RÉGIE DE L'ÉNERGIE DU QUÉBEC

# R-3401-98
# HYDRO-QUÉBEC'S REVISED APPLICATION FOR THE MODIFICATION OF RATES FOR THE TRANSMISION OF ELECTRIC POWER

TESTIMONY OF

**PHILIP RAPHALS,**
**PETER BRADFORD**
**AND ELLIS O. DISHER**

ON BEHALF OF THE RNCREQ

February 7, 2001

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# 1. Introduction

## *1.1. Mandate*

The RNCREQ has mandated the Helios Centre to prepare a report addressing a number of issues raised by Hydro-Québec's revised application for the modification of rates for the transmision of electric power (R-3401-98).

To meet this request, the Helios Centre called upon two American experts to complement its own expertise: Peter A. Bradford, a leading expert in regulation of electric utilities, and Ellis O. Disher, a specialist in transmission regulation. The authors' qualifications are summarized briefly in the following section.

In this first rate case concerning Hydro-Québec's transmission activities, the Régie has identified a broad range of questions to be debated. The RNCREQ asked us to focus our testimony on the following issues:

First, it asked us to review the context in which the present hearing occurs, specifically with respect to Hydro-Québec's adoption of an open access tariff and its American subsidiary's application to the FERC to obtain authorization as a power marketer (chapter 2).

Second, it asked us to comment on Hydro-Québec's proposed policies for a) discounting point-to-point rates and b) the treatment of costs related to additions to the transmission network (chapters 3 and 4).

Third, it asked us to analyze the implications of Hydro-Québec's proposed modifications to the rates set out in reg. 659, both concerning point-to-point rates and the setting of charges for network service (chapter 5).

Fourth, it asked us to address Hydro-Québec's proposal that, from now on, native load be served without execution of a network integration service agreement under reg. 659 (chapter 6).

Fifth, it has asked us to discuss Hydro-Québec's conformity with the provisions of reg. 659 (chapter 7).

Sixth, it has asked us to comment on certain aspects of Hydro-Québec's proposed transmission revenue requirement, in particular the appropriate treatment of telecommunications assets and expenses (chapter 8).

Seventh, it has asked us to make recommendations as to additional modifications to reg. 659 that might be required, taking into account the particular policy situation in Québec (chapter 9). We make two such suggestions, concerning:

- priority of service for Native Load in the event of curtailments, and
- the obligation to build.

Finally, it has asked us to provide guidance as to the modalities that the Régie might use in approving additions or modifications to the network (chapter 10).

### *1.2. Qualifications*

**Philip Raphals**, associate director of the Helios Centre, has provided expert testimony before the Régie on several occasions in the past. Together with Peter Bradford, he provided testimony in R-3398-98 (on Hydro-Québec's proposed supply tariff) and in R-3405-98 (general principles for the regulation of transmission). He has also provided expert testimony in R-3416-98 (small hydro) and R-3416-98 (security of supply). He has prepared numerous reports and studies on a variety of matters concerning electricity policy for a broad group of clients, ranging from the Commission parlementaire sur l'économie et du travail to First Nations to public interest groups in Québec, Canada and the United States. Recently, he was an invited speaker at the Symposium on Understanding the Linkages between Trade and the Environment in Washington, D.C., sponsored by the North American Commission for Environmental Cooperation.

**Peter A. Bradford** has had a long and illustrious career as a regulator. Chair of the Maine Public Utilities Commission for 1982 to 1987 and of the New York State Public Service Commission from 1987 to 1995, he has also served as a member of the United States Nuclear Regulatory Commission and as the president of the National Association of Regulatory Utilities Commissioners (NARUC). Since 1996, he has advised a large number of regulators in the United States and abroad on issues related to the restructuring of the electricity industry. He teaches courses concerning energy and the environment at Yale University and at Vermont Law School, and is a fellow if the Regulatory Assistance Project.

**Ellis O. Disher** is the principal of Signal Hill Consulting Group LLC, in New Haven, Connecticut. As a consultant, his primary activities have involved assisting developers of merchant power plants in their relationships with transmission providers and with the Independent System Operators in New England and New York. Previously, as Director of Strategic Analysis for The United Illuminating Company (an electric utility in New Haven), he was responsible for coordination of NEPOOL activities, interaction with state and federal regulatory agencies, transmission contracting, and development of strategies for use of UI's generation and transmission assets. He also had oversight responsibilities for power contracting and for analytical work related to resource alternatives, transmission system operation and expansion, and interconnected system operation.

Throughout Mr. Disher's career at UI, he was engaged in a variety of NEPOOL-related efforts. He represented UI, at various times, on the Transmission Task Force, the Operations Committee, the Policy Planning Committee, the Review Committee, and several ad hoc working groups. He chaired the Operations Committee (1991-1992) and the Review Committee (1994-1997). During his tenure as Chair of the Review Committee, the committee was responsible for guiding the restructuring of NEPOOL in view of the deregulation that was emerging in the electric industry.

## 2. Context

Before entering into the substance of Hydro-Québec's application to modify its transmission tariff (reg. 659), it is important to review the context in which it was introduced. As we shall see in section 2.1, obtaining power marketer authorization (PMA) from the Federal Energy Regulatory Commission (FERC) for Hydro-Québec's American subsidiary H.Q. Energy Services (U.S.) Inc. (HQUS) was the driving force behind the adoption of this tariff. In section 2.2, we will review the criteria which govern the attribution of PMAs by FERC. Finally, in section 2.3, we will discuss the relevance of FERC's policies for the present application.

### *2.1. Hydro-Québec's adoption of an open access transmission tariff*

The energy policy promulgated by the Québec government in the fall of 1996 announced for the first time that Hydro-Québec would adopt a transmission tariff. It did so in the following terms:

> The *Act respecting the Régie de l'énergie* makes a specific provision enabling the Régie to set or modify tariffs and conditions under which electricity is transmitted, upon the request of Hydro-Québec. This provision makes reference to wheeling activities and extends the jurisdiction of the Régie to these activities. Hydro-Québec will take advantage of this provision.
>
> The initiative taken here by the government will make it possible to respect the reciprocity requirement formulated by the Federal Energy Regulatory Commission, in its April 1996 order. At that time the FERC stipulated that before foreign regions could have access at market prices and on an equal footing with competing American companies, they must first offer equivalent access to their own grids. The provisions included in the *Act respecting the Régie de l'énergie* make the setting-up of such a service possible, thus opening the door for Hydro-Québec to deal on the American market as an electricity trader.[1] (emphasis added)

The relationship between the transmission tariff and HQUS' PMA application to the FERC was made even clearer in the order-in-council by which the Government of Québec approved HQ's first open access transmission tariff (reg. 652). The government chose to exempt the order from prior publication,[2] and justified this exemption in the following terms:

— the new regulatory framework for wholesale electric transmission in the United States will come into force on 1 January 1997;

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[1] Government of Québec, *Energy at the Service of Québec: A Sustainable Development Perspective* (1996), p. 57.

[2] Under art. 12 of the *Regulations Act*, prior publication of a draft regulation can be dispensed with when the urgency of the situation so requires.

— potential sales of Hydro-Québec to the United States will be vulnerable to complaints from the competition if the Corporation does not comply with the new regulatory framework by filing with the "Federal Energy Regulatory Commission" an application for authorization to sell electricity at market prices and a bylaw establishing the conditions and rates of wholesale electric transmission service approved by the Government;

— Hydro-Québec will be able to profit by new sales opportunities to the Unites States as soon as it may avail itself of the conditions of the new American regulatory framework;

— it is expedient for the Government to approve as soon as possible Hydro-Québec bylaw number 652 establishing the conditions and rates of wholesale electric transmission service;3 (emphasis added)

Two months later, on February 14, 1997 Hydro-Québec's Board of Directors replaced this tariff with reg. 659, after FERC denied a PMA to Powerex (B.C. Hydro's marketing affiliate), despite that company's adoption of a transmission tariff very similar to reg. 652. In its decision, FERC made it clear that reciprocity would only be granted if the Canadian utility adopted a tariff "consistent with or superior to" the *pro forma* tariff prescribed for all utilities under FERC jurisdiction in Order 888.[4]

The new tariff, reg. 659, was then approved by Cabinet on March 5, 1997; once again, it was exempted from prior publication, for reasons very similar to those quoted above.[5] That same day, HQUS resubmitted its application to FERC. In its application, it stated that:

> Functionally, jurisdictionally and procedurally, the Régie closely resembles the Federal Energy Regulatory Commission.[6]

It stated further that:

> By design, the non-rate terms of Hydro-Québec's Revised Tariff are virtually identical in all substantive respects to the pro forma tariff and include the provisions adopted by the Commission to ensure open access, comparable transmission service to transmission customers.[7]

This statement is supported by a redline version of reg. 659, showing all textual differences between reg. 659 and the pro forma tariff (Exhibit 7).

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[3] Order in Council 1559-96, 11 December 1996, *Gazette officielle du Québec,* December 31, 1996, vol. 129, no. 10, p. 1248.

[4] FERC, British Columbia Power Exchange Corporation, *Order Rejecting Market-Based Rates Without Prejudice*, Docket ER97-556-000, Jan. 1, 1997.

[5] Order in Council 276-97, 5 March 1997, *Gazette officielle du Québec,* March 12, 1997, vol. 128, no. 54, p. 5487.

[6] FERC, *Revised application of H.Q. Energy Services (U.S.) Inc.*, Docket No. ER97-851-000, March 5, 1997, page 2.

[7] *Ibid.,* p. 5.

FERC accepted reg. 659 as adequate "mitigation" of Hydro-Québec's transmission market power on May 9, 1997,[8] and granted the PMA on November 12, 1997.[9]

### *2.2. Power marketer authorization*

As early as 1989, FERC began to recognize that, under certain conditions, it could loosen its regulatory control over prices for wholesale electricity sales without opening the door to monopoly power. Thus, FERC has granted certain companies the right to buy and sell "bulk" electricity without obtaining prior regulatory approval — in other words, to engage in transactions at market-based rates — once it was convinced that they couldn't exercise monopoly power.

At first, this so-called "energy marketer status" was granted only to independent marketers that did not own generation or transmission facilities, had no monopoly service territory and were not affiliated with any such company.[10] In 1993, FERC decided to grant similar status to marketers affiliated with independent power producers (IPPs), as long as they had neither transmission nor a monopoly service territory.[11] More broadly, it would allow such marketers to transact at market-based rates, as long as neither the marketer nor its IPP affiliate had the ability to exercise monopoly control or "market power."

The following year, in its landmark *Heartland* decision,[12] FERC defined the criteria it would apply to the much broader category of marketers affiliated with a utility having a monopoly service territory and/or generation or transmission assets. The criteria established by FERC in *Heartland,* which it still applies today, are that such a marketer must demonstrate that neither it nor its affiliates can exercise market power in either generation or transmission.

**Generation market power** occurs when a firm owns or controls a significant percentage of generating capacity in the target market or in areas directly interconnected to it.[13] Traditionally, FERC has used "hub-and-spoke" analysis to look at the market share of the affiliated companies for total resources (installed capacity) and uncommitted resources

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[8] FERC, *Order Directing Further Information and Analysis and Deferring Action on Market-Based Rates,* Docket No. ER97-851-000, May 9, 1997.

[9] FERC, *Order Accepting for Filing Proposed Market-Based Rates,* Docket No. ER97-851-000, Nov. 12, 1997. This order was challenged before the U.S. Court of Appeal by the Grand Council of the Crees (of Québec); the appeal was rejected on a matter of standing, without adjudication of the substantive arguments raised (The Grand Council of the Crees (of Quebec) and New England Coalition for Energy Efficiency and the Environment, v. FERC, United States Court of Appeals, D.C. Circuit, No. 98-1280, Jan. 11, 2000).

[10] FERC, *Citizens Power & Light Corp.,* 48 FERC 61,120 (1989).

[11] FERC, *Enron Power Marketing, Inc.*, 65 FERC 61,305 (1993).

[12] FERC, *Heartland Energy Services Inc.*, 68 FERC 61,223 (1994).

[13] Energy that is committed under long-term contract to non-affiliated companies is excluded from this analysis.

(surplus capacity) in each "first-tier" market (those markets that are directly interconnected with it). It is increasingly clear, however, that this tool is inadequate — it was recently described by Commissioner William L. Massey as an "anachronism."[14] According to Massey, FERC must redefine its standards for evaluating market power, and should do so in a rulemaking or other generic proceeding.[15] Massey also believes that participation in a Regional Transmission Organization (RTO) should be a condition for market-based rates.[16]

**Transmission market power** refers to the ability of the marketer or an affiliated company to hinder its competitors from accessing the target market through its control of the transmission system. This could take the form of denying transmission service outright, or of imposing discriminatory rates or conditions.

Since the adoption of Order 888 in 1996, FERC considers that the remedy for transmission market power is for the transmission-owning company affiliated to the marketer to adopt an open access tariff that sets out the terms, conditions and prices for transmission and that guarantees access to all competitors on a non-discriminatory basis. This tariff must be equivalent or superior to the pro forma tariff attached to Order 888. While the adoption of such a tariff is obligatory for all "jurisdictional utilities," there is no such obligation for Canadian utilities or for municipal utilities or co-ops in the U.S. that are not subject to FERC's jurisdiction. However, the reciprocity clause (s. 6) ensures that only non-jurisdictional utilities which have themselves adopted an open access tariff may take advantage of the access rights created by the *pro forma* tariff.

Order 888 was later clarified by Orders 888-A and 888-B. FERC's understanding of "equivalent or superior" is further expressed in the long series cases decided since then in which it has indicated the extent to which it will accept variations from the pro forma tariff proposed by utilities under its jurisdiction, as well as by non-jurisdictional entities seeking to take advantage of Order 888's reciprocity provisions.

## *2.3. Relevance of* pro forma tariff *for the Régie*

Given the present context, in which the Régie is called upon to modify a transmission tariff designed by a foreign regulator, there is no Québec or Canadian record to turn to for insight into the meaning or intent of its at times complex provisions. These same provisions have, however, been debated in depth in proceedings before the FERC, and that Commission's orders — which, over time, have articulated, explained, clarified and enforced these very provisions — taken together represent a highly coherent body of jurisprudence elucidating

14 William L. Massey, "Three Messages from Volatile Electric Markets," EBA Mid-Year 2000 Program, Washington, D.C., Nov. 17, 2000.

15 Massey, concurring, in FERC, *Order Accepting for Filing Revised Rate Tariffs and Codes of Conduct,* Docket No. ER00-3691-000, 93 FERC 61,193, Nov. 21, 2000.

16 Ibid. This same view was expressed by several intervenors in the RTO NOPR. In its Order 2000, FERC did not adopt this position, but stated rather that the issue should be addressed on a case-by-case basis.

these provisions and the concepts that underlie them. These orders are essential sources of reference and interpretation for this complex document and, by extension, for Hydro-Québec's reg. 659.

At the same time, it is important to recognize that FERC and the Régie operate under very different legislative mandates. Order 888, and the *pro forma* tariff it contains, were the direct result of the adoption by the U.S. Congress of the Energy Policy Act of 1992, as stipulated in the following passages from the introduction to Order 888:

> <u>A goal of the Energy Policy Act was to promote greater competition in bulk power markets by encouraging new generation entrants</u>, … and by expanding the Commission's authority under sections 211 and 212 of the FPA to approve applications for transmission services. [note omitted][17]
>
> <u>…</u>
>
> As stated by the Commission, <u>in recognition of the Congressional goal in the Energy Policy Act of creating competitive bulk power markets</u>:
>
> > <u>Our goal is to facilitate the development of competitively priced generation supply options, and to ensure that wholesale purchasers of electric energy can reach alternative power suppliers and vice versa</u>. …
>
> As discussed infra, based on the mounting competitive pressures in the industry and rapidly evolving markets, <u>we have concluded that section 211 alone is not enough to eliminate undue discrimination</u>.[18]
>
> In what follows [the body of Order 888], <u>we set out the changes necessary to remedy undue discrimination and to ensure a fair transition to a more competitive regulatory regime</u>.[19] (emphasis added)

No equivalent goals have been set out in the Régie's constitutive legislation or in other binding or non-binding instruments of the Québec government, nor has the Régie adopted such principles on its own.[20]

Finally, we have seen that Hydro-Québec's intention to meet FERC's PMA criteria was the driving force behind its decision to adopt an open access transmission tariff in the first place, and in its design. To the extent that this enters into conflict with other legislative, regulatory

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[17] Order 888, pp. 29-30.

[18] *Ibid.*, pp. 34-35. Quote from Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Notice of Proposed Rulemaking, 59 FR 35274 (July 11, 1994), FERC Stats. & Regs., Proposed Regulations P32,507 at 32,866 (Stranded Cost NOPR).

[19] Ibid., p. 51.

[20] In R-3405-98, concerning general principles related to transmission tariffs, the RNCREQ asked that the Régie reflect on such questions, and in particular whether or not it should adopt the principles underlying Order 888. In D-98-88, however, the Régie chose not to include these questions in R-3405-98.

and policy goals unique to Québec, the Régie may have to make sigificant tradeoffs. To do so, it will need to understand how the issues addressed in this hearing are understood by the FERC. Only a careful review of FERC rulings will allow the Régie to predict or foresee the effect, if any, of a given modification of reg. 659 on the PMA, and hence on Hydro-Québec's access to the American market.[21]

In this regard, several assertions made by Hydro-Québec in its evidence are somewhat surprising. In response to a request from the Régie to provide, for each proposed modification to reg. 659, the *raison d'être* of the original provision in FERC's pro forma tariff, Hydro-Québec stated that it had not undertaken any study or analysis of the reasoning that guided the FERC in establishing the *pro forma* tariff. It simply states that, in 1997, it had "adapted the pro forma to the Québec context," and that it now wishes to "update it and improve its adaptation to the Quebec context."[22] It reiterated this same response when asked by the Régie to provide the *raison d'être* or purpose of the provisions of reg. 659 that it now wishes to change.[23] Hydro-Québec thus appears not to be concerned whether or not the modifications it proposes, or those proposed by other participants, might affects its subsidiary's PMA.

Similarly, Hydro-Québec has expressed little concern for the implications of FERC's RTO Order (Order 2000), despite the fact that it suggested, as noted above, that RTO membership might eventually be a necessary condition for obtaining a PMA. In its brief to FERC concerning the RTO NOPR, TransÉnergie argued that it "already satisfies the minimum characteristics and functions that the Commission's [sic] has proposed under the RTO NOPR,"[24] an affirmation that was called into question by a number of intervenors.[25]

Asked by the RNCREQ whether Hydro-Québec would once again undertake structural modifications to maintain its access to U.S. markets in the event that FERC found it to be not in conformity with Order 2000, Hydro-Québec merely responded that it "had not examined this hypothetical question."[26] The Motion to Intervene presented by the New Brunswick

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[21] In its 1998 decision on B.C. Hydro's Wholesale Transmission Services, the British Columbia Utilities Commission (BCUC) expressed considerable concern as to the effects its decision might have on Powerex' PMA. BCUC, In the matter of B. C. Hydro and Power Authority, Wholesale Transmission services, Decision, April 23, 1998, pp. 38-41.

[22] HQT-13, doc. 1, R90.1. Unless otherwise noted, any quotations from Hydro-Québec's evidence are our translation.

[23] HQT-13, doc. 1.1, R32.1.

[24] FERC, Docket No. RM99-2-000, Initial Comments of TransÉnergie, Aug. 23, 1999, pp. 1-2.

[25] FERC, Docket No. RM99-2-000, Reply Comments of the Grand Council of the Crees (of Quebec), Greenpeace Canada, Sierra Club of Canada, Mouvement au Courant, the Centre d'analyses de politiques énergétiques and New England Coalition for Energy Efficiency and the Environment, undated; Reply Comments of Project for Sustainable FERC Energy Policy (doc. 19991006-0456). The first required characteristic of an RTO is independence of market participants (FERC, Order 2000, p. 152). As a division of an integrated utility which is an active participant in bulk power markets, it is hard to see on its face how TransÉnergie could meet this requirement.

[26] HQT-13, doc. 14, R5.4.

Power Corp. in this instance stated clearly that Hydro-Québec is involved in discussions with neighbouring utilities for the direct purpose of forming an RTO. In its response, however, Hydro-Québec took the trouble to insist that this issue is unrelated to the present file.

In light of the above, we urge the Régie to take cognizance of FERC's perspective on the various issues raised in this hearing, before arriving at its own conclusions, based on its own legislative, regulatory and policy context. As these contexts are very different from those in the U.S., its conclusions may well differ from those made by FERC.

# 3. Hydro-Québec's proposed policy for discounting short-term point-to-point rates

## *3.1. Hydro-Québec's proposed discount policy*

In its decision D-2000-102, the Régie stated that the issue of discounts for point-to-point transmission service should be addressed in this hearing, and ordered Hydro-Québec to file a proposed discount policy.[27]

Hydro-Québec explains its approach to discounting as follows:

> TransÉnergie offers discounts on short-term transmission services when it judges that they would increase use of the network and thus of the revenues it generates, by allowing transactions to take place which otherwise would not. (HQT-13, doc. 13.1, p. 2)

While Hydro-Québec's direct testimony does not include a precise statement of a proposed discount policy, it appears from section 2.6.3 of HQT-10, doc. 1 that Hydro-Québec's proposition is roughly as follows:

- TransÉnergie may continue to offer discounts when it considers that doing so will allow it to maximize its revenues (p. 27),
- All discounts must be posted on OASIS and made available to all transmission customers (p. 29),
- Any request for a discount from a customer must be made via OASIS (p. 29), and
- TransÉnergie's discounts should apply only to non-constrained paths leading to the same point of delivery, without being obliged to offer the same discount to all points of delivery (p. 28).

This last point would require a modification of the text of reg. 659, as described on HQT-11, doc. 1, p. 13, and illustrated in the redline version of Annexe 7.[28]

As Hydro-Québec's proposed policy is, apart from this one modification, to continue the discount policy it has applied since reg. 659 was adopted in 1997, it is important to examine in detail the way this policy has been applied to date.

