RÉPONSES DE RIO TINTO ALCAN (« RTA »)
À LA
DEMANDE DE RENSEIGNEMENTS N^o 1 DE LA RÉGIE DE L'ÉNERGIE (LA « RÉGIE »)

Exclusions des PVI

1. Références : (i) Pièce C-RTA-0024, p. 2;
(ii) Pièce C-RTA-0024, p. 8.

Préambule :

(i) RTA dépose le rapport d'AESI, dont sont extraits les éléments suivants :

« *Moreover, we are concerned that extending the immensely administratively burdensome program requirements for either a "high" or "medium" impact rating categorization of the RTA Installations* […] *is inconsistent in application of the CIP standards by other jurisdiction's within Canada and the United States for other installations of Local Networks ("LN") or industrial customers with generation <u>behind the retail meter</u>, that are applied in accordance with the NERC BES definitions*[5] *exclusions E3 and E2 respectively, and within the context of the reliability objectives*[6] *of CIP-002-5.1, Attachment 1 criterion for a 1500 MW or greater impact to the Interconnection.*

[5] *<u>BES Definition Reference Document</u>, Exclusion E2, at p 51; having a meaning similar to a PVI Installation and E3 at p 54 for LN.*

[6] *<u>NERC Petition for the Approval version 4 of the CIP reliability standards</u>, at p 15 and at p 27.* » [nous soulignons]

(ii) Le rapport d'AESI précise les exclusions E2 et E3, auxquelles il réfère en (i) :

« *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 Load with electric energy if : (i) the net capacity provided to the BES does not exceed 75 MVA, and <u>(ii) standby, back-up, and maintenance power services are provided to the generating unit or multiple generating units or to the retail Load by a Balancing Authority, or provided pursuant to a binding obligation with a Generator Owner or Generator Operator, or under terms approved by the applicable regulatory authority</u>.*

E3 Local networks (LN): A group of contiguous transmission Elements operated at less than 300 KV that distribute power to Load rather than transfer bulk power across the interconnected system. LN's emanate from multiple points of connection at 100 kV or higher to improve the level of service to retail customers and not to accommodate bulk power transfer across the interconnected system. The LN is characterized by all of the following :

(a) Limits on connected generation: The LN and its underlying Elements do not include generation resources identified in Inclusions I2, I3, or I4 and do not have an aggregate capacity of nonretail generation greater than 75 MVA (gross nameplate rating);
<u>(b) Real Power flows only into the LN and the LN does not transfer energy originating outside the LN for delivery through the LN; and</u>

<u>(c) Not part of a Flowgate or transfer path: The LN does not contain any part of a permanent Flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection, or a comparable monitored Facility in the ERCOT or Quebec Interconnections, and is not a monitored Facility included in an Interconnection Reliability Operating Limit (IROL)</u> » [nous soulignons]

Demandes :

1.1 Veuillez commenter le statut des installations de RTA en relation avec la disposition (ii) de l'exclusion E2, telle soulignée en référence (ii).

Réponse RTA :

Condition (ii) of exclusion E2 requires that the generation on the retail side of the meter serving the retail customer load self-provide reserves (i.e., standby, backup, and maintenance power), through agreements with various listed registered entity types[1] depending on the nature of the market or system operations or applicable tariffs in place within its jurisdiction and is essential for the integrity of the exclusion.

RTA carries reserves at all times based on its largest generator loss contingency and in addition has an agreement in place with Hydro-Québec Distribution for the provision of additional backup energy in the event of a contingency with its own generation resources. Therefore, RTA meets this condition.

AESI's intent in its report was not to imply that RTA meets exclusion E2, but rather to use exclusion E2, along with the previous Régie decision on TOP-006 that uses the concept of net power at the connection points of a PVI system as relevant for reliability, along with the Régie decision on the CIP version 5 reliability standards that establishes more precise exclusion criteria for Québec, in order to:

(i) propose that the RTP definition should be refined to be more precise for PVI; and

(ii) establish the validity of using the principle of "net injection" or net impact to the BES when:

a. determining applicability of one or more NERC reliability standards or requirements to PVI; and

[1] R-3947-2015: Bulk Electric System Definition Reference Document, Version 2, April 2014, C-RTA-0021, p. 51:

"*These services are provided under contract or tariff with Generator Owners, Generator Operators, or Balancing Authorities in regions that do not have Independent System Operators (ISOs) or Regional Transmission Operators (RTOs), and provided by ISOs and RTOs where "organized markets" operate. These terms and conditions will be understood in Balancing Authority Areas where it is applicable, as it reflects existing industry practice".*

b. in particular, applying and evaluating the 1500 MW threshold in criterion 2.11 of CIP-002-5.1 Attachment 1.

