators are usually related to their consumption.

Table 6: RTA system interchange (black box – auxiliary carrier model)

	Energy exchanged (GWh)		Net interchange RTA to HQ > 75 MW	
	Total exports from RTA	Net interchange between RTA and HQ	Hours	% of hours
2009	[redacted]	[redacted]	[redacted]	[redacted]
2010	[redacted]	[redacted]	[redacted]	[redacted]
2011	[redacted]	[redacted]	[redacted]	[redacted]
2012	[redacted]	[redacted]	[redacted]	[redacted]
2013	[redacted]	[redacted]	[redacted]	[redacted]
2014	[redacted]	[redacted]	[redacted]	[redacted]
2015	[redacted]	[redacted]	[redacted]	[redacted]
2016	[redacted]	[redacted]	[redacted]	[redacted]
2017[29]	[redacted]	[redacted]	[redacted]	[redacted]

Note: A negative value for energy exchanged means that RTA was a net importer of electricity during the year.

Figure 5: Percentage of hours according to power flow ranges in MW (2009 vs. 2016)

Confidential

Redacted

[28] The data is compiled with hourly sampling from January 1, 2009 at 00:00 to June 29, 2017 at 23:59.
[29] Data for 2017 is from January 1 to June 30 inclusive.

Table 6 shows that between 2009 and 2017, RTA has become a net generator (positive value for net interchange). RTA has been a net electricity generator on an annual basis since 2015, meaning that the amount of electricity exiting the RTA system is now clearly greater than the amount entering it. In particular, it exported more than 75 MW for more than half of the year in 2015 and 2016.

The two bar charts in Figure 5 further show a substantial upward trend in the export of RTA generation in 2016 compared to 2009. RTA has shifted in status from a consumer with little generation to a major generator on the power system. For example, RTA generated more than [redacted] MW for about [redacted] of the hours in 2016 for the rest of the Québec Interconnection.

6.2 Calculation of limits for interconnections between the RTA and HQT systems

Limits between RTA and the HQT system are determined based on the "black box – radial" model, as illustrated in Figure 6:

Figure 6: Black box – radial model of the RTA system

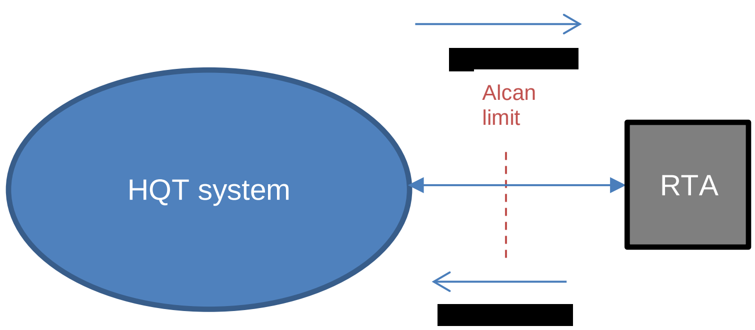

Table 7: Power flows between the RTA and HQT system (black box model – radial)

	Max. power flow (MW)	
	HQT to RTA	RTA to HQT
2009	[redacted]	[redacted]
2010	[redacted]	[redacted]
2011	[redacted]	[redacted]
2012	[redacted]	[redacted]
2013	[redacted]	[redacted]
2014	[redacted]	[redacted]
2015	[redacted]	[redacted]
2016	[redacted]	[redacted]
2017[30]	[redacted]	[redacted]

Normal operating limits are set to [redacted] MW for exporting (to RTA) and [redacted] MW for importing (to HQT). Those limits should be set based on the capacity of the RTA system to withstand certain events, specifically faults and smelter pot trips. As shown in Table 7, net hourly RTA power flows have varied between exporting [redacted] MW to the RTA system and importing [redacted] MW to the HQT system. Note that the RTA system occasionally exceeds operating limits when importing to the HQT system. Exceedances typical occur [redacted]. As transmission operator (TOP), the Coordinator must take the necessary actions to bring such flows back within the limits.

The limits are normally set based on criteria like the robustness of a system to a three-phase fault. In Application R-3944-2015, however, RTA pointed out that its system could not withstand a three-phase fault. The impact of this lack of robustness cannot be evaluated without specific data on the RTA system.

It is also likely that the present limits do not take all possible configurations of the RTA system into account since the Coordinator does not receive the Relevant Data.