[27] D-2000-102, p. 68.

[28] HQT-11, doc. 2, en liasse, "Feuille originale no 84."

## *3.2. Background*

### 3.2.1. Relevant provisions of reg. 659

Reg. 659 specifies point-to-point transmission rates as follows:

| | firm | non-firm |
|---|---|---|
| **annual** | $71.09/kW-yr | |
| **monthly** | $8.01/kW-month | $8.01/kW-month |
| **weekly** | $2.00/kW-week | $2.00/kW-week |
| **daily** | $0.40/kW-day | $0.40/kW-day |
| **hourly** | | $16.67/MW-hr |

Under s. 14.3, Hydro-Québec must use point-to-point service for its off-system sales. It appears from Hydro-Québec's evidence that it is the only user of long-term point-to-point service, while twelve other entities as well as Groupe Production Hydro-Québec (HQ-Production, or HQ-P) have signed umbrella agreements for short-term service (less than one year).[29] While Hydro-Québec has not indicated precise figures, these twelve entities probably account for only a very small proportion of short-term point-to-point sales.

### 3.2.2. Hydro-Québec has deeply discounted virtually all of its point-to-point transactions

According to HQ's evidence, it only offers discounts when necessary in order to allow transactions to occur which would otherwise have been non-economic. However, according to Hydro-Québec, *all* its short-term point-to-point transactions, with the exception of a single transaction in June, 2000, have been discounted.[30] In most months since this service was first offered in May 1997, short-term point-to-point rates have been discounted between 70 and 90%. Only in one month (June 2000) were average short-term discounts less than 60%.[31] On average, short-term point-to-point rates were discounted by about 80% over the period for which data are available, as shown in the following table.[32]

**Average discounts to short-term point-to-point tariffs**

| | 1997 | 1998 | 1999 | 2000 | total |
|---|---|---|---|---|---|
| **revenues** | 4,8 | 3,5 | 21 | 4,6 | 33,9 |
| **revenues based on tariff** | 45,5 | 19,7 | 87,3 | 17,7 | 170,2 |
| **average discount** | 89,5% | 82,2% | 75,9% | 74,0% | 80,1% |

[29] HQT-4, doc. 1, pp. 12-14.

[30] HQT-13, doc. 14.1, p. 13, R131.

[31] HQT-10, doc. 1.3, p. 2.

[32] This table and the following one are derived from HQT-10, doc. 1.3.

Furthermore, and perhaps even more surprisingly, firm rates were discounted even more than non-firm rates, as shown in the following table:

**Average discounts to short-term point-to-point tariffs**

| | 1997 | 1998 | 1999 | 2000 |
|---|---|---|---|---|
| **firm** | 91% | 84% | 78% | 76% |
| **non-firm** | 89% | 81% | 66% | 70% |

Hydro-Québec has provided no explanation for this unusual practice, which contrasts sharply with that of other jurisdictions described by Hydro-Québec's expert Dr. Ren Orens.[33] According to Dr. Orens, prices for firm service in British Columbia are subject to a minimum transmission rate of $2/MWh (37.7% of the regular rate), whereas non-firm services can be priced as low as $1.[34] As for the other jurisdictions he discusses, Dr. Orens makes no mention of discounts for firm service, but only for non-firm.

While Hydro-Québec asserts that it only offers discounts when it estimates that transactions would not take place in their absence, it has provided no evidence that the very substantial discounts offered in the past were justified. Indeed, our analysis shows that Hydro-Québec has routinely offered substantial discounts even when market prices were clearly high enough to constitute no impediment to transactions taking place.[35]

For example, the following chart shows the spot market prices in New England for the month of May 1999, together with Hydro-Québec's regular and discounted hourly transmission tariff.[36] Despite the substantial variations in market price from hour to hour and from day to day, the price was always substantially higher than the regular hourly tariff ($16.67CAD/MW-hr). Nonetheless, on May 4, 1999, TransÉnergie decided to discount the non-firm hourly rate for the entire month of May to $6.00CAD/MWh on peak, and to $0.50CAD/MWh off-peak, discounts of 64% and 97%, respectively.[37]

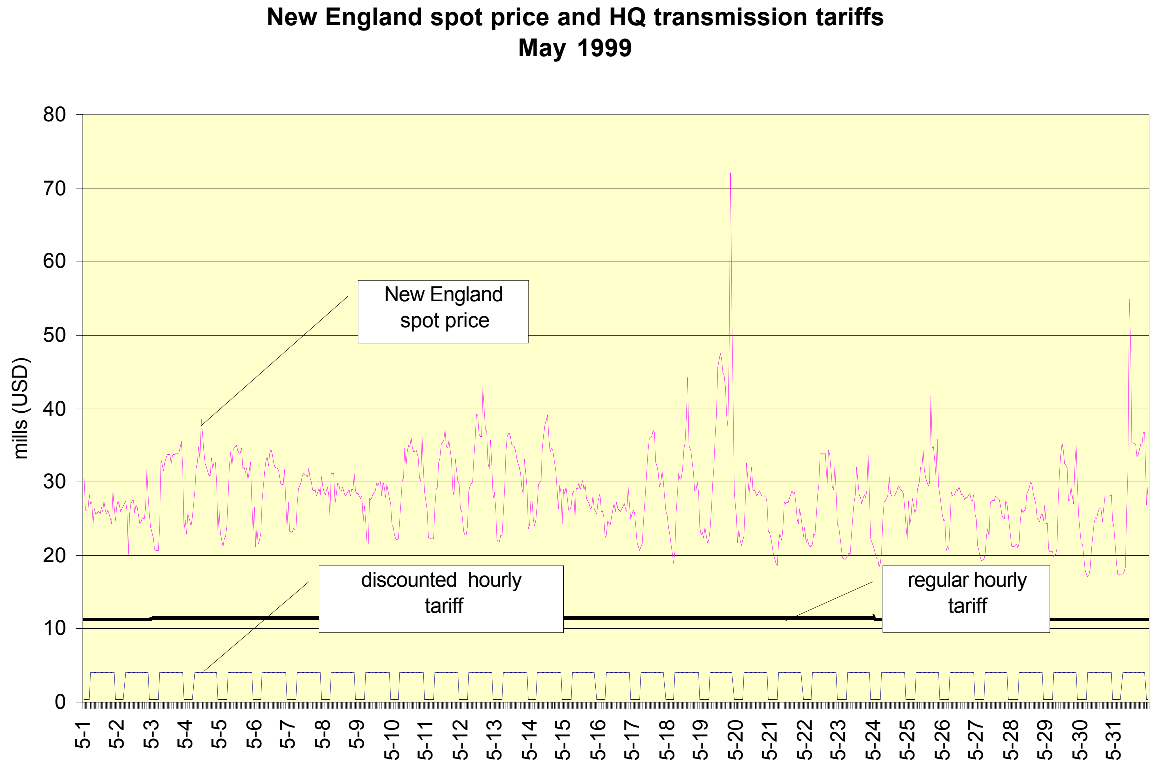
[33] HQT-13, doc. 1, p. 101.

[34] For a review of the policies of the British Columbia Utilities Commission regarding discounts for short-term point-to-point service, see page 24, below.

[35] In D-2000-102, the Régie stipulated that the profitability of Hydro-Québec's exports and buy-sell transactions would not be examined in the present case (p. 63). This issue is raised here only insofar as the expected unprofitability of such transactions is invoked by TransÉnergie as a justification for discounting point-to-point rates.

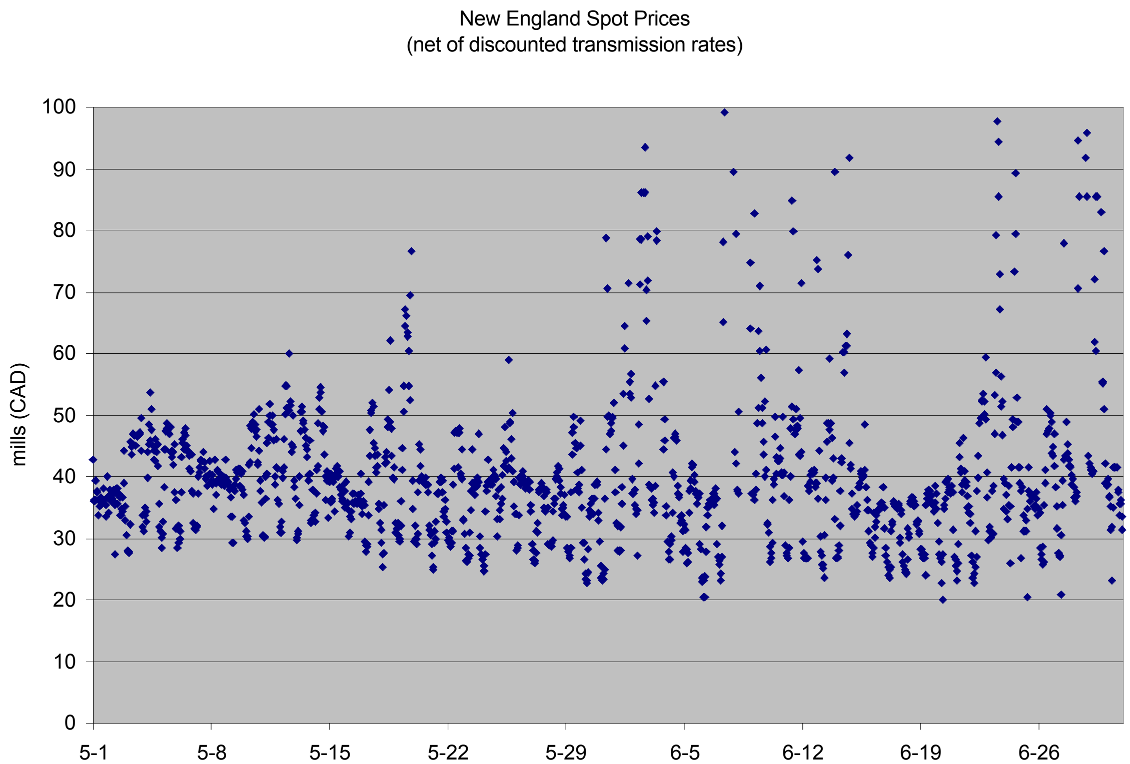
[36] We have limited our analysis to the New England price record since the NE-ISO began operations in May 1999. While we have not analyzed the record of prices in New York, electricity prices in the two areas tend to track each other fairly closely.

[37] HQT-10, doc. 1.3.1.



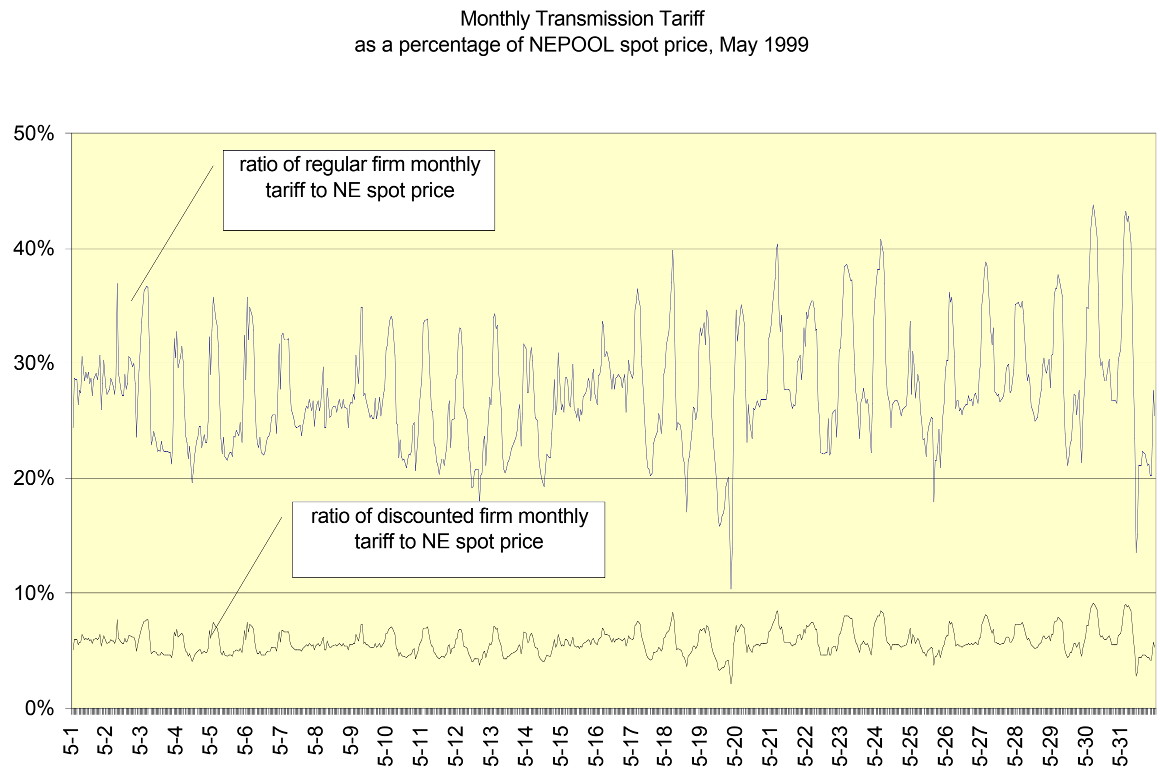

The following chart shows the price that HQ-Production would have received from hourly sales into the NEPOOL market in May and June 1999, net of the discounted transmission rates charged by TransÉnergie.[38] It is noteworthy that the vast majority of transactions would have produced revenues (net of transmission charges) of between 2.5 and 4.5¢ CAD for HQ-P. A similar exercise undertaken for the off-peak period only shows an even stronger concentration between 2.5 and 3.5¢ CAD.

[38] Several much higher-value sales during price spikes in June are not shown on this chart.




These observations suggest that TransÉnergie's discounting policy was designed to allow HQ-P a net revenue of at least 2.5¢ CAD for sales at any time throughout this two-month period, and thus to make it indifferent as to whether its sales are on- or off-peak. (Of course, it still has an obvious interest in selling into price spikes). The implications of this policy will be discussed in the next section.

As we have seen above, firm, longer-term transmission tariffs were also discounted, and to an even greater extent. In May 1999, the rate for firm monthly service was discounted by almost 80%. According to the justification offered by Hydro-Québec, one would expect that, without this discount, transmission costs would have been so high as to make sales unprofitable. To test this hypothesis, we once again compared hourly prices in the New England market to the regular and discounted monthly transmission tariff. The following chart shows these rates as a percentage of the New England spot price.




This chart shows that, as the New England spot price varied, transmission costs under the regular monthly tariff would only rarely have accounted for more than 35% of the sales revenues; on many occasions, they would have accounted for less than 25%. On average, the regular transmission tariff would have represented just 26.7% of the market price. In other words, were HQ-P to export to New England paying the full transmission tariff, 26.7¢ out of every dollar of export revenues would have gone to pay for transmission.

While this amount is substantial, it is by no means unreasonable. These exports are for the most part made possible by surplus generation and transmission capacity, both of which were built primarily to satisfy domestic needs; in both cases, virtually all costs are sunk and short-term marginal costs are near zero. There is thus no inherent reason that export revenues should be allocated primarily to generation. Given that the generation:transmission asset ratio for Hydro-Québec is approximately 60:40,[39] allocating 26.7% of export revenues to transmission appears not to be excessive.

It seems, however, that Hydro-Québec prefers that export revenues be credited to generation rather than to transmission; after discounting the monthly firm transmission tariff by almost 80%, the discounted tariff on average accounted for just 5.8% of the market price. Thus, for every dollar of revenues from sales to New England taken under firm monthly service, just

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39 According to Hydro-Québec's 1999 Annual Report (p. 78), in-service generation assets amount to $26,494 billion, and in-service transmission assets are $17,732 billion.

5.8 cents went to contribute to the transmission revenue requirement, with the remainder (minus marketing costs and overhead) going to the generation account. Since transmission is regulated on a cost-of-service basis, the portion of export revenues allocated to transmission are, in effect, returned to consumers, whereas the part retained by HQ-P is instead kept by the company and hence by its shareholder, the Québec government.

One might expect that, given the high level of market prices in May 1999 relative to the discounted transmission tariff, TransÉnergie would greatly reduce its discount for the following month. At the end of May 1999, TransÉnergie did indeed reduce its discounts for the following month. The June discounts were reduced to 76% (from 79%) for firm service, while remaining unchanged for off-peak hourly service.

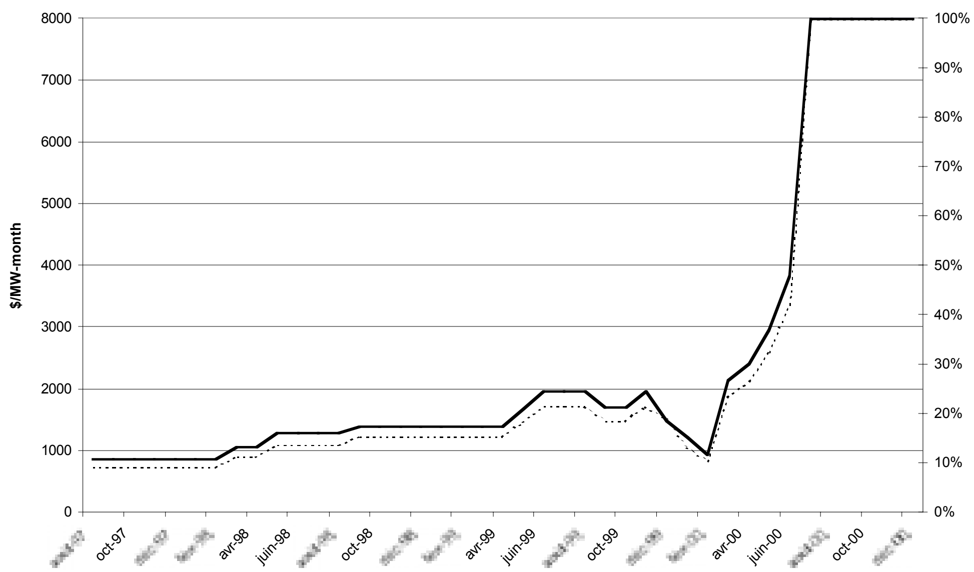
However, these modifications hardly changed the portrait described above, since market prices, predictably, also rose, as New England entered its peak summer season. As shown in the following table, the discounted transmission tariff have accounted for just 7.1% of the average hourly spot market price in June 1999, down from 10.7% in June.

| | **May** | | **June** | |
|---|---|---|---|---|
| average energy price ($USD/MWh) | 28,2 | | 49,2 | |
| discounted transmission tariff ($USD/MWh) | 3,0 | 10,7% | 3,5 | 7,1% |
| regular transmission tariff | 11,3 | 40,1% | 11,3 | 22,9% |

### 3.2.3. Recent changes in Hydro-Québec's discounting policy

As the following chart shows, Hydro-Québec discounted monthly firm and non-firm service by 80-90% for all of 1997 through 1999; however, starting in the spring of 2000, discounts were greatly reduced. According to the month-by-month confirmations of rate reductions filed by Hydro-Québec in late December 2000 (HQT-10, doc. 1.3.1), there have been no discounts offered at all since June 2000, for either firm or non-firm service, as seen in the following chart.

**Discounted Monthly Transmission Tariffs**
**(firm and non-firm)**




It is not clear how to reconcile this information with Hydro-Québec's statement on November 11, 2000 that only one transaction has taken place without discounts (in June 2000).[40] As Hydro-Québec has not released data for short-term point-to-point sales subsequent to June 2000, we are unable to confirm whether or not Hydro-Québec has actually purchased any transmission capacity at the undiscounted rate, or whether it has instead augmented its purchases at the much lower annual rate.

We are also unable to explain this sudden reversal in discounting policy. While market prices trended strongly upwards in the last half of 2000, they were falling in the spring, when the reductions in discounts began. By June, Hydro-Québec's monthly transmission tariff had increased eight-fold from its earlier levels, whereas market prices remained for the most part under $40 US/MWh. New England prices did indeed increase sharply in the fall of 2000 but, to the best of our knowledge, this was not foreseen by market analysts in the early summer.

In its evidence, Hydro-Québec implies that it carefully adjusts its discounts to follow the evolution of market prices in its target markets. applying discounts only when necessary.[41] Hydro-Québec certainly did not modify its discounts in response to the high prices in New England in the summer of 1999, and it is difficult to explain the elimination of discounts in the spring of 2000.

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40 HQT-13, doc. 14.1, p. 13, R131.

41 HQT-13, doc. 1, p. 119.

### 3.2.4. Adapting discounting theory to hydroelectric systems

The use of discounts to increase throughput is a widely accepted regulatory practice. Assuming that the marginal cost of transmission is zero, operators can increase revenues and therefore reduce costs to other users by discounting rates in order to promote transactions which would otherwise be uneconomic.

When market prices are so low that, net of undiscounted transmission tariffs, they do not cover the marginal costs of production, thermal generators will reduce production levels. If discounting will allow additional transactions to occur, it will increase transmission revenues, in turn reduce the cost burden for native load. As such, the optimal level of discounting is related to the difference between the market price and the generator's *marginal* cost of production.

The nature of a hydro system alters this basic logic. While the total annual production of a thermal unit diminishes each day it does not run, that of a hydro unit is fixed by runoff (though reservoir storage allows generation to be shifted in time). In a hydro system, if a sale is not made because it is uneconomic at a particular moment, the water will remain in the reservoir, to be sold at a future time. The transmission throughput resulting from its generation is thus also fixed; what is not sold today can and will be sold tomorrow. Refusal to discount thus does not cause the transmission operator to lose revenue, but only to defer it.

In other words, while a thermal generator cannot make today's sales tomorrow, a hydro generator *can* defer sales. Thus, low prices that would make a sale uneconomic today result in reduced sales in both the short and the long term for a thermal generator (and for its transmission provider), but not for a hydro generator. For the latter, these sales are deferred but are never lost.

