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TransÉnergie's *Tarifs et conditions*: comments concerning rates, discounts, interconnection costs and generation imbalance service

Testimony of Philip Raphals

On behalf of the RNCREQ and the UMQ

R-3549-04, phase 2

Régie de l'énergie

October 18, 2005

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1 Qualifications

Quel est votre nom, titre et adresse d'affaires ?

Je m'appelle Philip Raphals. Je suis directeur général du Centre Hélios, situé au 326 boul. St.-Joseph est, suite 100, Montréal, Québec, H2T 1J2.

Veuillez décrire le Centre Hélios.

Fondé en 1996, le Centre Hélios est un organisme de recherche à but non lucratif, offrant une expertise indépendante dans le secteur de l'énergie. Le Centre Hélios produit et rend disponibles les connaissances requises pour la mise en œuvre de stratégies, politiques, approches réglementaires et choix économiques favorisant le développement durable et équilibré du secteur énergétique. Depuis 2005, il produit également des analyses approfondies à l'égard des changements climatiques.

Veuillez décrire votre expérience professionnelle.

Mon expérience est résumée dans mon Curriculum vitae, qui est joint à ce témoignage. Mes activités professionnelles ont touché un grand nombre de sujets reliés à la planification, la réglementation et la tarification des réseaux électriques. Ceux-ci incluent, entre autres, la restructuration des marchés énergétiques, les processus de planification, la réglementation du transport d'électricité, l'efficacité énergétique et la sécurité des approvisionnements dans un réseau hydraulique.

Avez-vous déjà été reconnu comme témoin expert par la Régie de l'énergie ?

Oui, à plusieurs reprises. J'ai témoigné à titre d'expert dans les dossiers suivants : R-3398-98 (tarifs de fourniture), R-3401 (tarif de transport d'Hydro-Québec), R-3410 (avis sur une quote-part pour la petite production hydroélectrique), R-3470 (premier Plan d'approvisionnement d'Hydro-Québec), R-3473-02 (Plan d'efficacité énergétique d'Hydro-Québec), R-3493-02 (tarifs de transport de court terme), R-3518-04 (option interruptible), R-3519-03 (coûts évités), R-3525-04 (critère non monétaire de développement durable) et R-3550-04 (deuxième Plan d'approvisionnement d'Hydro-Québec). J'ai également préparé un rapport d'expert dans le cadre des travaux de la Régie sur la demande du Ministre d'un avis relativement au projet Suroît (R-3526-04).

Avez-vous déjà témoigné sur la tarification du transport d'électricité ?

Oui. Dans le dossier R-3401-98, j'étais l'auteur principal, avec Peter Bradford et feu Ellis O. Disher, d'un rapport d'expert qui explorait en détail plusieurs aspects de la tarification du transport.

Ce rapport a été cité maintes fois dans la décision de la Régie. Plusieurs éléments de cette décision découlaient directement de nos recommandations, dont :

- les exigences d'une code de conduite
- le traitement des actifs de télécommunications
- la radiation de projets totalisant 654,7 M $ de la base de tarification
- la méthodologie pour estimer les revenus des ventes à court terme
- la politique de discount
- le besoin d'une codification des conditions de desserte de la charge locale.

J'ai également fourni une expertise concernant les tarifs de transport à court terme dans le cadre du dossier R-3493-02, dans lequel Hydro-Québec demandait la révision de la décision D-2002-95.

En 2004, j'ai témoigné lors de la phase 1 du présent dossier.

Veuillez expliquer l'évolution de votre expertise à l'égard des tarifs et conditions de transport d'électricité.

Mon expertise sur ce sujet a commencé à se développer pendant la période 1996-98, dans le cadre de ses travaux à l'égard de la restructuration des marchés énergétiques. Il est bien connu que la réglementation du transport est au cœur de l'ouverture des marchés d'électricité. Or, mes travaux sur ce sujet, dont notamment la rédaction d'une étude majeure, *Ouverture des marché de l'électricité au Québec – Options, impératifs d'une réelle concurrence et conséquences pour les prix* (Option consommateurs, 1997) et un rapport pour la Commission de l'économie et du travail de l'Assemblée nationale sur *La restructuration des marchés de l'électricité* la même année, m'ont amené à étudier en détail la réglementation des réseaux de transport.

Pendant cette même période, j'ai été appelé à contribuer à certaines interventions auprès de la FERC au nom du Grand conseil des cris du Québec. J'ai également produit un rapport d'expert qui a été déposé dans le cadre d'une demande en révision d'une décision de la FERC devant la Cour d'appel fédéral. Ces mandats m'ont donc permis d'approfondir mes connaissances de la FERC et de ses approches à la réglementation du transport d'électricité.

Entre 1998 et 2001, j'ai approfondi mes connaissances sur le réglementation du transport d'électricité, en général, et sur le régime de réglementation mis en place par la FERC, en particulier, en travaillant étroitement sur cette question avec deux experts renommés, soit M. Peter A. Bradford, ancien président des Public Service Commissions de New York et du Maine, et feu Ellis O. Disher, ancien directeur d'analyses stratégiques pour United Illuminating (Connecticut). M. Disher a été profondement impliqué dans l'évolution de NEPOOL, notamment à l'égard de son tarif de transport. Entre autres, nous avons produit conjointement un rapport d'expert dans le cadre du dossier R-3401-98, dont j'étais est l'auteur principal. Ce rapport, ainsi que les nombreux témoignages oraux qui l'ont suivi — dont j'ai fait la présentation seul pour la plupart —, traitait principalement les tarifs et conditions applicables au réseau québécois de transport, dans le contexte de l'ouverture des réseaux américains entamée par la FERC.

Il importe de rappeler que les *Tarifs et conditions* de TransÉnergie ont au départ été empruntés directement de la *pro forma tariff* de la FERC, qui demeure donc la source principale de l'architecture du document qui fait l'objet de la présente audience. Tout au long de ma collaboration avec MM. Bradford et Disher, j'ai pu profité de celle-ci pour approfondir mon expertise au niveau nord américain. De fait, et de commun accord, suite au dépôt de notre rapport initial, j'étais la personne responsable pour tout les travaux qui en ont découlé.

Entre 2002 et 2004, j'ai continué à approfondir et mettre à jour mon expertise sur l'évolution du régime de réglementation du transport de la FERC dans le cadre d'un mandat de l'Organisation latinoaméricaine de l'énergie (un organisme multi-latéral). Dans le cadre de ce mandat, j'ai préparé, en collaboration avec M. Bradford, un rapport sur l'évolution des marchés concurrentiels en Amérique du nord. Ce mandat m'a permis d'étaler en détail mes connaissances sur l'évolution des régimes de réglementation du transport dans les différentes juridictions nord américaines[1]. Pendant cette période, j'ai également produit un rapport d'expert sur la question de la tarification du service de point à point de court terme, déposé à la Régie dans le cadre du dossier R-3493-02[2].

Finalement, en 2005, mon expertise sur ce sujet a été reconnue par ma nomination à titre de Senior Policy Advisor par le cabinet juridique de Scott Hempling, à Washington DC. Il s'agit d'un cabinet prestigieux spécialisé en droit de l'énergie, qui compte parmi ses clients des dizaines de régulateurs

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[1] Le rapport est disponible sur le site d'OLADE à http://www.olade.org.ec/olade/php/index.php?arb =ARB0000157.

[2] Ce rapport est disponible à http://www.regie-energie.qc.ca/audiences/3493-02/PreuveInterv3493/Preuve_RNCREQ-16sept02.pdf.

et instances gouvernementales, et qui est souvent appelé à plaider des causes devant la FERC et devant des tribunaux supérieurs, notamment sur les questions de transport[3].

2 Mandat

Veuillez décrire le mandat que vous ont donné le RNCREQ et L'UMQ.

Dans un premier temps, ces deux organismes m'ont demandé d'étudier les raisons qui sous-tendent la chute importante des revenus du service de point à point du Transporteur depuis sa dernière cause tarifaire, et de faire toute recommandation pertinente pour augmenter la contribution de ce service aux revenus requis du Transporteur. Dans ce contexte, ils m'ont demandé de porter une attention particulière la politique de rabais proposée par le Transporteur.

Dans un deuxième temps, ils m'ont demandé de commenter la proposition du Transporteur d'établir un service d'écart de reception, notamment à l'égard de ses implications pour des producteurs éoliens qui pourraient vouloir s'établir au Québec.

Finalement, ils m'ont demandé de commenter les nouvelles dispositions proposées concernant le raccordement des centrales et les ajouts correspondants au réseau, notamment l'article 12A.2 des *Tarifs et conditions.*

Étant donné le temps très limité pour la préparation de ce rapport, il a été convenu que la présente expertise serait rédigée en anglais.

3 Introduction : TransÉnergie's point to point revenues

The following table presents several key indicators that demonstrate the changes that have occurred since 2001.

[3] Voir http://www.hemplinglaw.com/clients.htm et http://www.hemplinglaw.com/experience.htm#Electric%20Industry.

Table 1

	2001	**2004**	**change**
Long-term reservations (MW)	3,982	405	-90%
Total point to point revenues ($M)	305	96	-69%
from HQP ($M)	293	92	-69%
from third parties ($M)	12	4	-67%
Short-term point to point revenues ($M)	15	66	340%
Volume transmitted (export) (TWh)	15	9	-40%
HQP net exports (TWh)	10.2	1.5	-85%
Revenue requirements ($M)	2,685	2,591	-4%
Native load charges ($M)	2,313	2,483	7%

sources : HQT-2, doc. 2, pp. 6, 8 et 10; HQT-4, doc. 2, p. 3; HQT-6, doc. 7, p. 21; R-3401, HQT-10, doc. 1, pp. 20; HQT-10, doc. 1.2, p. 2; HQ Annual Reports 2002 and 2004.

