DEMANDE DU TRANSPORTEUR RELATIVE À LA CONSTRUCTION D'UNE LIGNE DE 735 KV ENTRE LES POSTES MICOUA ET DU SAGUENAY (THE "MICOUA-SAGUENAY LINE")

FILE R-4052-2018

AMENDED EVIDENCE OF

NALCOR ENERGY MARKETING CORPORATION ("NEMC")

PRESENTED TO THE RÉGIE DE L'ÉNERGIE DU QUÉBEC ("RÉGIE")

FEBRUARY 15, 2019

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1. PRELIMINARY REMARKS

1. NEMC is an active Hydro-Québec TransÉnergie ("**HQT**") point-to-point client. NEMC is also an active energy marketer on several electricity markets in eastern Canada and in the northeast of the United States. As one of HQT's largest point-to-point clients, NEMC is a regular intervener before the Régie in proceedings that have an impact on transmission rates and on the quality of the electricity transmission services.

2. NEMC requested the intervener status in the current proceedings mainly due to the impact of the proposed investment on the transmission rates. Assuming NEMC maintains its firm transmission entitlements of 265 megawatts ("**MW**") over the next 20 years, the proposed $793 million investment project could represent approximately five (5) million of dollars in rates just for NEMC. Thus, as it will be further discussed, NEMC's main objective in the present file is to ensure that the proposed investment project meets the Québec regulatory principles and good utility practice but with minimum potential impact on rates.

2. REGULATORY FRAMEWORK

2.1 SECTION 73 OF THE ACT RESPECTING THE RÉGIE DE L'ÉNERGIE AND ITS REQUIREMENTS

3. As provided by Section 73 of the *Act respecting the Régie de l'énergie* ("**Act**") and Section 1 of the *Regulation respecting the conditions and cases where authorization is required from the Régie de l'énergie* ("**Regulation**"), investments greater than $25 million must be approved by the Régie:

> Section 73 of the Act:
>
> "**73**. The electric power carrier, the electric power distributor and natural gas distributors must obtain the authorization of the Régie, subject to the conditions and in the cases determined by regulation by the Régie, to
>
> (1) acquire, construct or dispose of immovables or assets for transmission or distribution purposes;
>
> (2) extend, modify or change the use of their transmission or distribution system;
>
> (3) cease or suspend operations; or
>
> (4) restructure their operations with the result that part thereof would be excluded from the application of this Act.
>
> When examining an application for authorization, the Régie shall consider such economic, social and environmental concerns as have been identified by order by the Government and, in the case of an application for the purposes of subparagraph 1 of the first paragraph, the Régie shall consider, where applicable

(1) the sales forecasts of the electric power distributor or natural gas distributors and their obligation to distribute electric power or natural gas; and

(2) the contractual commitments of the consumers served by the electric power transmission service and, where applicable, their financial contributions to the acquisition or construction of transmission assets, and the economic feasibility of the project.

The Régie may authorize the project on the conditions it determines.

An authorization under this section does not constitute a dispensation from seeking any other authorization required by law."

Section 1 of the Regulation:

"**1.** Authorization from the Régie de l'énergie is required:

(1) to acquire, construct or dispose of immovables or assets for energy transmission or distribution purposes as well as to extend, modify or change the use of the transmission or distribution system as part of a project involving:

(*a*) the transmission of electric power worth $25 million or more;

(*b*) the distribution of electric power worth $10 million or more;

(*c*) the distribution of natural gas worth $1.5 million or more, where the distributor's total annual delivery is 1 billion cubic metres or more; or

(*d*) the distribution of natural gas worth $450,000 or more where the distributor's total annual delivery is less than 1 billion cubic metres;

(2) to cease or suspend the operations of the carrier or distributor for reasons other than public safety or normal system operation; and

(3) to restructure the carrier's or distributor's operations so that a part thereof would be excluded from the application of the Act.

Authorization is also required for projects the cost of which is under the limits set in subparagraph 1 of the first paragraph and which have not yet been recognized as prudently acquired and useful for the operation of the electric power transmission system or electric power or natural gas distribution system under subparagraph 1 of the first paragraph of section 49 of the Act respecting the Régie de l'énergie (chapter R-6.01).

The second paragraph does not apply to projects for restoring service, or to connections required of the carrier or distributor after the date an application for authorization was filed."

4. The electric power carrier (HQT) shall also comply with Sections 2 and 5 of the Regulation which states the following:

> "**2.** An application for authorization under the first paragraph of section 1 shall contain the following:
>
> (1) the project objectives;
>
> (2) the project description;
>
> (3) the justification of the project with regard to the objectives;
>
> […]
>
> (7) the <u>impact on the rates</u> including a sensitivity analysis;
>
> […]
>
> **5**. An application for authorization referred to in the second paragraph of section 1 shall be made according to investment category and shall contain the following:
>
> (1) the descriptive summary of the investments and their objectives;
>
> (2) the costs based on the investment category;
>
> (3) the justification of the investments with regard to the objectives;
>
> (4) <u>the impact on rates</u>; and
>
> (5) the impact on the reliability of the electric power transmission system and the quality of the electric power transmission service or electric power or natural gas distribution service."
>
> (Our underlining)

5. As indicated in the extracts above, one of the conditions is that HQT must provide information pertaining to the potential impact of an investment project on rates. This condition is important since if the investment is approved by the Régie, the costs associated with the investment project may eventually be integrated in the rate base in a future rate case hearing.

2.2 ADDITIONAL PRINCIPLES TO CONSIDER IN NETWORK UPGRADING MATTERS

6. Under the current regulatory framework, network upgrades are closely monitored by the Régie. As reiterated by the Régie in the 2014 network upgrade file bearing number R-3888-2014, HQT's network upgrades have to respect some fundamental regulatory principles generally applied in most of North America networks that are regulated by the Federal Energy Regulatory Commission ("**FERC**"). Accordingly, the Régie reiterated the importance of protecting the existing clients from excessive network upgrades resulting from new electricity

transmission service requests. In its decision D-2015-209, the Régie described the key regulatory principles behind network upgrades as follows[1]:

> "[76] De plus, la Régie constate que les principes directeurs proposés par le Transporteur sont cohérents avec la pratique courante de l'industrie en Amérique du Nord. À cet égard, la Régie retient que la *higher-of policy* de la FERC, mise en place au début de la restructuration du secteur électrique américain, continue d'être un élément de référence dans la pratique nord-américaine en matière de politique d'ajouts.
>
> […]
>
> **[83] C'est dans ce contexte que la Régie adopte, aux fins de la Politique d'ajouts, les principes directeurs suivants :**
>
> **1. éviter les coûts excessifs d'ajouts au réseau demandés par un client et, ainsi, protéger les clients existants;**
>
> **2. assurer la couverture des coûts des ajouts au réseau réalisés pour un client;**
>
> **3. assurer un traitement équitable et un accès non discriminatoire au réseau de transport à tous les clients du Transporteur**."

7. Moreover, one should also consider the particular nature of the electricity market in Québec where the sole provider of bulk transmission services is a division of a vertically integrated public utility. Hydro-Québec Production ("**HQP**"), HQT's affiliate, is an unregulated division that is using transmission services to sell power into neighboring jurisdictions. In that context, it is worth reiterating the importance of having an open and transparent system planning process to ensure that HQT does not plan its system in order to favor its affiliates. The Régie recognized that reality when it approved the inclusion of the Appendix K related to the planning process in *Hydro-Québec's Open Access Transmission Tariff* ("**OATT**")[2]:

> "[303] Néanmoins, la Régie juge que l'objectif de la FERC d'assurer une protection suffisante contre les risques de discrimination indue en matière de planification des réseaux de transport mérite une attention particulière, en raison, d'une part, du caractère monopolistique des activités de transport d'électricité au Québec et, d'autre part, de la présence d'affiliées dans les secteurs de la distribution et du marché de gros de l'électricité.
>
> [304] La Régie réitère l'objectif fondamental d'assurer le traitement équitable et non discriminatoire de l'ensemble des clients dans leur accès au réseau, objectif qu'elle a énoncé à plusieurs reprises dans ses décisions[127]. <u>À cette fin, la Régie a adopté, au fil des ans, divers outils réglementaires</u>, dont le texte des Tarifs et conditions, lequel inclut une partie IV portant sur les conditions applicables à la desserte de la charge locale au Québec <u>et un appendice J portant sur la politique d'ajouts au réseau</u>. Ces outils comprennent également le système OASIS, le code de conduite du Transporteur ainsi que le processus de traitement des plaintes des clients du réseau de transport."

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[1] Decision D-2015-209.
[2] Decision D-2012-010.

(Our underlining)

8. In the extract above, the Régie recognized the importance of the regulation of system planning in order to protect existing clients from potential undue discrimination that could result from it.

9. Said principles are worth keeping in mind in the context of investment matters such as the present file.

3. <u>ANALYSIS OF THE MICOUA-SAGUENAY LINE DRIVERS</u>

10. As per HQT, there are three (3) reasons why the current system needs the Micoua-Saguenay Line upgrade: (1) the lower load in the Côte-Nord region, (2) the closure of Tracy, La Citière and Gentilly-2 power plants have degraded the system reliability on the Manic-Québec corridor, and (3) the system needs to fully integrate the capacity of the hydroelectric complex 3 and 4 on the Rivière Romaine ("**La Romaine 3 and 4**"):

> "La diminution importante depuis 2013 de la prévision de la demande d'électricité sur la Côte-Nord, combinée à la fermeture des centrales de Tracy, de La Citière et de Gentilly-2, accentue la sévérité de certains événements sur les lignes du corridor Manic-Québec entraînant une dégradation de la fiabilité du réseau de transport principal."[3]

> "Pour obtenir un réseau représentatif avec chacune des solutions, il est aussi requis de considérer l'intégration complète du complexe de La Romaine ainsi que l'ajout d'interconnexions."[4]

11. One of the reasons for the need for this reliability investment is outside the control of all customers, namely the lower load in the Côte-Nord region. However, the other reasons resulted from HQP's actions. Who should ultimately, further to a rate case hearing, bear the cost of the investment due to those reasons? NEMC intends to address some of these issues in the following sections.

3.1 HISTORY OF THE MANIC-QUÉBEC CORRIDOR

12. The Manic-Québec corridor has long been a major path in the HQT electric network that has faced serious transient and dynamic stability issues. Reviewing its development provides valuable background for this case, because it demonstrates that HQT has considerable knowledge and experience with the unique reliability challenges in the Manic-Québec corridor, and therefore would have immediately recognized the potential for reliability issues when Tracy, La Citière and Gentilly-2 plants closed, and when the load forecast dropped in the Côte-Nord region.

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[3] HQT-1, Document 1, page 8, lines 13 to17.
[4] HQT-2, Document 1.1, page 18, lines 8 to 10.

13. Hydro-Québec's electric network evolved from a 315 kV network in the 1950's to a high voltage 735 kV network in the beginning of 1965. It began with the development of hydroelectric generation projects on the Outardes and Manicouagan rivers as explained in a 1968 CIGRE paper[5].

14. The need for the *"extra-high-voltage at 735 kV"* was driven by stability studies. The 1968 plan to integrate Churchill Falls generation into HQT's network was to add three (3) 735 kV circuits in three segments each between Churchill Falls and Manicouagan/Outardes with series compensation on all segments. There was also a need to add three (3) more 735 kV circuits to Québec City and two (2) more to Montréal. In 1968, the proposed system in the CIGRE paper cited above was as follows:

Figure 1

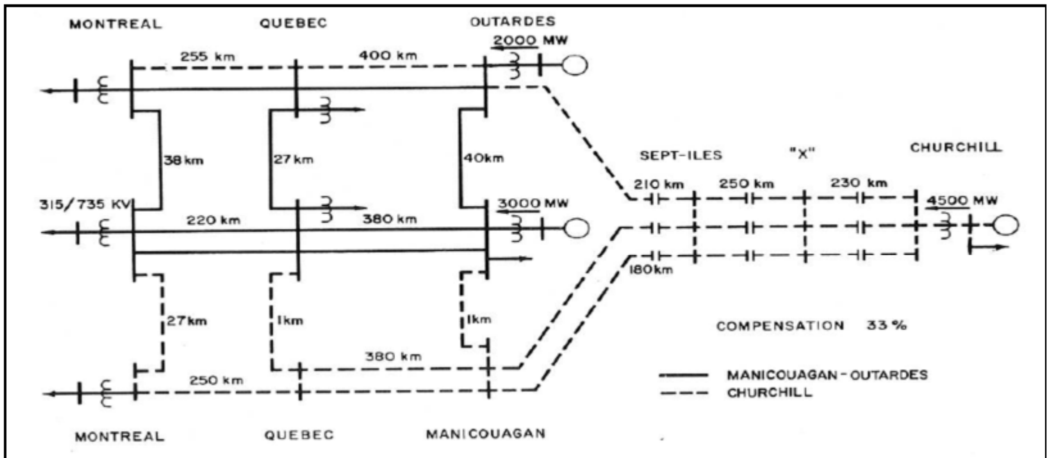

Figure 6 - 735 kV system extension to incorportate Churchill Falls

15. The stability issues that concerned Hydro-Québec at that time were not only the traditional transient (first swing) instability issue but also the dynamic (multi-swing) instability oscillations of the hydroelectric generators in the Côte-Nord region (St. Lawrence River north shore) against the system in the south. For readers that do not understand the difference between these two concepts, we have attached as Appendix A an explanation of the theory behind these two power system stability issues.