Hydro-Québec's reservoirs are large, but they are not unlimited.[42] Making the reasonable assumption that Hydro-Québec will only spill water as a last resort, every litre of water that enters its reservoirs can be thought of as a quantity of electricity that will, sooner or later, be generated, transmitted and sold. HQ-Production will do its best to maximize its profits by manipulating the timing of those sales, within the existing regulatory, technical and economic constraints, but TransÉnergie is largely indifferent to these manoeuvres.

Thus, discounting transmission rates in order to guarantee HQ-P's net revenues per kWh does not increase TransÉnergie's total revenues, but rather decreases them. If TransÉnergie were concerned only with maximizing its own point-to-point revenues, and thus in minimizing the cost to network and native load customers, it would not offer these discounts, since, over time, HQ-P's point-to-point sales will be precisely equal to its hydraulic inflows minus domestic demand. Any such discounts thus constitute a transfer of costs from

[42] The Hydro-Québec system includes about 111 TWh of inter-annual storage, and an additional 60 TWh of inter-seasonal storage. Régie de l'énergie, *General Description of Hydro-Québec's System*, March 12, 1998, p. 4.

TransÉnergie's affiliated generator to its regulated end-use customers, i.e. a transfer of wealth in the opposite direction.

To the extent that the discounts result in increased usage by other system users, they might still be justified. However, Hydro-Québec has provided no evidence that its discounts have resulted in significant additional usage by non-affiliated transmission customers. In all likelihood, then, discounts serve no practical purpose for TransÉnergie and its network (native load) customers.

## *3.3. Regulatory practice elsewhere in North America*

### 3.3.1. FERC

FERC's primary concern in transmission regulation is that utilities treat other users of their transmission system on a comparable basis to their own use of it:

> [T]he real issue is assuring that utilities bear the costs associated with their own uses of the system in a manner comparable to how they charge others.[43]

Thus, it required that:

> [I]f a transmission provider offers a rate discount to its affiliate, or if the transmission provider attributes a discounted rate to its own transactions, the same discounted rate must also be offered at the same time to non-affiliates <u>on the same transmission path and on all unconstrained transmission paths</u>. We will further require that any affiliate discounts from the maximum firm rate must be transparent, readily understandable, and posted on the transmission provider's OASIS in advance so that all eligible customers have an equal opportunity to purchase non-firm transmission at the discounted rate.[44]

In Order 888-A, it explained that:

> <u>A transmission provider should discount only if necessary to increase throughput on its system</u>. While <u>the potential for abuse is most obvious in situations involving the transmission provider's own wholesale use or use by an affiliate</u> (own use/affiliate), [note omitted] we must also be concerned with a transmission provider agreeing to discount to non-affiliates in any unduly discriminatory manner.[45]

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43 Order 888, p. 198.

44 *Ibid.*, pp. 319-320.

45 Order 888-A, p. 290.

It then revised its discounting policy in several ways, by requiring that OASIS be used for all negotiations of discounts and by allowing discounts that only apply to particular paths.[46] It added, however, the following disclaimer:

> Finally, we recognize that even with this revised policy utilities may engage in affiliate abuse by offering discounts only at times or along paths that are of advantage to it or its affiliates. While requiring the posting of discount information on the OASIS does not completely eliminate the possibility of affiliate abuse, these procedures will allow ready identification of unduly discriminatory or preferential transactions, and thus make easier the preparation of complaints that the transmission provider is engaging in a pattern of discounting that indicates affiliate abuse, such as offering discounts preferentially at times or on paths that only the transmission provider or its affiliate can take advantage of, without offering discounts at times or on paths that its competitors can take advantage of.

As we have seen, TransÉnergie's discounting policy is almost exclusively of this nature, in that its "affiliate" is the only entity so situated as to be able to take advantage of the discounts offered, and because such discounts are in to way necessary to increase throughput on the Hydro-Québec system. In fact, they have no practical effect on total throughput at all, if measured over a sufficiently long period of time.

### 3.3.2. British Columbia

The British Columbia Utilities Commission (BCUC) addressed the question of discounting short-term point-to-point rates in its 1998 decision on the proposed transmission tariff of West Kootenay Power (WKP). WKP had proposed a policy in which it would only offer discounts on short-term firm and non-firm point-to-point service if:

> (i) the customer can demonstrate that an alternative transmission path with another transmission provider is available at a lower cost;
>
> (ii) the lack of a discount will result in curtailment of transmission use for economic reasons; and
>
> (iii) the increased usage will not add to system costs over the term requested.[47]

WKP indicated that, since all three conditions would need to be met before a discount would be offered, this would likely mean that discounts would not occur.[48]

The Commission accepted the utility's policy regarding short-term discounts, stating that:

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[46] This is equivalent to the modification requested by Hydro-Québec, mentioned above on p. 14.

[47] BCUC, West Kootenary Power Ltd., Transmission Access Application, Decision, March 10, 1999, p. 19.

[48] *Ibid.,* p. 18.

> Although the Utility's proposal would result in discounts in only limited cases, the Commission does not believe that a more generous discount policy would act to increase the use of the system. Accordingly, a more generous discount policy would act only to decrease the amount of revenue recovered through Point-to-Point rates and increase the amount of revenue which would need to be recovered from Network and Native Load Customers.[49] (emphasis added)

The same conclusion applies to the use of the TransÉnergie system.

### *3.4. Recommendation*

It is clear from this analysis that TransÉnergie's discounting policy has resulted, over the years since reg. 659 was adopted, in an under-collection of short-term point-to-point revenues from HQ-Production, and hence in an increased cost burden on TransÉnergie's sole network customer (and hence on ratepayers). In our view, these discounts amount to a clear pattern of affiliate abuse, as described by FERC in the passage quoted on page 24.

In the years 1997-2000, total revenues from short-term point-to-point service have been some $135 million lower than they would have been without discounts. As explained above, eliminating these discounts would not (over the long run) reduce the total volumes transmitted by HQ-Production, and thus would maximize TransÉnergie's point-to-point revenues and minimize the transmission charges borne by native load.

Thus, the interests of TransÉnergie's network customers would be served by eliminating altogether or at least drastically restricting TransÉnergie's discounting of short-term point-to-point service. Indeed, this would be the effect of adopting WKP's proposed policy, in that neither condition i) nor condition ii) would in all likelihood ever be met.[50]

We therefore urge that the Régie order TransÉnergie not to offer short-term discounts on point-to-point service, except when it can demonstrate that such discounts will increase its total point-to-point revenues over the long term and will not result in increased costs for network or native load users.

Given the extent to which TransÉnergie has in the past offered discounts which fail to meet these criteria, it is recommended that, for the present, prior authorization by the Régie be required before such discounts are offered. However, this requirement may be waived at a later date, once a number of such requests have been examined and adjudicated by the Régie.

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[49] *Ibid.,* p. 21.

[50] While condition ii) might be met in the immediate time frame, any such curtailment would be counterbalanced by increased usage at a later date.

# 4. Hydro-Québec's proposed policy for the treatment of costs related to additions to the capacity of the grid

## *4.1. Hydro-Québec's proposed policy*

In section 3.2 of HQT-10, doc. 1, Hydro-Québec presents its proposal concerning additions to the capacity of the transmission grid. It divides this into two categories: network upgrades (*améliorations du réseau de transport)* and direct assignment facilities (*installations d'attribution particulière*).

### 4.1.1. Network upgrades

To distinguish network upgrades from direct assignment facilities, Hydro-Québec refers to the definitions contained in reg. 659. Network upgrades are defined as:

> **1.27 Network Upgrades:** Modifications or additions to transmission-related facilities that are integrated with and support the Transmission Provider's overall Transmission System <u>for the general benefit of all users of such Transmission System</u>.[51]

Hydro-Québec proposes that the costs of all network upgrades be integrated into the Transmission Provider's ratebase.[52] As justification, it cites the evidence of Mr. Priddle to the effect that this approach is in conformity with natural gas regulation in Canada, as well as FERC's Order 409 stipulating that all network users should share the cost, since they all benefit from it (HQT-10, doc. 1, p. 38, l 24-25 and note 15).[53]

In citing Order 409, Hydro-Québec fails to indicate that the passage cited was in fact one in which FERC quoted its earlier *Masspower* decision[54] and not part of the holding in Order 409. Order 409 is indeed consistent with *Masspower*, but goes beyond it. First, it reaffirms the Commission's transmission pricing guidelines, to the effect that, when network upgrades are involved, a transmission customer can be charged *either* an average-cost (rolled-in) rate like the one proposed by Hydro-Québec, *or* an incremental-cost (transaction-specific) rate for transmission service,[55] in addition to direct assignment of interconnection costs. In this decision, FERC makes clear that cost-shifting to native load customers can be avoided precisely by using an incremental cost rate based on the cost of the grid upgrades when that

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51 S. 1.3 in the French version.

52 HQT-10, doc. 1, p. 38, l. 13-14.

53 FERC, Order 409, <u>Western Massachusetts Electric Company,</u> Docket ER92-67-000, 77 FERC P61,268 (1996).

54 FERC, <u>Western Massachusetts Electric Company,</u> 63 FERC P61,222 (1993).

55 Incremental cost is defined as "the cost of increasing the level of service provided. In practice, it typically refers to the cost of additional facilities needed to provide the requested service." FERC, Transmission Pricing Policy Statement, 69 F.E.R.C. P61,086, note 6.

approach would lead to a higher rate than the average (rolled-in) rate.[56] Hydro-Québec's proposal eliminates this possibility, by requiring that all network upgrades be rolled in. It thus makes inevitable that high-cost network upgrades will indeed result in cost-shifting to other network and point-to-point customers, an undesirable outcome that utilities under FERC's jurisdiction can avoid by using an incremental rate.

### 4.1.2. Direct Assignment Facilities

Direct Assignment Facilities (DAFs) are defined in reg. 659 as:

> **1.10 Direct Assignment Facilities:** Facilities or portions of facilities that are <u>constructed by the Transmission Provider for the sole use/benefit of a particular Transmission Customer</u> requesting service under the Tariff. Direct Assignment Facilities shall be specified in the Service Agreement that governs service to the Transmission Customer and shall be subject to Régie approval.[57] (emphasis added)

Hydro-Québec's proposal is that DAFs be integrated into the cost of service for transmission and thus rolled into the transmission rate base, up to an amount equivalent to the annual point-to-point transmission tariff.[58] Based on a number of assumptions, it calculates that up to $625/kW of DAFs should be rolled into the transmission rate base; any additional DAF costs should be paid up-front by the transmission customer.[59]

It explains that the idea behind this approach is to recognize that even though a new client may create additional costs, it also generates additional volumes of point-to-point service; these revenues help to reduce the unit cost of existing installations, to the advantage of all consumers.[60] However, it should be noted that Hydro-Québec is apparently willing to invest up to $625/kW in dedicated facilities for a transmission customer without any commitment other than a long-term (1 year or more) point-to-point service agreement. Since no commitment longer than on year is required, no financial guarantees are demanded either.

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[56] It also excludes "and" pricing, where the customer is charged *both* a rolled-in rate *and* a direct contribution to incremental costs.

[57] Reg. 659, s. 1.10 of English version, s. 1.24 of French version.

[58] According to HQT-13, doc. 1, p. 167, this proposal should be adopted by the Régie as the policy referred to in s. 27 of the tariff.

[59] In jurisdictions where it is usually the load-serving entity that contracts for transmission service, these costs are generally included in the producer's Interconnection Agreement, not in the transmission service agreement. However, since HQ-P contracts for transmission service on behalf of HQ-D's load, it is entirely appropriate to treat these costs as DAFs.

[60] HQT-10, doc. 1, p. 39, l. 10-13.

## *4.2. Discussion*

### 4.2.1. Charging DAF costs to all users

Before turning to Hydro-Québec's detailed proposal, we note a number of difficulties it creates. First, it appears to conflict with FERC transmission policy, which makes no provision for collecting all or part of DAF costs from users other than the one responsible for these costs. As noted in Order 409, the distinction between network upgrades and DAFs is based on the facilities' "configuration and use." In this order, FERC stated that "the utility … may directly assign the costs of interconnecting a particular customer or building a radial line to the customer, i.e., a line not integral to the utility's system."[61] Just as network upgrade costs cannot be directly assigned, so direct assignment costs are not properly recovered in rolled-in rates.[62, 63]

Collecting DAF charges from rolled-in rates would violate the fundamental utility pricing principle that costs should be allocated to those who cause them, and could result in the construction of generation and transmission facilities that society neither needs nor wants. Insofar as some or all of the costs required to allow a particular producer to connect to the grid are shared by all users, including those that do not purchase power from that producer, his costs are in effect subsidized as a result. As Dr. Alfred Kahn states in his definitive text on utility economics, a buyer must pay the full avoidable cost of a purchased good if prices are to serve their fundamental function of allocating resources in accordance with maximum customer satisfaction:

> If price is below incremental costs, perhaps because the suppliers are being subsidized, production of the products in question will be higher (and of all other products taken together lower) than it ought to be: society is sacrificing more of other goods and services to produce the additional quantities of the subsidized service than customers would willingly have authorized, had the price to them fully reflected that marginal opportunity cost[64].

For this reason, the principle of cost causation is a fundamental tenet of regulatory economics.

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[61] Order 409, *op. cit.*

[62] Since transmission providers are generally presumed to be profit maximizers, there is no reason for FERC to specify that such costs *must be* directly assigned. Given the particular nature of the Québec system, where virtually the sole point-to-point customer of Hydro-Québec is Hydro-Québec, and where even third party users (e.g. Churchill Falls-Labrador Co.) are affiliated with the Transmission Provider, it may be necessary for the Régie to make such a stipulation.

[63] In this regard, it is noteworthy that Hydro-Québec's summary definition of DAFs makes mention of interconnection equipment but not of radial lines (HQT-10, doc. 1, p. 39, l. 5-6). Arguably, Québec (like British Columbia) is one of the few regions where DAFs are more likely to consist of radial lines than of interconnections.

[64] Alfred Kahn, The Economics of Regulation, (MIT Press, 1988), vol. 1, p. 67.

There is another reason why DAFs should not be collected, even in part, as part of a rolled-in charge. As in the situation discussed in Order 409, it is entirely possible that a facility which requires DAFs (interconnection equipement and/or radial lines) will *also* require network upgrades. Assume that a hypothetical facility would require network upgrades such that an incremental rate (the cost of the additional facilities needed) would be slightly lower than the embedded cost rate. If, as on would expect, the transmission provider chooses to charge a rolled-in rate, its revenue requirement will indeed increase, reflecting the costs of the additional facilities. However, any resulting increase in transmission rates would normally be mitigated by the additional revenues resulting from this new point-to-point customer.

Hydro-Québec, in effect, seeks to apply this same logic to DAFs as well. However, the additional revenues can only be applied once. If they are already offsetting the increased revenue requirement resulting from rolling in the network upgrades, they are not available to also offset the additional costs of the Direct Assignment Facilities (interconnection equipment and/or radial lines). To apply Hydro-Québec's proposed treatment for DAFs would therefore open the door to double-counting, and to significant cost shifting from the new point-to-point customer to other network and point-to-point customers.[65] While FERC would be unlikely to be concerned about the former, since it has no responsibility to protect the interests of Hydro-Québec's network customers, the same cannot be said of Hydro-Québec's point-to-point customers. Indeed, the high level of Hydro-Québec's point-to-point rates resulting from the rolling in of radial lines connecting Hydro-Québec's remote generators to its transmission grid has already been invoked by U.S. energy marketers as a reason for FERC to withdraw HQUS' PMA.[66]

A similar problem arises concerning the comparability principle, which FERC describes as the "'golden rule of pricing' — a transmission owner should charge itself and its affiliates on the same or comparable basis that it charges others for the same service."[67] It appears from Hydro-Québec's evidence that the interconnection equipment and radial lines needed to connect existing generators are rolled into the average rate, rather than being assigned directly to those generators. New generators will thus be treated in a different manner than existing ones. Since Hydro-Québec is the owner of the vast majority of the existing generation facilities (or, in the case of Churchill Falls, the beneficiary of the power purchase contract), this asymmetry works strongly in Hydro-Québec's favour.[68]

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[65] An example is discussed in section 4.2.2.

[66] *Protest of Enron Power Marketing Inc. and Coral Power, L.L.C.*, FERC, Docket No. ER97-851-012, Dec. 7, 2000.

[67] FERC, Transmission Pricing Policy Statement.

[68] On pages 42 and 43 of HQT-10, doc. 1, Hydro-Québec proposes a mechanism to treat step-up transformers at existing facilities of non-utility generators in a manner equivalent to that proposed for new facilities. However, no similar treatment is proposed for Hydro-Québec's own existing generation.

### 4.2.2. Hydro-Québec's proposed policy may result in cost shifting

Let us assume, for the sake of argument, that Newfoundland Labrador Hydro (NLH) proceeds with the Lower Churchill project and files a request with TransÉnergie for point-to-point service to transmit 1,000 MW to the U.S. border for the year 2008. Assume further that studies determine that providing this service will require a) an additional radial line, to interconnect with the Hydro-Québec transmission system, at a cost of $600 million and b) network upgrades, consisting of additional lines, series compensation, etc., at an additional cost of 800 million.

Under Hydro-Québec's proposal, NLH would not be required to pay any costs related to Direct Assignment Facilities, since the cost of interconnections and radial lines would not exceed $625/kW, or $625 million. NLH would therefore only pay the regular transmission tariff of around $80/kW (assuming moderate rate increases over the next 7 years), or $80 million for the year 2008. The $600 million of network upgrades will be rolled into TransÉnergie's ratebase, even though they would be unnecessary were it not for the NLH service request.

Hydro-Québec's reasoning is that NLH will continue to renew its yearly reservation for at least 20 years, resulting in total revenues which, when discounted, are equivalent to $625/kW. These revenues should, in the long run, compensate TransÉnergie for having advanced the DAF costs that would otherwise have been assessed to NLH. They could not, however, at the same time compensate for the additional investments in network upgrades. These costs would be borne by all other users of the TransÉnergie system, in the form of increases in annual rates.

Under FERC's transmission pricing policy, this outcome would not occur. First, *all* DAF costs would be assigned to NLH, without applying a "deductible." Second, instead of rolling the network upgrade costs into its ratebase, TransÉnergie would have the option of charging NLH a rate based on its *incremental costs*, rather than its regular rolled-in rate. In this case, since rolling in the network upgrade investments would result in a rate increase for other users, an incremental rate would be assessed to recover the upgrade costs directly from NLH.[69] This would insulate other users from the rate increase that would otherwise result.

It should also be noted that, under the Hydro-Québec proposal, no long-term commitment is required of a generator requesting transmission service, even when very substantial investments are required. In the event that the generator ceases operations or disposes of its power in ways that do not require transmission service over the TransÉnergie network, TransÉnergie and its network customers will be left "holding the bag" for these investments. This could occur either if an alternate transmission system provides service at a lower cost, or, more generally, if loads are developed that can be reached without using the Hydro-Québec transmission system.

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[69] This could either be front-loaded or spread out over a long period, assuming that sufficient financial guarantees are put in place.

Pursuing the example further, if a nickel smelter were eventually to be built in Labrador in conjunction with the mine at Voisey's Bay, the quantity of energy from Lower Churchill transmitted over the Hydro-Québec system could be greatly reduced.[70] The result would be that the financial burden of the new lines would be borne by TransÉnergie's other customers (primarily native load), just as Québec's citizens would continue to bear the environmental burden caused by the new lines.

### *4.3. "Uniform rates throughout the territory"*

Hydro-Québec's proposal also raises troublesome questions with respect to the interpretation of the Act, as amended by the *Act to Modify the Act Respecting the Régie de l'énergie* ("Bill 116"), adopted and put into force in June 2000. Section 11 of Bill 116 amended s. 49 of the Act to read:

> **49.** When fixing or modifying rates for the transmission of electric power or for the transmission, delivery or storage of natural gas, the Régie shall, in particular,
> …
>
> (11) maintain, subject to any government order to the contrary, uniform rates throughout the territory served by the electric power transmission system.

In its evidence, Hydro-Québec asserts that this requires that point-to-point transmission service be charged a postage-stamp rate in which all transmission assets, as defined by the Act,[71] are rolled in.[72] At the same time, Hydro-Québec apparently believes that its DAF proposal is consistent with s. 49(11). Under this proposal, some generators would be assessed an additional up-front charge, over and above the postage-stamp rate, to account for Direct Assignment Facilities above the threshold of existing rates. Thus, in the example provided by Hydro-Québec,[73] the generator would be required to pay $11.4 million in excess DAF costs, in addition to the annual point-to-point rate of $75.18. Another generator, in a different location, could be required to pay a greater or lesser amount.

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[70] A similar problem would arise if a generator were built to serve the needs of industrial plants that would be built gradually over a period of several years (i.e. the major petrochemical facility just announced for the eastern part of Montreal). As new plants were built on-site, the transmission capacity reserved by the generator to market its surplus production could be expected to diminish over time.

[71] Section 2 of the Act, as amended by Bill 116, reads:

> … "electric power transmission system" means a network of installations for the transmission of electric power, including step-up transformers located at production sites, transmission lines at voltages of 44 kV or higher, transmission and transformation substations and any other connecting installation between production sites and the distribution system ;"

[72] HQT-13, doc. 1, p. 107. While many U.S. utilities use postage-stamp transmission pricing, FERC's transmission pricing policy also explicitly allows other approaches, such as zonal or distance-based pricing.

[73] HQT-10, doc. 1, p. 41.

We suggest that s. 49(11) is conducive to several different interpretations. At one extreme, it could be read to exclude any and all charges other than a postage-stamp rate. Under this interpretation, Hydro-Québec's DAF proposal would be unacceptable, and all DAFs would have to be rolled in, regardless of their magnitude (as Hydro-Québec proposes for network upgrades).