Thus, point to point revenues have decreased by $209 M, or 69%. The contribution required from Native Load for transmission service has increased by $170 M, or 7%, despite the fact that TransÉnergie's revenue requirement has declined by $94 M.

This reduction in point to point revenues is a consequence both of a reduction in the volume of reservations purchased and of the average unit cost for short-term services.

These findings are discouraging, given the primary objective underlying Quebec's transmission policy of increasing point to point revenues in order to optimize the use of the grid and decrease the charges to Native Load. More specifically, the decline in point to point revenues observed since 2001 is largely due to two factors:

- the **decline in net exports** by HQ Production from 10.2 TWh in 2001 to 1.4 TWh in 2004. Net exports depend on the interplay between hydraulic inflows, domestic demand and desired storage levels. As I demonstrated in the report filed in R-3526-04,[4] the decline in net exports was due in large part to excessive levels of net exports in prior years, combined with an extended series of low-inflow years.

- the decrease in short-term point to point rates, from $16.67 to $8.33 per MWh, as per D-2002-95, which in turn led HQP to abandon most of its annual reaservations in favour of hourly service. The effect was compounded by discounts offered in 2002 and 2003.

[4] http://www.regie-energie.qc.ca/audiences/3526-04/MemoiresParticip3526/Memoire_CentreHelios_23avr04.pdf.

Short term point to point tariffs are discussed in the following section.

4 Short-term point to point tariffs

In its decision D-2002-95, the Régie chose to base short-term point to point rates on 1-CP, rather than on 12-CP as they were in Reg. 659. This methodological modification resulted in reducing these rates substantially.

In R-3493, TransÉnergie sought revision of this decision, arguing that this would lead to a significant loss of annual long-term reservations, and hence to a loss of point to point revenues. [5] As seen in Table 1, this has indeed occurred. HQP failed to renew 90% of its long-term reservations, and total point to point revenues have fallen by 69%. Transmission for most of HQP's exports is now reserved on an hourly basis.

At the time, I agreed that the modification could well result in a significant loss of point to point revenues, but suggested that it would be more appropriate to raise this point in a subsequent filing.[6] I also recommended that the next rate case explore the possibility of establishing on- and off-peak hourly rates.[7] Unfortunately, TransÉnergie did not file a rate case for the rate years 2002, 2003 or 2004.

In its evidence in the present proceeding, TransÉnergie asserts that the reduction in point to point revenues was mainly caused by the evolution of day-ahead and hourly markets in neighboring jurisdictions. Its expert Dr. Orans expressed agreement with this point of view.[8] In reponse to information requests, however, he indicated that he had not attempted to separate the relative effects of this evolution and the decline of short-term point to point rates in explaining the shift from longer to shorter term transmission service.[9]

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[5] The request for revision was rejected.

[6] http://www.regie-energie.qc.ca/audiences/3493-02/PreuveInterv3493/Preuve_RNCREQ-16sept02.pdf, p. 15. As D-2002-95 only established a revenue requirement for 2001, at the time the motion for revision was filed, TransÉnergie could simply have requested the modification of its rates for 2002 or even 2003.

[7] Ibid., page 4-5.

[8] HQT-4, doc. 3, p. 21.

[9] HQT-6, doc. 8, R. 45.2.

In my view, the arguments made by TransÉnergie in R-3493 remain persuasive. While reduced volumes of net exports is of course also a contributing factor to the decline in point to point revenues, the reduction by half of the unit price clearly is as well.

In light of the very significant change in transmission strategy by TransÉnergie's principal client since the decision D-2002-95 was rendered, I believe it is appropriate to revisit the question of hourly pricing. The survey of pricing in other North American jurisdictions provided by Dr. Orans[10] shows that TransÉnergie is unique in offering hourly service at all times based on the daily non-firm rate divided by 24. All but one of the North American jurisdictions mentioned in his survey that uses the open access model provides separate rates for on-peak and off-peak hourly service.[11] In each one, the on-peak hourly rate consists of the on-peak daily rate divided by 16, while the off-peak hourly rate consists of the off-peak daily rate divided by 24.

Portland General Electric is a typical example. Its monthly, weekly and daily rates are identical for firm and non-firm service. Annual service is offered on a firm basis only; hourly service on a non-firm basis only. Daily and hourly rates distinguish between on-peak and off-peak periods. On-peak daily rates are equal to the annual rate divided by 301[12], while off-peak daily rates are equal to the annual rate divided by 365. On-peak hourly rates are equal to the on-peak daily rate divided by 16, while off-peak hourly rates are equal to the off-peak daily rate divided by 24. This approach, commonly known as the AEP method, would result in on-peak hourly rates for TransÉnergie of $15.09/MWh, about 80% more than the current hourly rate.

As Dr. Orans points out, TransÉnergie's short-term rates are consistent with the AEP approach, except with respect to hourly on-peak service.[13] He nevertheless supports maintaining the current approach. Specifically, he suggests that establishing an hourly on-peak rate could cause:

- "instability in the rate design process,"
- rate shock for point to point customers, and

[10] HQT-6, doc. 8, R. 58.1 and 58.2.

[11] These are BPA, Puget Sound Energy, Portland General Electric, Southern Company and Entergy, in the U.S., and SaskPower, Manitoba and New Brunswick, in Canada. The one exception is the B.C. Transmission Company, which uses an open access approach but fixes the hourly price based on the differential between the COB and Alberta market prices.

[12] Portland General treats Saturday as part of the peak period.

[13] Ibid., R. 54.3.

- a significant barrier to trade, substantially reducing point to point use.

At the same time, he recognizes that "the resulting loss in transmission sales would potentially be offset, to some extent, by an increase in margin from the remaining point to point use."[14]

In my opinion, these concerns are exaggerated. The rate shock, such as it is, would apply only to hourly service, and would only reverse the "rate windfall" created by D-2002-95. If the consequence were to divert point to point clients back to longer-term service, this would be entirely consistent with TransÉnergie's stated intentions in R-3401-98 and R-3493-02, and with the interests of its unaffiliated clientele.

In rejecting TransÉnergie's approach to short-term rates, the Régie stated that "la Régie choisit de se référer à la pratique nord-américaine la plus courante pour la détermination des tarifs de court terme" (D-2002-95, p. 264). Thus, it said, it would base all short-term rates on the annual rate. It established firm and non-firm daily rates, by dividing the annual rate by 260 and 365, respectively.

D-2002-95 does not explain its decision not to distinguish between peak and off-peak periods for daily and hourly rates though, as Dr. Orans' survey shows, this is clearly part of standard North American practice. Indeed, the logic of using the annual rate divided by 260 is based on the number of working (on-peak) days in the year, not on the reservation's firmness. Thus, the Régie in fact diverged from standard practice in North America by applying the higher rate to firm daily service, rather than to on-peak daily service. It would thus be entirely consistent with the principle underlying its previous decision if the Régie were to establish an on-peak hourly rate according to the so-called AEP, or Appalachian, approach.

In summarizing TransÉnergie's views, D-2002-95 stated:

> Selon le transporteur, cette approche prend en considération le fait que la demande énergétique est tout au long de l'année généralement plus faible le week-end que les jours ouvrables de la semaine et que cela se traduit par une valeur économique du transport moins élevée durant le week-end. (D-2002-95, p. 257)

The problem with current practice is precisely that it takes a rate designed to reflect the lower value electricity during off-peak periods, and makes it available at all times.

With respect to non-firm rates, the Régie wrote:

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[14] Ibid.

> [L[a Régie est d'avis que la qualité du service à court terme fourni devrait se refléter dans les prix du transport. La possibilité pour le service non ferme d'être interrompu à tout moment explique en grande partie sa qualité moindre et justifie l'octroi de prix inférieurs à ceux applicables aux services fermes.
>
> La Régie prend note de la constatation de NEG à l'effet que dans plusieurs juridictions américaines, le service non ferme est moins cher que le service ferme car il est moins fiable et donc de moindre qualité. (D-2002-95, p. 265)

As explained in section 6.4, below, it is exceedingly unusual for a major point to point customer to use hourly non-firm service for the vast majority of its transmission needs, as HQ Production currently does. It can only do so because the uncongested state of the grid combined with the near-absence of other point to point users means that it can obtain service that is in practice firm, while paying discounted non-firm prices.

When the Régie chose in D-2002-95 to apply AEP off-peak hourly pricing to all hourly service, it had no reason to expect that this would become the vehicle for the vast majority of HQP's point to point transmission service. Given the developments since 2001, it is entirely appropriate for the Régie to revisit this question.

As noted above, setting an on-peak hourly rate based on the standard methodology might well incent HQP and other users to use longer period reservations. Furthermore, rate discounts can be used to ensure that the short-term point to point rates do not prevent transactions that otherwise would not have occurred, as discussed in the following section.

5 Discounts for point to point service

5.1 Background

At this time, there are no discounts applied to short-term service. Substantial discounts were applied during the late 1990s, which we analyzed in depth in our expert report in R-3401-98. In D-2002-95, the Régie established a temporary discount of 25% on all short-term transactions which, as explained in TransÉnergie's evidence, significantly reduced point to point revenues during this period. Such revenue reductions constitute a real danger for point to point discounts in a context where a significant proportion of the point to point transactions result from HQ Production's net export requirements, which are largely insensitive to transmission price. In 2003, the Régie approved a transient discount policy for a one-year period. In its report on this policy, TransÉnergie concluded that it led primarily to a loss of revenues.[15]

In its TransÉnergie's initial filing in June 2005, stated that it was unable to propose a discount policy that would benefit its clientele and meet the criteria set out by the Régie. Urged by the Régie to complete its evidence, however, TransÉnergie subsequently filed a new proposal for a discount policy.