16. Transient instability is primarily driven by the amount of reactance X between a generator and the bulk system to which it is connected. The value of reactance X varies with the length of the connecting transmission lines. For a short line, the value of X is small and the connection is tight and stable. For long lines, X is large and it needs to be reduced. The only way to reduce X is to add more transmission lines in parallel, add series compensation or both.

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[5] "*Planning of Extension to Hydro-Québec System to Incorporate Churchill Falls in 3300 Mile Network*", Paper 42-02, CIGRE Summer Session, June 1968, page 6.

17. Dynamic oscillations have low frequencies (0.5 Hz to 2 Hz) that are primarily dependent on the inertia constants (H)[6] of the generators and the system to which they are connected. It helps to have large thermal generators in the system because they have larger H values than hydroelectric generators. The greater the amount of H the lower the frequency of dynamic oscillations and the quicker that they are damped.

18. At that time (1968-1972), dynamic instability was a major concern of power system researchers[7,8] who were looking at the use of power system stabilizers ("**PSS**") to damp low frequency oscillations of voltage and power angle. By 1972, Hydro-Québec had conducted several studies and reversed its decision to utilize series compensation on the Churchill Falls connection lines. Instead, it chose to apply "power stabilizers" as documented in a 1972 CIGRE paper[9].

19. While PSS eliminated the need for series compensation at that time, it did not totally resolve the system stability issue. Transient stability in combination with dynamic stability was still a concern and it increased the performance requirements for a fault on the transmission from Churchill Falls. Other than stability, the 1972 CIGRE paper cited above indicated there was a concern by Hydro-Québec's engineers for reduced operational flexibility by voltage and frequency fluctuations caused by switching operations on the transmission lines. There was hope based on studies that synchronized condensers could possibly solve the problem[10].

20. The addition of the power stabilizers, the synchronous condensers and series compensation between Manicouagan/Outardes and Québec reduced the need for one 735 kV transmission line. Three lines were constructed to connect Churchill Falls to Manicouagan/Outardes but, rather than three (3) additional lines between Manicouagan/Outardes and Québec as originally proposed to integrate Churchill Falls, only two (2) lines were constructed. Little has changed since as the Manic-Québec corridor continues to be made up of five (5) 735 kV lines.

3.2 HYDRO-QUÉBEC'S DEVELOPMENT SINCE CHURCHILL FALLS

21. While few changes occurred on the Manic-Québec corridor, there were large new hydroelectric generation projects in the James Bay region to the far north plus many more 735 kV transmission lines to connect to the southern loads. In addition, a long +/-450 kV High Voltage Direct Current ("**HVDC**") line was added to connect directly from the James Bay region to southern Québec and on to Massachusetts. Other new HVDC interconnections were added to connect to New York, Vermont, New Brunswick and Ontario. Also, in the early 1980's, the Gentilly Nuclear power

[6] H is defined as the megajoules of stored energy of a machine at synchronous speed per megavolt-ampere of the machine rating.
[7] F. de Mello and C. Concordia, *"Concepts of synchronous machine stability as affected by excitation control*" IEEE Transactions on Power Systems, PAS-88, 1969, pages 316 to 329.
[8] Marshall, WK and Smolinski, Walter, "*Field Tests of the Dynamic Performance of a Synchronous Machine*", presented to IEEE Meeting, New York, 1973.
[9] *"Optimization of Hydro-Québec's 735 kV Transmission System"*, Paper 31-10, CIGRE Summer session, 1972, page 6.
[10] *Ibid*, page 5.

plant with its inertia was added in the southern load centre. This added damping to the dynamic oscillations across the Manic-Québec corridor and improved overall system stability.

22. There have been few changes to the Manic-Québec corridor since, but reliability of the system was still an issue. Several major power outages in the 1980's occurred, which created a need to re-assess system design and planning criteria. An IEEE paper notes the possible challenges faced by the HQT's system:

> "Depending on the triggering event, Hydro-Québec's system may be faced with:
>
> (i) transient instability;
>
> (ii) dynamic instability (interregional oscillations at 0.5 Hz);
>
> (iii) voltage instability;
>
> (iv) frequency instability (over- or underfrequency)[11]."

23. The IEEE paper summarizes the successive lines of defense employed by HQT to this day. The two lines of defense most relevant to this case as they have evolved to today are:

> N-1 criteria - Frequent events are to be recovered from with no loss of load without any special protection systems ("SPS")
>
> N-1-1,500 criteria - Rare events can utilize SPS and will have fast recovery for partial outages if they occur.

3.3 HYDRO-QUÉBEC'S RESEARCH AND DEVELOPMENT INITIATIVES

24. As explained in Section 3.1, the integration of Manicouagan, Outardes and Churchill Falls power plants using 735 kV transmission lines resulted from significant studies, researches and development. It resulted in the complex use of various control strategies that have continued developing for fifty (50) years.

25. Much of the research and development was done by the Institut de recherche en électricité du Québec ("**IREQ**"), which was created by Hydro-Québec in 1967. The IREQ's focus continues to be on the optimization of HQT's system through improvement of power stabilizers, improved detection of eminent instability and optimal tuning of control equipment. A sampling of the work on power stabilizers to improve transient and dynamic stability up to 2010 is provided in Appendix B.

26. HQT and the IREQ have been recognized globally through their work on power system dynamics as attested by the above referenced work in Appendix B.

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[11] J. Trudel, J-P. Gingras, J-R. Pierre, *"Designing a Reliable Power System: Hydro-Québec's Integrated Approach"*, Proceedings of the IEEE, Vol. 93, No. 5, 2005, page 908.

3.4 CHRONOLOGY OF EVENTS SINCE 2010

27. In February of 2011, HQT filed an application before the Régie requesting the approval to add to its network transmission facilities to integrate the 1,550 MW from the hydroelectric complex on the Rivière Romaine ("**Romaine Project**"). In its revised evidence, HQT stated that the Romaine Project would have no rate impact, that it would meet all required reliability criteria and that no impact on transfer capacities was identified[12]:

> " […] le Projet ne génère pas d'impact à la hausse sur le tarif de transport.
>
> […]
>
> La réalisation du Projet permet de répondre à la demande du Producteur tout en assurant un niveau de fiabilité adéquat et ce, dans le respect des critères de conception et d'exploitation du Transporteur et du NPCC.
>
> […]
>
> Le Transporteur souligne que les ajouts prévus pour le complexe de la Romaine n'ont pas d'impact direct lors de l'exploitation du réseau, notamment sur les limites d'opération du réseau et sur les grands automatismes de sauvegarde du réseau. Les ajouts identifiés sur le réseau principal n'ont pour but que de maintenir le même niveau de fiabilité qu'avant l'intégration du complexe de la Romaine. Ainsi, aucun impact sur les transits n'est identifié."

28. In its decision D-2011-083 rendered on June 16, 2011, the Régie approved HQT's request, subject to annual filing updates on its progress.

29. A few months before, on March 1, 2011[13], the 660 MW Tracy thermal power plant was retired. This power plant retirement removed about 5 MW/MVA of inertia constant H (about [redacted] MW of stabilizing energy) from the southern system of HQT as well as significant voltage support in that system. It is understood by NEMC that its removal was not included in the analysis regarding integration of the Romaine Project.

30. The next year, the 308 MW La Citière combustion turbine power plant and the 675 MW Gentilly-2 nuclear power plant were retired in March and December 2012, respectively. In total, about [redacted] MW of stabilizing energy was lost.

31. All of the 1,643 MW removed from HQT's system were located in the southern load centre and all contributed to the inertia in the southern system. Without these power plants, the dynamic oscillations between the Côte-Nord generators and the southern system would be of lower frequency with less damping. It is understood by NEMC that these removals were not included in the analysis regarding the

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[12] R-3757-2011, HQT-1, Document 1 (Revised, May 6, 2011) (Exhibit B-0019), page 52, lines 3 and 4, page 53, lines 10 to 12 and page 54, lines 1 to 6.

[13] Tracy Thermal Power Plant, Wikipedia at:
< https://en.wikipedia.org/wiki/Tracy_Thermal_Generating_Station.> (Website consulted on January 8, 2019).

integration of the Romaine Project. This is a question of concern and it will be explored more later.

32. By 2013, load forecasts received by HQT from Hydro-Québec when carrying on electric power distribution activities ("**HQD**") for the Côte-Nord region for 2021 and beyond were successively lower than previously forecast, the whole as shown below[14]:

Figure 2

Tableau 2
Évolution de la prévision* de la demande d'électricité sur la Côte-Nord

Date d'émission de la prévision	Pointe de l'hiver 2020-2021		Pointe de l'hiver 2030-2031***	
	Total (MW)	Écart (MW)**	Total (MW)	Écart (MW)**
2010	3296	0	3302	0
2011	3206	-89	3213	-89
2012	2988	-308	3010	-291
2013	2355	-940	2422	-879
2014	2707	-588	2858	-443
2015	2196	-1100	2276	-1026
2016	2205	-1091	2249	-1052
2017	2318	-978	2372	-930

* Prévision annuelle du Distributeur.
** Écart avec la prévision émise en 2010.
*** Valeurs de l'hiver 2030-2031 extrapolées à partir des prévisions du Distributeur.

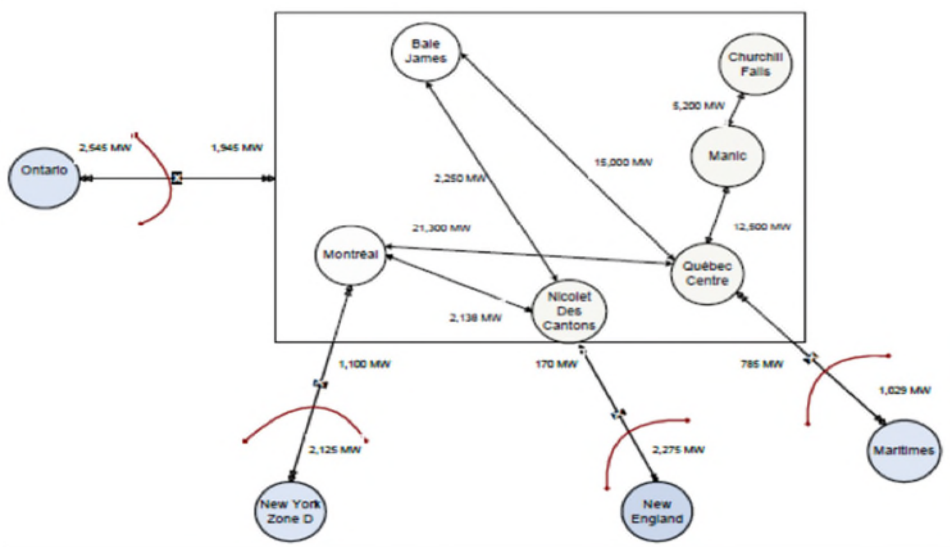
33. It should be noted that the forecast of 2013 indicated that the peak load in the Côte-Nord region for the winter of 2020-2021 was 940 MW less than that of 2010. The 2010 forecast, or one similar, would have been the load forecast known by HQT before they submitted the request at the Régie for the integration of the Romaine Project. It is understood that the current load in the Côte-Nord region is about 2,300 MW, which is also a concern and will be discussed later.

34. HQT has filed a Comprehensive Review of Resource Adequacy for the Québec Balancing Authority Area in 2011, 2014 and 2017[15]. It is an assessment of the Loss of Load Expectation ("**LOLE**") over the next five (5) years for the load in the area in days/years. It is compared to the Northeast Power Coordinating Council ("**NPCC**") Resource Adequacy Criteria of 0.1 days/year or less. The LOLE analysis requires that transmission limits for internal interfaces (like the Manic-Québec corridor) as well as external interconnections (Ontario, New York, New England and New Brunswick) are considered. Each of the reviews has included a diagram illustrating the interfaces for HQT's system plus a table stating the transfer capacities between sub-areas for the first and last years of the review. The diagram has been essentially the same for each review but the transfer capacities have not. The diagram plus the transfer capacities for the Churchill Falls-Manic and Manic-Québec corridors are shown below:

[14] HQT-1, Document 1, Table 2, page 7.
[15] These reviews are available at:
< https://www.npcc.org/Library/Resource%20Adequacy/Forms/Public%20List.aspx.>

Figure 3

Figure A-7.2 Québec's Internal Interfaces and Interconnections (2014-2015)



Sub area		2008 Comprehensive Review	2011 Comprehensive Review	
From	To		2011/12 winter peak period	2015/16 winter peak period
Churchill Falls	Manicouagan	5,200	5,200	5,200
Manicouagan	Québec Centre	11,750	12,100	12,900

Sub area		2011 Comprehensive Review	2014 Comprehensive Review	
From	To		2014-15 winter peak period	2018-19 winter peak period
Churchill Falls	Manicouagan	5,200	5,200	5,200
Manicouagan	Québec Centre	12,900	12,500	13,200

Sub area		2014 Comprehensive Review	2017 Comprehensive Review	
From	To		2017-18 winter peak period	2021-22 winter peak period
Churchill Falls	Manicouagan	5,200	5,200	5,200
Manicouagan	Québec Centre	13,200	12,500	12,500

35. As shown above, the transfer capacity for the Churchill Falls-Manic corridor has remained constant at 5,200 MW, but the Manic-Québec corridor has varied significantly from a low of 11,750 MW in 2008 to a high of 13,200 MW for the 2018-2019 winter peak in the 2014 review. In the 2017 review, the Manic-Québec corridor transfer capacity was revised down to 12,500 MW for 2017-2018 through 2021-2022. These variations in transfer capacity will be discussed later.