At the other extreme, s. 49(11) could be read to require only that transmission rates to consumers be uniform throughout the territory. This interpretation would be consistent with the passages of the Québec energy policy cited by Hydro-Québec in support of its postage-stamp tariff, which refer exclusively to *electricity* tariffs, i.e. to rates charged to consumers. It would also be consistent with the arguments raised by the Government in support of this provision in Bill 116, which were based on the Québec "social compact" (*pacte social*). As the social compact is generally understood to be a commitment to citizen/consumers (and not to wholesale transmission customers[74]), one could conclude that the intent of s. 49(11) was to ensure that *consumers* across the province do not face different rates for the transmission of the electricity they consume.

Under this interpretation, the provision would not prohibit assessing different charges to *producers* who are differently situated. Indeed, the transmission tariff in use in Alberta makes precisely this distinction, with a uniform tariff charged to consumers, and a locational tariff charged to producers, in order to incite generators to locate in areas that would make it possible to avoid transmission upgrades, thereby minimizing total revenue requirements.[75]

If this were the intent of the provision, it would in reality be satisfied by the fact that HQ-Production purchases transmission service for HQ-Distribution (HQ-D) under the network integration tariff and that the resulting charges are shared equally by consumers in each rate class, without regard to their geographic location. Seen in this way, we suggest that the Act would not prevent the Régie from adopting incremental transmission rates, or even zonal or distance-based transmission rates for point-to-point service —since no Québec ratepayers are served under the point-to-point tariff.

Finally, one could interpret s. 49(11) to require a postage-stamp tariff, but to allow additional lump-sum charges such as those proposed by Hydro-Québec for DAFs above the $625 "deductible." By this same logic, and following the retroactive approach Hydro-Québec proposes for dealing with DAFs of existing private producers, Hydro-Québec could be assessed a direct contribution to compensate TransÉnergie (and thus, indirectly, its other customers) for the DAFs (interconnection equipment and radial lines) associated with its existing generation system.[76] To fail to do so would, as indicated above, contradict the comparability principle.

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[74] This same distinction can be seen in Hydro-Québec's explanation of why allowing point-to-point discounts to vary from one path to another does not violate s. 49(11). HQT-13, doc. 1, p. 110, R63.1.

[75] Alberta Interconnected Electric System, *Transmission Development Plan 2000-2009*, p. 2.

[76] This treatment would in many ways be equivalent to the BCUC's decision to assign the cost of B.C. Hydro's radial lines to the generation function in its cost allocation (BCUC, B.C. Hydro, Wholesale Transmission Services, Decision, April 23, 1998, p. 18). However, treating these assets

### *4.4. Recommendation*

Hydro-Québec's proposal to reduce the DAF charge by an amount equivalent to the rolled-in transmission rate should be rejected because, under certain circumstances, it virtually ensures that double-counting and cost-shifting will occur, as explained above. Rather, the Régie should adopt FERC's policy wereby all generators are charged the full cost of their Direct Attribution Facilities, including both interconnection equipment and radial lines. In the case of Hydro-Québec's existing generating stations, these charges could be based on the depreciated (book) value of the assets in question.

As for network upgrades, Hydro-Québec's proposed policy of rolling in all such upgrades, regardless of their size, could result in unacceptable rate impacts for other users. The Régie should instead require Hydro-Québec, again in accordance with FERC policy, to charge incremental rates when that would serve ratepayers' interest. Should the Régie consider that incremental rates are excluded by s. 49(11) of the Act, one option would be to turn instead to lump-sum payments for incremental costs, such as those proposed by Hydro-Québec for DAFs. Like HQ's DAF proposal, this would result in assessing two charges: a rolled-in transmission rate and a lump-sum incremental charge. While such an approach could be seen by FERC as an unacceptable "and" tariff, the alternative — rolling in all upgrade costs even when they result in significant rate impacts for other users — is an even less acceptable solution.

as Direct Assignment Facilities rather than Generation-Related Transmission Assets is more consistent with reg. 659, and thus with FERC transmission pricing policy, than is the B.C. approach, which is more closely related to methodologies for setting bundled rates for a vertically integrated utility.

# 5. Rates

## *5.1. Point-to-point rates*

### 5.1.1. Hydro-Québec's proposal

Hydro-Québec's proposed point-to-point rates for long-term service (one year or more) are based on dividing the revenue requirement by the sum of the annual peak (network service/native load) and the forecast reservations for annual point-to-point service. The calculation can thus be described as:

$$r_a = RR / (P_a + Q_a),$$

where

$r_a$ = the annual rate for firm point-to-point service,

RR = the annual revenue requirement (net of projected non-firm point-to-point revenues),

$P_a$ = the projected annual peak for network service/native load, and

$Q_a$ = the estimated annual point-to-point reservations for 2001.

Hence:

$$r_a = \$2{,}674\text{ M} / (31{,}726\text{ MW} + 3{,}844\text{ MW})$$

$$= \$75.18/\text{kW-yr}$$

According to Hydro-Québec's proposal, however, firm rates for shorter periods are not based on the annual peak (1-CP) but on the sum of twelve monthly peaks (12-CP). Thus, the monthly point-to-point rate is set as follows:

$$r_m = RR / (\sum P_m + Q_a{*}12)$$

where

$r_m$ = the monthly rate for firm point-to-point service, and

$\sum P_m$ = the sum of the projected monthly peaks (network service/native load) for 2001.

Thus,

$$r_m = (\$2{,}674 / 333{,}210\text{ MW})$$

= $8.02 / kW-month

The weekly and daily firm rates are set by dividing the monthly rate by 4 and 20, respectively, representing the number of weeks and work days in a month. Non-firm rates are set equal to firm rates; a non-firm hourly rate is also offered, set by dividing the daily rate by 24.

### 5.1.2. Discussion

The most surprising element of Hydro-Québec's proposed rates is the use of a 1-CP methodology for annual rates and of a 12-CP methodology for shorter reservation periods. Hydro-Québec explains its use of the 12-CP approach for shorter reservation periods as follows:

- because using 1-CP for setting monthly rates would not provide sufficient revenues to meet its annual revenue requirement, and
- because using 12-CP for shorter reservation periods incites clients to choose annual service over monthly service.[77]

The first argument is of little merit. The example provided by Hydro-Québec on page 28 of the document cited in the last note proves only that assessing charges for network service by multiplying the monthly load (12-CP) by a point-to-point rate based on the annual peak (1-CP) would not provide sufficient revenues.[78] This is obvious, given that the 1-CP method produces a lower point-to-point rate than does 12-CP.

In our view, the only real justification for using 1-CP for annual reservations and 12-CP for shorter terms is to provide a lower rate for long-term service. While this may indeed "incite" certain users to choose annual reservations, it can also be seen as pricing that favors one class of point-to-point users (long-term) over another (short-term). To the best of our knowledge, FERC has never condoned this type of hybrid approach to point-to-point ratemaking.

In fact, the use of 1-CP for point-to-point rates is disadvantageous to the Transmission Provider and to its network/native load clients, in that it results in lower point-to-point rates. For this reason, most utilities prefer the 12-CP approach.[79] Indeed, if TransÉnergie's annual point-to-point rates were set based on 12-CP, its revenues from this service would be substantially higher, resulting in lower charges for network/native load service, as well shall see on page 43, below.

Based on 12-CP, the annual point-to-point rate would be equal to:

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[77] HQT-13, doc. 13, p. 26-27.

[78] The question of whether network rates should be computed on a monthly or on an annual basis is addressed in section 5.2.3.2, below.

[79] Prior to Order 888, FERC generally required the use of 1-CP for setting point-to-point rates.

$$r_a = 12 * (RR / (\sum P_m + Q_a*12)$$

$$= 12 * (\$2,674 \text{ M} / (287,082 \text{ MW} + 3,844*12))$$

$$= 12 * (\$2,674 \text{ M} / 333,210 \text{ MW})$$

$$= 12 * \$8.02$$

$$= \$96.30 \text{ kW/yr.}$$

## *5.2. Determining charges for network integration service*

### 5.2.1. Hydro-Québec's proposed modifications to its open access tariff

Hydro-Québec proposes substantial modification to the provisions of reg. 659 that determine charges for network integration service. These modifications are indicated in the redline tariff version found at HQT-11, doc. 2 (en liasse). The proposed text reads as follows (our translation):

> **1.17**[80] **Load Ratio Share:** Ratio of a ~~Transmission Customer's Network Load to the Transmission Provider's total load~~ Network Customer's Annual Network Load and the Annual Transmission System Load, computed in accordance with Sections 34.2 and 34.3 of the Network Integration Transmission Service under Part III of the present Tariff ~~and calculated on a rolling twelve month basis~~.

> **34.2 Determination of Network Customer's ~~Monthly~~ Annual Network Load:** The ~~Network Customer's monthly Network Load is its hourly load (including its designated Network Load not physically interconnected with the Transmission Provider under Section 31.3) coincident with the Transmission Provider's Monthly Transmission System Peak.~~ Corresponds to the Network Customer's forecast maximum annual load.

> **34.3 Determination of Annual ~~Monthly~~ Transmission System Load:** ~~The Transmission Provider's monthly Transmission System load is the Transmission Provider's Monthly Transmission System Peak minus the coincident peak usage of all Firm Point-To-Point Transmission Service customers pursuant to Part II of this Tariff plus the Reserved Capacity of all Firm Point-To-Point Transmission Service customers.~~ Corresponds to the sum of the maximum annual load forecast for Native Load and the maximum annual load forecast for each Network Customer.

Hydro-Québec describe these changes as follows:

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80 S. 1.27 in the French version.

> 1.27 The definition [of Load Ratio Share] is modified to reflect the proposed content of ss. 34.2 and 34.3.
>
> 34.2 A calculation based on the annual system peak is better adapted to the particularities of Québec consumption which led Hydro-Québec to build its grid to meet the winter peak. Correction of a methodological error.
>
> 34.3 A calculation based on the annual system peak is better adapted to the particularities of Québec consumption which led Hydro-Québec to build its grid to meet the winter peak. Correction of a methodological error.[81]

In his evidence on behalf of Hydro-Québec, Mr. Albert Chéhadé elucidates this "methodological error," explaining that the definition of Load Ratio Share must be modified because it does not permit recovery of the revenue requirement specified in Attachment H:[82]

> Taking into account the addition of point-to-point capacities in the denominator, the sum of the load ratio shares of network integration clients will never reach 100%.[83]

This explanation reflects an important misunderstanding of the FERC's methodology for recovering the transmission revenue requirement, as set out in the *pro forma* tariff and described in the following section.

### 5.2.2. Setting network integration rates under the *pro forma* tariff

Under the pro forma tariff, and hence under reg. 659 in its current form, network integration rates are set as follows:

- According to s. 34.1, the network service customer pays a Monthly Demand Charge (*Prix requis mensuel*), equal to one-twelfth of the Annual Transmission Revenue Requirement specified in Attachment H, multiplied by the customer's Load Ratio Share (*Part du ratio de charge*).
- According to s. 1.17 (or s. 1.27 in the French version), the Load Ratio Share is the ratio of the customer's Network Load (*Charge en réseau*) to the Transmission Provider's total system load (*charge totale du transporteur*), calculated on a rolling twelve-month basis.
- According to s. 34.2, the customer's Network Load is its hourly load coincident with the Transmission Provider's monthly system peak.

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81 HQT-11, doc. 1, pp. 12-13.

82 HQT-10, doc. 1, pp. 29-30.

83 HQT-10, doc. 1, p. 30, l. 15-17. « En considérant les capacités de point à point au dénominateur, la somme de toutes les parts du ratio de charge des clients en réseau intégré n'atteint jamais 100 %. »

- According to s. 34.3, the Transmission Provider's Total System Load is defined as its monthly system peak, minus coincident peak usage of all firm point-to-point customers, plus the reserved capacity of all firm point-to-point customers.

Thus, the monthly charge for a network customer is set at:

$$r_m = RR * LRS / 12 \qquad \text{(s. 34.1)}$$

where

$$LRS = \frac{\text{Network Load at system peak}}{\text{Total System Load}} \qquad \text{(s. 1.17)}$$

and:

Total System Load = monthly system peak
– coincident point-to-point usage
+ point-to-point reservations at system peak (s. 34.3)

Calculating adjusted system load in this way has the effect of replacing the *actual* point-to-point load during the system peak with the *reserved* firm point-to-point load at system peak. Thus, Total System Load (the denominator of the LRS calculation) can also be thought of as equal to:

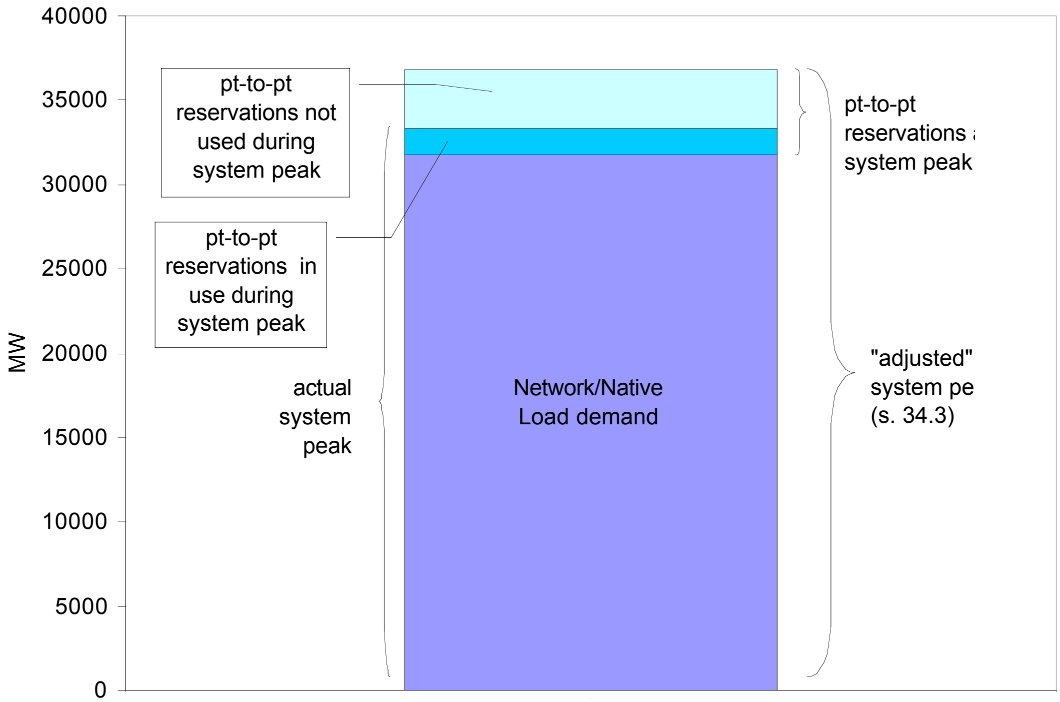
= actual system peak + unused point-to-point firm reservations,[84]

or

= Network Load + Firm Point-to-Point Reservations at system peak,

as seen in the following chart:

[84] It is described in these terms by B.C. Hydro in B.C. Hydro, Grid Operations & InterUtility Affairs, *Wholesale Transmission Services Pricing: Simplified Guide,* p. 1.




Under this system, in the case where there is just one network customer and no firm point-to-point reservations at the monthly system peak, the network customer is charged 100% of the monthly revenue requirement. However, if there are firm point-to-point reservations in effect at the moment of the system peak, the network customer's charge is reduced to reflect the percentage of Total System Load for which the point-to-point customer is responsible, whether or not his reservation was actually used at that moment.

The underlying logic is that, since the Transmission Provider must meet point-to-point reservations as well as network needs at its system peak, the revenue requirement should be shared between them on a *pro rata* basis. This logic was explained by FERC in Order 888:

> The flexibility and reassignment rights of this [firm point-to-point] transmission service require the transmission provider to hold the firm contract capacity available regardless of the customer's own load characteristics or its actual use. In other words, a transmission provider's obligation to plan for, and its ability to use, a transmission customer's reserved capacity is clearly defined by that customer's contract reservation. <u>For these reasons, it is appropriate to consider a firm reservation as the equivalent of a load for cost allocation and planning purposes.</u>[85]
>
> In order to prevent over-recovery of costs for those who use this approach, <u>we will require transmission providers to include firm point-to-point capacity reservations in the derivation of their load ratio calculations for billings under network service</u>. In

[85] This view is apparently not shared by Hydro-Québec, which states that the ultimate responsibility for meeting the cost of service rests with native load (HQT-13, doc. 1, p. 105).

> addition, revenue from non-firm service should continue to be reflected as a revenue credit in the derivation of firm transmission tariff rates.[86] (emphasis added)

In other words, since the Transmission Provider must make reserved capacity available, even if it is not used, and since the point-to-point customer must pay for that reservation even if he does not use it, the network customer's payments should be reduced based on reservations and not on usage.

Because this mechanism is based on capacity reservations, not on *revenues* from point-to-point reservations, it follows that the network charge will be the same, whether or not point-to-point rates are discounted. This further implies that the transmission provider will only recover its full revenue requirement to the extent that its firm point-to-point service is not discounted. It thus means that any discounts for firm service are in the end absorbed by the shareholder, not the regulated ratepayer.

Given this structure, there can be no doubt that the "Annual Revenue Requirement for purposes of the Network Integration Transmission Service" indicated in Attachment H is the Transmission Provider's full revenue requirement, not just the portion to be paid by network customers. It would thus be entirely inappropriate to recover this entire amount from network customers, as Hydro-Québec has done since 1997 and as it proposes to formalize in the modifications to reg. 659 proposed in the present filing.

Furthermore, insofar as the amount given in Attachment H of reg. 659 reflected Hydro-Québec's real revenue requirement when the tariff was adopted in 1997, it would also appear that the utility has overcollected its revenue requirement in each year, since the network customer made payments equal to this full amount, with no deduction for point-to-point revenues.

### 5.2.3. Setting network rates under Hydro-Québec's proposal

Hydro-Québec's proposed modifications to s. 34 would have the effect of completely removing point-to-point reservations from the calculation of Load Ratio Shares. At the same time, they would in effect change the basis for pricing of network service from 12-CP to 1-CP. We will address these two issues in the following sections:

#### 5.2.3.1. Treatment of point-to-point reservations in determining Load Ratio Share

Hydro-Québec's proposed methodology consists of the following steps:[87]

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[86] FERC, Order 888, pp. 303-304.

[87] HQT-10, doc. 1, p. 32.

| | |
|---|---|
| determine the total revenue requirement, based on cost of service and reasonable return on equity (p. 14) | $2,685 million |
| subtract forecast short-term point-to-point revenues, based on average revenues 1997-2000 | - $ 11 million |
| leaving the *residual revenue requirement* | $2,674 million |
| estimate long-term point-to-point revenues for 2001, based on: | |
| forecast long-term[88] point-to-point reservations (3,844 MW) | |
| forecast the long-term point-to-point rate, based on 1-CP ($75.18/kW-yr ) (p. 24) | |
| 2,844 MW * $75.18/kW-yr = | - $ 289 million |
| subtract this amount from the residual revenue requirement, to leave a *net residual revenue requirement* | = $2,385 million |
| divide this amount among Native Load and network clients on the basis of their Load Share Ratio (according to HQ's new definition). Since Native Load is the only such user, it pays 100% of the net residual revenue requirement. | = $2,385 million |

The differences between the methodology set out in reg. 659 and the one proposed by Hydro-Québec can be summarized as follows:

| reg. 659 (pro forma) | HQ proposal |
|---|---|
| set revenue requirement (Attachment H) | set revenue requirement |
| Subtract forecast *non-firm* pt-to-pt revenues = residual revenue requirement | Subtract forecast short-term pt-to-pt revenues (*firm and non-firm*) = residual revenue requirement |
| | Subtract forecast long-term point-to-point revenues = net residual revenue requirement (Attachment H) |
| divide by Load Ratio Share of Total System Load (≈ 82%) | Divide by Load Ratio Share of network peak load (100%) |

Hydro-Québec's proposal thus departs significantly from the *pro forma* tariff (and hence from reg. 659) in the way it accounts for point-to-point transactions: instead of increasing the denominator to account for point-to-point reservations (whether or not they are used), Hydro-Québec would reduce revenues by forecast point-to-point *revenues*, which in turn are based on historical (heavily discounted) averages.

In excluding point-to-point *reservations* from the Load Ratio Share calculation, Hydro-Québec directly violates the requirement established by FERC in Order 888 quoted above. The most important implication of this change is that, under the Hydro-Québec approach, discounting of point-to-point rates affects network charges, causing them to increase to make up the revenue shortfall resulting from the discounts. This would be unacceptable to FERC, which specified in 1997 that:

> A pro rata share of the transmission revenue requirement is allocated to VEPCO's firm reservation <u>regardless of whether VEPCO offers its merchant function discounted transmission service.</u>[89]

[88] Reservations of 1 year or longer.

It follows that, for FERC, transmission discounts are to be borne by the shareholder rather than by the regulated ratepayer. Hydro-Québec's proposal would do the opposite.