Furthermore, AESI wishes to emphasize that RTA is not objecting to the applicability of version 5 of the CIP reliability standards. As required by Requirement R1 of the CIP-002-5.1 standard, RTA is merely attempting to self-identify and self-categorize its BES Cyber Systems (BCS) pursuant to the established and approved reliability standard CIP-002-5.1 Attachment 1 criteria in the context of a PVI. Specifically, AESI wishes to establish a common and appropriate interpretation of the applicability of CIP-002-5.1 Attachment 1 criterion 2.11 in the context of a PVI that will then be used in RTA's initial self-identification and self-categorization of its BCS, and used in RTA's subsequent reviews of such self-identification and self-categorization of its BCS every 15 calendar months as required by Requirement R2 of the CIP-002-5.1 standard. Importantly, an interpretation of the criterion 2.11 that will also be used by future auditors along with a more precise RTP definition specifically for a PVI when reviewing and validating RTA's self-identification and self-categorization of its BCS.

1.2 Veuillez commenter le statut des installations de RTA en relation avec les dispositions (b) et (c) de l'exclusion E3, telle soulignée en référence (ii).

Réponse RTA :

Condition (b) of exclusion E3 requires that Real Power flow only into the Local Network and not transfer energy across it. Real Power flows both into and out of RTA's network under various conditions. Therefore, as is currently written and defined by NERC, RTA does not meet this condition.

Condition (b) was written with the restriction that Real Power flow only into the Local Network at its connection points as the simplest method to ensure that the local network is acting only as a distribution service and not contributing to, nor necessary for, the reliable operation of the BES[2]. The NERC Planning Committee (the "**PC**") reviewed several technical alternatives to this condition, recommended an alternative to this condition, and stated in its report that even if portions of a Local Network allowed parallel flow, the remaining portions of a Local Network should be further studied and those remaining portions of the Local Network could meet this condition for exclusion[3]. Considering the PC's report and review of the Local Network exclusion, if it were concluded that RTA's network primarily only acts as a distribution service and does not contribute to, nor necessary for, the reliable operation of the BES, regardless of Real Power flows into or out of its network, then in AESI's opinion, RTA would meet the intent of this condition.

Condition (c) of exclusion E3 requires that the Local Network not be part of a Flowgate or transfer path or comparable monitored Facility in the Québec Interconnection. RTA has not been identified

[2] Local Network Exclusion, technical justification, p. 3 (RTA-10).

[3] Review of Bulk Electric System Definition Thresholds, dated March 2013, p. 24 (RTA-11).

by Hydro-Québec as being part of a Flowgate or transfer path or comparable monitored Facility in the Québec Interconnection; therefore, RTA meets this condition.

Again, AESI's intent in its report was not to imply that RTA meets exclusion E3, but rather to use exclusion E3, along with the previous Régie decision on TOP-006 that uses the concept of net power at the connection points of a PVI system as relevant for reliability, along with the Régie decision on the CIP version 5 reliability standards that establishes more precise exclusion criteria for Québec, in order to:

(i) propose that the RTP definition should be refined to be more precise for PVI; and

(ii) establish the validity of using the principle of "net injection" or net impact to the BES when:

a. determining applicability of one or more NERC reliability standards or requirements to PVI; and

b. in particular, applying and evaluating the 1500 MW threshold in criterion 2.11 of CIP-002-5.1 Attachment 1.

The 1500 MW threshold for the CIP-002-5.1 criteria was based on impact to the BES, i.e. based on the average Contingency Reserves required for each Interconnection to be carried by Balancing Authorities in accordance with the NERC BAL-002 reliability standard to cover the most severe single contingency. Therefore, AESI submits that the net injection principle itself is just and sound, and should be used when determining if a PVI meets the 1500 MW threshold when evaluating the criterion 2.11 in Attachment 1 of CIP-002-5.1, and when determining if CIP standards apply to PVI installations under the Régie approved threshold value of 300 MVA for applicability of the CIP standards.

AESI is also advocating that exclusions such as E2 and E3 that are appropriate for Québec, and that the principle of net injection or net impact to the BES, should be considered when determining the applicability of the NERC standards and requirements to all PVI, regardless if RTA itself meets such exclusions or not.