In short, RTA enjoys high interchange limits with the HQT system. They were established based on criteria less strict than elsewhere in North America and on the basis of partial information.

6.3 Disturbances [redacted]

[redacted] the Coordinator monitors disturbances with an impact on Québec

[30] Data for 2017 is from January 1 to June 28 inclusive.

Interconnection frequency exceeding 0.20 Hz in order to track trends. [redacted]

Confidential

Redacted

***Data from January to August 2017*

Figure 7: [redacted]

[redacted]

Confidential

Redacted

Figure 8: Disturbances in the Québec Interconnection in 2016

[redacted]

6.4 RTA system parallel flow

As shown in Figure 9, the RTA system provides a path for power flow parallel to HQT’s 735-kV [redacted] corridor, composed of elements classified as BPS critical for reliability and constituting an interconnection reliability operating limit (IROL).[31] Power flow along this parallel transmission path, called a “parallel flow”, adds 0 to 100 MW of uncertainty to the limit on the [redacted] corridor. This [redacted] MW difference is important since the limit is an IROL.

[31] IROLs (interconnection reliability operating limits) are the most important limits managed by a reliability coordinator. Reliability of the Interconnection is at risk when these limits are exceeded.

Due to the lack of real-time information on the RTA system, the impact of this parallel flow on the HQT system cannot be evaluated correctly by the Coordinator's operating tools. Those tools are presented in Section 8.2. The parallel flow in question impacts the power flow of [redacted] substation transformers and management of the IROL associated with them. The Coordinator demonstrates this in Section 8.3.4.

Furthermore, when an event occurs on the HQT system [redacted], which is in parallel with the RTA system, the post-event power flow distribution may potentially have consequences on the RTA system. Communicating the Relevant Data from the RTA system will contribute in such cases to RTA system reliability and to the HQD customers connected via that system.

Confidential

Redacted

Figure 9: Model of the RTA system with parallel flow

6.5 Impact of the RTA system on the Québec Interconnection

The RTA system does not comprise elements classified as BPS, meaning that none of its elements can lead to a cascading outage of the Interconnection for a noble system. Applying reliability standards only to BPS elements, however, is insufficient for ensuring Québec system reliability (see Section 4.2.1). Though RTA facilities are not classified as BPS, they can lead to limit violations on RTP elements, as explained in detail in Section 8.2.2.

In Application R-3947-2015, the Coordinator has demonstrated by dynamic studies [redacted]. The Régie concluded that this was convincing proof.[32] [redacted], an operator lacking adequate tools or the necessary information can accomplish by mistake. The Coordinator points out that a number of North American blackouts, for example the Southwest Blackout, arose from human error occurring when the system was in a fragile state.

6.6 RTA registration in Québec

RTA is an entity included in the Register as a generator owner (GO), generator operator (GOP), transmission owner (TO) and distribution provider (DP). RTA is designated as an industrial generator (PVI) but that designation is not a function.

RTA operates a private power system and plans it with the support of HQT. In the rest of North America, RTA's 161- and 345-kV transmission facilities would be subject to the reliability standards. RTA net generation throughout the year would make it subject to the reliability standards, and the fact that it supplies the system during peak periods would prevent it from qualifying for an exception included in the NERC process.

The Coordinator supports this point based on expert Brian Evans-Mongeon's report.[33]

7 Non-RTP scope

7.1 Non-BES scope in North America

A cascading failure of 88-kV transmission lines, i.e., ones at a voltage lower than the 100-kV BES inclusion threshold, was an important factor in the 2011 Southwest Blackout. Subsequently, FERC, NERC and the industry decided to maintain the 100-kV bright-line criterion in the definition of BES and address this situation in two ways. Firstly, the BES exception process makes it possible to include in the BES certain facilities of importance for reliability. This is the inclusion process. Secondly, designating facilities in applying the Relevant TOP-IRO Standards makes it mandatory to submit data for certain non-BES facilities for real-time operations in order to give the reliability coordinator a wide-area view of the facilities that it deems necessary for the reliability of its area. In analyzing the 2011 Southwest Blackout, FERC and NERC determined that the reliability coordinator for the

[32] D-2017-031, paragraph 85.
[33] Exhibit HQCF-5, Document 2.