36. In October 2017, HQP filed the 440 MW Sainte-Marguerite project with HQT for a system impact study ("**SIS**").

37. In July 2018, HQT filed its application for the Micoua-Saguenay Line.

3.5 HQT'S RATIONALE FOR THE MICOUA-SAGUENAY LINE

38. According to HQT's evidence, the current electric system will not meet the system planning criteria in 2020-2021:

> "Les analyses du Transporteur révèlent que, pour les niveaux de transits prévus tant à l'horizon 2020-2021 qu'à l'horizon 2030-2031, les critères de conception du réseau de transport ne sont plus respectés. Ces analyses sont effectuées en simulant le comportement du réseau de transport à la suite de divers événements dans des conditions initiales de réseau prédéfinies. Le comportement attendu du réseau de transport, les différentes conditions de réseau considérées et les divers types d'événements simulés sont encadrés par les critères de conception du Transporteur, les critères du Northeast Power Coordinating Council, Inc. et la norme de fiabilité TPL-001-4 adoptée par la Régie."[16]

39. We have indicated above the reasons submitted by HQT justifying the Micoua-Saguenay Line.

40. According to HQT, the lower load in the Côte-Nord region created two effects regarding dynamic stability. It increased the amount of generation that needed to flow across the Côte-Nord corridor and it reduced the amount of inertia in the region provided by the industrial load.

41. NEMC has completed an analysis of operation of the Manic-Québec corridor using the HQD load forecast for 2020-2021, the Côte-Nord transmission losses on the 735 kV system[17] and the transfer capacities[18] provided in the Resource Adequacy reviews provided by Hydro-Quebec to the NPCC. All values are in MW. The table below seems to indicate that there would be no issue until a small deficiency by the 2017 forecast:

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[16] HQT-1, Document 1, page 8, lines 17 to 25.

[17] Transmission losses on the high voltage HQT system (66 kV - 735 kV) are not included in the HQD load forecast so they must be subtracted to determine the delivered MW. The transmission losses have been estimated at 500 MW.

[18] Transfer capacity is the N-1 firm transmission across an interconnection or a corridor.

Table 1

	Côte-Nord Region			Manic-Québec Corridor		
Forecast Year	Generation in 2020-21	Load in 2020-21	Transmission Losses	Delivered at Quebec	Transfer Capacity	Surplus (Deficit)
2010	15,400	3,296	500	11,604	12,900	1296
2011	15,400	3,206	500	11,694	12,900	1206
2012	15,400	2,988	500	11,912	12,900	988
2013	15,400	2,355	500	12,545	12,900	**355**
2014	15,400	2,707	500	12,193	13,200	**1007**
2015	15,400	2,196	500	12,704	13,200	**496**
2016	15,400	2,205	500	12,695	13,200	**505**
2017	15,400	2,318	500	12,582	12,500	**-82**

42. The difficulty with this result is that the actual transfer capacities for years 2012 to 2016 were lower. With the closure of the power plants in the south, by 2012, the transfer capacity would have deteriorated to at least 12,500 MW. Redoing the analysis results in the following table:

Table 2

	Côte-Nord Region			Manic-Québec Corridor		
Forecast Year	Generation in 2020-21	Load in 2020-21	Transmission Losses	Delivered at Quebec	Transfer Capacity	Surplus (Deficit)
2010	15,400	3,296	500	11,604	12,900	1296
2011	15,400	3,206	500	11,694	12,500	806
2012	15,400	2,988	500	11,912	12,500	588
2013	15,400	2,355	500	12,545	12,500	**-45**
2014	15,400	2,707	500	12,193	12,500	307
2015	15,400	2,196	500	12,704	12,500	**-204**
2016	15,400	2,205	500	12,695	12,500	**-195**
2017	15,400	2,318	500	12,582	12,500	**-82**

43. This result is not encouraging and it assumes that the transfer capacity of 12,500 MW is actually achievable in the existing system. The HQT (and IREQ) system modellers would have known in 2013 or 2014 that there was a looming problem with the Manic-Québec corridor transfer capability. Having done studies since at least 2013, HQT acknowledges this timing in its evidence:

> "Le Transporteur a réalisé plusieurs études depuis 2013 qui permettent d'identifier les besoins liés au Projet. L'étude de planification dont les hypothèses sont les plus à jour a été réalisée en 2016."[19]
>
> Pour le Projet, la première analyse a été réalisée en 2014 et a permis de recommander le début de la phase avant-projet de la solution 1 [Micoua-Saguenay Line], retenue en novembre 2014."[20]

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[19] HQT-2, Document 1.1, page 5, lines 25 to 27.
[20] HQT-1, Document 1, page 22, lines 8 to 10.

44. While HQT should have been concerned about the Manic-Québec corridor transfer capacity since 2013 and took until 2016 to finalize a solution, HQD filed with the NPCC in 2014 that the Manic-Québec corridor transfer capacity for 2018-2019 would be 13,200 MW. As stated in response to NEMC's information request, HQT assumed that the transmission upgrades would be able to be approved by the Régie and be in service[21].

45. The decision taken by HQT at that time was to proceed with the Micoua-Saguenay Line. It was taken without notifying the Régie of the material changes to the network since the approval for the integration of the Romaine Project. If La Romaine 3 and 4 had been delayed, the Côte-Nord generation would have been reduced by 640 MW and the cost of the transmission line to Montagnais would have been avoided. The transfer results would be as follows assuming that the 12,500 MW transfer capacity was still valid:

Table 3

	Côte-Nord Region			Manic-Québec Corridor		
Forecast Year	**Generation in 2020-21**	**Load in 2020-21**	**Transmission Losses**	**Delivered at Quebec**	**Transfer Capacity**	**Surplus (Deficit)**
2010	14,760	3,296	500	10,964	12,900	1936
2011	14,760	3,206	500	11,054	12,500	1446
2012	14,760	2,988	500	11,272	12,500	1228
2013	14,760	2,355	500	11,905	12,500	595
2014	14,760	2,707	500	11,553	12,500	947
2015	14,760	2,196	500	12,064	12,500	436
2016	14,760	2,205	500	12,055	12,500	445
2017	14,760	2,318	500	11,942	12,500	558

46. Given that the Manic-Québec corridor transfer capacity is actually 12,500 MW, the need for the Micoua-Saguenay Line possibly could have been avoided if La Romaine 3 and 4 were delayed.

47. Based on the analysis regarding projected transfer capacities, it was clear in 2013 that there were issues with integration of the Romaine Project, especially La Romaine 3 and 4. HQT should have informed the Régie and revisited its integration requirements.

3.6 THE MANIC-QUÉBEC CORRIDOR TRANSFER CAPACITY LIMIT VS SYSTEM DESIGN REQUIREMENTS

48. [redacted]

[21] R-4052-2018, HQT-3, Document 5, R.2.2, page 12.

49. [redacted]

50.

51.

52.

22 HQT-2, Document 1.1, Tableau 3, page 8.

53. [redacted]

54. [redacted]

55. [redacted]

3.7 IMPACT OF MORE GENERATION IN THE CÔTE-NORD REGION

56. Given that the 440 MW Sainte-Marguerite project is currently under study by HQT to determine system impact issues and connection facilities requirements, it will likely be added to the system in 2025. What is the required Côte-Nord transfer capacity to handle it for N-1 conditions and what are the maximum flows that meet the N-1-1,500 requirement? Based on the 14,000 MW transfer capacity estimate by NEMC, the Micoua-Saguenay Line option provides surplus capacity that would accommodate the Sainte-Marguerite Project.

57. This information would be determined by the system impact study and under HQT's OATT[23] should normally have been completed by the end of February 2018. An additional 12 months has passed and HQT has responded that the system impact is not yet completed. This is well beyond "a reasonable time" to complete the study especially as it would include findings that are relevant to this file.

58. NEMC understands that the Régie is not required to speculate on future issues for this file but optimal system planning would consider this generation addition as HQD did in their project analysis. It clearly appears that the Sainte-Marguerite project will benefit from any extra capacity available on the Micoua-Saguenay Line. This project has multiple beneficiaries (namely the Sainte-Marguerite project and the Romaine Project as explained below). It improves reliability for the system but it is not only a reliability project. It also adds transfer capacity to the Manic-Québec corridor that supports integration of generation. How the optimal costs are allocated is a major issue. More on this will be discussed later.

59. To address the impact of each solution presented on the integration of future generation, more information would be required. Specifically, for each of the three alternatives, what is the N-1 transfer capacity of the Côte-Nord corridor and what is the maximum flow to meet the N-1-1,500 criteria? Based on our analysis for the N-1-1,500 criteria, the firm N-1 transfer capacity of the corridor after the addition of the Micoua-Saguenay Line is roughly 14,000 MW. This leaves additional capacity for the integration of future generation. NEMC requested further information via its information request number 2 regarding the reliability criteria and transfer capacities which could contribute to this analysis. No transfer capacities were provided by HQT.

60. The series compensation solution solves the reliability issue, which we know because HQT included it as a proposed solution. Its capital costs are much lower than the Micoua-Saguenay Line, and its overall costs are lower according to NEMC's economic analysis. If the series compensation solution is selected in this file, and then the integration of future generation requires the Micoua-Saguenay Line, the series compensation investment may be replaced. This would be similar to the way that the Chamouchouane-Bout-de-l'île line replaced certain portions of the Romaine integration work. In that case, the entity that requested the generation integration would presumably pay the balance of the cost. The higher losses of the series compensation would never materialize, and costs would be allocated for the Micoua-Saguenay Line according to the principle of cost causation.

[23] Sections 19.3 and 32.3 of the OATT specify that HQT would "use due diligence to complete the SIS within 120 days" and in Section 40.3 would "use due diligence to complete the SIS within a reasonable time"

3.8 GENERATION CONNECTION COSTS FOR LA ROMAINE PROJECT

61. During the November 13, 2015 information and discussion meeting on transmission system planning, HQT made a presentation pertaining to its main transmission system. In the figure below, we have copied slide number 3 of the above-mentioned presentation (redacted version)[24] where it is clearly mentioned that generation was increasing in the Côte-Nord region.

Figure 4

62. In the current proceedings, HQT justifies namely the need for the new line mainly based on the following factors: the reduction in forecasted demand for the year 2020-2021 and the permanent closures of southern thermal plants owned and operated by HQP.

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24 http://www.oasis.oati.com/hqt/index.html

63. As shown above, it appears that the Romaine Project is an important driver for the Micoua-Saguenay Line. In response to NEMC's information request number 1 (question 1.8)[25], HQT confirmed that the increased generation mentioned in the above figure does in fact refer to the Romaine Project.

64. NEMC intends to address this issue by reviewing the impact of the Romaine Project that added 1,550 MW of new generation upstream of the Manic-Québec corridor over the 2014-2021 period.

3.8.1 Description of the Romaine Project

65. The Romaine Project involved the construction of two (2) 735 kV transmission lines operated at 315 kV. One line is connecting the Romaine 1 and 2 to the Arnaud substation and the other line connect the Romaine 3 and 4 to the Montagnais substation. These investments are labeled as local network investments.

66. The project also involved investments on the "bulk system" or main transmission system for the purpose of this evidence. These investments are related to the addition of series compensation scattered on several existing 735 kV lines and also the construction of a new substation called Outardes located in the Côte-Nord region.

67. As approved by the Régie in the Chamouchouane-Bout-de-l'île 735 kV transmission line project filing (R-3887-2014), that project replaced some of the already approved main transmission system investments approved in the Romaine Project filing (R-3757-2011).

68. The Micoua-Saguenay Line analysis assumed the following commissioning dates:

- Romaine-1: 270 MW commissioned in 2016;
- Romaine-2: 640 MW commissioned in 2014;
- Romaine-3: 395 MW commissioned in 2017;
- Romaine-4: 245 MW, initially planned for commissioning in 2020 (now 2021).