1.3 Considérant l'importance relative (MW installés RTA/MW installés Interconnexion Québec) de la production et de la charge, veuillez préciser s'il existe en Amérique du Nord des cas de figure comparables. Les présenter le cas échéant.

Réponse RTA :

AESI is currently unaware of any other PVI type ("generation behind the retail meter") installations comparable in size to the RTA Installations in North America. Furthermore, the applications of version 5 of the CIP reliability standards have yet to be tested for any PVI type installations specifically with respect to application of the 1500 MW threshold of the criterion 2.11 from a Contingency Reserve perspective, similarly as established for a BA network generation resource.

Nonetheless having said that, AESI stands behind the premise that once a registered entity meets the "bright line" criteria, "entity size" is immaterial, in a paradigm that establishes reliability standards applicability solely based on a defined “bright line” criteria approach; that is establishing applicability based on the BES definition or in Québec’s case, based on the RTP definition, and as is further specifically delineated within the applicability criteria for each standard.

This position is consistent with the approach supported by FERC in Order 693[4] in establishing the “Statement of Compliance Registry Criteria” as the basis for establishing reliability standard applicability, and in Order 743[5] issued November 18, 2010, directing NERC to develop a new BES definition stating that:

> “[A]s a result, and consistent with our previous statements in Order No. 672 we find it is best for the ERO (NERC) to establish a uniform definition that eliminates subjectivity and regional variation in order to ensure reliable operation of the bulk electric system”. (emphasis added)

For example, the same reliability standards apply to a 20 MW generator or 1000 MW generator, or in the case of a BA that covers some 14 states and 2 Provinces like Midcontinent Independent System Operator (MISO) or a Balancing Authority (BA) for the Province of Nova Scotia, both forming part of the Eastern Interconnection. In each case, the same reliability standards apply for each registered entity type, regardless of size. With respect to the CIP reliability standards, further delineation of applicability is based on the defined criteria, within reliability standard CIP-002-5.1 Attachment 1. Therefore, in this paradigm of “bright line”, a large PVI should be treated no different than a small PVI, as long as the BES inclusion or exclusion criteria as established are met.

The Régie is being required to establish the criterion appropriate for a PVI within the context of a 1500 MW impact to reliability of the BES as it was intended in AESI’s view from the BA Contingency Reserve perspective for the criterion 2.11 of CIP-002-5.1 Attachment 1, and consistent with the Régie’s approved threshold value of 300 MVA for applicability of the CIP standards for a generation resource.

1.4 Veuillez préciser les différences, en matière d’impact sur la fiabilité d’un réseau interconnecté, entre le fait qu’une centrale de production et une charge associée soient ou ne soient pas raccordées « *behind the retail meter* », tel que souligné en référence (i).

Réponse RTA :

There is no difference, in situations where the generation resource “behind the retail meter” is also injecting energy into the interconnected network and meets the established applicability threshold (75 MW per the exclusion E2 of the BES definition for other jurisdictions).

However, with respect to these network resources (for Québec a Québec Interconnection resource - a generation facility connected to HQT network or a PVI injection to the HQT network or an Interruptible load), the applicability of the NERC standards is primarily[6] based on the reliability

[4] https://www.ferc.gov/whats-new/comm-meet/2007/031507/e-13.pdf, Para [94] (RTA-12).

[5] https://www.ferc.gov/whats-new/comm-meet/2010/111810/E-2.pdf, Para [96] (RTA-13).

[6] Other considerations come into play if that generation resource is used for network AGC control, used for system restoration black-start, is or forms part an IROL, is or forms part of a Type 1 or Type II special protection scheme

impact that the loss of that resource has on the "load – generation" balance that the Balancing Authority (BA) must maintain.

Within North-America, a bright line aggregate value of 75 MW has been established as the threshold value for establishing applicability, including when assessing the impact of a PVI type installation or Local Network. Generation "behind the retail meter" principally serves its own load, only impacts that load when lost and generally has no/little impact to the "load – generation" balance that the Balancing Authority (BA) must maintain, and has therefore been excluded if it does not meet the BES 75 MW aggregated threshold.

In Québec, for applicability of the CIP reliability standards, this threshold value has been set to greater than 300 MVA for a generation resource as outlined in Decision D-2016-119 issued by the Régie on July 29, 2016 for the Québec Interconnection. AESI proposes that the similar threshold be applied for a PVI injecting greater than 300 MVA into the HQT network, given it has the same reliability impact to the BA. In addition, AESI proposes that the reliability standard CIP-002-5.1, Attachment 1, criterion 2.11, be based on the same principle afforded to a generating plant resource – that is the Contingency Reserve impact to the BA based on net MW injections to the Québec Interconnection.