WECC region had violated certain requirements of the IRO standards designed to give the reliability coordinator a wide-area view sufficient to ensure reliability. This clearly demonstrates the importance of giving the Coordinator the authority it needs to obtain the data essential to fulfilling its responsibilities.

When a facility is designated as BES, all the standards can apply; whereas, when it is designated under certain requirements of the Relevant TOP-IRO Standards, only those standards apply for obtaining information. Together, these two ways of dealing with important non-BES facilities make it possible to target the right entities and limit application of the reliability standards to the right facilities based on their importance for system reliability.

7.2 Non-RTP scope in Québec

In Québec, the Coordinator can modify its methodology for identifying elements of the main transmission system (RTP) and, with the Régie's approval, designate a facility as an element of the RTP in order that all the standards apply to it. In applying the Relevant TOP-IRO Standards, it can also designate a facility in order that the owner submits data about it that is important for reliability. The Coordinator labels such facilities "designated non-RTP facilities". Table 8 gives a breakdown of the number of Québec generating stations and substations for which the Coordinator wishes to obtain the data in order to maintain system reliability.

Table 8: Classification of Québec generating stations and substations

Classification	Number of facilities	Percentage of Québec Interconnection facilities (%)
BPS	41	6
Non-BPS RTP	186	25
Designated non-RTP	157	21

* The count of designated non-RTP facilities also includes certain partially RTP facilities.

The Coordinator is filing the list of non-RTP facilities for which it intends to request real-time information in Exhibit HQCF-5, Document 7. In fact, non-RTP facilities can, in their local area, lead to limit violations on RTP facilities. However, the Coordinator does not believe it necessary to apply all of the reliability standards to those facilities since it only needs the Relevant Data.

Most designated non-RTP facilities belong to either HQT or HQP and their data is already integrated into the Coordinator's systems. The impact on other entities is therefore expected to be modest.

7.3 Non-RTP scope applied to RTA facilities

The Coordinator explicitly excluded industrial generators (PVIs) from Criterion 2.4 on the integration of generation and ignored parallel flow on RTA lines when setting Criterion 2.3 of the methodology for identifying RTP elements.[34] Data from certain facilities being essential for reliability, the Coordinator could have proposed to designate certain lines of the RTA system as being elements of the RTP. However, designating them so would have had the effect of applying all reliability standards to those facilities. Presently, the Coordinator considers that obtaining the Relevant Data in real time is sufficient. With the approach chosen by the Coordinator, certain RTA facilities are designated only for the specific purpose of applying the TOP-IRO Standards, minimizing the impact on RTA.

7.4 Designation of non-RTP elements in Québec

The reliability standards include mechanisms for communicating data-related operator needs to entities.[35] Those mechanisms are flexible and may change over time. Regulatory approval with its resulting delays is neither necessary nor desirable since the data is needed during operations, always in real time.

The Coordinator only plans to include the entities that possess RTP facilities and that are in the Register of Entities. It thus proposes that the Register of Entities Subject to Reliability Standards not be modified.

[34] R-3952-2015, B-0075.

[35] See IRO-010-2 and TOP-003-3, which require that the RC, BA and TOP develop a specification of the data needed for reliability and distribute it to the entities involved.

8 Relevance of the data requested for Québec Interconnection reliability

8.1 Data requested and Coordinator's concerns

The Coordinator is seeking to obtain the Relevant Data, more specifically the following:

- In real time, the generation from RTA generating stations;
- In real time, the state, configuration, (real and reactive) power and voltage of every element of the transmission facilities in the RTA system at 161 kV or higher.

Though RTA generating stations are presently part of the RTP, the Relevant Data is subject to a PVI exemption granted under Application R-3699-2009. The Coordinator thus requests the real-time generation data from those generating stations.

Furthermore, since RTA transmission facilities are not part of the RTP, the Coordinator requests that the real-time data from those facilities be submitted to it in enforcing the Relevant TOP-IRO Standards. Those facilities would be categorized as designated non-RTP facilities.

Real-time data for such facilities is available to all other North American transmission operators (TOPs), balancing authorities (BAs) and reliability coordinators (RCs), who use it to ensure the reliability of their power systems.