3.8.2 Romaine Project integration request to the Régie[26]

69. The Romaine Project was presented to the Régie for approval in 2011. The proposed project cost was $1.73 billion detailed as follows: $1.33 billion for the interconnections of the power plants to the existing network (local network investment) and $0.4 billion for the main transmission system investments. In the evidence pertaining to the economic justification of the project, HQT presented three (3) solutions for the investments on the main transmission system. Only one

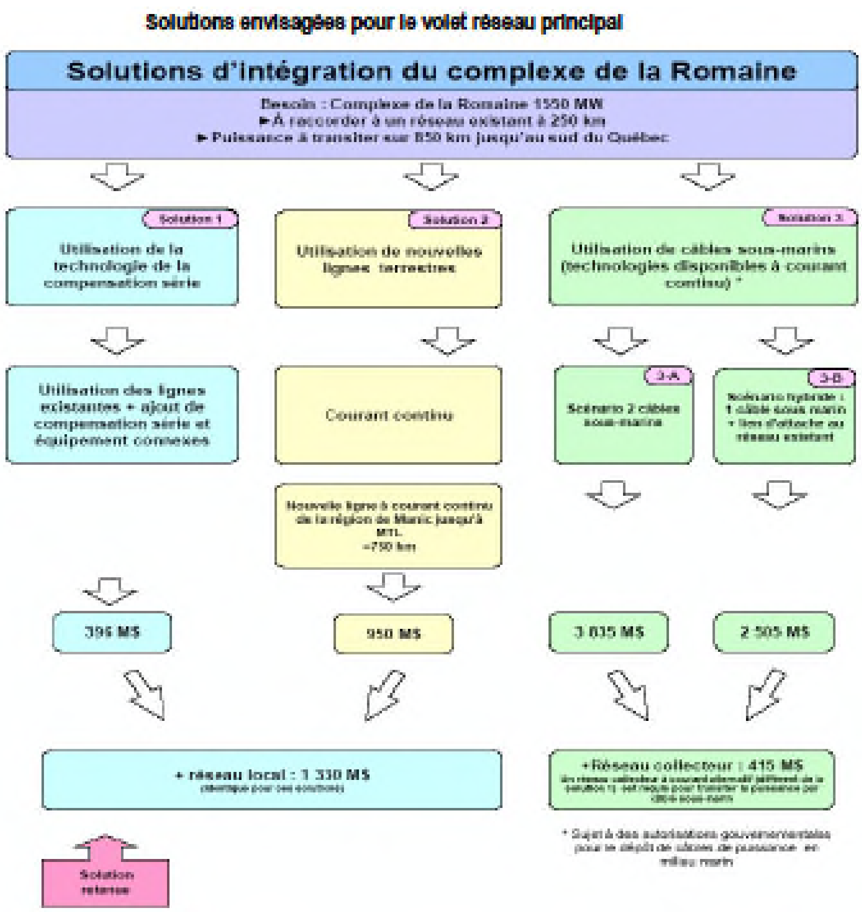
[25] Exhibit B-0043, page 8.
[26] Docket R-3757-2011.

solution was presented for the investments related to the local network. The three (3) solutions presented to the Régie were:

- Solution 1: series compensation (preferred option);
- Solution 2: new 750 km 1,000 MW HVDC transmission line between the Côte-Nord region and the southern portion of HQT's network;
- Solution 3: consisting of two (2) scenarios involving one or two underwater cables between the Côte-Nord region and the southern portion of HQT's network.

70. You will find below a figure prepared by HQT in the evidence filed at the Régie summarizing the proposed solutions[27]:

Figure 5



[27] R-3757-2011, Exhibit B-0004, page 33.

71. As one can notice, solution 3 was too expensive to be considered as a realistic alternative. Solution 1 (series compensation) and 2 (above ground transmission line) are similar in nature to solution 3 (series compensation) and solution 1 (above ground transmission line) in the current Micoua-Saguenay investment file.

72. That being said, there is one major difference between both files. In the Romaine Project submitted for approval to the Régie, the economic analysis justifying the main transmission system investment did not consider the impact on system losses when comparing the solutions. This is a significant difference since system losses is the most important cost factor that favors the transmission line option in the Micoua-Saguenay investment file. Losses were also a pivotal factor in the economic analysis of the Chamouchouane-Bout-de-l'île transmission line project[28].

73. The decision not to include the losses is surprising since HQT was fully aware of the impact of adding generation from the Romaine Project on system-wide losses and its economic value. In the 2004 system impact study (SIS) number 75R_9 (see Appendix C) provided by HQT to Newfoundland and Labrador Hydro, we can read[29]:

> "7.2 Les coûts des pertes en énergie et en puissance
>
> Le coût des pertes est calculé en tenant compte des pertes en puissance et énergie du facteur d'utilisation de la centrale, et ce pendant 50 ans. En utilisant un facteur de pertes de 0,3087, le coût des pertes est évalué à 1,65 M$/MW.
>
> Les pertes engendrées sur l'ensemble du réseau dues à l'intégration du complexe Romaine étant de 169 MW, le coût combiné de ces pertes se chiffre donc à 278 844 000 $ (actualisé en $ 2003).
>
> À titre de comparaison, les 25 MW économisés par l'utilisation du 735 kV pour intégrer le complexe Romaine vis-à-vis l'utilisation du 315 kV telle que préconisée dans le scénario 1, ont une valeur de 41 250 000 $."

74. The system losses presented in the extract above are based on the impact of adding the Romaine generation vs the state of the system as it was before the integration. We could expect the economic impact of losses associated with integration of the Romaine Project using series compensation (solution 1) to be significantly higher when compared to the solution involving the above ground 1,000 MW HVDC transmission line (solution 2).

75. In order to compare the economic analysis done in the Romaine Project and the ones done in the Micoua-Saguenay and Chamouchouane-Bout-de-l'île files, we compared the proposed solutions costs, from those files, with and without the impact of losses:

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[28] R-3887-2014, Exhibit B-0006, Table 3, page 34.
[29] R-3757-2011, Exhibit B-0017, page 3.

Table 5

	R-4052-2018 (Micoua-Saguenay)			R-3557-2011 (Romaine)		R-3887-2014 (Chamouchouane-Bout-de-l'île)	
	Solution 1: Micoua-Saguenay line	Solution 2: Outardes-Laurentides line	Solution 1: Series compensations	Solution 1: Series compensation	Solution 2: 1000 MW HVDC line	Solution 1: 735 kV line	Solution 2: series Compensation1000 MW HVDC line
Total cost excluding losses	$ 563.2 M	$ 898.5 M	**$ 290.9 M**	**$ 396 M**	$ 950 M	$ 699.9 M	**$ 578.6 M**
Losses (only available in the R-4052-2018 docket)	$ 268.5 M	$ 0 M	$ 602.6 M	$? M	$ 0 M	$ 0 M	$ 873.7M
Total Cost including losses	**$831.7 M**	$898.5 M	$893.5 M	$? M	**$950 M**	**$ 699M**	$1,450 M

76. The figures in bold represent the lower cost option depending on the inclusion or not of the impact of losses in the economic analysis. When we are not considering the transmission losses, the series compensation options in the files R-3887-2014 and R-4052-2018 would have been considered the lowest costs options as it was the case in the R-3757-2011 proceedings.

77. The losses assumptions for the series compensation solution in the Romaine Project were not provided in the regulatory filing. That being said, based on HQT's loss estimates in the R-3887-2014 and R-4052-2018 proceedings, we can assume that adding a loss component to the economic analysis would have made the series compensation significantly more costly compared to the HVDC transmission line option.

78. NEMC understands that the technical solutions discussed in SIS 75R_9 are not exactly the same as the one presented in the R-3757-2011 proceedings, but it shows that HQT was fully aware, as early as 2004, of the economic impact of system losses associated with the integration of the Romaine Project to its network. It appears that the approach to the project economic analysis used in the Romaine Project was different from those associated with reliability driven projects that are proposed to be socialized among all HQT's customers such as file R-3887-2014 and the current Micoua-Saguenay Line.

3.9 EVOLUTION OF THE ROMAINE PROJECT

79. In its decision D-2011-083, the Régie provided the reasoning for authorizing HQT's request to integrate the Romaine Project. In that decision, recognition is given to the effect that such a large project deployed over a long period of time (10 years) may need modifications due to the network and market conditions[30]. HTQ also recognized that if a project change would substantially modify its costs and profitability, it would require a new authorization before the Régie.

80. NEMC is of the view that HQT should have informed the Régie of the decreasing load in the Côte-Nord region starting in 2013 as well as the thermal plant closures which may have triggered a re-evaluation of the integration of the Romaine Project before the Régie.

[30] D-2011-083, pages 52 and 53.

81. Furthermore, as reported in the HQT annual report for the year 2013[31], as of December 31, 2013, practically no investment was made for the integration of the Romaine 3 and 4:

Figure 6

La Romaine - Coûts des travaux par installation (1)
EN MILLIERS DE DOLLARS DE RÉALISATION

	Budget	Réalisé au 2013-12-31	Prévision	Budget	Réalisé au 2013-12-31	Prévision
RÉSEAU LOCAL						
Installation de transport						
Ligne Arnaud - de la Romaine-2	429 373,4	415 998,4	510 966,6	23,5%	81,4%	25,4%
Ligne Montagnais - de la Romaine-4	315 114,3	34 098,5	528 843,9	17,2%	6,4%	26,3%
Ligne de la Romaine-3 - de la Romaine-4	92 284,6			5,0%		
Ligne de la Romaine-1 - de la Romaine-2	34 187,7	2 623,6	34 588,2	1,9%	7,6%	1,7%
Total Lignes	**870 959,9**	**452 720,5**	**1 074 398,7**	**47,6%**	**42,1%**	**53,5%**
Poste de la Romaine-1	55 899,6	5 917,9	66 181,1	3,1%	8,9%	3,3%
Poste de la Romaine-2	103 188,1	90 405,4	111 444,4	5,6%	81,1%	5,5%
Poste de la Romaine-3	37 222,0	3 086,0	45 385,7	2,0%	6,8%	2,3%
Poste de la Romaine-4	145 331,1	17,4	97 320,5	7,9%	0,0%	4,8%
Poste Arnaud	32 582,0	41 737,8	53 522,9	1,8%	78,0%	2,7%
Poste Montagnais	11 368,9	74,9	21 409,2	0,6%	0,3%	1,1%
Total Postes	**385 591,7**	**141 239,4**	**395 243,8**	**21,1%**	**35,7%**	**19,7%**
Installation de télécommunications (coûts paramétriques)						
Complexe de la Romaine	73 906,0	24 480,2	73 600,1	4,0%	33,3%	3,7%
Total Télécommunications	**73 906,0**	**24 480,2**	**73 600,1**	**4,0%**	**33,3%**	**3,7%**
Total RÉSEAU LOCAL	**1 330 457,6**	**618 440,1**	**1 543 242,6**	**72,7%**	**40,1%**	**76,8%**

82. At that time (2013), HQT was aware of the load forecast decrease for the year 2020-2021. Such a change in the network configuration should have given an incentive for HQT to modify the Romaine Project and inform the Régie in order for the system to be able to integrate the new generation.

83. The new reality resulting from the combination of an actual loss of industrial load, the closures of the thermal plants and the addition of new generation (Romaine Project) should have then be addressed.

4. ECONOMIC ANALYSIS

4.1 HQT'S ECONOMIC ANALYSIS

84. HQT indicates that "*les résultats de l'analyse économique réalisée par le Transporteur démontrent clairement que les coûts globaux actualisés de la solution 1 retenue sont inférieurs à ceux des solutions 2 et 3.*" The actual results of HQT's analysis are summarized as follows[32]:

[31] <http://www.regie-energie.qc.ca/audiences/RappHQT2013/HQT-03-01AvancementProjetsmajeurs2013_2014-07-04.pdf>, page 31.

[32] HQT-1, Document 1, page 23, lines 1 to 3.

Figure 7

Tableau 4 Comparaison économique des solutions (M$ actualisés 2018)			
	Solution 1 Nouvelle ligne à 735 kV Micoua-Saguenay	**Solution 2** Nouvelle ligne à 735 kV Outardes-Laurentides	**Solution 3** Compensation série dans le corridor Manic-Québec
Investissements	585,7	929,0	277,5
Valeurs résiduelles	-67,9	-102,0	-2,7
Taxe sur les services publics	45,4	71,5	16,1
Charges d'exploitation Pertes électriques	222,6	——	571,4
Coûts globaux actualisés (CGA)	**785,7**	**898,5**	**862,3**

85. HQT indicates that *"*[l]*e détail de l'analyse économique et les paramètres utilisés sont présentés à l'annexe 5*"[33]. NEMC has reviewed said Schedule 5 and has four (4) issues with HQT's economic analysis, which are the following:

- The loss factor used is too high;
- The energy cost of the transmission losses is too high;
- The capacity cost of losses is too high.

4.2 THE LOSS FACTOR USED IS TOO HIGH

86. HQT determines capacity losses and energy losses as follows:

> "Le Transporteur précise que les écarts de pertes en puissance à la pointe du réseau (P_{PP}) entre diverses solutions qu'il utilise sont déterminés par la comparaison des écoulements de puissance de chacune des solutions. Le Transporteur précise également que les écarts de pertes en énergie sur une base annuelle (P_{EA}) entre plusieurs solutions sont établis par l'équation qui suit :
>
> $P_{EA} = P_{PP} \times F_P \times 8760$ heures
>
> Où :
>
> P_{PP} représente la valeur des écarts de pertes en puissance à la pointe du réseau. F_P est le facteur de pertes calculé à partir de l'équation polynomiale suivante :
>
> $F_P = 0{,}9 \times F_C^2 + 0{,}1 \times F_C$
>
> où :

33 *Ibid*, page 23, line 4.

F_C = facteur de charge correspond normalement à un taux d'utilisation du réseau de 70 %. Cette valeur a été déterminée en fonction de valeurs mesurées sur le réseau.