1.5 Veuillez préciser si d'autres considérations que techniques ont été prises en compte par la NERC ou la FERC en lien avec l'établissement des exclusions citées en références (i) et (ii). Le cas échéant, veuillez les documenter.

Réponse RTA :

Exclusion E2 was based upon pre-existing language present from Appendix 5B, Statement of Compliance Registry Criteria, dated December 20, 2012[7], in effect at the time of NERC's petition to FERC for approval of the revised definition of "Bulk Electric System" (BES). The pre-existing language stated:

> "As a general matter, a customer-owned or operated generator/generation that serves all or part of retail load with electric energy on the customer's side of the retail meter may be excluded as a candidate for Registration based on these criteria if (i) the net capacity provided to the Bulk Power System does not exceed the criteria above or the Regional Entity otherwise determines the generator is not material to the Bulk Power System and (ii) standby, back-up and maintenance power services are provided to the generator or to the retail load pursuant to a binding obligation with another Generator Owner/Operator or under terms approved by the local regulatory authority or the Federal Energy Regulatory Commission, as applicable."

It should be noted that the registry criteria upon which exclusion E2 was based originally allowed a Regional Entity to have discretion to exclude PVI generation from the Bulk Power System if it

(SPS), etc. In such cases, specific criteria have been incorporated in the applicable reliability standards for these considerations, as is the case with CIP-002-5.1 Attachment 1.

7 See the second exclusion following §III.c.4 on page 10 in Appendix 5B of the NERC Rules of Procedure, dated December 20, 2012 (RTA-14).

determined that the PVI generation was not material to the Bulk Power System. This Regional Entity discretion was not included in the language of the exclusion; however, NERC developed a BES exception procedure and guidelines to allow exclusions from the BES definition as appropriate on a case by case basis.

Exclusion E3 was specifically designed to exclude, from the BES, facilities that are used in the local distribution of electrical energy from the BES. Such clarifications were provided in both paragraphs 22 and 25 of FERC Order 743-A[8,9]. NERC then provided a technical justification for the exclusion.

AESI is unaware of specific non-technical considerations taken into account by NERC and the FERC with respect to the establishment of exclusions E2 and E3; however, that does not mean that NERC and the FERC did not consider any non-technical aspects, and furthermore, this does not necessarily mean that the Régie should not consider any non-technical aspects in its establishment or application of similar exclusions that are appropriate for the Québec Interconnection.

Impact des installations de RTA sur la fiabilité de l'Interconnexion Québec

2. Référence : Pièce C-RTA-0018, p. 6.

Préambule :

« *24. Ainsi, les installations de RTA assurent principalement les besoins énergétiques de ses propres installations industrielles et, à ce titre, RTA n'est pas tenue à des obligations de livraison fermes d'énergie à HQ. En conséquence, RTA et ses installations industrielles subiraient les impacts éventuels d'une perturbation du réseau engendrée par les installations de RTA, sans incidence significative nuisible sur la fiabilité de l'ensemble de l'Interconnexion ou du réseau « bulk » du Québec. D'ailleurs, les études de stabilité réalisées par HQ ont démontré que les installations de RTA ne pourraient pas déclencher des pannes d'électricité en cascades.* » [nous soulignons]

Demande :

2.1 Veuillez déposer les études de stabilité, dont il est question dans l'extrait souligné de la référence (i), qui démontrent que les installations de RTA ne pourraient déclencher des pannes d'électricité en cascades.

Réponse RTA :

The statements made in paragraph [24] of the AESI Report (C-RTA-0018) are not based on specific stability studies available to RTA or AESI but are instead based on the following:

8 Local Network Exclusion, technical justification, p. 2 (RTA-10).

9 FERC Order No. 743-A, dated March 17, 2011, Para [22] and [25] (RTA-15).

- a long standing position maintained by Hydro-Québec, and as filed with the Régie[10], stating that the *"[c]urrent configuration of the Alcan network, the transmitter [HQT as transmission operator] believes that an event on the Alcan network will have no harmful material impact on the reliability of the network "bulk", which in fact gives it its current status of "non-bulk*"]",[11] meaning in AESI's view, it has local area impact only as defined by NPCC[12] and as articulated in AESI's 2010 report filed before the Régie in the matter R-3699-2009[13];

- an understanding that such statements by HQCMÉ were based on analytical studies, and that there has been little change to the RTA Installations and its interconnections with HQT since then to change that perspective;

- engineering judgment and operating experience based on actual events that have occurred on the RTA Installations over the years.