The Coordinator notes that the RTA transmission facilities would be classified as BES in the rest of North America and would be subject to the TOP-IRO Standards with no exemption, as pointed out by expert Brian Evans-Mongeon.[36]

The Coordinator is concerned by its lack of real-time data for the RTA system. Such lack of situational awareness[37] for a reliability authority was one of the causes of the 2003 Blackout, and the reliability standards were explicitly implemented to prevent this lack of situational awareness. The 2011 Southwest Blackout confirmed that a wide-area view was critical for ensuring reliability.

As indicated in Section 6, the [redacted][38] Furthermore, as demonstrated in Section 6.5, events on the RTA system can affect RTP reliability, incidentally causing limit violations on RTP elements. In this context, the Coordinator must be more concerned about the condition and situational

[36] Exhibit HQCF-5, Document 2.
[37] The terms "situational awareness" and "visibility" have the same meaning.
[38] See sections 6.2 and 6.3.

awareness of this system, located in the middle of the Québec Interconnection power system.

The Coordinator presently obtains the Relevant Data from the other regional systems, e.g., the Abitibi, Gaspésie and Outaouais systems, in order to ensure RTP reliability. The Coordinator can thus issue directives to the operators of the regional systems to clear limit violations on RTP elements. The information received from those regional systems is thus crucial for maintaining RTP reliability. The same is true for data coming the RTA system.

For these reasons, the Coordinator considers that the information from the RTA system is needed to ensure Québec Interconnection reliability.

The Coordinator supports this point based on the report of expert Kim Warren, who also considers that the Relevant Data is necessary for reliable operation of the Québec Interconnection.[39]

8.2 Impact of the missing data on Coordinator tools

Lack of the Relevant Data reduces the Coordinator's situational awareness of the entire system that it supervises and hence the capacity of its tools to simulate and correctly evaluate situations leading to limit violations on RTP elements. The sections below present the monitoring tools at the Coordinator's disposal.

8.2.1 LASER (System security analysis software)

LASER evaluates exceedances of thermal limits on RTP elements. It is comprised of two functional units: a state estimator and a contingency analysis tool.

- The state estimator eliminates measurement errors by reproducing a power flow that is as faithful as possible to the system's actual power flow. To work properly, it must have all of the measurements associated with the elements it models, and those measurements must be as redundant as possible.
- The contingency analysis tool uses the power flow from the state estimator and simulates contingencies, i.e., the loss of all single RTP elements. It transmits alarms during limit violations, which the operator must clear using operating instructions. To evaluate RTP reliability correctly, the contingency analysis tool must be able to simulate the effect of non-RTP elements causing parallel flow.

[39] Exhibit HQCF-5, Document 3.

8.2.2 Impact of non-RTP elements on evaluating RTP reliability

As indicated in the preceding sections, parallel flow due to non-RTP elements can lead to limit violations on RTP elements and thus impact Québec Interconnection reliability. It is impossible to model RTA in the LASER state estimator, however, due to the lack of access to RTA system states and measurements. The representation of the RTA system that connects that system to the HQT system, as illustrated in Figure 9, must thus be simplified using loads and generators depending on the direction of power flow. This simplification converts RTA's parallel power flow into radial power flow.

This distorts the evaluation of limit violations by the LASER contingency analysis tool. Any contingency leading to the loss of connections with RTA results in a loss of loads or generators, without impacting other connections and thus RTP elements around those connections. What actually happens is very different, however, as demonstrated in Section 8.3.

Two types of problems may thus occur in real time due to this missing data:

- An invisible limit violation that the Coordinator cannot recognize;
- A false limit violation that the Coordinator perceives and takes measures to clear.

Invisible problems are preoccupying, however, false problems like false limit violations are not inconsequential since erroneous resource allocation and confusion arises due to them. Minimally, the attention paid to a false problem can confuse the operator during real-time decisions confronting real operating problems. The resulting directives normally reduce transmission system or generation dispatch efficiency. As with any operation in the power system, there is a risk of error that may create new issues.

Furthermore, the missing RTA data complicates and sometimes prevents adequate analysis of past events. Assumptions must be made to simulate the parallel flow caused by RTA, making the simulations inaccurate and preventing validation of the limits.

The Coordinator reiterates that it has very limited situational awareness of the RTA system and RTA has no formal responsibility for its operational reliability and responds to imperatives other than Québec Interconnection reliability, specifically its industrial generation purpose.

The sections below give a number of illustrations of various problems that may occur in real time.