Ainsi, $F_P = 0{,}9 \times 0{,}7^2 + 0{,}1 \times 0{,}7 = 0{,}511$"[34]

87. NEMC is of the view that the loss factor (F_P) equal to 0.511 used by HQT in its analysis is not correct because the load factor (F_C) required in the formula to determine F_P is not the 70% value applied by HQT. This is an assumed number by HQT that is not consistent with annual peak and energy data provided in the 2017 Annual Report of Hydro-Québec. The analysis of such data for the last five (5) years as shown below indicates that the average load factor (F_C) is rather 0.6732 and the average loss factor (F_P) over the five (5) years would be 0.4749:

Table 6

Determination of HQ Historical Load and Loss Factors

	2017/18	2016/17	2015/16	2014/15	2013/14	Average
HQ 2017 Annual Report[1]						
Peak Load (MW)	38,204	36,797	37,347	38,743	39,031	38,024
Energy (GWh)	226,824	223,143	222,172	222,045	226,576	224,152
Calculated Values						
Load Factor (F_C)[2]	0.6778	0.6923	0.6791	0.6542	0.6627	0.6729
Loss Factor (F_P)[3]	0.4812	0.5005	0.4830	0.4507	0.4615	**0.4749**

Where:

1 Peak and energy data from **Operating Statistics Table,** page 77, **HQ 2017 Annual Report**

2 Load Factor (F_C) = Total energy (GWh) /(Peak Load (GW) x 8,760 hrs)

3 Loss Factor (F_P) = $0.9xF_C^2 + 0.1xF_C$ (from HQT-2, Document 1.1, page 17, line 16)

88. The 0.4749 loss factor was applied in NEMC's original evidence. Since then, it has been determined in HQT-11, Document 2 filed in the Régie's file R-4058-2018, at page 14, that HQT applies a system load factor equal to 0.591 for its 2019 cost of service allocation. NEMC noted this in its responses to the Régie's information request number 1 to NEMC and stated that it should apply to the base case economic evaluation for this file. The use of 59.1% as the load factor (F_C) reduces the loss factor (F_P) to be used in the economic analysis to 0.37345.

89. The effect of lowering the loss factor (F_p) on the economic analysis is to lower the amount of energy losses. This will lower the cost of losses in each solution but the greatest reduction will be in the series compensation option because it has the highest capacity losses. NEMC is thus of the view that HQT's economic analysis is incorrect and needs to be redone.

[34] HQT-2, Document 1.1, page 17, lines 7 to 20.

4.3 THE ENERGY COST OF THE TRANSMISSION LOSSES IS TOO HIGH

90. The cost of the transmission losses used by HQT in its economic analysis were based on "*la valeur des coûts évités en puissance et en énergie du Distributeur*"[35]. The cost of the transmission losses from 2023 to 2029 are summarized below. It should be noted that the energy rate more than doubles in 2028 and the capacity rate is six times higher in 2026.

Table 7

Costs of Losses	2023	2024	2025	2026	2027	2028	2029	...
Energy Rate ($/MWh)	46	47	48	48	49	108	110	...
Capacity Rate ($/MW-yr)	22965	23424	23893	131695	134329	137015	139756	...
Escallation		2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	...

91. NEMC disagrees with the use of HQD's avoided costs for this analysis. They are not avoided costs for HQT, they are simply internal transfers within Hydro-Québec. The cost of differential losses for the solution options is the lost opportunity of HQP to gain export revenue from external markets. System losses are incremental to supply of loads and are similar to negative energy imbalances which cause an incremental increase in generation. Using the lost export market revenue is not just appropriate on its own, it is consistent with the manner by which HQT settles energy imbalance in Schedule 4 of HQT's OATT. Energy Imbalance is based on market prices as it was requested by the Régie in its Decision D-2009-015:

> "La Régie considère que l'utilisation d'un prix de marché satisfait l'objectif d'offrir une juste compensation au fournisseur du service, sans créer d'opportunités d'arbitrage pour les clients du Transporteur.
>
> **La Régie est d'avis que le prix de référence doit refléter les prix horaires sur les marchés limitrophes, ajustée des coûts de transport.**"[36]

92. The pricing of negative energy imbalances as approved by the Régie in Schedule 5 of HQT's OATT are based on the incremental price defined as follows:

> "Incremental price: This price equals the highest hourly price for each hour among the following three (3) markets: (1) New York: the NYISO Real-time price (Zone M) less US$0.18/MWh, less the applicable rate for the Transmission Provider's point-to-point hourly transmission service, including applicable rates for ancillary services necessary to deliver energy to the NYISO's Zone M ("NY Incremental Price"); (2) New England: the ISO-NE Real-time price for Phase II (Sandy Pond) less US$6.00/MWh, less the applicable rate for the Transmission Provider's point-to-point hourly transmission service, including applicable rates for ancillary services necessary to deliver energy to Sandy Pond ("NE Incremental

[35] HQT-2, Document 1.1, page 20, line 1.

[36] D-2009-15, page 111.

> Price"); and (3) Ontario: the IESO hourly market price (HOEP) less the applicable rate for the Transmission Provider's point-to-point hourly transmission service, including applicable rates for ancillary services necessary to deliver energy to Ontario ("ONT Incremental Price")."[37]
>
> (Our underlining)

93. Historically, the highest priced market has been the ISO-NE market but its access for loss savings is currently limited because the Phase 2 interconnection is often at capacity. Loss savings would need to be sold to a lower price market which would reduce netback revenue. In the longer term it is highly probable that an additional interconnection[38] to ISO-NE will be likely. Rather than include a probability of lower prices during congested access to ISO-NE, NEMC believes that using ISO-NE prices for all losses may be conservative but is appropriate. As a result, the energy price in the economic analysis of the transmission options should be **"the ISO-NE Real-time price for Phase II (Sandy Pond) less US$6.00/MWh**."

94. NEMC subscribes to the PIRA/Platts forecasting service[39] and proposes that its forecast for the Mass Hub energy price be used in the economic analysis of the solution options. Historically, for the past five years, the Phase 2 node price has been 98.4% of the Mass Hub price. The netback prices for evaluation of losses in Québec are provided in table below:

Table 8

			2023	2024	2025	2026	...	2040	...	2062
Mass Hub Average Price	$US/MWh	a	39.75	40.56	42.03	44.42	...	67.58	...	104.47
Phase 2 Node Price	$US/MWh	b=a*98.4%	39.12	39.91	41.36	43.71	...	66.49	...	102.80
Less Phase 2 Transmission	$US/MWh	c	6.00	6.00	6.00	6.00	...	6.00	...	6.00
Price at HQ interconnection	$US/MWh	d=b-c	33.12	33.91	35.36	37.71	...	60.49	...	96.80
Exchange rate	$US/$Cdn	e	0.8	0.8	0.8	0.8	...	0.8	...	0.8
ISO-NE Energy Price to HQP	$Cdn/MWh	f=d/e	41.40	42.39	44.20	47.13	...	76.97	...	123.09

4.4 THE CAPACITY COST OF THE TRANSMISSION LOSSES IS TOO HIGH

95. ISO-NE operates a Forward Capacity Market ("**FCM**") which is explained on the ISO-NE web site as follows.

> "The Forward Capacity Market (FCM) ensures that the New England power system will have sufficient resources to meet the future demand for electricity. Forward Capacity Auctions (FCAs) are held annually, three years in advance of the operating period. Resources compete in the auctions to obtain a commitment to supply capacity in exchange for a market-priced capacity payment."[40]

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[37] HQT's OATT, Schedule 4, Generator Imbalance Service, page 110.

[38] The New England Clean Energy Connect (NECEC) through Maine is currently under regulatory review and its acceptance is likely.

[39] S&P Global Platts, PIRA Eastern Grid-ERCOT Long-Term Electricity Forecast, October 5, 2018.

[40] ISO-NE at <https://www.iso-ne.com/markets-operations/markets/forward-capacity-market/>.

96. The FCM has operated since 2008 and system-wide prices have varied from a low of $US2.95/kW-month for 2012/2013 and 2013/2014 to a high in FCA #9 for 2018/2019 of $US9.55/kW-month and down to $US4.63/kW-month for 2021/2022. Prices for importers like Hydro-Québec and NB Power are usually lower because of their distance from the Mass Hub.

97. Hydro-Québec regularly participates in the FCM and, as result of the FCA #12 in 2018, for delivery in 2021-2022 "Imports from Québec totaling 442 MW and from New Brunswick totaling 194 MW will be paid $3.70/kW-month and $3.16/kW-month, respectively[41]".

98. Because of increased capacity resources in recent years FCM prices are expected to stay low for a few years. A reasonable price for Hydro-Québec for the years 2023-2025 of the economic analysis is its 2021/2022 price of $US3.70/kW-month. Assuming an exchange rate of $US0.80/CDN$1.00 the capacity value for years 2023-2025 of the analysis would be ($3.70 x 1000 x 12)/0.8 = $55, 500/MW-yr. For the longer term, the escalating cost of a combustion turbine ("CT") is recognized as appropriate.

99. An escalating cost is used because it allows for comparison of capital projects with differing lives. It is the deferral value of such a project and is regularly applied in long term planning studies. A CT is used as it is the lowest cost form of new capacity that is only used for peak loads or operating reserve and not for supply of energy. The table below determined the escalating cost for capacity in 2026.

[41] *Ibid*, at <https://www.iso-ne.com/about/key-stats/markets#fcaresults>.

Table 9

	Capacity Cost Based on a Proxy Combustion Turbine Accepted by NBEUB in 2018								
	Capital ($M)		110						
	Capacity(MW)		93						
	Capital ($/MW)		$ 1,182,796						
	Life (Yrs)		25						
	Finance (%)		5.233%	Hydro-Quebec financing cost					
	Fixed O&M ($/MW-yr)		$ 14,730						
	Year dollars		2017						
	Inflation		2.0%						
	Power Costs								
		Book	Depreciation	Interest	Fixed O&M	Annual Cost	NPV Cost	Escalating Cost	Esc NPV Cost
	Year	($/MW)	($/MW-yr)	($/MW-yr)	($/MW-yr)	($/MW-yr)	($/MW-yr)	($/MW-yr)	($/MW-yr)
1	2017	1,182,796	47,312	61,896	14,730	123,938	123,938	85,329.85	85,330
2	2018	1,135,484	47,312	59,420	15,025	121,756	115,702	87,036	82,708
3	2019	1,088,172	47,312	56,944	15,325	119,581	107,984	88,777	80,167
4	2020	1,040,860	47,312	54,468	15,632	117,412	100,752	90,553	77,704
5	2021	993,548	47,312	51,992	15,944	115,248	93,978	92,364	75,317
6	2022	946,237	47,312	49,517	16,263	113,091	87,634	94,211	73,003
7	2023	898,925	47,312	47,041	16,588	110,941	81,692	96,095	70,760
8	2024	851,613	47,312	44,565	16,920	108,797	76,129	98,017	68,586
9	2025	804,301	47,312	42,089	17,259	106,659	70,922	99,978	66,479
10	2026	756,989	47,312	39,613	17,604	104,529	66,049	101,977.07	64,437
11	2027	709,677	47,312	37,137	17,956	102,405	61,490	104,017	62,457
12	2028	662,366	47,312	34,662	18,315	100,288	57,224	106,097	60,538
13	2029	615,054	47,312	32,186	18,681	98,179	53,235	108,219	58,679
14	2030	567,742	47,312	29,710	19,055	96,077	49,504	110,383	56,876
15	2031	520,430	47,312	27,234	19,436	93,982	46,017	112,591	55,128
16	2032	473,118	47,312	24,758	19,825	91,895	42,757	114,843	53,435
17	2033	425,806	47,312	22,282	20,221	89,815	39,712	117,140	51,793
18	2034	378,495	47,312	19,807	20,626	87,744	36,867	119,482	50,202
19	2035	331,183	47,312	17,331	21,038	85,681	34,210	121,872	48,660
20	2036	283,871	47,312	14,855	21,459	83,626	31,729	124,309	47,165
21	2037	236,559	47,312	12,379	21,888	81,579	29,413	126,796	45,716
22	2038	189,247	47,312	9,903	22,326	79,541	27,252	129,332	44,311
23	2039	141,935	47,312	7,427	22,772	77,512	25,236	131,918	42,950
24	2040	94,624	47,312	4,952	23,228	75,491	23,356	134,557	41,630
25	2041	47,312	47,312	2,476	23,692	73,480	21,603	137,248	40,351
							1,504,385		1,504,385

100. The data used for the CT in the table is that applied by NB Power for costing of a CT in its 2018 Matter 415 OATT filing which was accepted by the New Brunswick Energy and Utilities Board ("**NBEUB**")[42]. The only deviations are that financing costs and inflationary escalation are equal to the values applied by HQT in its economic analysis. The resulting capacity value for 2026 and beyond in the economic analysis should be $101,977.07/MW-year escalating at 2.0%.

4.5 UPDATED ECONOMIC ANALYSIS

101. NEMC has constructed an EXCEL spreadsheet to match the economic analysis provided by HQT in Annexe 5. It used this spreadsheet to complete an updated economic analysis using the revisions discussed for loss factor and for capacity and energy prices.