5.2 TransÉnergie's proposal

TransÉnergie proposes a new discount policy, set out in HQT-2, doc. 5, is based on the following formula:

(1) $\text{Discount} = T_{HQT} - [(P_b - T_b) - (P_a + T_a)]$

It follows that the discounted transmission tariff T_R is equal to

(2) $T_R = (P_b - P_a) - (T_a + T_b)$,

where

$\$2.00 < T_R = \$8.33.$

This is equivalent to the gross margin from buying power in region A and simultaneously reselling it in region B, net of the transmission charges required for the transaction.[16]

5.3 Analyzing the consequences of the proposed policy

The purpose of the discount policy is of course to increase point to point revenues by making possible transactions that otherwise would not have taken place.[17] Just as obviously, the primary concern is the potential loss of revenue that could occur from discounting transactions that would indeed have taken place in the absence of a discount.

[15] HQT-2, doc. 3, p. 19.

[16] HQT-6, doc. 1, p. 17

[17] HQT-2, doc. 5, p. 11.

To properly judge the proposed policy, both factors must be taken into account. Will the proposed policy actually increase transactions? And what is the risk of free ridership? It is only in comparing the expected benefits (increased transactions) from the expected costs (reduced revenue for transactions that would have taken place anyway) that one can predict the consequences of the proposed policy on TransÉnergie's revenues.

The analysis presented in TransÉnergie's evidence is weak on both counts. First, it is based on the premise that transactions occur whenever market differential is greater than zero.[18] While this might be true in a marketplace populated by traders with near-zero transaction costs, that is not a good description of the Quebec wholesale electricity market. Rather, it is essential to examine the different types of transmission users in TransÉnergie's real business environment to determine to what extent the proposed formula adequately represents the incentives actually facing them. At the same time, it is essential to carefully analyze the risks with regard to each type of clientele.

In the following sections, we will look at the incentives and risk of free ridership for each category of TransÉnergie's clientele.

5.3.1 Third party clients

Third parties make up a very small part of TransÉnergie's point to point clientele (about 4% of revenues), but one with considerable potential for growth. It is thus important to carefully analyze the incentives facing this clientèle, in order to design an appropriate discount mechanism that will increase third party point to point revenues.

For the purposes of this analysis, we will look at three distinct types of client: real-time traders (arbitragers), generators in regions with hourly markets, and generators in regions without hourly markets.

Real-time traders. A real-time trader is a transmission customer that buys and sells power in real time, using transmission to arbitrage prices between different markets. TransÉnergie's proposed discount policy would indeed provide a certain incentive for additional transactions for such a customer. However, no evidence has been presented that any of TransÉnergie's current point to point customers are real-time traders, or that other firms are interested in entering the line of business.

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[18] HQT-2, doc. 5, p. 12, lines 16-18.

Unfortunately, the incentive provided to such a trader would be practically nil, because, as proposed, the discounted transmission tariff uses up the entire margin of profitability in the transaction. More specifically, the premise referred to earlier is clearly false:

> [L]e Transporteur estime qu'il y avait du potentiel pour la réalisation de transactions additionnelles au niveau du service de point à point horaire, <u>en prenant pour hypothèse que les participants au marché auraient réalisé toutes les transactions qui ne leur auraient par généré de perte de revenu</u>. (HQT-2, doc. 5, p. 12) (emphasis added)

Normally, a real-time trader would not undertake transactions unless they would produce a profit greater than its own marginal transaction costs. A profit potential of zero, in other words, is not sufficient to promote additional transactions. In order to be effective in this situation, the discount would have to be increased somewhat, in relation to the value resulting from equation (1).

Generator in region with hourly market. Here we look at the situation of a transmission customer that owns generation in a region with an hourly market, such as Ontario. Here, the logic of the proposed discount policy is more persuasive.

Consider first the situation of a merchant generator selling into the hourly market. He can be expected to sell into the New England market, for example, if the market price there, net of transmission, is greater than in Ontario. During those hours where, at TransÉnergie's published transmission tariff, the Ontario is more attractive but, with a discounted transmission tariff, the New England sale would be more profitable, discounting will indeed produce additional revenue for TransÉnergie. (It might not be desirable for our neighbours in Ontario, who are having difficulty meeting their energy needs, but this is apparently not TransÉnergie's problem.)

As in the previous example, however, zero profitability will probably not incent additional transactions. In this case, the transaction costs will be lower (arranging transmission only, as opposed to the cost for the real-time trader of buying and selling power). Nevertheless, the discount mechanism must allow some residual profitability if it is to actually succeed in incenting trade.

Generator in region without hourly market. In this situation, TransÉnergie proposes using as proxy the lowest priced interconnected market.[19] The reasoning would be sound for a real-time trader (arbitrager): if he buys in a non-market region (Quebec or New Brunswick), it must be because it is no more expensive than cheapest market he can buy in. But as we've seen, this

[19] HQT-2, doc. 5, p. 9, lines 3-8.

example has little relevance to the TransÉnergie's real clients. So let's look more closely at the incentives facing generators in non-market regions, such as New Brunswick.

As seen in the first example provided by TransÉnergie,[20] the formula presumes that the New Brunswick generator will only sell in New York if the price differential *from New England or Ontario* to New York is positive. However, a generator's real incentive to use the TransÉnergie system is based on the relationship between his **marginal cost of generation** and the remote market price (net of transmission costs).

The purchase price in other remote markets is thus of no relevance. Is there any reason to think that, instead of wheeling its own generation from New Brunswick to New England, NB Power would instead purchase a MW in New York and wheel it through Quebec to New England? If the price differential made such a transaction profitable, it might do it anyway – though it would no doubt be even more profitable to wheel directly from New York to New England, without using TransÉnergie. But whether he undertakes such transactions or not, the question remains: is it cost-effective to generate in New Brunswick for sale in New England?

The answer obviously depends on the differential between the New England market price and the New Brunswick generator's costs for generating and transmitting an additional MW (variable operating costs, plus transmission costs). An appropriate economic discount mecanism for this type of client thus must be based on an estimation of his marginal generating costs, which have nothing to do with the hourly market price in New York.

Thus, formula (1) will at times provide a discount when none is necessary (e.g. when the three markets are close in price, but above New Brunswick generators marginal cost); and fail to provide it when it is necessary to promote an additional transaction (e.g. when prices in Ontario are far below those in New England, but the New England price is still only slightly higher than New Brunswick generator's marginal cost). In order to provide appropriate incentives to a generator in non-market regions such as New Brunswick, the value P_a in formula (1) and (2) must be based on the generator's marginal costs, not on market prices in a remote region.

[20] HQT-6, doc. 8 (révisé), R30.1.

5.3.2 HQ Production

Let us now turn to TransÉnergie's principal client, HQ Production. As in the case of New Brunswick, there is no hourly market in Quebec that a trader could use to arbitrage prices against the hourly markets in New York and New England. However, unlike TransÉnergie's New Brunswick clients, HQP is an active buyer and seller, and can and does make transactions based on market prices. The challenge is to design a discount mechanism that will actually facilitate additional transactions on the part of HQP, without reducing revenue from the very substantial volume of point to point transactions it already carries out.

TransÉnergie's analysis presumes that HQP functions like a real-time trader, executing transactions when the price differential makes it profitable. There is however no reason to believe that HQP actually executes this type of transaction to any significant extent. This is because, given its seamless access to a very large storage capacity, when HQP buys for resale, it has no need to resell the power at the same moment as it purchases it. Since the market price differential is usually far greater between time periods than it is during any given hour, purchase for later resale is normally far more lucrative than purchase for instantaneous resale (real-time arbitrage).

In this context, it is useful to recall that HQP divides its off-system sales into two categories: "net reservoir drawdown for sales outside Quebec"[21] (net export sales) and purchases for resale (buy-sell). The effects of transmission discounts are very different for these two types of sales, as discussed in the following paragraphs.

Net export sales. For HQP's net export sales (sales drawn from its reservoirs), the annual volume closely approximates difference between inflows and domestic needs (minus changes in storage from one year to the next). HQP has great discretion as to the timing of its sales, to maximize profits. However, it has no interest in keeping stocks higher than the level necessary to guarantee security of supply. Hence, the presence or absence of transmission discounts will not materially affect the volume of net of sales drawn from HQP's reservoirs.[22]

Thus, while the volume of net sales varies from year to year, transmission costs have little or no influence on their levels. Discounts will, however, affect transactions that would have occurred

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[21] Hydro-Québec, Annual Report 2002, p. 64.

[22] HQP's net exports in 2004 were far below historical levels, but they are expected to return to higher levels in the near future.

otherwise, thereby cutting into TransÉnergie's already greatly reduced point to point revenues. **There is thus a very real risk that the proposed discount policy will result in reduced revenues from point to point reservations undertaken with relation to HQP's net export sales.**

Purchase for resale (buy-sell transactions). Above and beyond these net export sales, HQP has increasingly in recent years taken advantage of the competitive advantage of its reservoirs, by purchasing for resale. The purchased power is provided directly to HQD under the heritage pool (patrimonial) contract, without additional transmission charges; the resale is subject to the point to point tariffs. Hence, the more HQP undertakes this type of transaction, the greater TransÉnergie's point to point revenues. TransÉnergie thus has a real interest in favouring this type of activity on HQPs part.