8.3 Potential problems resulting from the lack of data

8.3.1 Contingencies invisible on Coordinator monitoring tools leading to a major loss of generation – Possible situation

Certain configurations of the RTA system may, under single-contingency conditions, meaning after the loss of any one element, lead to sufficient generation tripping to [redacted] and trigger the remedial action scheme for underfrequency load-shedding (UFLS) of [redacted] MW or more under minimum summer load.[40] This scenario is illustrated in Appendix 1.

With the Relevant Data, the Coordinator can recognize configurations potentially leading to limit violations on RTP elements in real time and take action to eliminate them.

8.3.2 Contingencies invisible on Coordinator supervisory tools leading to line overloading – Possible situation

Not having access to the Relevant Data, operators must comply with capacity limits that are determined based on assumptions regarding the configuration of the RTA system. The Coordinator presumes that the RTA system is looped by lines [redacted].

However, if the RTA system is [redacted] (either by an operating choice or after an exceptional event) during the [redacted], Table 9 shows the difference between results based on the assumptions and the actual situation. This would lead to overloading line [redacted], a BPS element, and thus to a thermal operating limit violation. This violation is invisible on Coordinator monitoring tools, however, and the operator can neither evaluate it nor take action to avert the situation, such as de-energizing the line or curtailing generation from the RTA system. At the present time, the Québec Interconnection is subject to this risk, something unacceptable for the Coordinator. As indicated in Section 6.3, [redacted], making this type of contingency more likely than in the past.

40 [redacted]

Table 9: Post-contingency system assessment after the [redacted]

	Limit (20°C)	Feeder power flow	Post-contingency power flow	
			Situation simulated based on assumptions	Actual situation
To the HQT system	[redacted]	[redacted]		
[redacted]	[redacted]	[redacted]	[redacted]	XXXXX XXX
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

If this risk occurs, invisible to the operator on Coordinator supervisory tools, line [redacted] remains overloaded (at [redacted] MVA) until the operator becomes aware of the alarm, decides the measures that must be taken, communicates those measures, and the measures are implemented and take effect.

During this time, the line may overheat and be damaged permanently. The Coordinator stresses that facilities are necessary for reliable operation of the RTP. Consequently the operator must protect facilities. If the line is damaged and thus taken out of service for a long period of time, the power system in the Lac-Saint-Jean region becomes degraded and the risk of major power outages increases.

During line [redacted] overloading, it is also possible that the line stretches and approaches the ground, thus presenting a public safety hazard.

If the line trips after a few minutes of overloading, either because it is stretched due to the heat and contacts the ground or a tree, or because the operator is forced to de-energize it, the loss for the system would be [redacted] MW. In certain cases, that loss could trigger the UFLS remedial action scheme with load shedding spread across the Québec Interconnection.

8.3.3 Loss of 735-kV supply to a substation – Possible situation

Should element outages lead to the loss of the 735-kV [redacted] substation supply under single-contingency conditions, the LASER contingency analysis tool could not faithfully simulate the results of that major event. This would actually lead to [redacted] substation loads being supplied by parallel flow over the RTA system and thus undervoltage limit violations on RTP elements. Having no indication that the event could occur, the operator could not take action to avoid the violations. Appendix 2 covers this scenario in detail.

8.3.4 Transformer overloading at a substation – Real situation

The Coordinator has noted at least three cases of IROL violations at [redacted] substation transformers. Those problems are attributable to the impossibility of modeling RTA parallel flow in the LASER contingency analysis tool.

For example, on [redacted], there were heavy system loads and [redacted] circuit breaker [redacted] was unavailable due to damage. Simulation by the LASER contingency analysis tool of the loss of [redacted] bus [redacted] resulted in an IROL violation at the [redacted] transformers (BPS). The operator then de-energized line [redacted] to eliminate the violation. In Table 10, the Coordinator has compared the results of this contingency with the Transmission Planner's model, which allows parallel power flow via the RTA system.

Table 10: Results of the loss of [redacted] bus [redacted]
with and without modeling the RTA system

	Feeder power flow (MVA)	Post-contingency power flow (MVA)		Difference (MVA)
		Operator's model (without RTA)	Planner's model (with RTA)	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted] transformers	[redacted]	[redacted]	[redacted]	[redacted]

It turns out in this specific case that the operator had to take the same action since in both models the [redacted]-MVA transformer limit was exceeded.