[42] NBEUB, Matter 415, Document NBP4.12(1) AS Proxy Costs Revised, Schedule 1.0 at <http://www.NBEUB.ca.>

102. NEMC only analysed two of the proposed solutions – the Micoua-Saguenay Line and series compensation. The summary table below shows that the NEMC analysis matched HQT's base case analysis to four significant figures. It also shows that use of the revised lower loss factor with the same energy and capacity cost data as the HQT base case reduces the cost differential between the options from $76.560 million to $2.575 million and that with the updated assumption data shown, the NEMC model determined that the series compensation option is $88.369 million less costly than the Micoua-Saguenay Line:

Table 10

	NEMC Modelling Summary Results ($000)					
	HQT Base Case		Revised HQT Base Case		Revised NEMC Update	
	Mic-Sag Line	Series Comp	Mic-Sag Line	Series Comp	Mic-Sag Line	Series Comp
Investment	571,790	248,548	571,790	248,548	571,790	248,548
Reinvestment	13,886	28,948	13,886	28,948	13,886	28,948
Residual	67,883	2,744	67,883	2,744	67,883	2,744
Taxes	45,329	16,205	45,329	16,205	45,329	16,205
Losses	222,598	451,794	177,053	451,794	**118,629**	**302,426**
NEMC Total	785,721	862,367	740,176	742,751	**681,752**	**593,384**
HQT Total	785,748	862,308				
Differential Cost		76,560		2,575	**88,369**	
Assumptions						
Loss Factor	0.511		0.37345		0.37345	
Energy cost ($/MWh)	45.8 in 2023 esc @ 2.0%		45.8 in 2023 esc @ 2.0%		PIRA/Platts to 2040 less $6 then 2%	
	107.75 in 2028 esc @ 2.0%		107.75 in 2028 esc @ 2.0%		42.2 in 2023 to 77.0 in 2040 then 2% esc	
Capacity ($/kW-yr)	$22.97/kW-yr in 2023-2025		$22.97/kW-yr in 2023-2025		$55.5/kW-yr in 2023-2025	
from 2026	131.7kW-yr esc @ 2%		131.7kW-yr esc @ 2%		$101.98/kW-yr esc @ 2%	

4.6 SENSITIVITY ANALYSIS

103. In decision D-2018-121, the Régie asked HQT to provide some sensitivity analysis concerning the valuation of losses. In HQT-2, Document 1.1, HQT states that "*le Transporteur identifie trois sources d'incertitudes possibles à l'égard du coût des pertes inclus dans l'analyse économique*:

- la valeur des coûts évités en puissance et en énergie du Distributeur;
- la valeur calculée de l'écart de pertes en puissance à la pointe du réseau (P_{PP});
- la valeur du facteur de charge (F_C) utilisé pour estimer l'écart d'énergie annuelle."[43]

[43] HQT-2, Document 1.1, page 19, lines 15 to 17 and page 20, lines 1 to 3.

104. In Table 15, HQT provides results for a sensitivity case with capacity losses reduced by 5% and the system load factor (F_C) equal to 0.6, which would reduce the loss factor (F_P) to 0.384. NEMC agrees that a 5% reduction in capacity losses is a reasonable sensitivity, but disagrees with a load factor of 0.6. With 0.591 as the load factor for the base case, a sensitivity should be 0.55 and it produces a loss factor equal to 0.32725.

105. HQT did a separate sensitivity for HQD avoided costs but did not include them with the other sensitivities. As stated earlier, NEMC disagrees with the use of HQD avoided costs. Rather, ISO-NE capacity and energy costs should be used. A sensitivity for these would be that energy costs should be less when the Phase 2 line to ISO-NE is at capacity and exports must go to other markets with lower prices. This could lower the price for energy losses by 5% but capacity sales would not be affected.

106. An additional sensitivity would be for the US-Canadian exchange rate. Rather than 80 cents the exchange rate could be 75 cents US for $CDN1.00. This would increase energy costs for all years and capacity costs for 2013 to 2025.

107. A comparison of each of the sensitivities with NEMC's updated economic analysis is provided in the table below:

Table 11

NEMC Economic Update and Sensitivity Results ($000)			
	Series Comp	**Mic-Sag Line**	**Differential**
Updated Analysis	593,384	681,752	88,369
<u>Sensitivities</u>			
Loss Factor = 0.32725	568,787	672,497	103,710
Loss capacity 5% less	577,706	681,532	103,826
Energy price 5% less	582,886	677,802	94,916
Exchange rate = $0. 75US	606,532	686,640	80,108

108. The results in the table above indicate that the series compensation option is the least cost option not just for the update analysis but also for all sensitivity cases. NEMC recommends that it be the solution approved by the Régie to address system design requirements. It was confirmed by HQT in response to NEMC's request for information number 1 (question 2.3) that it meets all reliability criteria.[44]

[44] HQT-3, Document 5.1, Exhibit B-0043.

109. In response to the Régie's information request number 2 to NEMC, NEMC provided additional sensitivity results that combined the lower load factor of 0.55 and the 5% reduction in capacity losses. It also included the HQT sensitivity provided in Tableau 15 of HQT-2, Document 1.1. For convenience, that result is provided in Table 12 below:

Table 12

	Revised Sensitivity Modelling Results ($000)					
	HQT Tableau 15 Sensitivity		Revised HQT Sensitivity		Revised NEMC Sensitivity	
	Mic-Sag Line	Series Comp	Mic-Sag Line	Series Comp	Mic-Sag Line	Series Comp
Investment	571,790	248,548	571,790	248,548	571,790	248,548
Reinvestment	13,886	28,948	13,886	28,948	13,886	28,948
Residual	67,883	2,744	67,883	2,744	67,883	2,744
Taxes	45,329	16,205	45,329	16,205	45,329	16,205
Losses	171,701	437,702	153,854	390,842	104,106	263,807
NEMC Total	**734,824**	**728,659**	**716,977**	**681,799**	**667,229**	**554,764**
HQT Total	733,800	728,800				
Percentage Cost Ratio	100%	99%	100%	95%	100%	83%
<u>Assumptions</u>						
MW/GWH cost data	HQT		HQT		NEMC	
System Utilization (F_C)	60%		55%		55%	
Loss Factor (F_P)	0.3840		0.32725		0.32725	
MW Loss Reduction (%)	5%		5%		5%	

4.6.1 <u>Costs associated with the ice storm reliability criteria</u>

110. In section 7.4 of the complementary evidence filed by HQT in response to Decision D-2018-121, HQT amended its economic analysis to reflect the cost of the ice storm protection investment strategy, adding $279.2 million to the cost of the series compensation scenario. No details were provided to justify that extra cost.

111. In order to better understand the position of HQT with regard to intervention needed to strengthen its network for ice storm protection, NEMC reviewed past HQT filings in relation with that topic.

112. One filing was particularly interesting in that regard. In 2003, HQT requested the Régie's approval to invest $190 million in a de-icing device at the Lévis substation. In that filing HQT described its strategy to increase the reliability of its network following the 1998 ice storm.

113. In its final argument[45], HQT added a citation from the Warren Committee[46] that was put in place to establish a strategy to protect the electric network from the risk of severe ice storms.

[45] Docket R-3522-2003, page 7.

[46] <http://www.regie-energie.qc.ca/audiences/3522-03/mainWarrenNicolet.htm>.

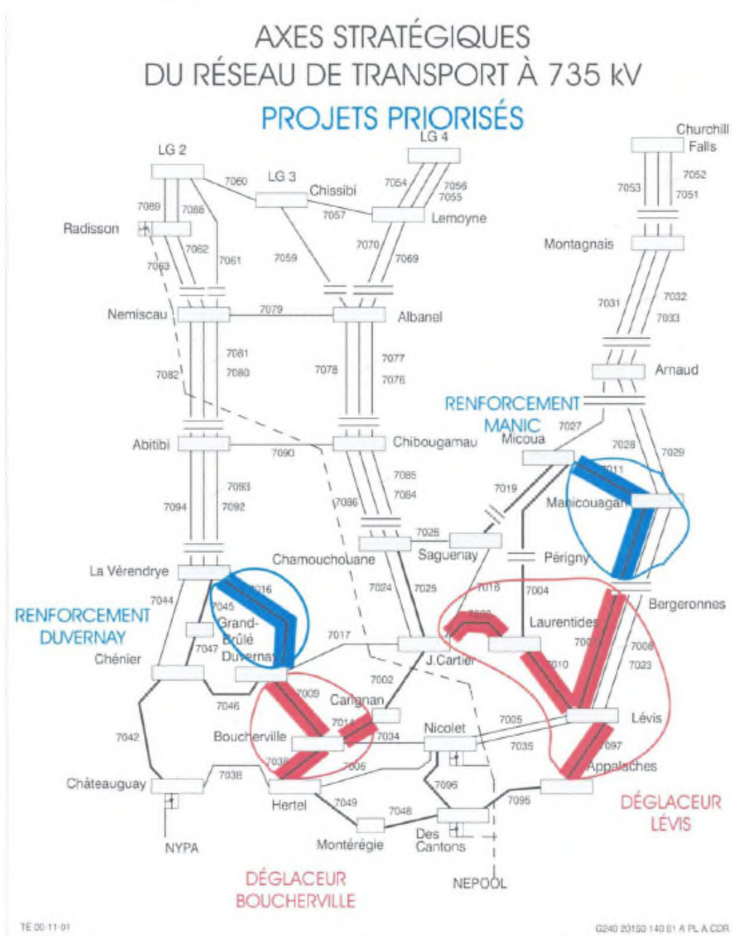
> "Les régions à forte densité de population, comme celles de Québec et de Montréal, sont particulièrement critiques et doivent être prioritaires dans l'implantation des lignes stratégiques. Vu la configuration du réseau, le recours à des lignes stratégiques dans le Nord-Est n'est peut-être pas aussi important que dans les deux autres zones, puisque les charges essentielles des principaux centres urbains pourraient continuer d'être alimentées malgré la perte des lignes à 735 kV de la zone Nord-Est."
>
> (Our underlining)

114. In the extract above, it is mentioned that the focus regarding the ice storm protection strategy should be put on the Montréal and Québec City regions before the North-East region.

115. That being said, even if HQT was to decide to apply the ice storm reliability criteria in the North-East region, the plan was to focus on the Micoua-Manicouagan and the Manicouagan-Bergeronne paths and not the Micoua-Saguenay path as per the figure below:

Figure 8

Figure 1 – Projets identifiés pour l'amélioration de la sécurité du réseau face au verglas



116. It is important to note that HQT did not include ice storm protection in its original evidence. It has only been included after the Régie requested that the economic analysis be redone with various sensitivities that made the series compensation option more competitive. Also, it was not included in the series compensation solution for the integration of the Romaine complex in R-3757-2011. It was raised in the Chamouchouane-Bout-de-l'île file but not included in the economic analysis. Furthermore, a portion of that line was in the high priority Montréal area.

117. NEMC does not believe that the addition of ice storm protection is relevant for this file and it should not be applied to solution 3 in the economic analysis.

4.7 SERIES COMPENSATION REQUIREMENTS

118. HQT's evidence is lacking information on the amount of series compensation that is proposed. The two transmission line projects provide increased blocks of transfer capacity while series compensation provides incremental transfer capacity dependent on the amount added. This raises several questions that should be considered in the economic evaluation of the options. Consider the following:

- Is the amount of Series Compensation evaluated by HQT equal to the minimum amount needed to meet the N-1-1,500 criteria?
- Is the amount of Series Compensation evaluated by HQT an amount that would provide equivalent transfer capacity to the Micoua-Saguenay project, or the Outardes-Laurentides project?
- Do the two transmission line projects provide identical or different transfer capacities?
- Is it possible to phase in series compensation or is it all required for year 2020-21?

119. If there are any differences in the operational performance of the options (other than system losses), they should be considered in the economic evaluation.

120. Finally, the Régie should consider the most recent development in the evolution of load forecast in the Côte-Nord region. Any additional load demand in the Côte-Nord[47] region would reduce the scale of series compensation option, which would reduce its cost.

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[47] <https://ici.radio-canada.ca/nouvelle/1144857/des-projets-miniers-pour-la-cote-nord-en-2019>.

121. NEMC requested clarification of these issues regarding the amount of series compensation needed in its request for information number 2. In its response, HQT did not provide the transfer capacity of the series compensation option (or any other option) and it did not acknowledge the incremental nature of the series compensation option. It is apparent that HQT developed the series compensation scenario to transfer [redacted] MW and did not consider that increased load in the Côte-Nord region would be supplied by regional generation which would reduce the amount of generation to be transferred.[48]

5. CONCLUDING REMARKS

122. NEMC recognizes the need for investment in the Micoua-Saguenay region due to reliability concerns on the system.

123. NEMC believes that the lowest-cost solution to solve the reliability issue on the Manic-Québec corridor is the series compensation solution. The series compensation solution is an adequate and more flexible solution, because its economics would be further improved by any load demand growth in the north shore, which would reduce the scale of the series compensation option and the resultant losses. As well, there is potential for future generation integration requests to trigger the Micoua-Saguenay Line, which would replace the series compensation investment and better allocate the costs of investment in the Manic-Québec corridor, while meeting reliability and network integration needs.

124. Although NEMC believes that the series compensation solution is the adequate solution, NEMC believes that the principles of cost causation and rate neutrality will have to be carefully considered in the rate hearing to integrate the investment costs into rates. As raised in this report, NEMC is of the view that reliability issues raised by HQT to justify the need for new investments are mostly driven by changes in the production profile of HQP. Whether we refer to the closures of the thermal power plants in the southern portion of HQT's system or the addition of 1,550 MW upstream of the Manic-Québec corridor in both case, they are in fact the result of corporate decisions of an unregulated HQT client that should not impact the rates of the other HQT clients.