  The most recent event on June 8th, 2014 and the associated follow-up work with HQT and discussions within the Joint Technical Committee14 to assess the event and its subsequent RTA report15, where the RTA Installations separated from the HQT system, within one (1) second, after a three (3) phase ground fault16 failed to be cleared by its Protection System. The event having no material impact on the HQT Interconnection and no HQT RTP Facilities tripped;

  The event, apart from impacting the RTA Installations themselves, only resulting in minor frequency excursion and local area implications resulting in the loss of local loads and depressed local area voltages for a brief period until the fault was cleared.

- RTA's response to HQCMÉ Question 6.7[17], dated February 19, 2010, with respect to local area impact and plausible "worst case" contingencies;

- RTA's response to HQCMÉ Question 6.1[18], dated February 19, 2010, with respect to local area impact;

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10 R-3498-2002: HQT-6, Document 1, February 5, 2003, at R2.1, p. 5 of 11.

11 AESI internal translation from the French version.

12 NPCC "Glossary of Terms", p. 9, Formerly NPCC Document A7, p. 10 (RTA-16).

13 R-3699-2009: AESI Final Report, dated January 7, 2010, C-5-12, reference 12, p. 5.

14 [redacted]

15 [redacted]

16 A ground fault caused by a failed potential transformed (PT) and breaker that exploded at the Isle-Maligne 161kV Sub-station.

17 R-3699-2009: C-5-16, R6.7, p. 29.

18 R-3699-2009: C-5-16, R6.1, p. 6.

- the established Common Instructions[19] with respect to the operations of the interconnects between RTA and HQT and their related System Operating Limit (SOL) for various outage configuration that makes no reference to Interconnected Reliability Operating Limits (IROL); and

- that neither HQT nor HQCMÉ have advised RTA of any changes to such status with respect to version 5 of the CIP-002-5.1 reliability standard criterion 2.6 related to IROLs implications or criterion 2.3 related to the RTA generating Facilities, being necessary to avoid an "Adverse Reliability Impact"[20] in the planning horizon of more than one year out.

> "CIP-002-5.1 Attachment 1:
>
> 2.3. Each generation Facility that its Planning Coordinator or Transmission Planner designates, and informs the Generator Owner or Generator Operator, as necessary to avoid an Adverse Reliability Impact in the planning horizon of more than one year.
>
> 2.6. Generation at a single plant location or Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies."

Importantly, AESI is of the view, consistent with its intent of applying the defined criteria, that if HQCMÉ (or HQT) has conducted subsequent studies that support the position that the RTA Installations or its Facilities are identified "*as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies*", or that the RTA generating Facilities "*as necessary to avoid an Adverse Reliability Impact in the planning horizon of more than one year*" then the BES Cyber Systems for those identified Facilities must be categorizes as "medium" impact per criterion 2.6 or per criterion 2.3 respectively, as the case may be. The same would hold true for any HQT controlled Facilities on those interconnections. Otherwise, for criteria 2.6 and 2.3, the BES Cyber Systems for the RTA Installations remain a "low" impact.

AESI maintains its view that applicability be based on the approved criteria in the context of a PVI.

AESI reiterates that RTA is not objecting to the applicability of version 5 of the CIP reliability standards. As required by Requirement R1 of the CIP-002-5.1 standard, RTA is merely attempting to self-identify and self-categorize its BES Cyber Systems (BCS) pursuant to the established and approved reliability standard CIP-002-5.1 Attachment 1 criteria in the context of a PVI. Specifically, AESI wishes to establish a common and appropriate interpretation of the applicability of CIP-002-5.1 Attachment 1 criterion 2.11 in the context of a PVI that will then be used in RTA's

19 [redacted]

20 R-3947-2015: Glossary of Terms and Acronyms used in Reliability Standards, B-0044 and B-0045, p. 2.

initial self-identification and self-categorization of its BCS, and used in RTA's subsequent reviews of such self-identification and self-categorization of its BCS every 15 calendar months as required by Requirement R2 of the CIP-002-5.1 standard. Importantly, an interpretation of the criterion 2.11 that will also be used by future auditors along with a more precise RTP definition specifically for a PVI when reviewing and validating RTA's self-identification and self-categorization of its BCS.