However, there does exist a difference in the results from the two models. This demonstrates that the transformer limit violation could be false in certain configurations. The action taken by the operator could thus be useless. This situation could create confusion at the control centre and impair real-time decision-making and hence RTP reliability.

Note that to enable simulation of the power flow with the Planner's model of RTA, the Planner had to make unverifiable assumptions regarding the generating capability and load in the RTA system, and do so based only on power flow measurements at the interconnection points between the two systems. It is impossible to know which if any of these simulations is faithful to reality. The Planner's simulation then cannot accurately reproduce the operating data due to the lack of data. In other words, the planning engineers cannot adequately reproduce the situations occurring in operations due to the lack of the Relevant Data in real time from RTA.[41]

8.4 Deficiency of data now transmitted

The Coordinator presently obtains data at the interconnection points with the RTA system. That system is a black box since the Coordinator is kept in the dark regarding energy flows within the RTA system.

The Planner's model estimates RTA system generation and load based on interchanges. That model is sensitive and cannot always reproduce the behavior of the system observed. Real-time interchanges are thus not sufficient to model the RTA system. Not receiving the Relevant Data, the Planner and Coordinator have no other choice but to use this theoretical model. For all its shortcomings, a theoretical model is needed to represent the interior of the RTA system for planning and operational purposes.

Furthermore, when examining three-phase faults applicable to the RTA system, the Planner has stated that the limit from the RTA system to the HQT system depends on the output of [redacted] generating station.

The Coordinator cannot adequately manage its power system without knowing what is going on inside the RTA system. The situation now existing would no more acceptable to other North American reliability coordinators, as mentioned in the expert reports by Kim Warren[42] and Brian Evans-Mongeon.[43]

[41] The Coordinator points out that Standard MOD-033-1 concerns the quality of modeling. That standard includes an ongoing process whereby the Planner evaluates the match between the actual behavior of part of the system and the planning model. Coordinator efforts to make this comparison for analysis purposes have demonstrated that the model of the region around the RTA system is difficult to rebuild to match real-time data.

[42] Exhibit HQCF-5, Document 3.

[43] Exhibit HQCF-5, Document 2.

9 Fairness among system users

In Application R-3699-2009, the Régie reaches the following conclusion regarding a potential 500-MW power failure on HQD loads in Lac-Saint-Jean:

> *"[...] the Régie notes that the Coordinator submits that an RTA system power failure may lead to an impact of about 500 MW on the HQD load in Lac-Saint-Jean. However, the Coordinator has not demonstrated that such a failure could threaten Québec Interconnection reliability."*

The Coordinator wishes to add that the impact on reliability is not the only pertinent consideration for the Coordinator. The *Reliability Coordinator Code of Conduct* specifies that:

> "*Staff [...] shall treat all system users in a fair and non-discriminatory manner.*"

Regional systems other than the RTA system submit information on the state of their facilities in real time to the Coordinator on request. That information flow improves the reliability of the regional system in question as well as that of the neighboring systems.

In the Coordinator's view, it is not fair to other Québec transmission system users (HQT, HQD, HQD customers, the Rivière-du-Moulin generator and other registered entities) that the RTA system need not comply with minimum North American industry practices as embodied in the reliability standards. The Coordinator develops these points in greater detail in the sections below.

9.1 Impact on HQD customers

The Coordinator notes that RTA acts as an "auxiliary carrier" as understood in the Act. In particular, it carries energy for HQT to Saguenay native load, including RTA, industrial customers connected to the RTA system and other local loads. All are HQD customers.

RTA also supplies energy for certain clients during peak periods.

When RTA mentions that the Coordinator can separate from the RTA system to avoid an impact on the HQT system,[44] which necessarily entails a situation of probable RTA system collapse and thus a blackout for HQD customers.

In the Coordinator's view, it is unfair for HQD's Saguenay customers to have an entity (RTA) that does not comply with the same standards as all of North America. This undermines local reliability.

[44] Application R-3947-2015, C-RTA-0018, p. 8, paragraph 32.