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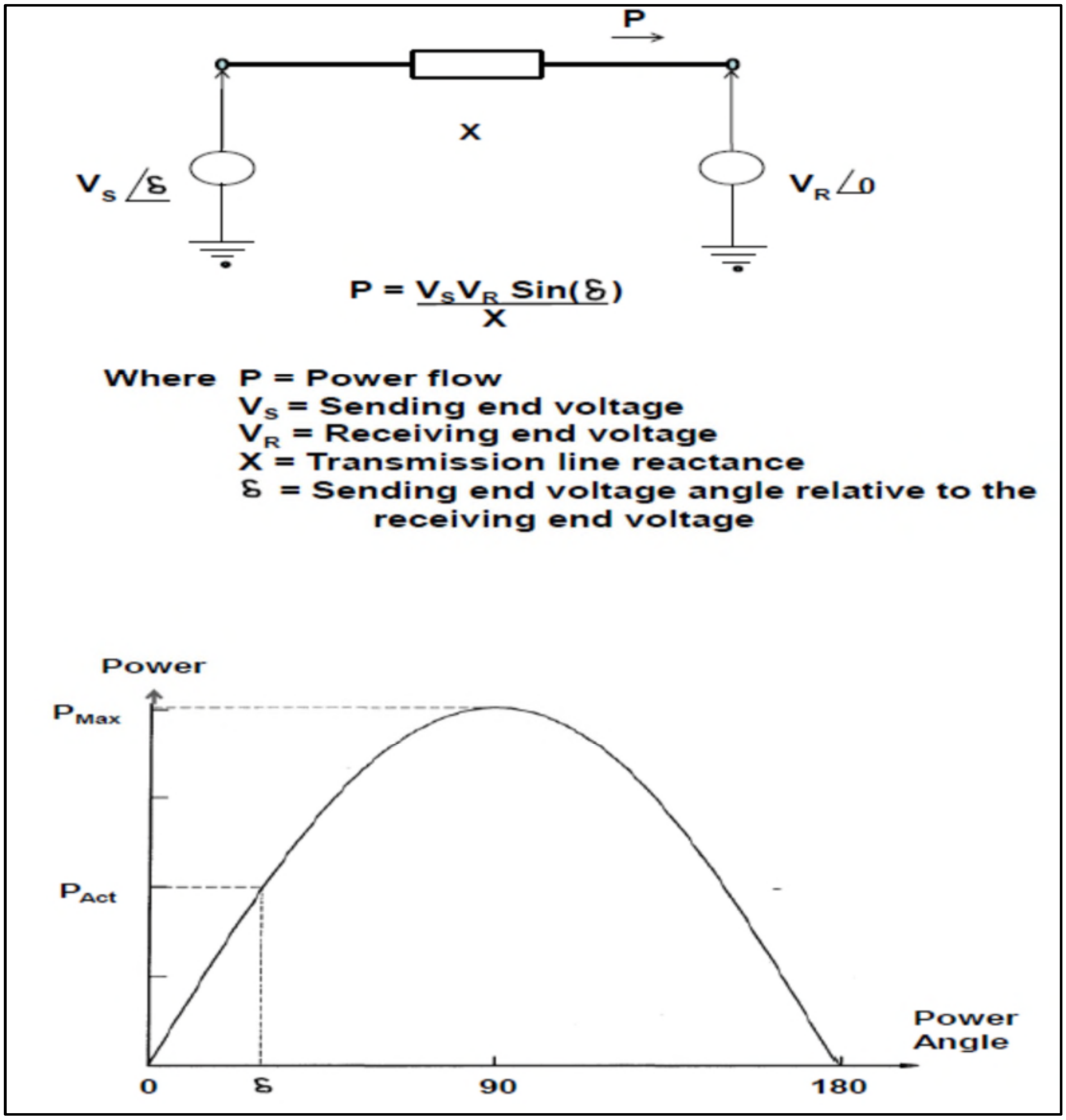
[48] See responses to NEMC's IR#2, R2.1.1 and R2.2.

APPENDIX A

ATTACHMENT A - STABILITY OF POWER SYSTEMS

1. Power systems have multiple generators and loads that are constantly changing. How generators respond to these small perturbations is considered **dynamic stability**. The generators and loads are connected together by transmission lines that are open to the environment and subject to various natural events that can cause elements of the system to fail. Lightning strikes, tree contact, ice storms, animals causing short circuits as well as failure of insulating materials are some examples. All power systems are designed to be able to transition from one stable state to another stable state following the contingent loss of any one piece of equipment. This is **transient stability** and the maximum power flow at which the system can safely recover is referred to as the **transient stability limit**.

2. To begin, it is useful to describe the elements of power flow across a transmission line. In a power system the amount of power that can flow across a transmission line is dependent on the voltage at each end of the line, the impedance of the line and the sine of the angle between the voltages (the Power Angle). By ignoring the resistance of the line which is small relative to the reactance the impedance reduces to the reactance X. Consider the diagrams and Power equation below:



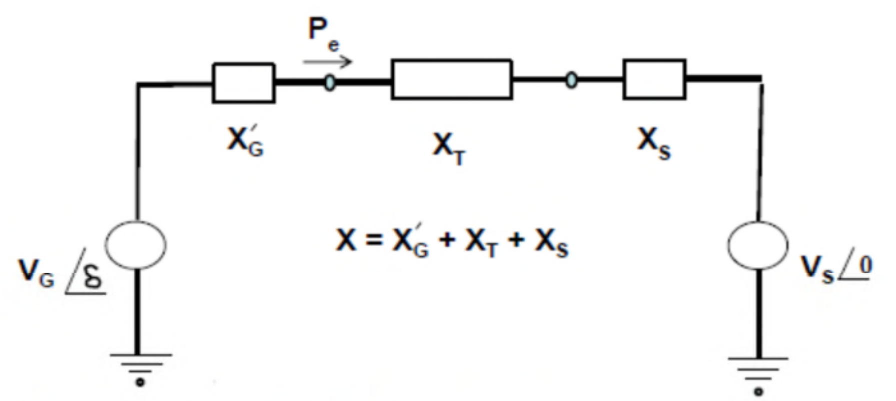
3. This introduction reveals several points. A power system normally operates at the design voltage with per unit values of 1.0 so the most influencing variable is the transmission reactance X. A small value of X causes a large amplitude P_{Max} (which is desirable) and consequently a small initial power angle δ (which is also desirable).

4. As you can see the amplitude of the sine function $V_S V_R / X$ is the maximum amount of power that can flow and it would be at a power angle of 90 degrees. This is the **steady state stability limit**. It is dangerous for power systems to be operated near the steady state stability limit because it leaves little opportunity for recovery should a contingency occur.

Transient Stability

5. Let us consider the system from Churchill Falls to Manicouagan/Micoua as an example to consider transient stability. It can be reduced to the simplified equivalent circuit by adding a classical equivalent made up of a voltage behind a reactance at

each end of the transmission. One represents Churchill Falls generators plus their power transformers and the other represents the HQT system beyond Manicouagan/Micoua.

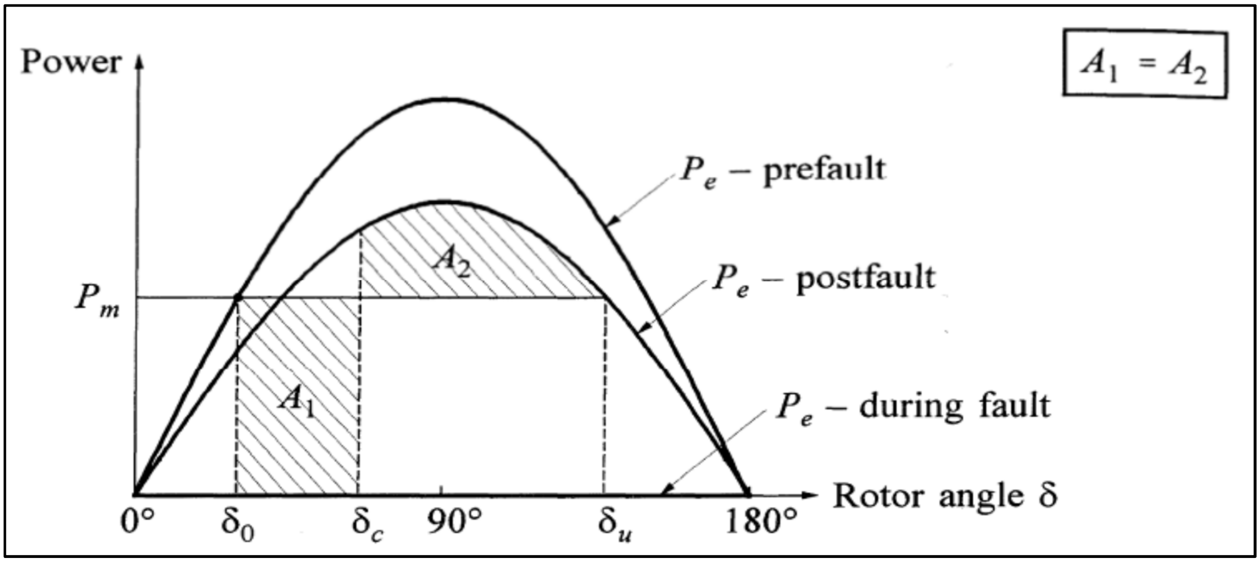


Where P_e **= Electrical Power flow**
V_G **= Internal equivalent generator voltage at Churchill Falls**
X'_G **= Generator equivalent transient reactance at Churchill Falls**
V_S **= System equivalent voltage at Manicuoagan**
X_S **= System equivalent reactance at Manicuoagan**
X_T **= Transmission system reactance between Churchill Falls and Manicouagan**
X **= Total reactance between generator voltage and system voltage**
δ **= Power angle between sending and receiving voltages**

6. Because the voltages in a power system are always maintained near the rated values on all system equipment we can assume that the per unit voltages are 1.0 so that the Power flow P_e before and after a fault is cleared is dependent on the sine of the power angle divided by the total reactance X. Before the fault, X is small because all three transmission lines between Churchill Falls and Manicouagan/Micoua are in service. This makes P_{Max} large which is good.

7. If there is a fault on one of the transmission lines near Churchill Falls, protective relays will sense the fault and send signals to open the transmission line breakers. This takes the transmission line out of service and increases X so P_{Max} is reduced. During the fault P_e is zero because of zero voltage at the fault. With the imbalance between P_m and P_e the generator rotor accelerates and the power angle increases. It can go beyond 90 degrees, and the system will attain transient stability if the power angle recovers to a steady state value well below 90 degrees. The transient stability limit that provides enough post fault restraining power to pull the generator back into

a stable synchronous state is illustrated by the diagram[49] below.



8. Area A_1 represents the imbalance accelerating power equal to the mechanical input power P_m during the fault which increases the rotor power angle. When the fault is cleared electrical power P_e is greater than mechanical power P_m by area A_2 and the rotor angle is pulled back. Stability will be maintained if area A_2 is greater than or equal to A_1. If it is not, the Power angle will increase beyond recovery and the system will go unstable.

9. Large single contingencies for the LAB-HQT path could be a three phase fault to ground at the Churchill Falls end of a transmission line from the plant or a three phase fault of a 230/735 kV transformer that connects two generators. Either of these faults would reduce the Churchill Falls bus voltage to zero and the electrical power delivered from the plant to zero as well. Such a contingency makes accelerating area A_1 have the largest possible value. This would cause the Churchill Falls generators to accelerate rapidly because of the imbalance between the electrical output power (which is zero) and the mechanical input power. This acceleration would increase the power angle and move the generators toward instability.

10. Fortunately power systems utilize sensitive protective relay equipment that would detect the fault and send signals to open the breakers to isolate the faulted equipment so that the fault would be cleared. This action is done in about a tenth of a second or less and it acts to make the accelerating area A_1 as small as possible.

11. It also takes the faulted equipment (the transmission line or transformer) out of service which will increase the reactance X_T of the transmission system and

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49 Diagram from **Power System Stability and Cont**rol by P. Kunder, Figure 13-60 (b), page 944

consequently the total X as well. In order for the system to remain stable the electrical power must be able to increase sufficiently to offset the generator acceleration and bring each generator back to a stable state. For this to happen, the decelerating area A_2 must be at least as large as accelerating area A_1. When the power system is operated at rated voltage, when the worst possible single contingency (N-1) is considered, and when the circuit breakers operate at the fastest speed possible, then the transient stability limit is determined exclusively by the strength of the electrical system which remains after the failed component transmission equipment is removed. A post-fault reactance X which is as small as possible means a large post-fault P_{Max} and a large A_2.