To illustrate this point, we will compare the charges to HQ-Distribution for 2001 under Hydro-Québec's proposal to the charges calculated according to the *pro forma* method. For purposes of this latter calculation, we will make a number of simplifying assumptions:

- Load Ratio Share will be calculated on a month-by-month basis, instead of using the rolling 12-month average called for in s. 34.2;
- HQ-D load in 2001 will precisely match Hydro-Québec's forecast; and
- point-to-point reservations in 2001 will be identical to those in the base year.[90]

Furthermore, since we do not know when the system peak in each month will occur, we will assume that weekly and daily reservations are spread evenly throughout the month. Non-firm reservations are disregarded, in accordance with FERC policy.[91]

The calculations for January 2001 are as follows:

| | | **source** |
|---|---|---|
| set revenue requirement (Attachment H) | \$2,685 M | HQT-10, doc. 1, p. 32 |
| - revenue credit for non-firm point-to-point transactions | \$0 | January 2000 non-firm revenues from HQT-10, doc. 1.3, p. 2 |
| residual revenue requirement | \$2,685 - \$0 = \$2,685 | |
| Native load peak for Jan 2001 | 31,726 MW | HQT-10, doc. 1, p. 21 |
| + the reserved capacity of all firm point-to-point customers | 4,205 MW (annual)<br>+ 605 MW (monthly)<br>+ 4 MW (weekly)<br>+ 7 MW (daily)<br>= 4,821 MW | annual: HQT-4, doc. 4, p. 2<br>short term: HQT-10, doc. 1.3, p. 6<br>with firm weekly and hourly reservations divided pro rata over the month. |
| = Total System Load | =36,547 MW | s. 34.3 |
| HQ-D Load Ratio Share | 31,726/36,547=86,8% | s. 1.17 (s. 1.27 in the French version) |
| HQ-D monthly network charge | 86.8% * \$2,685 = \$194 million | s. 34.1 |

Repeating this calculation for each month of 2001 yields a total charge to HQ-D of \$2,206 million for 2001, as shown in the following table.

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89 Virginia Electric and Power Company, Docket No. ER97-3561-000, 80 F.E.R.C. P61,275, *Order Conditionally Accepting For Filing Tariff For Market-Based Power Sales And Reassignment Of Transmission Capacity, And Establishing Hearing Procedures,* September 11, 1997.

90 For annual reservations, we will use the level in effect at the end of 2000. For shorter terms, since Hydro-Québec has declined to provide data from the last six months of 2000, we will use the first 6 months of 2000 and the last six months of 1999.

91 However, as suggested on page 48, below, it may be appropriate to revise the tariff to include non-firm reservations in this calculation as well.

| | Jan | Feb | Mar | Apr | May | June | July | Aug | Sept | Oct | Nov | Dec | total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| point-to-point reservations (MW) | 4 821 | 4 525 | 4 335 | 4 280 | 4 578 | 4 286 | 5 246 | 5 222 | 5 687 | 5 385 | 5 794 | 6 252 | 60 410 |
| network load (MW) | 31 726 | 29 968 | 27 609 | 23 866 | 20 167 | 18 258 | 18 524 | 18 779 | 19 446 | 22 113 | 26 187 | 30 439 | 287 082 |
| adjusted system load (MW) | 36 547 | 34 493 | 31 944 | 28 146 | 24 745 | 22 544 | 23 770 | 24 001 | 25 133 | 27 498 | 31 981 | 36 691 | 347 492 |
| load ratio share | 86,8% | 86,9% | 86,4% | 84,8% | 81,5% | 81,0% | 77,9% | 78,2% | 77,4% | 80,4% | 81,9% | 83,0% | 82,2% |
| Monthly network charge ($ M) | 194 | 194 | 193 | 190 | 182 | 181 | 174 | 175 | 173 | 180 | 183 | 186 | 2 206 |

The charges for network service in 2001 according to this example are $179 million lower than those resulting from Hydro-Québec's proposed methodology ($2,385 M).

#### 5.2.3.2. Using 1-CP for determining network rates

As we have seen, the network pricing mechanism currently in force is based on monthly calculations of load ratio share, and is thus implicitly based on the 12-CP approach, in accordance with Order 888 and the pro forma tariff. Hydro-Québec's proposal would replace this monthly calculation with one based on the annual system peak.

Hydro-Québec does not fully explain this proposed modification, simply stating that, by allocating costs based on the system peak, it would provide greater coherence with the way the network is planned. In fact, this modification would have the effect of replacing 12-CP with 1-CP as the basis for network charges. While FERC has stated on a number of occasions that utilities are free to propose 1-CP, we are not aware of any that have done so.

Using the 1-CP method to determine network charges leads to substantially higher network charges than does the 12-CP method currently in effect. Using the same assumptions as in the previous example, the network charge based on the 1-CP approach would be 86.8% of the annual revenue requirement, or $2,331 million, an increase of $124 million compared to the 12-CP method.[92]

### 5.2.4. Implications of Hydro-Québec's proposal

#### 5.2.4.1. Charges for native load

The impacts of Hydro-Québec's proposal on charges for network/native load result, on the one hand, from the modification in the definition of Load Ratio Share to exclude point-to-point reservations, and, on the other hand, from the implicit shift from 12-CP to 1-CP for calculating network charges. These impacts can be summarized as follows (all figures in millions of dollars):

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[92] This figure is nevertheless lower than the $2,385 million proposed by Hydro-Québec, because it excludes the effects described in section 5.2.3.1, above.

| | network charges | impact |
|---|---|---|
| as per reg. 659 | 2206 | |
| 1-CP instead of 12-CP for network rates | 2331 | 125 |
| 1-CP, with modified Load Ratio Share defn (HQ proposal) | 2385 | 54 |
| net impact of HQ proposal | | **179** |

### 5.2.4.2. Over-collection of the revenue requirement

As we have seen, the approach for setting network rates proposed by Hydro-Québec is based on a) eliminating point-to-point reservations from the calculation of Load Ratio Shares, and b) replacing the 12-CP method for determine network charges with 1-CP. Together, these proposals lead under the present circumstances to a substantial over-collection of the revenue requirement. Using Hydro-Québec's method with the same assumptions as above, Hydro-Québec's actual transmission revenues for 2001 would be:

| | **reservations** | **rate** | **$ M** | **$ M** |
|---|---|---|---|---|
| Network service | | | | 2 385 |
| Firm pt-to-pt service | | | | |
| annual | 4 205 | 75 | 316 | |
| monthly | 9 029 | 8 | 72 | |
| weekly | 3 154 | 2 | 6 | |
| daily | 2 644 | 0 | 1 | |
| Pt-to-pt total | | | 396 | 396 |
| Non-firm pt-to-pt service[93] | | | | 15 |
| Total revenues | | | | 2 796 |
| Revenue requirement | | | | 2 685 |
| **Over-collection** | | | | **111** |

The reason that the over-collection is less than the additional network charge of $179 million mentioned earlier is that Hydro-Québec has based the annual point-to-point rate on the 1-CP method rather than the 12-CP method. As noted earlier, the 12-CP method would result in a higher annual point-to-point rate that would produce an additional $89 million in annual revenues. The following table compares the results of Hydro-Québec's proposal with the consistent use of the 12-CP method together with the *pro forma* network rate mechanism.

[93] Revenues for non-firm point-to-point service are estimated based on the volumes reserved in the last six months of 1999 and the first six months of 2000, at the regular (non-discounted) rate, in accordance with our proposal in chapter 3. Using the discounted rate would reduce the revenues for non-firm service, and hence the over-collection, by $10 million.

| | HQ | 12CP |
|---|---|---|
| Network service | 2 385 | 2 206 |
| Firm pt-to-pt service | 396 | 484 |
| | | |
| Non-firm pt-to-pt service | 15 | 15 |
| Total revenues | 2 796 | 2 706 |
| Revenue requirement | 2 685 | 2 685 |

In other words, under Hydro-Québec's approach, it collects $89 million less from point-to-point service than it would under the consistent 12-CP/*pro forma* approach, and collects $179 million *more* from network/native load customers. There is thus a net over-collection of $111 million.

## *5.3. Recommendations*

### 5.3.1. Load Ratio Shares

Hydro-Québec proposes to modify the way that Load Ratio Shares are calculated under s. 34 of reg. 659 and, as a result, to change the method for setting charges applicable to network customers. The current methodology — the one set out in reg. 659, which is taken verbati from the *pro forma* tariff, and thus follows the approach adopted by FERC in Order 888 — results in transmission revenues which almost precisely equal the revenue requirement, without the use of any *post facto* true-up mechanism. In contrast, Hydro-Québec's proposed methodology creates a real possibility of over-recovery. In fact, in the present circumstances, Hydro-Québec's methodology would inevitably lead to over-recovery of the revenue requirement, due to the extensive discounting of firm point-to-point service in recent years.

Under the *pro forma* methodology, which is currently in effect, network customers pay a *pro rata* share of the revenue requirement, taking into account point-to-point *reservations* coincident with the monthly peak. Thus, past discounts have no effect at all on future rates.

Under Hydro-Québec's proposed approach, on the other hand, that share is proportional to the historic *revenues* for point-to-point service. Since these revenues were highly discounted, the proportion of the revenue requirement borne by point-to-point customers is less, and that borne by HQ-Distribution's regulated consumers is greater. Furthermore, if future point-to-point revenues are greater than those in the past (on which network charges are based), TransÉnergie's revenues would exceed the revenue requirement. Past discounts would therefore create a windfall for the company and its shareholder. This windfall could be taken gradually (if discounting decreases gradually) or all at once (if it ceases immediately).

We therefore recommend that Hydro-Québec maintain the existing approach to calculating Load Ratio Shares for network service, in keeping with the *pro forma* tariff. We further recommend that the Régie review the Load Ratio Share calculations for the period starting when reg. 659 came into force, to ascertain if s. 34 was correctly applied in determining charges for network service. If, as seems apparent from Hydro-Québec's explanation of its proposed modifications to s. 34, it has been collecting the entire transmission revenue requirement from network customers, it may be appropriate to correct for these overpayments with a balancing account or other regulatory mechanism.

Finally, it is important to note that the intent of the Load Ratio Share methodology — that point-to-point reservations be allocated costs on the same basis as network service, whether or not they are used at peak — could be undermined were Hydro-Québec to substitute discounted non-firm reservations for firm ones. Given the apparent lack of congestion on the HQ system, non-firm service is just as good as firm service; using discounted non-firm reservations would allow Hydro-Québec to continue to shift the lost revenues onto network customers, with no loss of reliability for its point-to-point sales. In a different context, the B.C. Utilities Commission noted that when a system is unconstrained, non-firm transmission service is essentially the same as firm service.[94] We therefore recommend that the Régie consider regarding non-firm reservations as equivalent to firm reservations for purposes of the Load Ratio Share calculations.

### 5.3.2. 1-CP versus 12-CP

As we have seen above, the combination of 1-CP and 12-CP rates that Hydro-Québec proposes for point-to-point rates is highly irregular. It marks a significant departure from standard utility practice, and the justification offered is far from convincing. At the same time, without identifying it as such, Hydro-Québec's proposed new definition of Load Ratio Share (s. 1.17 of reg. 659, or s. 1.27 of the French version) would change the basis on which network rates are calculated from 12-CP to 1-CP.

The difference between the two systems is clearly seen in the table on page 43. In this example, network load accounts for 86.8% of total system load in January, but only 77.4% in September. Under 1-CP ratemaking, the network customer (native load) would pay 86.8% of the full transmission revenue requirement; under 12-CP ratemaking, it would pay lesser proportions during off-peak months, in accordance with the shifting ratio between network load and point-to-point reservations.

Historically, point-to-point reservations have been higher in September than in January, and network load of course much lower. Data provided by Hydro-Québec shows that the January peak is due almost exclusively to residential demand, presumably related to space heating.[95] Thus, to continue to charge native load for its January load ratio share throughout the year, based on the argument that the system was built to meet the January peak, would ensure that the costs of meeting this peak are borne almost exclusively by network customers (i.e. by native load), and that they are not shared by Hydro-Québec's exports or by other wholesale

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[94] BCUC, West Kootenary Power, *op. cit.*, p. 20. The Commission made this point to justify its decision to maintain identical prices for firm and non-firm services, arguing that since the service they provided was identical, the price should be as well.

[95] HQT-13, doc. 12.1, p. 6.

transmission customers. In a sense, then, point-to-point customers would become "free riders" on a system paid for primarily by Québec's domestic load.

The *pacte social* is generally understood to include, among other things, ensuring that the costs of serving residential users are shared by other categories of consumers.[96] We see no reason why this cross-subsidization should be limited to industrial and commercial end-users and should not also include Hydro-Québec's exports and other users of the transmission system.

We therefore urge the Régie to require Hydro-Québec to use the 12-CP approach, both for network charges and for all its point-to-point rates, in keeping with standard utility practice and with its own proposed practice for shorter terms. This approach is more advantageous for network/native load customers, and results in point-to-point users (primarily Hydro-Québec's exports) paying a fairer share of the transmission revenue requirement. In our view, this approach is more equitable and better reconciles the public interest, consumer protection and the fair treatment of the electric power carrier, as is required by s. 5 of the Act.

[96] In his presentation of Bill 116 to the National Assembly, Natural Resources Minister Jacques Brassard made this point as follows:

> Premièrement, nous voulons préserver le pacte social issu de la nationalisation de l'électricité, suite à une campagne électorale qu'on peut qualifier de référendaire, en 1962. …
>
> [C]e pacte social, il tient toujours, il est toujours présent. Il a toujours été maintenu par tous les gouvernements qui se sont succédé et il tient à trois éléments. … troisième élément, des tarifs avantageux, des tarifs bas pour toutes les clientèles mais très particulièrement pour les clients résidentiels. C'est ça, le pacte social qui a été, en quelque sorte, conclu démocratiquement entre le peuple québécois et son gouvernement en 1962, et il n'a jamais été remis en question. Tous les gouvernements qui se sont succédé l'ont maintenu, renforcé, consolidé.
>
> Il existe aussi … ce qu'on appelle un interfinancement des tarifs en faveur de la clientèle résidentielle. En d'autres termes, quand vous regardez les tarifs, … c'est clair … que les clients résidentiels ne paient pas des tarifs qui sont en corrélation avec les coûts qu'ils devraient assumer. C'est d'autres catégories de consommateurs qui assument ces coûts. C'est ça, l'interfinancement, et c'est pour ça que les clients résidentiels au Québec jouissent, depuis les années soixante, de tarifs bas.

Assemblée nationale, *Journal des débats, Adoption en principe du projet de loi 116,* May 26, 2000.

# 6. Serving native load without a network integration service agreement

## *6.1. Background*

Since the adoption of reg. 659, Hydro-Québec has served its native load under a network service agreement, Initially, it was Hydro-Québec's Groupe Services énergétiques that contracted for transmission services both to serve domestic load and for point-to-point service. In a recent corporate reorganization, this group ceased to exist, with its functions transferred to Hydro-Québec's Groupe Production. The service agreement remained in force until Dec. 31, 2000 (HQT-4, doc. 3.3), but has not been renewed for 2001.

Hydro-Québec proposes henceforth to serve native load without executing a network service agreement. It maintains that this change will have no material effects whatsoever, as all service to Hydro-Québec is deemed to constitute a contract.[97]

## *6.2. Discussion*

The provisions of the *pro forma* tariff which mention Native Load are a consequence of the jurisdictional split in the United States between federal and state powers with respect to electric service. As noted by Dr. Orens in his testimony for Hydro-Québec, FERC has no jurisdiction over the sale of electricity to end-use customers, but only over bulk transactions. While FERC has indicated that it would like utilities to use the pro forma tariff to serve native load, it is powerless to require it.

In states where retail service is still provided by vertically integrated utilities, retail service to native load is performed under bundled tariffs set by state regulators. These bundled tariffs are based on cost allocation of a "bundled" revenue requirement, rather than on a transmission revenue requirement. These same utilities also file a transmission revenue requirement with FERC as part of their open access transmission tariff; the costs that make up the transmission revenue requirement are also part of the bundled revenue requirement. However, FERC has no jurisdiction to interfere with the bundled ratemaking process, nor to require that the rates based on the transmission revenue requirement be directly applied to retail service.[98]

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[97] HQT-4, doc. 1, pp. 6-7, HQT-11, doc. 1, p. 5.

[98] In Order 888-A, FERC explains the relationship between these two parallel jurisdictions. Although this passage concerns stranded costs (generation), the same logic applies to transmission:

> If a utility is regulated by both this Commission and a state commission, each commission, in setting cost-of-service rates within its jurisdiction, will separately and independently determine the utility's *total* cost of providing service (also known as the utility's total revenue requirement). This will be based on the expenses incurred in providing service and a reasonable profit on the utility's assets that are used to provide the service. The commissions may differ as to what assets are appropriately included in

In the U.S. context, therefore, vertically integrated utilities typically do not use the pro forma tariff to serve native load. In areas which have moved away from the vertically integrated utility model, however, such as the regions covered by the New York, New England or California ISO's, distribution utilities typically *do* take service under the FERC-approved transmission tariff.

The Régie has jurisdiction over both wholesale and retail service, thus combining the jurisdictions of FERC and of state commissions. Unlike FERC, it *does* have jurisdiction to require that its transmission tariff be used for serving native load.

Furthermore, under Bill 116 the transmission revenue requirement established in this hearing will be treated as a cost in the establishment of retail rates. Thus, the situation is different from that described earlier with respect to vertically integrated utilities in the U.S., where the process for setting bundled retail rates does not involve the setting of a distinct transmission revenue requirement.

Indeed, even Hydro-Québec's wants Native Load to be served under the open access transmission tariff; it simply prefers that it be called "Native Load" rather than be served under a network integration service agreement. However, while Hydro-Québec claims that this distinction would have no practical effect at all, this is not necessarily the case.

It is true, as Hydro-Québec points out, that certain provisions of reg. 659 require that native load be treated in a similar manner to network integration clients. In particular, this is the case with respect to the designation of network resources and loads (s. 28.2) — a provision with which, as we demonstrate in section 7.2.1, Hydro-Québec has so far failed to conform. However, the remaining provisions of Part III of the regulation ("Network Integration Transmission Service") do not automatically apply to native load.

The most important of these provisions is perhaps s. 34, which establishes the rates and charges to be paid by a network customer. S. 34 makes no reference to native load, either in its current formulation or under Hydro-Québec's proposed modifications, nor does

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total rate base, what other costs are appropriately included in the total cost of service, and what rate of return should be permitted. <u>Once each regulatory authority has determined the appropriate total revenue requirement, it then will determine what portion of that total revenue requirement should be borne by the utility's wholesale customers and what share should be borne by retail customers (also called cost allocation).</u> Each commission may also reach different conclusions on this split as well. Thus, under historical cost-based ratemaking, regulatory authorities do not carve out so-called "wholesale costs" that only this Commission can take into account in determining rates subject to its jurisdiction or so-called "retail costs" that only a state commission can take into account in determining rates subject to state jurisdiction. <u>Additionally, this Commission and state commissions have the discretion to determine whether costs are appropriately recovered through a transmission, generation, or distribution component of a rate</u> (also called functionalization of costs) within their respective jurisdictions. (emphasis added)

Order 888-A, Part III, p. 80, note 707.

Attachment H, which sets out "the Annual Transmission Revenue Requirement for Network Integration Transmission Service." Thus, though the costs assessed to HQ-Distribution for service of native load is arguably the central issue of this hearing, reg. 659 would not specify those costs.

Other provisions of reg. 659 that would not apply to Native Load service include :

- the obligation to obtain or provide Ancillary Services pursuant to Section 3 (s. 28.1),
- the obligation to replace losses associated with transmission service (s. 28.5),
- the obligation to provide the information required for a network service application (s. 29.2), including descriptions of network resources (including a 10-year projection of system expansions or upgrades). Based on the information provided by Hydro-Québec in this hearing, it would appear that these obligations have not been met to date either.

### *6.3. Recommendations*

As noted above, native load is excluded from the mandatory application of the *pro forma* tariff because, on the one hand, FERC has no jurisdiction over it and, on the other, because it is regulated on a bundled basis by state regulators. Neither of these situations applies to Hydro-Québec. Indeed, if the Régie were to exempt Hydro-Québec's service of native load from the application of reg. 659, it would have to define a separate regulatory regime governing that service. Hydro-Québec has explicitly rejected this option,[99] and with good reason.

The Régie should therefore reject Hydro-Québec's proposal and require it to serve native load under a network integration service agreement under reg. 659.

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[99] HQT-13, doc. 1, p. 157, R59.2.

# 7. Hydro-Québec's conformity with the provisions of reg. 659

As described in the opening chapter of this testimony, reg. 659 was adopted in March 1997 by Hydro-Québec and approved by the Québec government without discussion or review in any public forum. Since then, to the best of our knowledge, Hydro-Québec has been subject to no oversight concerning the conformity of its practices with the requirements and obligations created by this tariff.

While the terms and conditions of reg. 659 have never been debated in Québec, they are the fruit of a long and detailed consultative process in the U.S. Having adopted this tariff of its own volition, it is incumbent upon Hydro-Québec to respect its provisions or, if it finds them unacceptable, to seek their modification.

Our review of Hydro-Québec's evidence in this file leads us to believe that certain key provisions of reg. 659 have not to date been respected. As reg. 659 has been in force since May 1, 1997, Hydro-Québec must respect its provisions, until such time as they are modified.

Like FERC's *pro forma* tariff, reg. 659 requires the identification of specific generating resources for both point-to-point and network service. While maintaining a superficial appearance of conforming with these provisions, Hydro-Québec's practice fails to conform to either the spirit or the letter of the relevant provisions.

## *7.1. Multiple points of receipt for firm point-to-point service*

### 7.1.1. Hydro-Québec's evidence

The service agreements for long-term point-to-point service filed as HQT-4, doc. 3 indicate Montreal as the Point of Receipt. In response to an information request from the Régie, Hydro-Québec explained that this is due to the nature of Hydro-Québec's generating system, which includes a number of different generators located at different points on the grid, none of which is assigned to a specific load.

> Thus, all of Hydro-Québec's production is brought onto TransÉnergie's network via <u>multiple points of receipt</u>, of which Montreal constitutes the central point. This production is either used to supply native load, or delivered outside of the TransÉnergie network at Points of Delivery specified in the service agreements.[100]

Asked by the Régie if this practice is used in other jurisdictions that follow the *pro forma* tariff, Hydro-Québec responded that it has no knowledge of practices in other jurisdictions concerning this issue (R15.2).

[100] HQT-13, doc. 1, p. 22, R15.1.