9.2 Impact on Rivière-du-Moulin

Line [redacted] is one of four lines between the Hydro-Québec RTP and the RTA system. The Rivière-du-Moulin wind plant has been connected directly and only to that line since 2014. The plant belongs to a wind generator bound to HQD by a supply contract. Any damage to line [redacted] would impact Rivière-du-Moulin's ability to supply its generation to its customer. In the Coordinator's view, it is unfair that another entity suffer consequences due to the lack of information from RTA.

9.3 Inequitable enforcement of the reliability standards

The Coordinator must treat fairly the entities subject to reliability standards in the Québec Interconnection and, more specifically, in obtaining the Relevant Data.

For instance, the Gaspésie wind plants could insist that the Coordinator need not obtain their data since they are connected to a regional system and that only the interchange from the Gaspésie system to the RTP is needed to manage the RTP. However, the Coordinator occasionally requests preventive action in the Gaspésie system in order to protect the RTP from an uncontrolled collapse of that system. Information from those wind plants and information regarding the configuration of the Gaspésie system are thus needed to protect the RTP.

If the Régie exempts RTA, a number of other entities could also wish to obtain an exemption by invoking the grounds of fairness. Every such exemption would also be detrimental to reliability. Furthermore, every exemption granted makes the impact of the next greater, which weakens reliability of the Interconnection.

10 Impact on RTA of submitting the data

If the Régie accept its proposal, the Coordinator ultimately wants data for all facilities needed for reliability submitted to it automatically via telecommunication systems.

In Application R-3699-2009, RTA argues that real-time data on its system's load distribution, generation dispatching, total output and total load is confidential.

The standards include a security protocol[45] agreed upon by both parties regarding communication of the Relevant Data.

[45] As stipulated in IRO-010-2 Requirement R3.3 and TOP-003-3 Requirement R5.3.

The Coordinator already has the load data from other major industrial companies in the Québec Interconnection, including certain other aluminum smelters, and emphasizes that this situation has never caused problems for those users.

Furthermore, its staff is subject to a Code of Conduct and any entity that believes that a Coordinator staff member has transgressed the Code can report that to the Coordinator or to the Régie. No complaint has been lodged to date with the Coordinator or the Régie regarding the Code of Conduct.

The Coordinator further points out that five other coordinators in North America are not ISOs,[46] either because they are subsidiaries of entities offering energy services or because they themselves offer energy services.[47] Those entities also receive operating data such as the Relevant Data.

11 Conclusion

Respectfully, the Coordinator has demonstrated the impacts on the reliability of the Québec Interconnection arising from the lack of visibility into the Relevant Data. In particular, a major "black box" like the RTA system in the middle of Québec does not enable fair and reliable operation of the RTP. The purpose of a facility does not determine its impact on the power system.

The Coordinator has demonstrated the relevance of the reliability standards that it has filed for adoption. Furthermore, it considers that the impact of those standards on Québec entities is reasonable given their relevance for reliability.

Application of those reliability standards is fully in line with their application in neighboring jurisdictions, while the Relevant TOP-IRO Standards now in effect represent a regulatory relief that is unjustifiable from a reliability standpoint.

The Coordinator has demonstrated the evolution of the regulatory context and the changes in real-world system operation, where pressure on the Québec transmission system is greater than in 2009. The Coordinator requires greater precision in its data in order to ensure the reliability of the Québec Interconnection and fairness in its operation. It has also supported its request with two expert reports by Kim Warren and Brian Evans-Mongeon.

The Coordinator has demonstrated that the standards it is filing for adoption are needed to ensure Québec Interconnection reliability and fair enforcement of the reliability standards

[46] Independent System Operators.

[47] New Brunswick Power Corporation (same model as Hydro-Québec), SaskPower, Southern Company Services, Inc., Tennessee Valley Authority, VACAR-South (Duke Energy Carolinas, LLC as an "RC Agent").

among the entities subject to them. The Coordinator thus asks the Régie to adopt the Relevant TOP-IRO Standards.