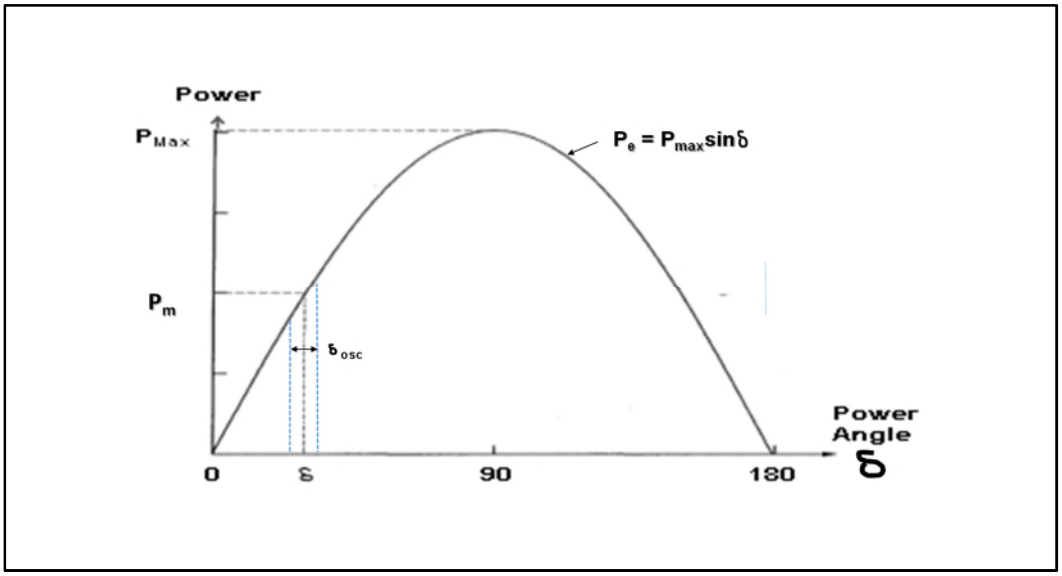
12. More simply, the transient stability limit provides enough power transfer margin to be able to withstand the worst single contingency (N-1) and return the system to a safe steady operation should such a contingency occur. This stability limit value is also referred to as the Total Transfer Capacity or Total Transfer Capability ("TTC") for an interface between two sub-areas of a transmission network. For the corridor between Churchill Falls and Manicouagan/Micoua the transfer capacity has been determined by HQT to be 5200 MW.

13. HQT would not use this simplified transient stability analysis to determine the Transfer Capacity for the LAB-HQT path. HQT would undertake a detailed computer simulation of the system that would model in real time all system variables (voltages, currents, power flows and phase angles) prior to the fault, during the fault and after the fault is cleared.

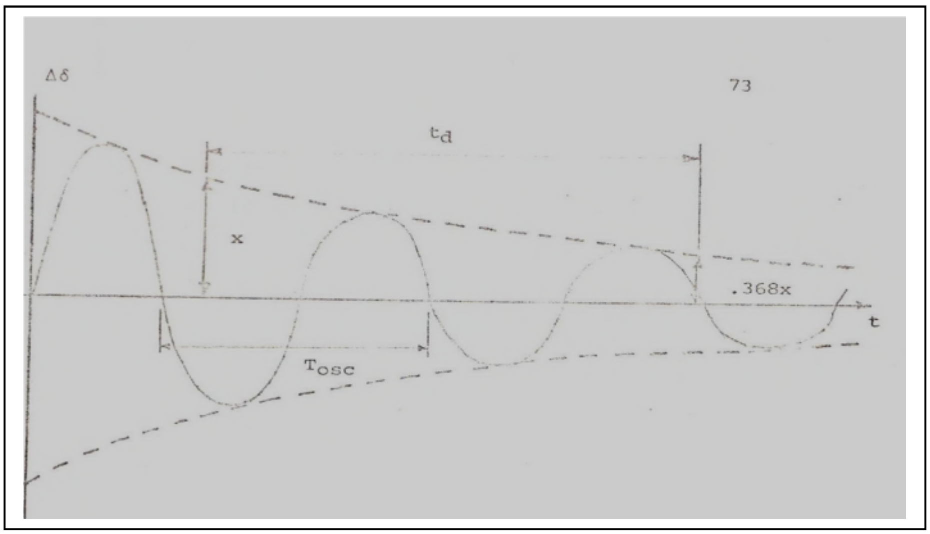
14. This simplified transient stability analysis is not as extensive as a complete real time stability model of the HQT system but is informative for us to understand why transfer capacities are different for different conditions. From the analysis we can see that there are three key variables related to transient stability (and therefore transfer capacity determination) as follows:
    a) Initial power at the generator and its starting power angle;
    b) The duration of the fault before it is cleared; and
    c) Most importantly the magnitude of the reactance X between the generators at Churchill Falls and the system at Manicouagan/Micoua.

Dynamic Stability

14. Power systems are never stationary in a specific steady state. They are continuously subject to small perturbations that cause the rotor angles of generators to oscillate around its equilibrium point where mechanical input power P_m is equal to the electrical output power P_e. After any small disturbance the oscillations may be damped back to the equilibrium point or may get larger and go dynamically unstable. Consider the two diagrams below.

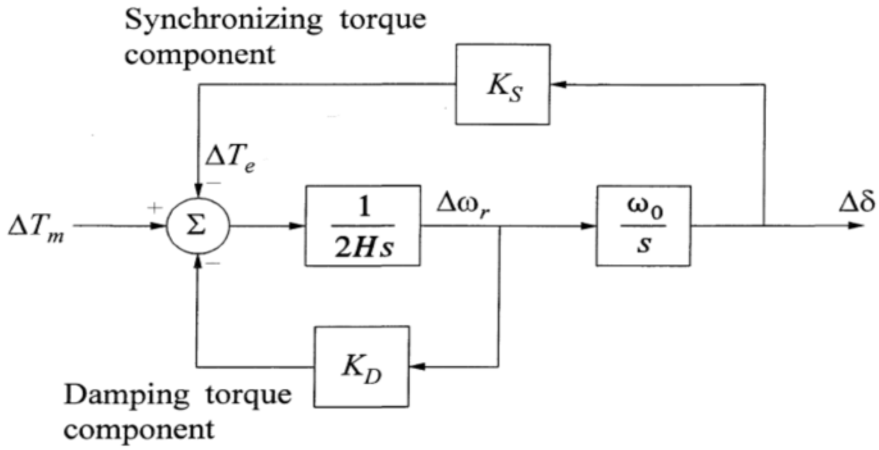


16.



The diagrams illustrate a small perturbation that is dynamically stable as the oscillations reduce in magnitude. The period of the oscillation frequency T_{osc} can be measured by field tests and determine the natural oscillating frequency as 1/ T_{osc} and the damping time constant is the time in seconds for oscillation amplitude to reduce by 63.2%. Note that T_d is the time in the diagram for the amplitude to reduce from x to 0.368x.

17. For a single generator connected to a large system the oscillation of the power angle can be modelled according to the diagram below.



K_S = synchronizing torque coefficient in pu torque/rad
K_D = damping torque coefficient in pu torque/pu speed deviation
H = inertia constant in MW·s/MVA
$\Delta\omega_r$ = speed deviation in pu = $(\omega_r - \omega_0)/\omega_0$
$\Delta\delta$ = rotor angle deviation in elec. rad
s = Laplace operator
ω_0 = rated speed in elec. rad/s = $2\pi f_0$
= 377 for a 60 Hz system

Figure 12.5 Block diagram of a single-machine infinite bus system with classical generator model

[50]

17. The natural frequency of the oscillations and the rate at which they are damped are dependent on the synchronizing torque coefficient (K_S), the damping torque coefficient (K_D) but **most importantly on the generator inertia constant (H)**. Note below Kundur's equations and comments.

Therefore, the undamped natural frequency is

$$\omega_n = \sqrt{K_S \frac{\omega_0}{2H}} \quad \text{rad/s}$$

and the damping ratio is

$$\zeta = \frac{1}{2}\frac{K_D}{2H\omega_n}$$

$$= \frac{1}{2}\frac{K_D}{\sqrt{K_S 2H\omega_0}}$$

[51]

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[50] Diagram is Figure 12.5 of "***Power System Stability and Control***" by P. Kundur as published by McGraw-Hill, Inc.
[51] Ibid, page 731

As the synchronizing torque coefficient K_S increases, the natural frequency increases and the damping ratio decreases. An increase in damping torque coefficient K_D increases the damping ratio, whereas an increase in inertia constant decreases both ω_n and ζ.

[52]

18. If the external system, to which the generator is connected, is not an infinite bus then H must be adjusted to include the system inertia (H_s) and the generator inertia (H_g). This enables the performance of a remote generator to be analysed in a similar manner. The adjustment to H is given as follows.

$$H = \frac{H_g H_s}{H_g + H_s}$$

19. Dynamic stability problems in a power system may be local to a single area of the system or global in nature. Note comments of Kundur at page 817 and pages 821-22.

Local problems involve a small part of the system. They may be associated with rotor angle oscillations of a single generator or a single plant against the rest of the power system. Such oscillations are called *local plant mode oscillations*. The stability problems related to such oscillations are similar to those of a single-machine infinite bus system as studied in Sections 12.3 to 12.6. Most commonly encountered small-signal stability problems are of this category.

Local problems may also be associated with oscillations between the rotors of a few generators close to each other. Such oscillations are called *intermachine or interplant mode oscillations*. Usually, the local plant mode and interplant mode oscillations have frequencies in the range of 0.7 to 2.0 Hz.

Global small-signal stability problems are caused by interactions among large groups of generators and have widespread effects. They involve oscillations of a group of generators in one area swinging against a group of generators in another area. Such oscillations are called *interarea mode oscillations*.

The characteristics of interarea modes of oscillation are very complex and in some respects significantly differ from the characteristics of local plant modes. Load characteristics, in particular, have a major effect on the stability of interarea modes. The manner in which excitation systems affect interarea oscillations depends on the types and locations of the exciters, and on the characteristics of loads [23].

Speed-governing systems normally do not have a very significant effect on interarea oscillations. However, if they are not properly tuned, they may decrease damping of the oscillations slightly. In extreme situations, this may be sufficient to aggravate the situation significantly. In the absence of any other convenient means of increasing the damping, adjustment or blocking of the governors may provide some relief [26].

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[52] Ibid, page 732

> Analysis of interarea oscillations requires detailed representation of the entire interconnected power system. Models for excitation systems and loads, in particular, should be accurate, and the same level of modelling detail should be used throughout the system.

19. As stated by Kundur, modelling of interarea oscillations is very complex and requires detailed computer simulation of all elements of the power system and this would be done by HQT. While there are ways to increase damping using power system stabilizers the main system components that limit oscillations are the inertia constants of generators and the characteristics of loads.

20. The inertia constant H is defined as *"the megajoules of stored energy of a machine at synchronous speed per megavolt-ampere of the machine rating."* [53] Typical values for different types of generators are also provided.

Large nuclear turbo generator	4.1
Large steam turbo-generators	
1800 rpm condensing	6
3600 rpm condensing	4
3600 rpm noncondensing	3
Large vertical shaft hydraulic generators	
450-514 rpm	4.5
200-400 rpm	4.0
138-180 rpm	3.5
80-120 rpm	3.0
Combustion turbine generators	4.7
Wind turbine generators	2.0

21. The amount of inertia constant H retired by Hydro-Quebec was about 20 in 2011 at Tracy, 13 in 2012 at La Citiere and 4.1 in 2012 at Gentilly. The total retirement is about 35 to 40 MWs/MVA.

22. Inertia is also provided by certain types of loads, especially industrial motor loads as they would contain kinetic energy that would tend to keep them rotating.

[53] W.D. Stevenson, ***"Elements of Power System Analysis"***, Second Edition, McGraw-Hill, Inc., 1962, page338

APPENDIX B

IREQ and HQT Technical Papers

a) Kamwa, R. Grondin, "*Estimation de la Frequence d'un Reseau par des Boucles a Verrouillage de Phase – Application a un Stabilisateur*", Canadian Conference on Electrical and Computer Engineering, Québec, Sept 1991

b) R. Grondin, I. Kamwa, L.Saulieres, R. Champagne, "*An approach to PSS design for transient stability improvement through supplementary damping of the common low frequency*", IEEE Transactions on Power Systems, Sept. 1993

c) I.Kamwa, R. Grondin, D.Asber, J-P. Gingras, G. Trudel, "*Active power stabilizers for multimachine power systems: Challenges and Prospects*", IEEE Xplore, Dec. 1998

d) Kamwa, G.Trudel, L. Gerin-Lajoie, "*Robust Design and Coordination of Multiple Damping Controllers Using Non-linear Constrained Optimization*", IEEE Transactions on Power Systems, Aug. 2000

e) R.Grondin, I.Kamwa, G.Trudel,J. Taborda, "*The Multi-\band PSS: A Flexible Technology Designed to meet Opening Markets*", CIGRE General Session, Sept. 2000

f) Kamwa, R. Grondin, "*PMU configuration for system dynamic performance measurement in large multiare power systems*", IEEE Transactions on Power Systems, June 2002

g) I.Kamwa, R. Grondin, G. Trudel, "*IEEE PSS2B versus IEEE PSS4B: The limits of performance of modern power system stabilizers*", IEEE Transactions on Power Systems, June 2005

h) J.Taborda, R. Grondin, I. Kamwa, G. Trudel, "*Wide Frequency Band Power System Damping Improvement by means of Multiband Power System Stabilizers*", POWER-GEN Asia Conference, Sept. 2006

i) H.N. Duc, L-A. Dessaint, A.F. Okou, I. Kamwa, "*A Power Oscillation Damping Control Scheme Based on Bang-Bang Modulation of FACTS Signals*", IEEE Transactions on Power Systems, Dec 2010

APPENDIX C