Does the proposed discount achieve this goal? Not necessarily, because the formula is based on the real-time (same hour) price differential between markets, whereas HQP's incentive for buy-sell transactions is based on differentials across time periods. For this reason, the proposed policy is likely to lead to discounting some transactions that would have occurred anyway, while failing to provide an adequate incentive for additional buy-sell transactions that would otherwise not have been cost-effective.

This fact is brought out clearly, if indirectly, by Dr. Orans' analysis. Unlike the analysis presented by TransÉnergie, his is based not on transmission value (real-time trader), but on "transmission value to a transmission customer with storage" (henceforth referred to as "storage value").[23] The only such customer on the TransÉnergie system in HQ Production. **Thus, Dr. Orans' analysis applies to HQP exclusively.**

To account for this storage value, Dr. Orans compared the intra-day differentials between prices in different markets. Thus, as he acknowledged, he was modelling a transmission customer engaged in "day-trading":

> A day trader in the context of this analysis buys energy in one period at a low price and resells it at a higher price in <u>the next period.</u>[24] (emphasis added).

Unfortunately, this too gives a poor indication of HQP's real trading environment, since nothing obliges it to resell a purchase in the same day. In fact, given the enormous unused capacity of its

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[23] HQT-6, doc. 9, R. 53.3.

[24] Ibid., R. 53.1.

reservoirs, [25] nothing prevents it from performing its buy-sell strategy on a seasonal basis, or even an inter-annual one.

Even on a daily basis, Orans found only a few transactions which required a discount to be cost-effective. Given the enormous flexibility it enjoys with respect to timing, there is no reason to believe that point to point tariffs ever constitute a real constraint on HQP's buy-sell activities. There is thus no reason to believe that discounting this tariff will result in additional buy-sell transactions to any significant degree.

Once again, as for the net export sales discussed above, to the extent that discounting is not necessary for the transaction to occur in the first place, it simply reduces revenues from a transction that would have taken place anyway. It thus once again appears that the proposed discount policy will only work to further reduce TransÉnergie's point to point revenues from its principal client, HQP. For a discount policy to actually increase these revenues, it would have to take into account the real incentives that affect these transactions.

5.4 Determining the cost basis for clients in regions without hourly markets

In order for a discount mechanism to effectively increase point to point revenues by increasing transactions originating in regions without hourly markets, the discount formula must take into account a realistic cost basis for each client against which the profitability of additional transactions should be measured. For thermal generators, this would normally be the marginal generation cost. For HQP, it would be a figure that represents its cost basis for buy-sell transactions.[26]

We propose therefore that these cost bases be fixed by the Régie on a case-by-case basis, on application by the transmission customer.

Thus, the proposed formula (1) could still be applied. However, in the case of transactions originating in regions without hourly markets, the value P_A would be based not on the hourly

[25] According to the table presented on p. 44 of D-2005-178, it appears that HQP will have at least 60 TWh of unused storage capacity at all times until May 2009, and indeed for the foreseeable future.

[26] While it is tempting to characterize this category as "hydro generators with significant storage," HQP is uniquely positioned to carry out buy-sell transactions without having to pay two point to point tariffs, because of its heritage contract with HQD.

market price in a remote market, but on a client-specific cost basis fixed by the Régie. Application for setting a cost basis would of course be entirely voluntary, but without it the transmission customer would not be eligible for point to point discounts.

For thermal generators, the cost basis would probably be based on their marginal generating cost. For HQP, the cost basis should probably be based on its average purchase price for its off-peak purchases from neighbouring grids, averaged over an appropriate time period. In both cases, it would be up to the transmission client to persuade TransÉnergie and the Régie that its proposed cost basis provides a realistic picture of its incentives for additional transactions.

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5.5 Conclusion

No evidence has been presented that the proposed discount policy will increase point to point revenues, and there is good reason to believe it will reduce them. It does have the potential to increase traffic from Ontario. For New Brunswick, it could incent additional transactions, but it could also lead to revenue losses for transactions that would have taken place without the discount. Given the very low volumes and revenues from these two regions, it is unlikely that the net result will be positive with respect to total point to point revenues.

With respect to HQ Production, there is a real likelihood of significant revenue losses for transactions that would have taken place without the discount, both for net export sales and for buy-sell transactions. While it is possible that the discount will lead to some additional buy-sell transactions, no evidence has been presented to suggest that transmission tariffs are in fact a limiting factor in these sales.

In the light of these findings, we present the following recommendations:

Quantum. For transactions eligible for the discount, the quantum should be increased to allow greater than zero profitability for the resulting transaction. Affected transmission customers should be consulted with respect to a formula for sharing residual profitability that will provide real incentives for additional transactions.

Eligibility. For transactions originating in regions with hourly markets, the rebate should be calculated based on the parameters proposed by TransÉnergie. However, transactions originating in regions without hourly markets should not be eligible for discounts under this formula, unless a customer-specific cost basis that adequately reflects the customer's marginal cost for additional point to point transactions has been approved by the Régie.

6 Interconnection costs

6.1 TransÉnergie's proposal

In the new s. 12A of its *Tarifs et conditions,* TransÉnergie sets out the procedures necessary for a new generator to interconnect to the grid. In s. 12A.2, it offers three types of commitment among which a generator can choose with respect to the interconnection and integration costs assumed by TransÉnergie.

TransÉnergie explains their purpose as follows:

> Ces dispositions ont pour but d'assurer la neutralité économique des coûts assumés par le Transporteur pour le raccordement de centrales à son réseau, en l'assurant d'obtenir des revenus au moins égaux à ces coûts lors d'un raccordement de centrale.[27]

The three options can be described as follows:

i) sign a firm long-term service agreement for point to point transmission service, with a net present value equal to or greater than TransÉnergie's net integration costs (minus any amount reimbursed to TransÉnergie);

ii) sign a commitment to purchase point to point transmission services, on a "take or pay" basis, for an amount equal to or greater than TransÉnergie's net integration costs (minus any amount reimbursed to TransÉnergie); or

iii) reimbursement of an amount equal to the net present value of TransÉnergie's net integration costs.

6.2 Issues raised by the three options

Each of the three options proposed in s. 12A.2 must be analyzed with respect to two main questions:

[27] HQT-5, doc. 1, p. 7.

- does it adequately protect native load and other transmission customers from the risk of having to bear the integration costs for the interconnection customer, and
- is it equitable and non-discriminatory with respect to other transmission customers?

We will examine the three options in reverse order.

6.2.1 Option iii)

The proposed text for option iii) reads as follows:

> iii) remboursement au Transporteur d'un montant égal en valeur actualisée aux coûts encourus par celui-ci pour assurer l'intégration de la centrale.

This option clearly provides adequate protection for native load and other transmission customers, since all investment costs are paid by the interconnection customer, whether it is affiliated with TransÉnergie or not. However, the high up-front costs make this option relatively undesirable. For a small generator, these costs may well be prohibitive. It would thus be surprising if any developers chose this option, since other two are much more attractive.

6.2.2 Option ii)

The proposed text for option ii) reads as follows:

> ii) signature d'un engagement d'achat de services de transport ferme ou non ferme de point à point de type "take or pay", pour un montant au moins égal en valeur actualisée aux coûts encourus par le Transporteur, moins tout montant remboursé au Transporteur, pour assurer l'intégration de la centrale;

In the case of an unaffiliated generator with no other plants, this option also provides adequate protection to native load and other transmission customers. As seen in Mercier agreement,[28] the annual amount is set such that its net present value after 20 years equals the integration costs, plus maintenance and taxes. Thus, if for any reason, the generator's use of point to point service declines below the level needed to ensure full cost recovery for TransÉnergie, he is obliged to continue paying as if he were using the full service. The result is to ensure that native load and

[28] HQT-2, doc. 1.3, annexe 4.

other transmission are protected against being held responsible for any of the generator's integration costs.

The situation is somewhat different, however, if the generation owner also owns other power plants, or if he uses point to point service for other reasons (i.e., a broker that wheels power through Quebec). If the new plant is large in relation to his other point to point use, the situation remains substantially the same as in the previous case. If, however, his other point to point purchases are large in relation to the size of the new plant, the commitment begins to lose its meaning. Thus, for example, if the client typically uses $50 M of point to point services in a year, a commitment to purchase at least $1 M per year would have little or no direct financial consequences. If for whatever reason the actual point to point transfers over the coming years were less than expected, TransÉnergie would not receive sufficient additional revenues to make up for its investment expenses, and the purchase commitment would not in practice oblige the owner to make any additional payments beyond the services he was already purchasing to serve his other activities. Under these circumstances, therefore, option ii) fails to fullfill its primary purpose of protecting native load and other transmission users from having to absorb the costs of a merchant generator's interconnection.