Appendix 1 Simulation of a bus with single-contingency generation[48]

[redacted]

[redacted]

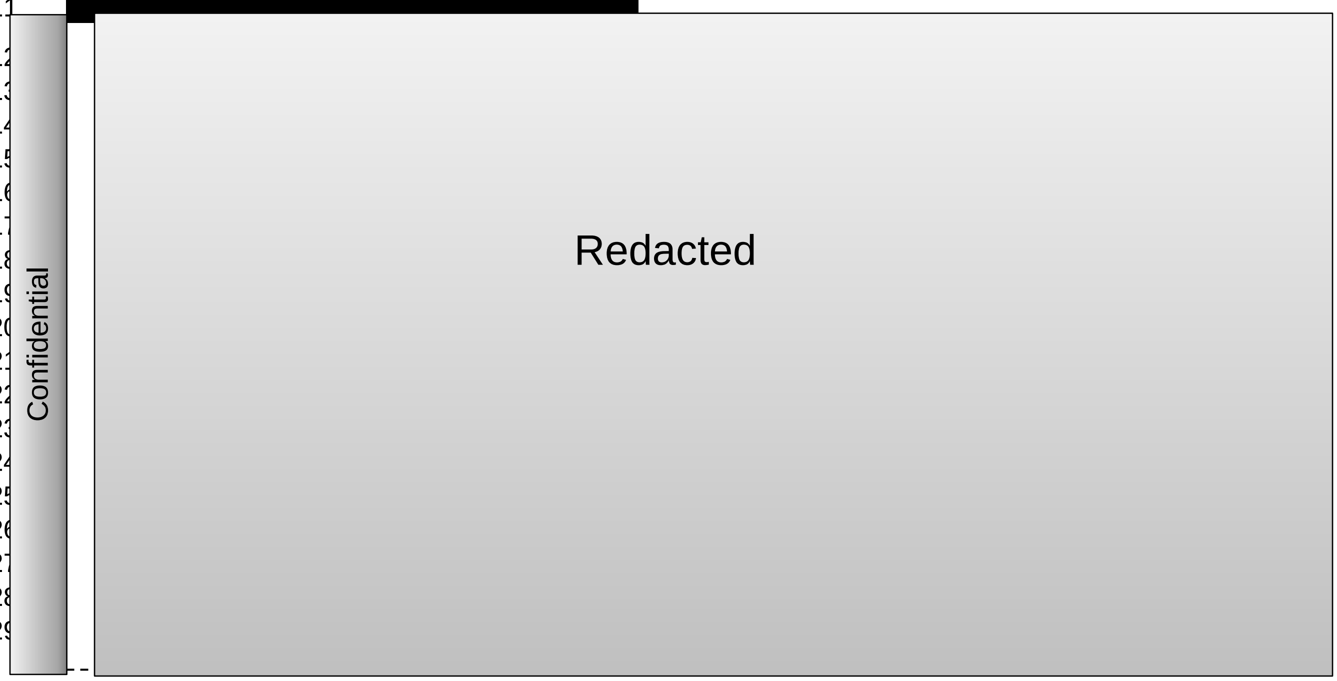

Figure 10: Frequency at [redacted] substation

[48] "Single-contingency generation" means generation that is lost following the loss of any single element (or contingency).

The simulations results presented in Figure 10 show that the HQT system frequency drops as low as [redacted] Hz, with the shedding about [redacted] MW of load due [redacted]. The load shedding occurs about 1.45 seconds after the simulation starts.

Appendix 2 Simulation of (radial) [redacted] substation in the RTA system

The event is simulated with the power system in its known conditions on [redacted] and a hypothetical RTA system.

[redacted]

[redacted]

Given the lack of RTA data, LASER must model [redacted] the 161-kV connection with RTA at [redacted] substation. Note that with the loss of line [redacted], the operator has no information on the state of HQT's Saguenay system.

A model of the RTA system and use of its data in LASER would make the operator aware of the undervoltage limit violations during simulation of the loss of line [redacted]. The voltage at 161-kV [redacted] substation would fall below the acceptability criterion of [redacted] p.u., resulting in a risk of uncontrolled tripping of Saguenay system loads.

By becoming aware of the violations, the operator could order the connection of the two capacitor banks available at 161-kV [redacted] substation. This measure would avoid the undervoltage in the Saguenay system due to the loss of line [redacted]. Table 11 summarizes the resulting voltage with and without the capacitors.

Table 11: Post-contingency evaluation with and without action

	Feeder voltage [redacted]	Voltage evaluated at [redacted] substation for the loss of line [redacted]	Voltage evaluated based on the Coordinator's model
No capacitor bank connected at [redacted] substation by the operator	[redacted]	[redacted]	[redacted]
Two capacitor banks ([redacted]) connected at [redacted] substation by the operator	[redacted]	[redacted]	[redacted]