In response to a follow-up question by the Régie, Hydro-Québec indicated that it would allow other similarly situated producers to designate Montreal as the Point of Receipt.[101]

### 7.1.2. Applicable provisions of reg. 659

According to the Preamble of Part II of reg. 659 (adopted verbatim from the pro forma tariff):

> Point-to-point transmission service is for the receipt of capacity and energy at designated Point(s) of Receipt and the transmission of such capacity and energy to designated Point(s) of Delivery.

Section 13.7 makes clear that a Point of Receipt is a single generating station or part thereof:

> **13.7(b)** The Transmission Customer may purchase transmission service to make sales of capacity and energy from multiple generating units that are on the Transmission Provider's Transmission System. For such a purchase of transmission service, the resources will be designated as multiple Point(s) of Receipt, unless the multiple generating units are at the same generating plant in which case the units would be treated as a single Point of Receipt.

It goes on to specify:

> **13.7(c)** Each Point(s) of Receipt at which firm transmission capacity is reserved by the Transmission Customer shall be set forth in the Firm point-to-point Service Agreement along with a corresponding capacity reservation associated with each Point(s) of Receipt.

### 7.1.3. Discussion

The provisions of s. 13.7 quoted above state unambiguously that a request for point-to-point transmission service must specify a specific Point of Receipt, and that multiple generators in different locations cannot be defined collectively as a single Point of Receipt. Thus, the practice described by Hydro-Québec in R15.1, quoted above, is on its face inconsistent with its open access transmission tariff.

A recent decision by FERC confirms this view. ExxonMobil Chemical Company and ExxonMobil Refining and Supply Company filed a complaint, based on the fact that Entergy, a transmission-owning utility, had refused to treat three generating stations, which were in physical proximity, as a single Point of Receipt under the pro forma tariff.[102]

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[101] HQT-13, doc. 1.1, p. 59, R31.2.

[102] FERC, ExxonMobil Chemical Company, ExxonMobil Refining & Supply Company v. Entergy Gulf States, Inc., Docket No. EL00-34-000, 91 F.E.R.C. P61,106, *Order Denying Complaint*, April 27, 2000.

> ExxonMobil maintains that while it produces electric energy from two QF's [Qualifying Facilities] which are one mile apart but are in the same general geographic area, the output of one of the QFs, the BRTG, is dedicated to ExxonMobil's internal load and thus should not be considered a source of the electric energy delivered to Entergy's system. [note omitted] ExxonMobil therefore argues that the sales take place from a single QF - - the Exxon Cogen. The next step in ExxonMobil's argument is that the specific configuration of four of the five individual generating units in the Exxon Cogen (and the three 230 kV substations) is such that ExxonMobil should be considered to be delivering power from a single generating plant. [note omitted]

FERC denied the complaint, as follows:

> ExxonMobil sells energy from two QFs, the BRTG and the Exxon Cogen, which clearly are not a single generating plant. … ExxonMobil is requesting that it be permitted to use the separate contract paths that originate at each of the three 230 kV transmission substations at different points onto Entergy's 230 kV transmission grid as a single firm point-to-point contract path in order to facilitate its sale of energy from its QF facilities in aggregate. This is not consistent with the OATT [open access transmission tariff].

It added:

> ExxonMobil has requested that it be permitted to have designated a single point of receipt in order to avoid having to make multiple reservations for delivery of QF power from the Exxon Cogen and thus, avoid making payments for multiple firm contract paths. However, ExxonMobil in fact will be making use of multiple contract paths on Entergy's transmission grid on a firm basis in order to export energy from its two QFs for resale. In these circumstances, ExxonMobil is required to pay for the reservation of each of these separate contract paths. As we stated in Commonwealth Edison, the real issue here is price. ExxonMobil essentially is asking Entergy to discount its transmission rates through the designation of a single point of receipt. As stated in Commonwealth Edison, effecting a rate reduction by changing the capacity reservation results in a discount and circumvents the discounting requirements of Order No. 888. [note omitted]

In the Commonwealth Edison case referred to here, FERC pointed out that the pro forma tariff clearly permits any transmission customer to designate multiple generating units as primary points of receipt if the customer needs that operational flexibility to support its particular power sale. However, it found that grouping reservations from several generators into a single point-to-point reservation amounts to an impermissible discount "largely to itself":

> The real issue presented here has to do with price. Under the pro forma tariff, if multiple generating units are designated as separate primary points of receipt, the customer will pay for separate reservations. For example, if 3 generating units on Commonwealth Edison's system are designated as points of receipt with reservations of 100 MW each in conjunction with one point of delivery with a reservation of 100 MW, the tariff customer will have a 300 MW capacity reservation (the sum of the reservations at the points of receipt). [note omitted] Under Commonwealth Edison's

> proposal, the charges under this example would be reduced 67 percent because the capacity reservation would be 100 MW rather than 300 MW. While we have no objection to Commonwealth Edison proposing revised rate sheets to offer lower rates on transactions with multiple receipt points, Commonwealth Edison's use of non-rate term and condition revisions to effect these rate reductions is objectionable. First, it creates confusion. Second, Commonwealth has created a new category of transmission service (firm point-to-point transmission service where the "underlying power sale" is a system sale) for what is, in fact, no more than a mere rate reduction.

It can be argued that Hydro-Québec's approach is not discriminatory to competitors, since it has offered to allow others to assign multiple generators as a single Point of Receipt as well. The offer might appear disingenuous, as there are few if any other generators with multiple generating stations in Québec who might conceivably take advantage of it. But, as the Commonwealth Edison case makes clear, the underlying issue is not comparability, but price. In refusing to properly specify the Point of Receipt for its export sales, Hydro-Québec greatly reduces its transmission rates from those that it would be required to pay under its own open access transmission tariff. The inevitable result is to increase the proportion of the transmission revenue requirement that must be borne by native load customers. Thus, in failing to respect the provisions of s.13.7, Hydro-Québec shifts costs from its marketing affiliate to its captive end-use customers. This policy therefore amounts to a hidden discount, contrary to the letter and spirit of reg. 659, and should be rejected.

## *7.2. Network integration service*

### 7.2.1. Designation of network resources

A similar issue arises with respect to the designation of network resources.

In HQT-11, doc. 5, Hydro-Québec indicates that the resources designated for network integration service to serve native load are those listed in its Annual Report, i.e. the totality of generating resources at its disposal (including purchases from Churchill Falls, from Alcan and from private producers in Québec).

In HQT-11, doc. 4, Hydro-Québec provides a forecast of its designated resources through 2015-16.[103] Again, all generating resources at Hydro-Québec's disposal are listed as designated resources.

#### 7.2.1.1. Applicable provisions of reg. 659

According to s. 30.1 :

[103] That this document concerns the designation of resources for network service is made clear in HQT-13, doc. 14, p. 111, R88.1.

> Network Resources shall include all generation owned or purchased[104] by the Network Customer designated to serve Network Load under the Tariff. Network Resources may not include resources, or any portion thereof, that are committed for sale to non-designated third party load or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis.

This same language is found in s. 1.26 (1.40 in the French version):

> Network Resource: Any designated generating resource owned or purchased by a Network Transmission Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis.

#### 7.2.1.2. Discussion

These provisions appear to unambiguously exclude the assignment as Network Resources of any generating resources used to serve firm off-system sales, in that they are thus unavailable "to meet the Network Customer's Network Load on a non-interruptible basis."

It should also be noted that, according to s. 30.4:

> The Network Customer shall not operate its designated Network Resources located in the Network Customer's or Transmission Provider's Control Area such that the output of those facilities exceeds its designated Network Load plus losses.

Hydro-Québec's designated load, described in HQT-11, doc. 5, consists of HQ-Distribution's customers within Québec. Thus, according to s. 30.4, if all of Hydro-Québec's generating resources are designated, it may not operate them such as to produce any surplus over domestic needs.

In reality, Hydro-Québec's approach to designating Network Resources is intimately related to its approach to designating Points of Receipt. As stated earlier, Hydro-Québec treats the totality of generating resources available to it as a single resource ("HQ system power"), which is used to serve both native (network) load and point-to-point sales, at its discretion.

It is just as clear that this refusal to designate generating resources for serving network load, on the one hand, or point-to-point sales, on the other, is incompatible with Hydro-Québec's open access transmission tariff and with the *pro forma* tariff from which it was derived.[105]

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[104] In Order 888-A, this language was modified to read "owned, purchased or leased".

[105] Another aspect of this problem is Hydro-Québec's insisting on treating its entire transmission system as a single node on its OASIS system, thereby refusing to divulge any information about power flows or congestion within its system.

More broadly, HQ's attempt to treat its entire generating system as a single resource is at odds with the very essence of the functional separation approach it accepted in adopting reg. 659. In effect, Hydro-Québec continues to operate its generation system on an integrated basis, to serve both native load and off-system sales, under a tariff which clearly requires it to distinguish the one from the other.

### 7.2.2. Application for network service

While, in this filing, Hydro-Québec announces its intention to serve native load without a network service agreement, such a service agreement has been in effect since May 1, 1997. However, it appears that Hydro-Québec failed to meet several of its obligations under reg. 659 with regard to the procedures for requesting this service.

According to s. 29.1 of reg. 659, network service is provided on the condition that:

> i) the Eligible Customer completes an Application for service as provided under Part III of the Tariff, …
>
> iii) the Eligible Customer executes a Service Agreement pursuant to Attachment F …,

Based on the documents filed by Hydro-Québec, it appears that neither of these conditions have been fully complied with.

According to s. 29.2, the application mentioned in s. 29.1 i) must include:

> (iii) A description of the Network Load at each delivery point. This description should separately identify and provide the Eligible Customer's best estimate of the total loads to be served at each transmission voltage level, and the loads to be served from each Transmission Provider substation at the same transmission voltage level. The description should include a ten (10) year forecast of summer and winter load and resource requirements beginning with the first year after the service is scheduled to commence;
>
> (iv) The amount and location of any interruptible loads included in the Network Load. This shall include the summer and winter capacity requirements for each interruptible load (had such load not been interruptible), that portion of the load subject to interruption, the conditions under which an interruption can be implemented and any limitations on the amount and frequency of interruptions. An Eligible Customer should identify the amount of interruptible customer load (if any) included in the 10 year load forecast provided in response to (iii) above;
>
> (v) A description of Network Resources (current and 10-year projection), which shall include, for each Network Resource:
>
> - Unit size and amount of capacity from that unit to be designated as Network Resource

- VAR capability (both leading and lagging) of all generators
- Operating restrictions
- Any periods of restricted operations throughout the year
- Maintenance schedules
- Minimum loading level of unit
- Normal operating level of unit
- Any must-run unit designations required for system reliability or contract reasons
- Approximate variable generating cost ($/MWH) for redispatch computations
- Arrangements governing sale and delivery of power to third parties from generating facilities located in the Transmission Provider Control Area, where only a portion of unit output is designated as a Network Resource
- Description of purchased power designated as a Network Resource including source of supply, Control Area location, transmission arrangements and delivery point(s) to the Transmission Provider's Transmission System;

Hydro-Québec's requests for network service (HQT-4, doc. 3.5) did not contain this information, but rather an indication that the required information was "already in your possession." In response to RNCREQ information request 48.2b, Hydro-Québec stated that, apart from the variable generating cost for redispatch calculations, this information was already in the possession of TransÉnergie.[106] When asked to provide the documents referred to as "already in your possession," Hydro-Québec produced documents for 1998, 1999 and 2000 (HQT-11, docs. 5,. 5.1 and 5.2).[107] Each of these three documents contains more than a hundred pages of information concerning Network Load (point iii). However, for the description of Network Resources (point v), they simply refer to Hydro-Québec's *Annual Report*. This document contains none of the information required under s. 29.2 v), except for the total installed capacity of each generator.

Furthermore, s. 29.1 iii) requires the filing of a service agreement pursuant to Attachment F, which includes a document entitled "Specifications for Network Integration Transmission Service." As detailed in reg. 659, this document includes, among other things, a description of any required Direct Assignment Facilities and any charges assessed for System Impact and/or Facilities Study Charges, Direct Assignment Facilities Charges Redispatch Charges and Network Upgrade Charges. However, Hydro-Québec acknowledges that it did not "fill out" a Network Integration Service Agreement pursuant to Attachment F, arguing that this was unnecessary given Hydro-Québec's integrated nature and given the Transmission Provider's knowledge of the distributor's needs.[108]

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[106] HQT-13, doc. 14.2, p. 10, R48.2a and b.

[107] HQT-13, doc. 14.2, p. 11, R90.2.2a.

[108] HQT-13, doc. 1, p. 33, R22.2. Instead of the Attachment F Service Agreement required by s. 29.1, Hydro-Québec executed a contract of its own design for the year 2000 to serve native load under network integration service (HQT-4, doc. 3.3). Similar agreements for 1997-99 are found at HQT-4, doc. 3.4.

Hydro-Québec's application for network service was thus defective, in that it failed to provide a complete description of the network loads and failed to provide any useful description of the generation resources designated for network service. This failing draws attention to the fact that, despite giving lip service to the notion of functional separation, Hydro-Québec still operates in many ways as an integrated which remains, to a large extent, unregulated.

### *7.3. Special arrangements for facilities studies (s. 32)*

Hydro-Québec has produced a special agreement executed between TransÉnergie, its Energy Services Group and its Production Group in March 1999 which provides for special study procedures to facilitate the addition of new "designated network resources" to the grid.[109] The agreement explains that it is meant to "optimize" administrative procedures and to make the process of system impact studies and facilities studies more efficient, given that HQ-Production intends to request several such studies over the coming years.

It would appear that the procedures agreed to in this document effectively replace those set out in section 32 of reg. 659, but only for HQ-Production. Furthermore, the agreement specifies that, while HQ-Production will pay for the system impact studies or facilities studies it requests, TransÉnergie shall reimburse these facilities study costs (with interest) for any project variant that is eventually constructed.

The Facilities Study Procedure in s. 32.4 makes no such provision for the reimbursement of study costs to the Customer. Thus, this agreement provides HQ-Production with more advantageous conditions for facilities studies than are provided to other transmission customers. In so doing, it violates once again the comparability principle that is central to Order 888:

> Comparability mandates that to the extent a transmission provider charges transmission customers for the costs of performing specific facilities or system impact studies related to a service request, the transmission provider also must separately record the costs associated with specific studies undertaken on behalf of its own native load customers, or, for example, for making an off-system sale. (p. 381)

While the comparability principle is a "golden rule" for the FERC, it has not, to the best of our knowledge, been adopted as such by the Régie. Indeed, it could be argued that, given the Québec social compact, it would be inappropriate for it to do so. This points once again to the difficulties created by adopting a transmission tariff from a foreign jurisdiction, based on principles which have been explicitly adopted by the foreign regulator but which have not been fully examined in Québec.

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[109] As we have seen, Hydro-Québec considers its entire generation plant to constitute "designated network resources," whether or not they are serving point-to-point sales. Even though Hydro-Québec is planning to build generating resources in the coming years which far exceed its domestic needs, it apparently considers all these planned facilities to be "designated network resources."

### *7.4. Recommendation*

Having chosen to adopt an open access transmission tariff modelled on FERC's *pro forma* tariff, Hydro-Québec is not free to ignore those provisions that do not suit it. As Hydro-Québec has not requested modification of these provisions of reg. 659, it should be obliged to operate in conformity to them.

To respect the provisions of its transmission tariff, Hydro-Québec should therefore be required to:

- designate the actual Point of Receipt for each point-to-point reservation, in accordance with s. 13.7.
- designate the specific generating resources assigned to service its network (native) load, in accordance with ss. 30.1 and 30.4; and
- submit a duly executed service agreement as provided for in Attachment F for network service of native load.

If it is unable or unwilling to do so, it should at a future date propose the modifications to reg. 659 that it considers appropriate.

Finally, unless Hydro-Québec can adequately explain why there should be one study procedure for its own needs and another for all other transmission customers, it should follow the procedure set out in s. 32 of reg. 659. Should Hydro-Québec consider these procedures inadequate, it may, as stated above, propose to the Régie in the future that these provisions be modified.

# 8. Revenue requirement

The scope of our mandate does not permit us to examine Hydro-Québec's proposed revenue requirement in detail. We shall nevertheless comment on several aspects of the rate base, namely the justification of additions and the regulatory treatment of telecommunications assets, and of the expenses included in the revenue requirement.

## *8.1. Rate base*

### 8.1.1. Additions

#### 8.1.1.1. Hydro-Québec's evidence

According to s. 164.1 of the Act, as amended by Bill 116:

> **164.1** For the purposes of subparagraph 1 of the first paragraph of section 49 and section 52.3,assets in operation and entered in the accounting records of the electric power carrier or distributor on or before 16 June 2000, those entered therein between that date and (*insert here the date of coming into force of the first regulation under subparagraph 1 of the first paragraph of section 7*3, assets the construction of which is authorized or exempted from authorization by law or by the Government as provided by law on or before 16 June 2000 and assets the construction of which is authorized or exempted from authorization by the Government as provided by law between that date and (*insert here the date of coming into force of the first regulation under subparagraph 1 of the first paragraph of section 7*3 are deemed to be prudently acquired and useful for the operation of an electric power transmission or distribution system.
>
> Moreover, any expenditures arising from transmission service contracts or distribution service contracts entered into before 16 June 2000 are deemed to be necessary for the provision of the service.[110]

In D-2000-102, the Régie indicated that, for additions to the rate base which have not already received final approvals, Hydro-Québec should present detailed information, including the

[110] This provision, in slightly different form, had been proposed by Hydro-Québec in May 1998, as one of the general principles the Régie should approve prior to proceeding with the present file. In D-98-88, the Régie added it to the list of questions to be debated in R-3405-98. It was later removed from that hearing after, on Jan. 27, 1999, just two days before Hydro-Québec submitted its evidence, the Government of Québec adopted Directive No. 1, which incorporated a similar provision. Directive No. 1 was struck down by Quebec Superior Court as *ultra vires* on June 6, 2000. However, a similar provision was incorporated into Bill 116, which was adopted by the Quebec Legislature on June 16, 2000, and immediately put into force.

alternatives and their cost as well as a justification of the prudence and of the selected options and the fact that they are at least cost.[111]

In its original submission, Hydro-Québec had failed to clearly identify the proposed additions to which the preceding requirements apply. In its decision D-2000-214 (p. 32), the Régie found the information provided to be entirely inadequate ("*nettement insuffisant"*). Recognizing that any projects which have already been authorized or which are exempt from authorization are deemed prudently acquired and useful, the Régie required, for any other projects, that a more detailed description be provided, either individually (for major projects) or for groups of smaller projects, including:

- the alternatives and their costs, and
- the justification of the prudence and least-cost nature of the selected option.

In HQT-13, doc. 1.2, p. 16, Hydro-Québec made it clear that, in its view, s. 164.1 applies to all the assets in its ratebase except for three (the reinforcement of regional grids, the La Baie substation and the construction of a new 40-km 120-kV line from Grand-Brulé to Saint-Saveur), with a total value of $18.2 million. At the Régie's request, it produced HQT-7, doc. 4.2, in which it lists all major additions for 2001 and identifies the relevant approvals.

According to this document, in addition to the three projects just mentioned, there are three other proposed additions which have not yet been authorized by the Government of Québec and thus are not covered by s. 164.1.[112] These are:

| | **status** | **date expected** | **value to be commissioned ($ million)** |
|---|---|---|---|
| Montérégie loop | decree requested: 20-01-00 | 15-03-01 | $2.9 |
| Outaouais loop | decree requested: 17-10-00 | 30-04-01 | $172.3 |
| Hertel substation | to come | | $4.1 |
| **TOTAL** | | | **$259.3** |

As noted in the above table, Hydro-Québec apparently expects the Government of Québec to authorize these projects in the near future. This appears to be the reason that it has failed to

111 « Les additions aux immobilisations qui n'auront pas déjà fait l'objet d'une approbation spécifique devront faire l'objet d'une présentation plus détaillée, incluant les alternatives et leur coût ainsi qu'une justification de la prudence et du moindre coût des choix retenus. » D-2000-102, p. 44.

112 These three additional projects are all mentioned in Part II of the Schedule to Bill 42, the *Act Respecting the Construction of Infrastructures and Equipment by Hydro-Québec on Account of the Ice Storm of 5 to 9 January 1998.* Under s. 6 of this Act, the projects listed in Part I of the Schedule are deemed to be prudently acquired and useful for the operation of Hydro-Québec's transmission system, but those in Part II are not. A challenge to the constitutionality of this Act is presently before the Superior Court of Québec.

provide any of the justification requested by the Régie for network additions.[113] However, no evidence to this effect has been presented to the Régie. Furthermore, it remains possible that the Régie's regulation concerning s. 73(1) will be adopted and approved before these orders-in-council are issued. Nevertheless, in its letter of January 22, 2001, Hydro-Québec stated that it is not at this time seeking the approval of the Régie for any proposed investments for 2001, "since they will probably all be deemed prudently acquired and useful" under s. 164.1 of the Act.

#### 8.1.1.2. Recommendation

The framework by which the Government of Québec will evaluate the prudence and least-cost nature of these investments by Hydro-Québec, without any of the benefits of independent and transparent regulation, is unlikely to produce satisfactory results, even in the best of cases. Since the Government is both the shareholder that would suffer if an investment were disallowed and the entity with the power to grant a preemptive approval, its incentive to grant such approvals is overwhelming. For the Régie to discharge its consumer protection function in the manner of a regulatory commission such as the FERC, to which Hydro-Québec has proclaimed it equivalent,[114] the opportunity for such pre-emption must be narrowly construed. The U.S. Government does not remove utility investments from FERC's review by deeming them prudent and least cost, and U.S. state governments exercise no such power with regard to utility investments either.

Since Hydro-Québec has presented no evidence to show that these investments were prudently acquired and are useful for the operation of its transmission system, and since they are not at this time exempted from the requirements of s. 49(1) under s. 164.1, the Régie should remove these assets from Hydro-Québec's 2001 ratebase. No other course will make clear to Hydro-Québec that the least-cost and prudency responsibilities of the Régie are every bit as serious as they would be in comparable regulatory agencies elsewhere and that they cannot be disrespected in anticipation of some future order from the government.