This situation is well illustrated in the Mercier interconnection agreement. Under section 1 of Engagement d'achat :

> Le Producteur s'engage à acheter du Transporteur des services de transport prévus au Tarif et à payer le prix annuel établi à l'article 2 (l'« Engagement d'achat annuel Mercier »).
>
> L'Engagement d'achat annuel Mercier est payable par le Producteur au Transporteur au 31 décembre de chaque année et ce, pour une période de 20 ans à compter de l'année de la mise en exploitation du premier groupe turbine-alternateur de la Centrale (la « Durée de l'engagement d'achat »).
>
> Pendant la Durée de l'engagement d'achat, <u>le Producteur doit payer au Transporteur</u>, le 31 décembre de chaque année, <u>la différence entre tous les engagements d'achat annuels</u> que le Producteur a pris auprès du Transporteur pour le raccordement de centrales au réseau de transport du Transporteur et <u>le montant que le Producteur a effectivement payé au Transporteur à titre de réservations de transport</u>, pour chaque période de 12 mois se terminant le 31 décembre, lorsque cette différence est supérieure à zéro dollar (0 $). (nous soulignons)

According to section 2, the annual purchase commitment for Mercier is estimated to be $1,525,709.28. Thus, as long as HQP purchases point to point transmission services worth at least $1.5 million in any given year, it has no other obligations under the purchase commitment. Let us recall that HQP's purchases of point to point services in 2004 were $92 million, including $30 million for its long-term reservations alone. Even if, for one reason or another, Mercier ceased to generate electricity for several years, it is practically inconceivable that HQP would have to make any additional payments to compensate the investments made by TransÉnergie to integrate Mercier into its grid.[29] If Mercier is not generating energy and its owner makes no payments other than the purchases it would have made anyway, native load and other transmission customers will ultimately have to bear the plant's integration costs.

Under what circumstances might this occur? Major technical problems are one possibility, of course, but there could be economic reasons as well. In the case of a merchant thermal plant (like the Suroît would have been, at least in the first years of its operations), it might stand idle for substantial periods if prices in neighbouring markets (net of transmission costs) were insufficient to cover its marginal generation costs. In the case of a small hydro plant, it could be that its flows are reduced as a result of an upstream diversion, as occurred as a result of HQP's Portneuf diversion. Finally, and most importantly, in the case of a new hydro development in Labrador, future industrial developments in Newfoundland and Labrador could greatly reduce the volumes of energy to be transmitted over the Quebec grid, thereby reducing the point to point revenues needed to offset the very substantial transmission investments that would no doubt be required to interconnect such a project.

These examples demonstrate clearly that option ii) is not adequate to protect native load from being required, under some circumstances, to bear costs incurred for the interconnection of a merchant plant.

Option ii) is also problematic because, though on its face it treats all generators in the same manner, in practice it is considerably harsher for small generators than for large ones. If the plant in question is the generator's only plant in Quebec, or if it is large in relation to the rest of the generator's Quebec capacity, then the "take or pay" provision would indeed have teeth: should the plant cease to operate, its own would have to continue making payments to TransÉnergie. Transmission customers with other plants would face no corresponding penalty. It is thus unduly discriminatory against smaller generators.

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[29] As long as Mercier is generating power, that electricity presumably either being transmitted under point to point service or provided to HQD as part of the heritage supply, in which case a corresponding volume of energy from another HQP generator will be freed up for exports. S. 3 of the Mercier purchase commitment calls for repayment of all the Integration costs incurred by TransÉnergie in the event that the project is cancelled, but only if it is cancelled before commissioning.

6.2.3 Option i)

At first glance, option i) seems to resemble option iii), in that it seems to guarantee that TransÉnergie will be able to recover all of its interconnection costs. In reality, however, it is more similar to option ii). As with option ii), the promoter commits to purchasing point to point services. Thus, for Mercier, if HQP had chosen option i) instead of option ii), it might have signed a firm multi-year service agreement (50.5 MW at $72.90/kW).

Would the signature of such a long-term service agreement ensure that TransÉnergie would fully recover its interconnection and integration investments? Not necessarily. First, let us recall that HQP currently has 405 MW of firm long-term (annual) service. The proposed text of s. 12A.2 does not specify that the long-term service agreement must be above and beyond those that already exist. HQP could thus apparently sign the multi-year 50.5 MW service agreement, and then next year renew only 354.5 MW of its ongoing annual reservations.

Should this occur, it is quite clear that TransÉnergie would have acquired no real guarantee of recovering the interconnection costs it will incur, nor will it protect other transmission customers from the risk of eventually having to support these costs.

Even if the text were to be modified to require that the long-term service agreement be additional to those already in effect, it would still provide no real protection. Recall that any generator in Quebec can use HQT as its Point of Receipt. There is thus no difference between the service agreement called for under option i) and any other long-term reservation.

Therefore, the new long term firm transmission convention could be used to deliver power from anywhere on the HQ system, thereby displacing the short-term reservations that would otherwise have been used to transmit this power. The result, once again, should the new plant go out of service prematurely, would be that Native Load and other transmission customers would be left to bear some of the interconnection and integration costs of the new merchant plant.

6.3 Comparison to comparable provisions in the U.S.

The issues raised by section 12A.2 have been addressed at great length by FERC in recent years. Reviewing these developments provides useful insight into these complex issues. It is also relevant with respect to maintaining an appropriate degree of compatibility with the U.S. regulatory system.[30]

6.3.1 Treatment of interconnection costs

Before directly addressing the question of interconnection costs, it is important to summarize some significant differences between the frameworks applied by the Régie and by FERC. As we know, Appendice J specifies that all interconnection and integration costs are rolled into transmission tariffs, up to the limit set forth in section E. No costs are directly assigned to the generator.[31]

This is very different from the framework applied in the U.S., where interconnection costs are now excluded from transmission rates.

> 743. The Commission believes that, <u>to ensure fully comparable treatment of all Generating Facilities, transmission rates should not include the costs of Interconnection Facilities</u>. As stated in the NOPR, this policy is consistent with the Commission's current treatment of generation step-up transformers, <u>appropriately assigns the costs of Interconnection Facilities to the generation customers using them</u>, and ensures that the Transmission Provider's own Generating Facilities and those of its competitors are treated comparably….[32] (emphasis added)

Thus, the first important difference is that interconnection costs are integrated into transmission rates in Quebec, but not in the U.S., where they are directly assigned to generators. The Régie explained its approach as follows :

> Cette position est équitable en regard des producteurs futurs. En effet, le tarif de transport inclut le coût des installations existantes qui permettent de raccorder et d'intégrer les centrales au réseau. Si les nouveaux producteurs devaient payer le coût de leurs installations, ils se trouveraient en position de payer deux fois les frais de raccordement et d'intégration : ils paieraient directement pour leurs propres besoins et ils paieraient indirectement le coût des installations des autres producteurs par le biais du tarif de transport. (D-2002-95, p. 298)

FERC's solution to this problem is to accept that all transmission users must pay past interconnection costs, but that, as of the date when it first indicated otherwise, interconnection costs

[30] See HQT-2, doc. 1, p. 8.

[31] D-2002-95, pp. 299-300.

[32] Order 2003, 104 FERC P61,103.

are the sole responsibility of generators. The purpose is to ensure that costs incurred for the benefit of a sole user are not borne by other users of the transmission system.

Thus, FERC requires that the interconnection costs of new generating facilities *not* be included in the transmission ratebase :

> 744. … Thus, the Commission presumes that after March 15, 2000, any Interconnection Agreement signed by the Transmission Provider provides for the direct assignment of Interconnection Facility costs to the Interconnection Customer. The Commission also presumes that the Transmission Provider can identify the costs of any Interconnection Facilities constructed for its own Generating Facilities after March 15, 2000. In this Final Rule, the Commission is requiring the Transmission Provider, in its next filed transmission rate case, to remove such costs from transmission rates.[33] (emphasis added)

For this reason, TransÉnergie's proposed *Tarifs et conditions* could be found to be out of conformity with FERC's minimum requirements for an Open Access Transmission Tariff.

This direct assignment policy described above refers to Interconnection Facilities, defined as all facilities and equipment between the generating facility and the point of interconnection with the transmission system, but not to Network Upgrades (system modifications past the point of interconnection), which FERC now uniformly rolls into transmission rates.[34] The purpose is to ensure that upgrades that benefit the transmission system as a whole are borne by all users.

In my view, FERC's approach for interconnection costs is better suited for protecting the interests of other network users than is the approach adopted by the Régie in D-2002-95. The risk of Native Load or other transmission customers being forced to absorb significant interconnection costs that only benefit a single user — the risk that the three options in section 12A.2 are meant to address — is far lower if they apply only to true Network Upgrades, and not also to interconnection costs. Furthermore, as shown below, two of the three options proposed in this section do not provide sufficient protection against this risk.

How then does FERC address costs related to Network Upgrades? Unlike the Régie, it requires generators to finance these upgrades; the generators are then eligible to be reimbursed for these costs by credits via their use of the interconnection facilities. This crediting policy is thus very

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[33] Ibid.

[34] This represents a change from the approach originally used in Order 888, which evaluated on a case-by-case basis which network modifications should be directly assigned to generators.

similar to the approach in TransÉnergie's proposed Purchase commitment (option ii). There are significant differences in their application, however, which are described in the next section.

The reason FERC requires generators to finance Network Upgrades is to ensure that they can be promptly executed — i.e. to ensure that necessary system upgrades are not stymied by an inability or unwillingness on the part of the Transmission Provider to make the required investments. While a realistic concern in the fragmented U.S. electric industry, this is not a significant concern in Quebec. Thus, we see no reason to follow FERC's practice in this regard.

The question of the circumstances under which a generator in the U.S. should receive credits for its interconnection investments and the guarantees that, in Quebec, a generator should provide in relation to the investments made on its behalf are in essence the same question. The policies adopted by FERC with respect to credits for network upgrade costs are thus quite relevant to the analysis of section 12A.2. In the next section, we will trace the evolution of FERC policies in this regard.

6.3.2 Treatment of network upgrade costs

In October 2001, FERC issued an Advance Notice of Proposed Rulemaking (ANOPR) concerning generator interconnection. This was followed in 2002 by a Notice of Proposed Rulemaking (NOPR) for Large Generator Interconnections (docket RM-02-1-000). The final rule, known as Order 2003, was issued in July 2003, followed by three Orders on Rehearing : Order 2003-A (March 2004), Order 2003-B (December 2004) and Order 2003-C (June 2005).

In accordance with past FERC policy, the Large Generator Interconnection Agreement (LGIA) proposed in the NOPR stipulated that the Interconnection Customer bear all costs of Interconnection Facilities and that Network Upgrades be funded by the Interconnection Customer, who would however receive credits (cash equivalent refund) that could be used to pay for transmission services purchased by the Interconnection Customer **with respect to the Generating Facility**.[35]

In Order 2003, however, FERC removed this restriction, concluding that :

> [T]he Interconnection Customer should receive credits for transmission (delivery) service taken anywhere on the Transmission Provider's Transmission System and that <u>credits should not be limited to service taken with respect to the Generating Facility at the point of receipt</u>,

[35] Order 2003, 104 FERC 61,103, at P676.

> as long as certain conditions are met. That is, as long as the Generating Facility has achieved commercial operation, continues to operate and there are unpaid credits outstanding, the Interconnection Customer should receive credits for all of the transmission charges that it pays, including charges for "through" transmission service. (Order 2003, P 730)

This formulation in fact resembles option ii) of TransÉnergie's proposed s. 12A.2 : any point to point service by the interconnection customer can be counted against the transmission investment costs, regardless of whether or not the point to point service involves the newly interconnected generating facility. It does however include the proviso that the generating facity must continue to operate, which option ii) does not.

However, this provision led to numerous requests for rehearing,[36] and FERC was ultimately persuaded to reverse its position on this issue. In Order 2003-A it wrote :

> 614. Nevertheless, we find merit in the arguments of petitioners that object to certain features of the crediting and reimbursement mechanisms. These features are <u>the right of the Interconnection Customer to receive credits for transmission service that does not include the Generating Facility as the source of the power transmitted</u>, and the right of the Interconnection Customer to receive a full reimbursement of the outstanding balance of its upfront payment after only five years. <u>The Commission agrees that</u>, in both instances, <u>these features may serve to insulate the Interconnection Customer from the consequences of its siting decision , as well as other factors that can significantly affect the cost of the interconnection, because if the Interconnection Customer continues to be a Transmission Customer (and receives credits unrelated to service from the Generating Facility at issue), it does not bear an appropriate level of risk that the Network Upgrades may be rendered unnecessary should its facility become commercially infeasible</u>. We note that, while all Transmission Customers benefit generally from upgrades to the transmission network, all customers do not necessarily benefit equally from upgrades that may be required for a particular interconnection. <u>To help ensure that the Interconnection Customer makes efficient and cost-effective siting decisions, we conclude that it is appropriate that credits be given only for transmission service that includes the Generating Facility as the source of the power transmitted</u>. We therefore grant rehearing with regard to these two features as described below.
>
> 615. First, we will no longer require the Transmission Provider to provide credits to the Interconnection Customer for all of the transmission services that it takes on the system, but instead will limit credits to transmission service taken with respect to the Generating Facility. <u>As petitioners have noted, allowing the Interconnection Customer to receive credits for services unrelated to the Generating Facility tends to shift risk from the entity in control of the investment to native load and other Transmission Customers. This shifting of risk may cause the construction of unneeded or more costly Network Upgrades. In addition, it may</u>

[36] The Federal Power Act contains no privative clause. Participants are free to petition FERC to reconsider its decisions, and they frequently do so. Significant policy reversals such as this one are however relatively rare.

> result in native load or other Transmission Customers having to bear the cost of the Network Upgrades in cases where the Interconnection Customer takes little additional transmission service that is associated with the new Generating Facility, or where the Interconnection Customer elects to retire the Generating Facility early. Therefore, we are restoring to Article 11.4.1 language from the NOPR LGIA that required the Transmission Provider to provide the Interconnection Customer with dollar-for-dollar credits only for the payments that are made for transmission services taken with respect to the Generating Facility. (emphasis added)

FERC thus reinstated the obligation that credits be issued only for transmission originating from the generating facility, in order to avoid shifting risk from the interconnection customer to native load and other transmission users. This position was upheld in both Order 2003-B[37] and Order 2003-C[38], both issued in response to subsequent requests for rehearing. In Order 2003-B, FERC wrote :

> 33. We strongly encourage policies that promote efficient investment decisions and protect native load and other Transmission Customers from having to bear the burden of the Interconnection Customer's Network Upgrade costs. Given these concerns, we continue to find that the Order No. 2003-A crediting policy provides a reasonable balance between the objectives of promoting competition and infrastructure development, protecting the interests of Interconnection Customers, and protecting native load and other Transmission Customers. (emphasis added)

It added :

> 56. In response to these petitioners, we first reaffirm that an important objective of our interconnection pricing policy continues to be the protection of existing Transmission Customers, including the Transmission Provider's native load, from adverse rate implications associated with Interconnection Facilities and Network Upgrades required to interconnect a new Generating Facility. … (emphasis added)

Though it has not stated it as succinctly, it is clear from its past decisions that the Regie shares this perspective.

6.3.3 Non-firm service

In Order 2003-B, FERC also addressed the subsidiary issue of the the situation where the Interconnection Customer takes firm point-to-point service from the Generating Facility, but then transfers the reservation to a secondary point of reception, as allowed under the *pro forma* tariff of Order 888. It concluded that :

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[37] 109 FERC 61,287.

[38] 111 FERC 61,401.

> 38. … If the Interconnection Customer or other Transmission Customer is taking firm Point-to-Point Transmission Service under the OATT with the Generating Facility as the source of the power transmitted, the customer continues to have all of the rights given under the OATT to change *temporarily* Points of Receipt or Delivery, if capacity is available, and is entitled to continue to receive credits toward the cost of the transmission service while doing so. (Order 2003-B) (emphasis added)

In Order 2003-C, FERC clarified this point further.22. The Commission is not persuaded to change the policy under which the Transmission Provider must provide transmission credits during periods when the Interconnection Customer is using, in accordance with the terms of its transmission service, a secondary receipt point rather than the Generating Facility. As long as the Interconnection Customer or another entity is taking transmission service that identifies the Generating Facility as the point of receipt for that service in the original firm point-to-point transmission service request, the Interconnection Customer is entitled to a credit toward the cost of that service. The possibility that this could lead to abuse is greatly overstated. A transmission customer that elects to use a secondary point of receipt or delivery under the OATT must take such service only on a non-firm basis and at the lowest priority level. The Commission does not believe that access to this non-firm service option is sufficient to lead to abuse. Furthermore, in response to PNM, the Commission clarifies that a sham designation of a transaction through a non-operating Generating Facility is not a permitted means of obtaining transmission credits.

> 23. The Commission clarifies that its use of the word "temporarily" is intended to distinguish a request to use secondary receipt point on a non-firm basis as permitted under the tariff from a request to change the point of receipt on a firm basis.

Thus, non-firm service from other Generating Facilities may be eligible for credits, but only when used temporarily. Sham designation of a non-operating Generating Facility is explicitly forbidden.

6.4 Conclusion

Let us now return to look at the options proposed in s. 12A.2, in light of the relevant FERC policies.

The purpose of s. 12A.2 is to ensure that native load and other transmission customers do not end up paying costs related to connecting new generators. Under the FERC regime, interconnection costs up to the point of interconnection with the transmission system are simply absorbed by the generator. Costs of network upgrades beyond this point are initially financed by the generator, but are returned to him as credits against transmission service **originating from the specific generating station.** In the event that, for technical, commercial or any other reasons, the actual use of that station does not generate revenues sufficient to cover the network upgrade costs, other users are insulated from bearing these costs.

In both systems, the generator only bears the cost of network upgrade investments if it fails to take enough transmission service.[39] In Quebec, but not in the U.S., the same is true for interconnection costs between the generator and the point of connection with the transmission system.

As noted in section 6.2.2 above, options i) and ii) fail to ensure that the generator bears the interconnection costs in the event that he does not take sufficient transmission service from the new plant. Because option ii) allows "credits" for all transmission service taken by the Interconnection Customer, regardless of whether or not it is related to the new plant that caused the interconnection costs, it fails to achieve the desired result. The same is true of option i).

One solution would be to require use of option iii), whereby the transmission customer reimburses TransÉnergie for an amount equal to its net costs. However, the large up-front costs of this option might well be prohibitive for small generators, thereby placing a chill on future unaffiliated generation investment.

Any alternate solution would have to ensure that the transmission service recognized ("credited") under the commitment actually **originate from the newly connected generator**. This is somewhat problematic due to the existence of the Point of Receipt HQT. In the U.S., the Point of Receipt normally clearly identifies the generator's location actual on the transmission system. On TransÉnergie's OASIS, however, there is no distinction between Points of Receipt located within Québec's borders.

From a scheduling perspective, however, TransÉnergie is nevertheless informed on a daily or hourly basis of the activity of each generating station. Thus TransÉnergie must be able to distinguish transactions which originate from the newly interconnected generating station from those that do not, even if the reservations on OASIS do not provide this information.

While FERC allows non-firm service from a secondary Point of Receipt to qualify for credits, its reasoning is based on conditions which do not exist in Quebec. FERC indicates that it is practically inconceivable that a generator would rely on non-firm service to deliver its power, since it could be forced to shut down at any moment if other transmission customers purchased firm capacity over the same paths. In Quebec, however, the absence of any significant congestion combined with the

[39] In Quebec, but not in the U.S., these investments are initially financed by the transmission provider.

near-total absence of third-party transmission users makes it practical, and indeed desirable, for HQ Production to use non-firm service for the vast majority of its off-system sales. In this sense, HQP is able to obtain service that is in practice firm, while paying only for non-firm service. This fact should not allow it to escape responsibility for its interconnection costs, in the circumstances described above.