### 8.1.2. Regulatory treatment of telecommunications assets

#### 8.1.2.1. Hydro-Québec's evidence

In R-3405-98, the example of Connexim was raised as a hypothetical example of a situation where sale of regulated assets at their book value might result in a transfer of wealth from the regulated consumer to the shareholder. The Régie stated at the time that this issue would be appropriate to address in R-3401-98.

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[113] HQT-7, doc. 4.3 includes brief descriptions of these projects, but not the information requested by the Régie concerning justification.

[114] See page 8, above.

The information presented by Hydro-Québec in its evidence does not clearly identify what assets were sold to Connexim, a non-regulated affiliate of Hydro-Québec.[115] According to a response provided to the RNCREQ, there are three different situations:

1. assets sold to Connexim,
2. assets belonging to Hydro-Québec which are managed by Connexim for Hydro-Québec's exclusive use, and
3. assets belonging to and managed by Hydro-Québec, which also are used by Connexim for services provided only to Hydro-Québec.[116]

It is not clear from this response which assets were sold to Connexim, and whether or not HQ's telecommunications infrastructure (e.g. fiber optic cables integrated into the *cables de garde* of the very high-voltage transmission network) was included in the sale. While the wording of the response suggests that it was not, an editorial that appeared in *Tête de ligne*, published by the Association des câblodistributeurs du Québec, indicates that ownership of the telecommunications network was indeed transferred to Connexim and that, at the same time, Bell Canada obtained exclusive rights to market all surplus capacity beyond Hydro-Québec's needs for a period of five years.[117]

Hydro-Québec has indicated that the sale of assets to Connexim was made based on the book value of the assets involved.[118] It has further specified that the price included an increase relative to the book value of 30% to account for installation, engineering and general costs, plus an additional 3.5% for capitalized interest, minus accumulated depreciation at the date when the contract was signed. The date of signature is not indicated, but presumably it was subsequent to Connexim's incorporation on January 27, 1999.[119]

If the description of the Connexim transaction reported in *Tête de ligne* is correct, it appears that, in selling its telecommunications assets to a non-regulated subsidiary, Hydro-Québec ceded an asset that may well have had a market value considerably greater than the price at which it was sold.

In its evidence, Hydro-Québec filed a report by META Group EIS Consulting, which found that the annualized cost of Hydro-Québec's communications network is $196.5 million, compared to a quantifiable "comparable" market value of $167 million. Several reasons are given which might justify charging internal customers costs which exceed "comparable"

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[115] Connexim is a limited partnership owned by Hydro-Québec and Bell Canada, in equal shares.

[116] HQT-13, doc. 14, p. 15, R9.3.4.

[117] Serge Hudon, « Connexim, l'aboutissement d'une démarch qui soulève bien des interrogations, » *Tête de ligne,* printemps 1999, p. 4 (RNCREQ-10).

[118] HQT-13, doc. 1.1, p. 11, R4.4.

[119] L'inspecteur général des institutions financières, système CIDREQ, matricule 3348282073, Connexim, Société en commandite.

value.[120] However, the document does not explain why it would be preferable to obtain telecom service from a subsidiary rather than from using the company's own assets, nor does it address the issue of pricing for the sale of such assets.

Hydro-Québec has specified that its billings from Connexim were $64.5 million in 1999, $60.7 million (estimated) in 2000 and are projected to be just over $50 million in 2001, including volume charges and fees for the trading floor (*parquet de courtage*). These latter costs, which appear to be related to Hydro-Québec's marketing function, should not be charged to TransÉnergie.

The potential for two different types of abuse emerge clearly in this situation. On the one hand, Hydro-Quebec is transferring assets to an affiliated company that plans to use them in competitive markets. The incentive to transfer assets at less than their market value in such a situation is strong, for it conveys a competitive advantage to the unregulated subsidiary. At the same time, the communications subsidiary is doing business with other competitive subsidiaries and with the regulated monopoly. To the extent it can overcharge the monopoly customers for these services, it can either subsidize its competitive affiliates or return unregulated profit to its shareholders. The history of regulation of transactions between monopoly companies and their corporate affiliates in the US is replete with such abuses.[121]

Without knowing the details of the assets sold to Connexim or their price, it is impossible to determine whether any of these charges are appropriate. However, there is no reason to believe that a sale price based on book value is fair to the customers. We can be sure that the transfer price was not too high, for if it were, Connexim would have purchased comparable assets elsewhere. However, the ability to use the rights-of-way and conduits of Hydro-Québec where similar assets could not easily be duplicated may be worth far more than the book value.

#### 8.1.2.2. Recommendation

In order to clarify the situation regarding the transfer of Hydro-Québec's telecommunications assets to Connexim, the Régie should order a valuation performed by an independent expert, chosen by it and working under its supervision. This valuation should include both the price paid for the assets and the prices that are now being paid by the monopoly for the services. Not only will this provide accurate information for purposes of this issue, but it will shed useful light on the approach of Hydro-Québec to the issue of affiliate transactions in general, and it will alert both Hydro-Québec and the FERC to the fact that these issues are taken seriously in Québec.

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[120] HQT-6, doc. 5.1, p. 2.

[121] See, for example, "Cablevision: Edison Cheating Customers, Says Company Leasing Assets to RCN at a Fraction of True Value", Boston Globe, February, 27, 1998, p. E1, and "Bay State Wants Edison to Dump Cable", Wall Street Journal, June 2, 1999, New England section, p. 1.

Even though the transaction has already been completed, if the Régie concludes that it resulted in an inappropriate loss of value for TransÉnergie and its regulated customers, it can use its ratemaking powers to remedy this situation.

In order to proceed toward a structured examination of the issue, the first question is to determine what regulatory treatment would have been appropriate before these assets were sold. Assuming that the transaction took place around the time that Connexim was incorporated (January 1999), these assets would have been owned by Hydro-Québec when the revenue requirements underlying reg. 659 were established in 1997.[122] The first question is thus: should these assets have been treated as part of the ratebase, or should they have been treated as an internal expense?

Hydro-Québec has made clear that it prefers not to include telecommunications and computer assets in the rate base. Telecommunications services are provided to TransÉnergie by Hydro-Québec's Department of Telecommunications and Information Services (DPTI), and TransÉnergie is billed a transfer price for the services rendered. In Hydro-Québec's revenue requirement, these charges therefore appear as an expense.

At the same time, it must be noted that the, under s. 49(1) of the Act, the rate base is made up of assets "prudently acquired and useful <u>for the operation of</u> … a transmission system."[123] Since, as Hydro-Québec has indicated in its evidence, the telecommunications system is essential to the operation of the transmission system, and indeed was built for that purpose, it probably should have been treated as part of the rate base in 1997, not as an expense.

In its evidence, Hydro-Québec explains that, when assets are disposed of, an amount (sometimes referred to as "net investment") equal to their original cost, plus any cost of dismantlement, minus accumulated depreciation, minus any salvage value (*valeur de récupération*), is assigned to a separate account and depreciated over up to ten years using a 3% sinking fund approach.[124]

If, prior to the transaction, the assets sold to Connexim were part of Hydro-Québec's transmission rate base, then proceeds of the transaction should have been treated as salvage value. If the assets were sold at book value (original cost minus depreciation) and the sale price was treated as the salvage value, there would of course remain no net investment to depreciate.

Should the Régie determine, however, that the assets were sold for less than their fair market value, the result would be to deprive TransÉnergie and its regulated customers of part of the assets' value. To remedy such a situation, the Régie could instead recognize the fair market value, rather than the actual transfer price, as the appropriate salvage value. The result would

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[122] In its evidence, Hydro-Québec has presented the revenue requirements underlying its current rates, set in 1997. See, for example, HQT-13, doc. 1, p. 124, R71.2.

[123] Despite the many changes made by Bill 116 to the ratemaking provisions of the Act, it did not modify this language.

[124] HQT-5, doc. 1, p. 5.

be to enter a negative net investment into the rate base. In depreciating this value over a number of years, this approach would gradually return to TransÉnergie's regulated customers the value they lost when the assets were sold at a below-market price.

The issues of interaffiliate transactions raised by the dealings with Connexim are likely to recur in many guises in the future. It will be important for the Régie to develop a full set of standards of conduct to govern such transactions in order to protect Québec customers and give credible assurance that cross-subsidy is not occurring. By way of an example, a rule often found in U.S. codes of conduct governing affiliate transactions is the NARUC Guidelines for Cost Allocations and Affiliate Transactions (adopted by NARUC in July, 1999). This rule states that the pricing of services, products and assets transferred from a regulated entity to its non-regulated affiliate should be at the higher of book or market, while the pricing of services, products and assets transferred from a non-regulated entity to its regulated affiliate should be at the lower of book or market value[125].

Such a rule can take the place of a more rigid and time-consuming process requiring preapproval by the Régie of all such transactions. However, a comprehensive set of protections against affiliate transaction abuse must be much broader in scope, and should be instituted as soon as possible.

### *8.2. Expenses*

Once again, the limited scope of this testimony does not allow for a full review of the operating expenses included in Hydro-Québec's revenue requirement. There are two points, however, which deserve brief mention.

According to Hydro-Québec's testimony, the corporate charges which are assigned on a *pro rata* basis to TransÉnergie include several elements which, in our view, should be allocated 100% to Hydro-Québec's marketing functions and hence excluded from the transmission revenue requirement.[126] While the amounts of money involved are small compared to the revenue requirement as a whole, the principle of excluding all expenses related to the non-regulated aspects of Hydro-Québec's operations from the transmission revenue requirement is important.

We have identified two categories of corporate costs that, in our view, should be excluded from the transmission revenue requirement: corporate advertising (including cultural donations) and regulatory and legal costs unrelated to transmission service. At the same

[125] See sections D1 to D3 of NARUC, "Guidelines for Cost Allocations and Affiliate Transactions," Attachment To Resolution Regarding Cost Allocation Guidelines for the Energy Industry, Summer 1999; http://www.naruc.org/Resolutions/summer99.htm#Attachment To Resolution Regarding Cost Allocation Guidelines for the Energy Industry "GUIDELINES FOR COST ALLOCATIONS AND AFFILIATE TRANSACTIONS"; attached as Appendix I.

[126] According to HQT-13, doc. 14, p. 124, 17.5% of these costs are assigned to the transmission revenue requirement.

time, we question Hydro-Québec's decision to allocate none of its DSM costs to the transmission revenue requirement, given that demand-side investments can result in deferral or avoidance of significant transmission investments (section 8.2.3).

### 8.2.1. Corporate advertising

As anyone who reads newspapers or watches television in Québec can attest, Hydro-Québec has undertaken a significant advertising campaign over the last several years. According to Hydro-Québec's evidence, the corporate advertising budget allocated to the transmission revenue requirement for 2001 is $0.41 million.[127] This amount, carried over from 2000, apparently represents 17.5% of the corporation's total advertising budget.

Hydro-Québec has not explained why transmission customers should be assessed any of these costs. As Scott Hempling explained in a talk at the World Forum on Energy Regulation hosted by the Régie in May 2000, many utilities engage in significant advertising in the years prior to the opening of retail competition, in order to create a barrier to entry and to increase their competitive advantage once the market opens.[128]

Under s. 167(3) of the original Act, the Régie was to advise the Government concerning the liberalization of electricity markets in Québec. This paragraph was never put into force. Instead, s. 56 of Bill 116 eliminated it, replacing it with:

> **167.** At the request of the Government and according to the parameters it determines,the Régie shall,on the proposal of the electric power distributor, fix the conditions of a pilot project to enable consumers or a class of consumers the Régie designates in accordance with the rules of the project to be supplied electric power by a supplier of their choice. The Régie shall then adjust the rate of the electric power distributor in accordance with the conditions of the pilot project.

It thus appears that Québec is one step closer to opening its retail markets to competition. In this context, Hydro-Québec's corporate advertising should properly be allocated entirely to its marketing function, unless it can be shown that it is directed exclusively toward transmission customers (i.e. generators and marketers).

For the same reasons, Hydro-Québec's donations to cultural activities ($1.22 million allocated to transmission) should also be seen as a marketing expense and therefore unrelated to the transmission revenue requirement.

Here again, the issue of overcharging the captive customers in order to confer competitive advantage on an unregulated activity or affiliate needs to be confronted comprehensively. We therefore reiterate our recommendation that the Régie develop standards of conduct to govern inter-affiliate transactions. In the meantime, and in accordance with its decision in R-

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[127] HQT-13, doc. 14.1, p. 9.

[128] Scott Hempling, "Implementing Competition in Retail Electricity: The Problem of Incumbent Advantages," presented at the World Forum on Energy Regulation, Montreal, May 24, 2000.

3405-98,[129] it should proceed on a case-by-case basis, making the necessary ratemaking adjustments in this proceeding.

### 8.2.2. Non-transmission regulatory and legal costs

We see no reason why Hydro-Québec's regulatory and legal costs should not be directly allocated to the services to which they apply. There is no question that the costs of the present proceeding and of R-3405-98 are properly attributable to the transmission revenue requirement for the years 1998-2001. Similarly, it seems clear that the costs of proceedings concerning wind power, small hydro, interruptible rates and electrotechnologies are related to Hydro-Québec's production and/or distribution services, but not to transmission.[130] Pro rata apportionment of these costs to the transmission revenue requirement is thus inappropriate.

Similarly, Hydro-Québec's legal costs related to its subsidiaries or other non-regulated aspects of its business should also be excluded from the transmission revenue requirement.

If these steps are not taken, the costs of competitive functions will be charged to captive customers, in effect subsidizing Hydro-Québec's competitive activities and placing its potential competitors at an unfair disadvantage. In the event that Québec eventually moves toward competition for electricity services, such cross-subsidies will have ominous implications for the successful development of customer choice.

### 8.2.3. Exclusion of DSM costs

According to Hydro-Québec's evidence, it appears that none of the costs of its ongoing or planned demand-side management (conservation and load management) programs are allocated to the transmission revenue requirement.

In many jurisdictions which have undergone restructuring, system benefits charges or other mechanisms have been established to fund DSM and related programs. However, in D-2000-102 the Régie determined it would be premature to debate such charges in the present hearing.

In the absence of such a charge, DSM costs must be seen as part of the utility's revenue requirement. The question of how those costs should be shared among Hydro-Québec's business units has yet to be addressed.

Since DSM investments reduce future demand growth and hence the need for transmission upgrades to serve native load, it seems clear that at least part of these costs should be

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129 D-99-120, p. 28.

130 The 1998 hearing on Hydro-Québec's supply tariff proposal (s. 167) primarily concerned the generation function, but arguably a portion of its costs could be attributed to transmission as well.

attributed to the transmission revenue requirement.[131] In its 1998 decision regarding B.C. Hydro's wholesale transmission rates, the British Columbia Utilities Commission ordered that 10% of B.C. Hydro's capitalized DSM costs be charged to the transmission revenue requirement, subject to modification in future hearings.[132]

In the absence of any evidence in the file as to Hydro-Québec's DSM costs or their allocation, we suggest that they be allocated *pro rata* to the transmission revenue requirement, on the same basis as other corporate charges.

### *8.3. Recommendation*

Based on the foregoing, we make the following recommendations:

- the six transmission projects discussed in section 8.1.1 which are not at this time deemed prudently acquired and useful should be excluded from the ratebase, unless sufficient justification is provided as per D-2000-102;
- the ratebase should also be adjusted to account for the market value of any telecommunications assets which have been sold at book value and which would otherwise form part of the transmission revenue requirement;
- corporate advertising and cultural donations should be excluded from the transmission revenue requirement;
- legal and regulatory costs other than those directly related to transmission should also be excluded from the transmission revenue requirement;

DSM costs should, for the moment, be allocated *pro rata* to the transmission revenue requirement. In the next rate case, the Régie should more carefully explore the allocation of these expenses.

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[131] Since, as Hydro-Québec explained in HQT-13, doc. 14.2, p. 7, its load forecasts do not take future DSM investments into account, it is reasonable to assume that its long-term transmission plan does not take them into account either. Thus, depending on the extent of these future investments, the need for transmission upgrades in coming years may be reduced.

[132] BCUC, B.C. Hydro, *op. cit.,* p. 29.

# 9. Conditions of service

Apart from the modifications to reg. 659 proposed by Hydro-Québec, the RNCREQ has asked us to comment on two provisions of the tariff in which the notion of non-discriminatory treatment of all transmission customers may come into conflict with the interests of the Québec public. These provisions concern the curtailment priority of native load, on the one hand, and the Transmission Provider's obligation to upgrade its network to provide point-to-point service, on the other.

## *9.1. Priority of service for native load*

### 9.1.1. Context

According to s. 13.6 of reg. 659, any reduction of transmission service due to unforeseen conditions must be shared proportionately between native load, network integration service and point-to-point service.

Nevertheless, Hydro-Québec's testimony states that native load has priority over other uses (HQT-3, doc. 1, p. 7).[133] Invited by the Régie to reconcile this statement with reg. 659 and to identify the sections of it that allow it to favour native load, Hydro-Québec responded:

> En dernier lieu, *une fois les besoins de la charge locale totalement satisfaits,* Hydro-Québec doit rendre aux clients du service de transport ferme de point à point le service auquel il [sic] sont en droit de s'attendre, c'est-à-dire un service <u>ferme</u>, un service sur lequel ils peuvent compter. Il s'agit d'un engagement sur lequel le transporteur ne revient pas.[134] (underlining in original, italics added)

This passage suggests that, for Hydro-Québec, firm point-to-point service is in some way subordinate to native load service.

Section 13.6 of reg. 659 was adopted verbatim from FERC's *pro forma* tariff. Like the provisions concerning "reservation priority," this "curtailment priority" provision was included in the *pro forma* tariff to ensure that transmission customers had access to service precisely equivalent to that provided by the utility to its retail customers.

> An essential element of non-discriminatory transmission access is the right of transmission customers to reserve and purchase transmission service that is of the same quality as that used by the transmission provider in serving its wholesale requirements customers and retail load.[135]

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[133] "À cet égard, la charge local bénéficie d'une priorité d'accès au réseau de transport."

[134] HQT-13, doc. 1, p. 159, R91.1. "Finally, once the native load needs are fully satisfied, Hydro-Québec must provide its firm point-to-point clients the service to which they are entitled, that is a <u>firm</u> service, on which they can count. This is a commitment which the carrier fully intends to respect."

[135] Order 888, pp. 326-327.

Under this provision, "any curtailment must be made on a non-discriminatory basis, including curtailment of the transmission provider's own use of the transmission system."[136]

This provision has led to complex litigation concerning whether or not FERC has jurisdiction to require utilities to curtail their retail customers. These questions do not arise in the Quebec context, where the Régie has jurisdiction over both retail and wholesale transactions. Here, if the non-discrimination principle is applied, it will inevitably require curtailment of native load when emergencies occur, as provided for in reg. 659.

Unlike the FERC, the Régie is not governed by any statutory obligation to implement competitive generation markets, nor has a policy of non-discriminatory treatment for third-party transmission customers been adopted by either Hydro-Québec, the Régie or the Québec government.[137] On the contrary, Québec's "social compact," invoked only months ago by the Québec government to justify the modifications to the Act embodied in Bill 116, would suggest that Québec consumers' needs should be paramount, as suggested in Hydro-Québec's testimony.

### 9.1.2. Recommendation

For these reasons, unless the Régie determines that non-discrimination should have precedence over the social compact, s. 13.6 should be modified to ensure that service to Quebec customers (whether characterized as native load or as network integration service) are never curtailed if such curtailment could be avoided by reducing service for exports or other wheeling activities.

Our proposed modifications to the French and English text of s. 13.6 are found in Appendix II. With these modifications, in the event that curtailments are required, they would be made first to non-firm point-to-point customers, then to firm point-to-point customers, and only then, if additional curtailments are still required to maintain reliability, to network integration customers (including native load). Within each category, curtailments would be distributed on a *pro rata* basis among all users.

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[136] *Ibid.*, p. 336.

[137] The Québec government's 1996 energy policy, *Energy at the Service of Québec: A Sustainable Development Perspective,* is based on four objectives:

- Ensure that Quebecers receive the necessary energy services at the best possible cost,
- Promote new ways of developing the economy,
- Respect or restore the environmental equilibrium,
- Guarantee equity and transparency. (pp. 11-12).

### *9.2. Obligation to expand or upgrade the network*

#### 9.2.1. Context

According to ss. 13.5 and 15.4 of reg. 659, Hydro-Québec is obligated to expand or upgrade its transmission system when it would otherwise be unable to accommodate a complete application for firm point-to-point transmission service.

Once again, these provisions were adopted verbatim from the *pro forma* tariff, and once again, they were included in the *pro forma* tariff in order to create comparable conditions between incumbent utilities and third-party transmission customers. In our view, the underlying reasoning is that, since utilities can and do build transmission upgrades in order to provide service for their customers, non-utility transmission customers must have the same right. Furthermore, if a transmission provider could refuse to construct interconnections or upgrades, it would be able to block generating projects that would compete with its generating affiliate, thereby restricting competition.

As noted earlier, comparability, non-discrimination and the promotion of competition in generation do not have the same bedrock status in the legislative and regulatory context of the present proceeding as they do for the FERC. At the same time, the Act creates certain imperatives for the Régie that are not shared by the FERC.

The most important of these are those embodied in s. 5 of the Act, quoted earlier, under which the Régie must "promote the satisfaction of energy needs through sustainable development" which, as noted earlier, has been interpreted by the Régie to include taking into account the environmental and social consequences of energy-related investments.

Under normal circumstances, the obligation to build established by these two provisions would be consistent with the Act, given that the Régie's approval under s. 73(1) is needed for any grid expansions undertaken under it. As the obligation to build rests on the transmission provider, the Régie's power to withhold authorization from any upgrades it finds to be inconsistent with sustainable development or with its other imperatives and constraints remain unaffected.