Thus, option ii) could be reformulated as follows:

> ii) signature d'un engagement d'achat de services de transport ferme ou non ferme de point à point de type "take or pay", pour un montant au moins égal en valeur actualisée aux coûts encourus par le Transporteur, moins tout montant remboursé au Transporteur, pour assurer l'intégration de la centrale. L'engagement doit préciser que seules des transactions ayant leur point d'origine à la centrale qui fait l'objet de l'Entente de raccordement peuvent être reconnues à l'égard de cet engagement d'achat;

And option i) can be modified as follows:

> i) signature d'une Convention de service pour le service de transport ferme à long terme dont la valeur actualisée des paiements à verser au Transporteur pendant la durée de la Convention signée est au moins égale aux coûts encourus par le Transporteur moins tout montant remboursé au Transporteur, pour assurer l'intégration de la centrale. Cette convention de service doit préciser qu'elle est valable uniquement pour des transactions ayant leur point d'origine à la centrale qui fait l'objet de l'Entente de raccordement;

With these two modifications, all three options will provide an effective guarantee that Native Load and other point to point users of the transmission system will not be forced to bear the interconnection costs of a generation which does not produce as much energy over the years as initially expected.

7 Energy imbalance and generator imbalance services

TransÉnergie proposes to add a new ancillary service, a generator imbalance service (*service de compensation pour écart de reception*, Annexe 4).[40] This new service has a very similar structure to TransÉnergie's energy imbalance service (*service de compensation pour écart de livraison*, Annexe 5), which has been in place since Reg. 659 was adopted in 1997, in terms essentially identical to those of FERC's *pro forma* tariff promulgated as part of Order 888.

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[40] See HQT-4, doc. 1, section 5.3.5 (page 33).

7.1 Energy imbalance service

It should be noted first of all that, while FERC considers energy imbalance service to be a true ancillary service, i.e. essential to the operation of a transmission system, this is not the case for generation imbalance service.

FERC made clear in Order 888 and 888-A that energy imbalance service is meant to cover only those unavoidable imbalances that result from the fact that "the amount of energy taken by load in an hour is variable and not subject to the control of either a wholesale seller or a wholesale requirements buyer."[41] For this reason, the rates to be applied to energy imbalance service are cost-based, not punitive. FERC established a bandwidth of ±1.5%, within which over- and undercharges are netted over the month; beyond that bandwidth, the charge for taking more energy than programmed is set at 110% of the costs actually incurred by the transmission provider to provide the additional energy that was delivered, and the credit for taking less energy than scheduled is set at 90% of these costs. The bandwidth is intended to promote good scheduling practice, and reflects the fact that, under the *pro forma* open access transmission tariff, schedules can be changed up until 20 minutes before the beginning of the hour.

Thus, FERC's approach to energy imbalance service charges is clearly not meant to be punitive or dissuasive. In this sense, the modification to TransÉnergie's energy imbalance service that was accepted by the Régie in R-3401-98 represents a marked departure from FERC's policy and rationale. Under Reg. 659, energy imbalance charges were based on Hydro-Québec's real-time hourly price (TTR), for imbalances beyond a 1.5% bandwidth. At TransÉnergie's request, this was replaced by a punitive regime, with the penalty based on the variable cost of peaking equipment (or interruptible supply) plus 50%, and the credit based on 50% of the actual (patrimonial) supply cost.[42] In the current application, these rates are set at 11.25¢ and 1.28¢, respectively.[43]

41 Order 888 at 31,703.

42 R-3401-98, HQT-10, doc. 1, pp. 54-55.

43 HQT-4, doc. 2, p. 5.

7.2 Generator imbalance service

While FERC has allowed generator imbalance service to be added to the transmission tariffs of some transmission providers, it has clarified that it does not consider it to be an ancillary service.[44]

In Order 888-A, FERC made clear that generator imbalance service is of a different nature than energy imbalance service, and that the bandwidth and price should be set differently.

> NIMO asserts that two types of energy imbalance can occur if the generator and the load are in different control areas. These are (1) a mismatch between the energy scheduled to be received in the load's control area and the actual hourly energy consumed by the load, and (2) a mismatch between energy scheduled for delivery from the generator's control area and the amount of energy actually generated in the hour. The Energy Imbalance Service in the Final Rule applies to the first case only. Although we agree that the second type of mismatch can occur, <u>we will not designate as Energy Imbalance Service a mismatch between energy scheduled and energy generated. Energy Imbalance Service in this Rule applies only to the obligation of the transmission provider to correct the first type of energy mismatch, one caused by load variations</u>.
>
> In general, the amount of energy taken by load in an hour is variable and not subject to the control of either a wholesale seller or a wholesale requirements buyer. <u>The Energy Imbalance Service that we require as our ancillary service has a bandwidth appropriate for load variations</u> and should have a price for exceeding the bandwidth that is appropriate for excessive load variations. Although NIMO states correctly that, where two control areas are involved, there can also be a mismatch between energy scheduled and energy generated, <u>NIMO has not explained why this mismatch should have the same bandwidth and price as our Energy Imbalance Service. Indeed, we believe it should not.</u>
>
> <u>A generator should be able to deliver its scheduled hourly energy with precision. If we were to allow the generator to deviate from its schedule by 1.5 percent without penalty, as long as it returned the energy in kind at another time, this would discourage good generator operating</u> practice. A generation supplier could intentionally generate less power when its generating cost is high and make it up when its cost is lower if the second type of mismatch is included in our Energy Imbalance Service. <u>Instead, a generator will have an interconnection agreement with its transmission provider or control area operator, and we expect that this agreement will specify the requirements for the generator to meet its schedule, and for any consequence for persistent failure to meet its schedule.</u> This agreement will be tailored to the parties' specific standards and circumstances, and, although such arrangements must not be unduly preferential or discriminatory (e.g., must be

[44] FERC, Notice of Proposed Rulemaking, Imbalance Provisions for Intermittent Resources, Docket RM05-10-000, April 14, 2005, p. 5.

> comparable for all wholesale sellers, including the transmission provider's own wholesale sales), we prefer not to set these standards generically for all parties.[45] (emphasis added)

Thus, from FERC's perspective, the 1.5% bandwidth proposed for TransÉnergie's generator imbalance service is, generally speaking, too broad, since "A generator should be able to deliver its scheduled hourly energy with precision."[46] That said, it should be noted that FERC has approved several OATT's including generation imbalance services with a 1.5% bandwidth.

There has been considerable debate at FERC as to whether or not generator imbalance service belongs in the open access transmission tariff (OATT) or in interconnection agreements.[47]

Starting with Niagara Mohawk in 1999, FERC has approved a number of OATT's which include generator imbalance service schedules. Generally speaking, they included penalties and credits that reflect the common practice for energy imbalance service.[48]

However, in Order 2003, FERC chose to place this obligation within the *pro forma* Large Generator Interconnection Agreement (LGIA), arguing that it is primarily a matter affecting the transmission provider's interconnection service for generators, rather than its delivery service for transmission customers. Specifically, it added sections 4.3 and 4.3.1 to the LGIA.[49]

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[45] Order 888-A, part 2, pages 164-166.

[46] Order 888-A.

[47] A similar uncertainty can be seen in TransÉnergie's treatment of the guarantees for interconnection costs discussed in the previous chapter. Until now, the Engagement d'achat has formed part of the interconnection agreement. Now, however, it is proposed to include these guarantees in the *Tarifs et conditions* (the OATT); at the same time, they have been removed from the *Entente type de raccordement pour l'intégration d'une centrale*.

[48] The bandwidth is usually set at 1.5% and charges are typically set at the greater of $100/MWh or 110% of incremental cost for under-delivery, and 90% of incremental cost for over-delivery.

[49] The text of these provisions reads:

4.3 Generator Balancing Service Arrangements. Interconnection Customer must demonstrate, to the Transmission Provider's reasonable satisfaction, that it has satisfied the requirements of this Article 4.3 <u>prior to the submission of any schedules for delivery service to such Transmission Provider identifying the Large Generating Facility as the Point of Receipt for such scheduled delivery</u>.

> **4.3.1** Interconnection Customer is responsible for ensuring that its actual Large Generating Facility output matches the scheduled delivery from the Large Generating Facility to the Transmission Provider's Transmission System, consistent with the scheduling requirements of the Transmission Provider's FERC-approved market structure, including ramping into and out of such scheduled delivery, as measured at the Point of Interconnection, consistent with the scheduling requirements of the Transmission Provider's Tariff and any applicable FERC-approved market structure.

On rehearing, however, the Commission found that such services belong more properly in the OATT than in the LGIA. Finally, however, in Order 2003-B, FERC ultimately concluded that the provision could be placed in either interconnection or transmission service agreements.

That said, the principle remains that a) it is the generator's responsibility to make arrangements for generation balancing service, b) if it fails to make other arrangements, the generator is deemed to have made such an arrangement with the applicable Control Area (the grid operator), and c) that insofar as the grid operator is the provider of generation balancing service, the charges for this service may be dissuasive.

> <u>Interconnection Customer shall arrange for the supply of energy when there is a difference</u> between the actual Large Generating Facility output and the scheduled delivery from the Large Generating Facility (the "Generator Balancing Service Arrangements").
>
> Interconnection Customer may satisfy its obligation for making such Generator Balancing Service Arrangements by:
>
> (a) <u>obtaining such service from another entity</u> that (i) has generating resources deliverable within the applicable Control Area, (ii) agrees to assume responsibility for providing such Generator Balancing Service Arrangements to the Interconnection Customer, and (iii) has appropriate coordination service arrangements or agreements with the applicable Control Area that addresses Generator Balancing Service Arrangements for all generating resources for which the entity is responsible within the applicable Control Area;
>
> (b) <u>committing sufficient additional unscheduled generating resources</u> to the control of and dispatch by the applicable Control Area operator that are capable of supplying energy not supplied by the Interconnection Customer's scheduled Large Generating Facility, and entering into an appropriate coordination services agreement with the applicable Control Area that addresses Generator Balancing Service Arrangements obligations for the Large Generating Facility;
>
> (c) <u>entering into an arrangement with another Control Area</u> to dynamically schedule the Interconnection Customer's Large Generating Facility out of the applicable Control Area and into such other Control Area;
>
> (d) entering into a Generator Balancing Service Arrangements with the applicable Control Area; or
>
> (e) in the event the load/generation balancing function of the applicable Control Area is accomplished through the function of its market structures approved by FERC, by entering into an arrangement consistent with such FERC-approved market structure.
>
> <u>In the event Interconnection Customer fails to demonstrate to the Transmission Provider that it has otherwise complied with this Article 4.3, the Interconnection Customer shall be deemed to have elected to enter into a Generator Balancing Service Arrangements with the applicable Control Area.</u>
>
> Nothing in this provision shall prejudice either Party from obtaining a FERC-approved tariff addressing its obligations and rights with respect to Generator Balancing Service Arrangements. (emphasis added)

7.3 Application of generator imbalance service to intermittent generators

As noted earlier, FERC at first was reticent to apply a standard bandwidth to generation imbalance service, as it believed that "A generator should be able to deliver its scheduled hourly energy with precision." By placing this issue in interconnection agreements negotiated individually with generators, FERC felt that appropriate terms could be determined that would reflect the real characteristics of each plant.

In Order 2003, however, as we have seen, FERC accepted the approach preferred by many companies to standardize this this service and integrate it into the transmission tariff. The 1.5% bandwidth originally criticized by FERC has thus gradually come to be accepted as a norm.

Many concerns have been raised, however, with respect the the applicability of this norm to wind power and potentially to other intermittent forms of generation. In November 2004, FERC published a staff briefing paper, *Assessing the State of Wind Energy in Wholesale Electricity Markets.*[50] In April 2005, FERC itself issued a Notice of Proposed Rulemaking (NOPR) concerning the establishment of a new Intermittent Generator Imbalance Service.[51] The final order in this rulemaking has yet to be issued.

In the NOPR, FERC clearly states that generator imbalance tariff provisions "have become outdated and have become unjust, unreasonable, unduly discriminatory or preferential, as applied to intermittent resources."[52] Consequently, FERC has proposed, for comment, the creation of a new generator imbalance service applicable only to intermittent generators that, if adopted, would be included in the *pro forma* tariff to be adopted by all transmission providers in their OATTs.

FERC acknowledges that, to date, virtually all wind resources are contracted as an integrated resource, used to serve Native Load — as in Québec. Indeed, some argue that this is the only profitable way to develop wind in the U.S., given the punitive charges for generator balancing service. However, the NOPR notes that there is considerable interest in the wind industry in

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[50] FERC, « Assessing the State of Wind Energy in Wholesale Electricity Markets, » Staff Briefing Paper, November 2004, p. 25, note 42.

[51] 111 FERC 61,026, Docket Nos. RM05-10-000 and AD04-13-000.

[52] P. 1.

pursuing a new business model, where their output could be sold at the busbar to customers other than the incumbent transmission provider.

In this context, FERC points out the inappropriateness of establishing penalties that a prudent customer cannot avoid, and the unfair advantage that these penalties create for thermal power in relation to wind power.

> The current treatment of generator imbalances with respect to intermittent resources appears to be unduly discriminatory under section 206 of the Federal Power Act. The Commission allows utilities to charge penalties to deter conduct that could threaten system reliability or service to other customers and provide incentives to conform to good utility practices. A properly designed penalty should also have minimal impacts on market participation. However, penalties should be avoidable by customer actions, and should not limit market participation. Thermal generators are subjected to generator imbalance provisions that are tailored to their abilities and give them an unfair and unduly discriminatory advantage over intermittent resources, which have much less control over their output. On the other hand, intermittent resources are faced with generator imbalance provisions that fail to recognize their unique needs and prevent them from competing on an equal basis with thermal generators. As noted above, penalties must be avoidable by customer actions, and should not limit market participation. Indeed, intermittent resources face charges that they cannot reasonably avoid, while thermal resources, which can control their generation schedules with much more precision, can generally avoid these charges. At this time, the Commission is concerned that existing generator imbalance provisions are unduly discriminatory against wind generators. Accordingly, the Commission is proposing to add a new Generator Imbalance Service, Schedule XYZ, under the pro forma OATT to address generator imbalances for intermittent resources. [footnote omitted][53]

The solution proposed by FERC is to increase the bandwidth to 10%, and to prescribe that the charges outside of this bandwidth be cost-based (using the traditional 110%-90% approach).

7.4 Applicability of FERC's proposed Intermittent Generation Imbalance Service in Québec

On their face, the arguments raised by the U.S. wind energy and described in FERC's NOPR are, for the most part, equally applicable in Quebec. Insofar as the standard generation imbalance service is applied to wind power — whether the one proposed by TransÉnergie or the one typically accepted up until now by FERC — it creates a probably insurmountable obstacle for this young

[53] Ibid., P57.

industry to pursue any developments other than those where their output is purchased by either HQP or HQD.

In the U.S., as in Quebec, wind developments currently do not use point to point transmission service to deliver power to third-party customers (i.e., customers not affiliated with the transmission provider), and the stated purpose of the proposed new service is to make such developments possible. The one significant difference is that, since Quebec loads do not have the option of choosing their energy provider, the client base for such a wind developer would largely be limited to exports.

There are, however, potential exceptions to this rule. If a municipal distribution company were to build wind generation at some distance from its own transmission system, it could conceivably use point to point transmission service to deliver the power to its distribution customers.[54]

If Annexe 4 were to be approved as proposed, such developments would almost certainly become impractical. Even if no such projects have to date been proposed, there is no reason to believe that developers and municipalities are not now evaluating their feasibility. The regulatory framework to be created, in part, by the Régie's decision in this hearing will form part of the context in which such decisions are made. Approval of TransÉnergie's proposed generator imbalance service, without an exemption or alternate framework for intermittent generators, could thus be expected to create an unnecessary brake on what could be a fruitful avenue for future wind power development in Québec.

For these reasons, we recommend that Régie establish a Intermittent Generator Imbalance Service, similar to that proposed by FERC in the NOPR mentioned above.

8 Summary of Recommendations

The analyses presented above lead to the following conclusions:

Short-term tariffs. The Régie should establish separate on-peak and off-peak tariffs for daily and hourly service.

[54] A similar argument could be made – though not necessarily successfully – for industrial customers that self-generate.

Discounts. The discount policy proposed by TransÉnergie should be rejected in its current form, as there is no convincing evidence that it will lead to any significant quantity of new transactions, and it will inevitably result in reduced revenues from some transactions that would have occurred otherwise. I recommend the following modifications to TransÉnergie's proposal:

- transactions originating in regions with hourly markets should be eligible for discounts based on a formula similar to that proposed by TransÉnergie. However, the amount of the discount be increased, in order to allow greater than zero profitability for the resulting transaction, following consultation with affected customers;

- transactions originating in regions without hourly markets should not be eligible for discounts unless a customer-specific cost basis (P_A) has ben approved by the Régie that adequatley reflect's the customer's marginal cost for additional point to point transactions. For thermal generators, this should probably be based on their marginal generating cost. For HQP, it should probably be based on its average purchase price for off-peak purchases from neighbouring grids, averaged over an appropriate time period.

Interconnection costs. In order to ensure that native load and other transmission customers are protected against having to bear costs related to the interconnection and integration of merchant generators, options i) and ii) of s. 12A.2 of the *Tarifs et conditions* should be modified as follows:

> i) signature d'une Convention de service pour le service de transport ferme à long terme dont la valeur actualisée des paiements à verser au Transporteur pendant la durée de la Convention signée est au moins égale aux coûts encourus par le Transporteur moins tout montant remboursé au Transporteur, pour assurer l'intégration de la centrale. Cette convention de service doit <u>préciser qu'elle est valable uniquement pour des transactions ayant leur point d'origine à la centrale qui fait l'objet de l'Entente de raccordement</u>;
>
> ii) signature d'un engagement d'achat de services de transport ferme ou non ferme de point à point de type "take or pay", pour un montant au moins égal en valeur actualisée aux coûts encourus par le Transporteur, moins tout montant remboursé au Transporteur, pour assurer l'intégration de la centrale<u>. L'engagement doit préciser que seules des transactions ayant leur point d'origine à la centrale qui fait l'objet de l'Entente de raccordement peuvent être reconnues à l'égard de cet engagement d'achat</u>;

Generator imbalance service. In order to avoid undue discrimination against intermittent generators and to avoid creating a major obstacle for wind developments in which the resulting energy is not sold to HQD or HQP, the Régie should establish an Intermittent Generator Imbalance Service similar to that proposed by FERC in its NOPR of April 14, 2005.