In s. 114(6), the Act provides that the Régie may determine by regulation the conditions and cases under which an activity referred to in s. 73 requires authorization. Under s. 115, any such regulation adopted by the Régie must be submitted to the government for approval.

To the best of our knowledge, the Régie has not yet adopted a regulation under s. 114(6) nor submitted it to the government for approval. In its evidence, Hydro-Québec takes the position that, in the absence of such a regulation, the authorization requirement created in s. 73(1) is inoperative.[138] Thus, according to this reading of the Act, the Régie does not currently have the power to grant or withhold authorization for a transmission project.

[138] HQT-13, doc. 1, p. 4.

Under these circumstances, to adopt a transmission tariff which creates an obligation on the part of the transmission carrier to build grid extensions which the Régie is not empowered to review would appear to be inconsistent with its obligations under s. 5.[139]

### 9.2.2. Recommendation

In order to remedy this untenable situation, the Régie should suspend the obligation to build until such time as the regulation mentioned in s. 114(6) comes into force. We therefore recommend that ss. 13.5 and 15.4 be modified as indicated in Appendix II.

Like the modification to s. 13.6 discussed in the previous section, these proposed modifications to the transmission tariff would represent a substantial variance from the *pro forma* tariff, and hence from FERC transmission policies. However, in our view, each of these modifications is necessary in order to respect the key tenets of Québec's energy policy: maintaining the social compact, and ensuring that new energy investments are compatible with sustainable development.

[139] At the present time, transmission investments are still subject to the obligation under s. 29(7) of the Hydro-Québec Act to obtain approval from the Québec cabinet. The cabinet, however, is not governed by the Act concerning the Régie de l'énergie. The argument therefore stands: the Régie should not create an obligation to build infrastructures that it would itself be unable to approve.

# 10. Modalities for approving additions or modifications

## *10.1. Context*

In its decision D-2000-102, the Régie determined that the issues to be debated in this hearing should include the modalities for approval of additions to the rate base in future hearings. Hydro-Québec's evidence does not address this issue directly.

In this same decision, the Régie enunciated an approach to the justification of additions and modifications in the present file which, in our view, can also form the basis for the modalities for approval of future additions to the rate base. It indicated that, for additions to the rate base which have not already received final approvals, Hydro-Québec should present detailed information, including the alternatives and their cost as well as a justification of the prudency and of the least-cost nature of the selected options.[140]

Furthermore, as noted above (page 61), in decision D-2000-214, having found the information provided by Hydro-Québec in this regard to be inadequate, the Régie specified further that, for all projects which are not deemed prudently acquired and useful under s. 164.1 of the Act (as amended), Hydro-Québec should present detailed information including the alternatives and their costs, as well as the justification of the prudence and least-cost nature of the selected option.

Applied to the question at hand, this would suggest that, for the purposes of future rate cases, additions to the rate base should be approved only when the Régie is satisfied that they constitute the least-cost solution to an identified need. Furthermore, given s. 5 of the Act,[141] least-cost should not be understood in a strictly financial sense, but rather should be taken to mean least "social" cost, taking environmental and social concerns into account.

In other words, in order for additions to the rate base to be approved in future rate cases, it must be demonstrated:

1. that the existing grid is not adequate to provide the required service,

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[140] D-2000-102, p. 44.

[141] Section 5, as amended by Bill 116, reads as follows:

> **5.** In the exercise of its functions, the Régie shall reconcile the public interest, consumer protection and the fair treatment of the electric power carrier and of distributors. It shall promote the satisfaction of energy needs through sustainable development and with due regard for equity both on the individual and collective planes.

In this regard, the Régie has stated that, for it, the expressions "public interest," "sustainable development" and "equity both on the individual and collective planes" include or may include economic, environmental and social concerns (D-2000-214, p. 41).

2. that the proposed solution is superior to alternative actions that would allow Hydro-Québec to provide the required service, taking into account economic, environmental and social concerns.

In this sense, project approval is intimately related to the transmission planning process, for it is precisely in planning the transmission system that needs and the relative costs and benefits of alternative solutions are assessed. Thus, the modalities in question must allow the Régie to determine that the planning process which resulted in the choice of the proposed project was fully satisfactory.

## *10.2. The role of transmission planning*

### 10.2.1. Planning and project approval

The problem before us is thus in many ways similar to that facing regulators of vertically integrated utilities in the 1970s and 80s. In the absence of any regulatory involvement in the planning process, they reviewed the prudence and usefulness of substantial investments in new facilities in the context of rate cases, once the facilities had been (or were about to be) commissioned. It was only after a series of spectacular failures — where massive investments in new plant were excluded from the ratebase because regulators found, *post facto*, that they were not prudent and useful, that utilities and their regulators began to see the virtues of regulatory involvement in the planning process. In obtaining regulatory approval for their long-term plans, utilities protected themselves in large measure from regulatory disallowance, once the facilities were built.

Thus was set in motion the evolution that eventually led to the integrated resource planning process, which became widespread among U.S. utilities in the 1980s and which indeed was a key feature of the Act as originally adopted in 1996. Under this process, needs were assessed and options examined in a transparent and participatory process; since the regulator eventually endorsed the resulting action plan, the likelihood of *post facto* regulatory disallowance was largely confined to cost overruns occurring after the regulatory approval of the project itself.

In the IRP process, transmission planning was included as one aspect of utility planning, together with planning for generation and demand-side efficiency investments. Thus, for example, the regulatory requirements for Integrated Resource Planning in the state of Nevada require that:

> 1. The plan must include demand or load forecasts (high, base and low growth); plans for conservation, demand-side management and load management (load shaping); analyses of options for supply for twenty years into the future; financial information and assumptions and integration analysis. <u>The options for supply include</u>
>
> a. Expansion of the utility's generating facilities;
> b. <u>Upgrading of the utility's transmission facilities;</u>

In other states, such as New York or Massachusetts, the resource selection process also included consideration of environmental (and sometimes other) externalities, i.e. societal costs not directly reflected in the costs and prices of the projects themselves.

Because s. 72 of the Act was amended in June 2000, however, Hydro-Québec is no longer required to submit for regulatory approval a resource plan to balance supply and demand. While transmission upgrades would presumably have been treated as options in such a resource plan, it is not clear how or to what extent they will be addressed in the supply plan required by the amended s. 72, which is to describe "the characteristics of the contracts that it intends to conclude to satisfy the needs of Quebec markets, after application of energy efficiency measures."

In this context, the Régie is left with the same problem that faced regulators of integrated utilities in the 1970s and 80s: how to assess the prudence and usefulness of transmission upgrades in the context of cost-of-service ratemaking, taking environmental and social concerns into account. At the same time, Hydro-Québec is faced with the same problem faced by utilities of that era, namely, how to avoid disallowance of major investments which have already been made without any form of regulatory pre-approval.

Hydro-Québec appears to favour the approach embodied in the present application, namely, that each year, in its transmission rate case, it will seek the Régie's authorization for "the projects for the extensions or modifications to the network as well as the other capital expenditures included in the 2001 capital budget submitted by the carrier."[142]

The difficulties with this approach are two-fold. First, as we have just seen, in the event that the Régie finds an investment to be inappropriate, its only recourse is to exclude the capital expenditures from the ratebase, thereby denying Hydro-Québec the possibility of recovering their costs through transmission rates. This is a very dull scalpel indeed, which only allows the Régie to punish the carrier (and the owner) if it finds, *post facto*, that its choices were inappropriate. This remedy proved unsatisfactory in the U.S. context. It will be doubly so where the entity punished by the disallowance is the Government of Québec, forcing citizens to make up as taxpayers the revenues that the Régie has found should not be charged to them as customers. Secondly, it imports complex transmission planning issues into what is already a complicated ratemaking hearing, virtually guaranteeing that they will not be addressed with the care they deserve.

Thus the Hydro-Québec approach actually combines the worst of both worlds. Unlike the historic prudence reviews, which only occurred in instances of substantial cost overrun, the Hydro-Québec approach requires that all projects be reviewed. However, unlike the coordinated least-cost plan review that largely displaced prudence reviews, the Hydro-Québec approach contemplates *ad hoc*, hurried, year-to-year reviews which can only be superficial and unsatisfactory.

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[142] Hydro-Québec, Revised Application for the Modification of Rates for the Transmission of Electric Power, R-3401-98, August 15, 2000, p. 6.

Once the Régie begins to exercise its jurisdiction under s. 73(1) to authorize proposed transmission investments, it will indeed have an opportunity to judge the appropriateness of transmission investments before they are made. [143] However, the issues that will face the Régie at that time are, for all intents and purposes, the same as those described here.

### 10.2.2. Ensuring that "non-wires" alternatives are considered

The situation is further complicated by the unavoidable fact that, by the very nature of a transmission system, the alternatives to a proposed transmission investment include not only other transmission investments, but also "non-wires" solutions (i.e. solutions to transmission constraints that do not involve adding new "wires") — whether on the supply side (generation) or the distribution side (conservation, load management, or small scale generation.). Depending on the precise nature of the anticipated need, it may be possible to resolve it either by adding appropriately located new generation facilities, or by reducing electricity demand in certain areas, thereby relieving congestion on the grid. Thus, an investment that might appear optimal from a transmission perspective might be ultimately determined by the Régie to have been imprudent, if a lower cost "non-wires" solution were available.

For all these reasons, it appears inevitable for the Régie to review Hydro-Québec's transmission planning, whether in the annual transmission rate case, in proceedings under s. 73 or in some other context. In order to assist the Régie in this regard, we will look briefly at the way that transmission planning is addressed in jurisdictions where vertically integrated utilities have been replaced with independent or functionally separate transmission entities.

## *10.3. Transmission planning and approval in other jurisdictions*

### 10.3.1. Comparing transmission and non-transmission options

In jurisdictions which have moved from vertically integrated utilities to a restructured industry model, the practice of integrated resource planning described above has in many

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[143] According to s. 73 of the Act, as amended by Bill 116:

> **73.** The electric power carrier, the electric power distributor and natural gas distributors must obtain the authorization of the Régie, subject to the conditions and in the cases determined by regulation by the Régie, to:
>
> (1) acquire, construct or dispose of immovables or assets for transmission or distribution purposes …

As noted in HQT-1, doc. 1, p. 24, l. 20-27, the regulation stipulating the conditions and cases in which such authorization is required has yet to be adopted by the Régie.

cases been suspended. Instead, separate processes govern each of the three resource categories mentioned above. Thus, generation in many cases is not "planned", in the traditional sense, but is left to the invisible hand of the market.[144] Demand-side resources are planned and implemented by distribution utilities, para-govermental agencies or by "conservation utilities" such as Efficiency Vermont,[145] subject to state regulatory oversight and, in many cases, funded by non-bypassable system benefits charges. Transmission system modifications are planned by some combination of transmission owners and ISOs (and eventually RTOs), subject to the requirements and oversight imposed by their regulators.

This fragmentation of the planning process can easily lead to inappropriate and sub-optimal resource allocation decisions. Indeed, its failure to integrate the demand-side potential is considered to be one of the principal causes of the current crisis in California. Similarly, the Advisory Board of the New England ISO has expressed concern that the transmission "uplift charge" currently includes costs that have not been subjected to any meaningful analysis of needs or alternatives.

In particular, a transmission provider may perceive the need to remedy transmission constraints by network upgrades or additions, when those same constraints might be better addressed through either supply-side or demand-side "non-wires" solutions. For this reason, processes to ensure that non-wires solutions are given full consideration before embarking on major transmission investments have been developed in a number of regions in North America. We will briefly examine the approaches used in the PJM Interconnection (Pennsylvania-New Jersey-Maryland), California and Alberta.

#### 10.3.1.1. PJM

Under the PJM Regional Transmission Expansion Planning Protocol, which has been in effect since 1998, the Office of the Interconnection prepares a ten-year Regional Transmission Expansion Plan, updated twice a year. The Protocol provides that enhancement and expansion studies shall include identification of any existing and projected system limitations, and "evaluation and analysis of potential enhancements and expansions, including alternatives thereto, needed to mitigate such limitations."[146] Alternatives can be proposed by any Regional Transmission Owner or by any participant of the Transmission Expansion Advisory Committee.[147]

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[144] However, thanks in part to the recent debacle in California where, according to one wag, "the invisible hand was caught in the cookie jar," there is renewed interest in generation planning.

[145] Efficiency Vermont, operated by the Vermont Energy Efficiency Corporation, a not-for-profit energy services organization, will consolidate the energy efficiency programs already offered by Vermont utilities and offer new ones on a statewide basis. It is funded by an "energy efficiency charge" on customers' bills, ranging from 0 to 2.5%. Vermont is the first jurisdiction in North America to implement the "conservco" model, believed by many to be the best way to provide energy efficiency services in a restructured environment.

[146] PJM Regional Transmission Expansion Planning Protocol, section 1.5.3.

[147] I*bid., s. 1.5.6 (c).*

This Advisory Committee is composed of a broad range of stakeholders, including not just transmission owners, generators and state regulators, but also environmental and consumer advocacy groups. It is briefed regularly on the proposed capacity additions, and consulted as to the scope of system studies.

While the identities of developers of new generation are not revealed until after a system impact study has been performed, the size and location (by substation) of all proposed generation additions are made public as soon as the ISO is informed of them.

The regional planning process includes all generation interconnections as well as proposed transmission solutions to reliability problems. Pilot programs are underway concerning load-response behaviors; they will eventually be integrated into the planning process.[148]

#### 10.3.1.2. California

Over the last few years, the California ISO has devoted considerable attention to the question of non-wires solutions. The debate has centred around whether there should be a comprehensive solicitation process to determine if there are cost-effective and reliable alternatives to each transmission project in a Transmission Owner's annual transmission plan, or whether instead the ISO should perform such solicitations on a case-by-case basis, focusing on those projects where the ISO's Board believes there are likely to be competitive alternatives.[149]

The process of soliciting non-wires alternatives was implemented by the California ISO on a pilot basis with respect to PG&E's Southern Tri-Valley Transmission Expansion Project. In response to its RFP, the ISO received a number of proposals for local generation and for load management services. While the ISO judged the alternatives to be more costly than the proposed project, it found in retrospect that several methodological weaknesses in the RFP process may have biased the result.[150]

#### 10.3.1.3. Alberta

The transmission system of the Alberta Interconnected Electric System is managed under contract by ESBI Alberta Ltd. (EAL) as Alberta's Independent Transmission Administrator.

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[148] Steven Herling, Chair, PJM Planning Committee, pers. comm.

[149] California ISO, Memorandum from Terry M. Winter, President and CEO and Kellan Fluckiger, Chief Operations Officer, to the Grid Reliability/Operations Committee, April 18, 2000. (Available at www1.caiso.com.)

[150] California ISO, Memorandum from Kellan Fluckiger, Chief Operations Officer, and Stephen Greenleaf, Director of Regulatory Affairs, to the Grid Reliability/Operations Committee, May 15, 2000. (Available at www1.caiso.com.)

It has recently published its third annual ten-year transmission plan.[151] Since 1998, EAL has favoured mitigating certain critical system constraints by encouraging appropriate siting of new generation through location-based economic signals. In 1999, it reported that the most significant transmission upgrades could be deferred, perhaps indefinitely, with appropriate generation additions.[152] In the 2000 plan, it reports that constraints on the Edmonton-Calgary transmission path will be relieved through 2004-05 through its location-based credits programs.[153] While the process set up by EAL apparently does not create any incentives for demand-side measures or for distributed generation that would mitigate these constraints, these should follow from the principles it has adopted.

### 10.3.2. Stakeholder involvement in transmission planning processes

While formal procedures to evaluate non-transmission alternatives are not universal, it is standard practice for the transmission planning process to include interested parties other than the utility, and transmission plans and related documents are treated as public documents. Thus:

- in California, each utility prepares its own transmission plan in close coordination with the Cal-ISO staff and interested electric market participants;[154]
- in Alberta, transmission issues are debated at the Transmission Planning Committee, which is open to all stakeholders;[155]
- in the PJM region, the Transmission Expansion Advisory Committee includes environmental and consumer advocacy groups, as noted above;
- In New England, the Transmission Expansion Planning Process is conducted by ISO-NE (which in turn is under the direction of an independent board without ties to market participants), together with the transmission owners. The resulting five-year NEPOOL Transmission Plan lists projects which have received NEPOOL review and approval, as well as those which have not. Other stakeholders can comment on the draft Plan through the NEPOOL Reliability Committee, one of three standing committees that provide for interaction between ISO-NE and market participant stakeholders. Additional stakeholder input can be provided on a less formal basis through the ISO's Advisory Committee, that is open to public interest groups and state agency representatives;

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151 ESBI Alberta Ltd, *Alberta Interconnected Electric System: Transmission Development Plan 2000-2010,* December 2000, http://www.eal.ab.ca/ts/2000_Development_Plan.pdf.

152 ESBI Alberta Ltd, *Alberta Interconnected Electric System: Transmission Development Plan 2000-2009,* December 1999, p. 5.

153 ESBI Alberta Ltd., *Transmission Development Plan 2000-2010*, p. 15.

154 PG&E, *Electric Transmission Grid Expansion Plan for the Years 2001-2005,* p. 3.

155 ESBI Alberta Ltd., *Transmission Development Plan 2000-2010*, p. 6.

- In New York, the Transmission Planning Advisory Subcommittee, which provides guidance to the NYISO transmission planning staff, is open to members and eligible customers of the ISO; others may participate as guests. The New York ISO publishes an annual long-term Transmission Plan, and maintains a constantly updated "transmission and interconnection study queue" on its website (http://www.nyiso.com/services/planning.html), listing all the studies that have been requested of the ISO for potential upgrades, additions and interconnections.

Finally, all transmission owners and operators subject to the jurisdiction of the FERC must annually file a Form 715 Report, a public document that includes forward-looking power flow base cases.[156]

### *10.4. Transmission planning in Québec*

Until recently, Hydro-Québec was required to consult with the public as part of its planning process. In conformity with a governmental decree,[157] Hydro-Québec carried out significant consultations in preparing its 1993 Development Plan.[158] Consultations in even greater depth were begun in preparation for the 1996 Development Plan, but work on the Plan was suspended when the Public Debate on Energy was launched in 1995. As public involvement in Hydro-Québec's planning was implicit in the integrated resource planning process required under s. 72 of the Act as originally adopted, the decree was eventually abrogated.

With the modification of s. 72 in Bill 116, the Régie no longer has the responsibility of ensuring that expansions of Hydro-Québec's generation system are in the public interest. It does, however, still have this responsibility with respect to expansion of Hydro-Québec's transmission system. The question is thus how that responsibility can best be exercised.

As noted above, while the degree of public involvement varies from one region to another, in every North American jurisdiction with which we are familiar, long-term transmission plans are public documents, and the process by which they are developed and approved is an open one. The arguments that are often raised as to why generation information should be treated as confidential have little or no relevance to transmission planning. Indeed, it is hard to see how it could be otherwise, since transmission is in most cases not a competitive activity but a regulated monopoly which is "affected with the public interest."[159]

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156 http://www.ferc.fed.us/electric/f715/715instr00.html#Part 6

157 Order-in-council 971-91 concerning the form, the tenor and the periodicity of Hydro-Québec's Development Plan (1991).

158 While these consultations focused primarily on generation options, transmission issues were also addressed.

159 The U.S. Supreme Court held in 1876 that states may regulate the use of private property when the use was "affected with the public interest." The expression was borrowed for an influential report prepared in 1994 for the National Association of Regulatory Utility Commissioners (NARUC) by Jan Hamrin, William Marcus, Carl Weinberg and Fred Morse, *Affected with the Public Interest: Electric Industry Restructuring in an Era of Competition.*

Given the integrated network of a transmission grid, it is in our view essential, in order for the Régie to assess future proposed additions and modifications to the transmission grid, that Hydro-Québec present its detailed long-term transmission plan to the Régie for review.

In HQT-3, doc. 1, pp. 37-38, Hydro-Québec explained its planning process, presented schematically on p. 44 of the same document. In response, the Régie ordered that it produce its *Plan de gestion des actifs* and its *Plan d'affaires*, both of which figure prominently in this schema. As of this writing, Hydro-Québec has not filed its *Plan de gestion des actifs*; however, in HQT-13, doc. 1.2, pp. 4-10, it has excerpted the information that it considers relevant. At the same time, it has filed a copy of its *Plan d'affaires* with the Régie, but has requested that it not be divulged to intervenors; the Régie has yet to rule on this request.

In the summary of its *Plan de gestion d'actifs,* Hydro-Québec anticipates the addition of 5,790 MW of new generating capacity over the next 10 years, which will require the construction of 689 km of new 735-kV lines by 2006, as well as the addition of significant series compensation from 2003 to 2006.[160] These investments are described as related to "demand growth," which we assume refers to the network service requirements of HQ-Distribution. No indication is given of additions that might be required to provide point-to-point service to Hydro-Québec or to other customers. Investments totalling $3.849 billion are planned for the period 2002-2008[161] — more than $500 for man, woman and child in Québec.

Given these massive investments foreseen by TransÉnergie over the coming years, it is all the more necessary that the Régie and the interested public have an opportunity to review these plans as a whole, rather than on a piecemeal basis.

Furthermore, as we discussed earlier, generation and conservation investments can under certain circumstances substitute for transmission investments. Given its statutory obligations under s. 5 of the Act, it is incumbent upon the Régie to ensure that "non-wires" solutions of lower economic, environmental and social cost have been thoroughly explored before it approves the construction of major new lines.

Unfortunately, TransÉnergie's planning process does not allow for the consideration of such alternatives. In response to a question from the RNCREQ in this regard, Hydro-Québec stated that, when an addition is required to meet demand growth, it is HQ-D, and not TransÉnergie, that is responsible for the choice to make an investment in transmission, rather than one in energy efficiency or in decentralized generation.[162] Presumably, this means that,

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160 Insofar as the capacity additions include the Gull Island project, which according to the preliminary supply-demand tables provided in HQT-11, doc. 5, would not come on-line until 2008, it appears that additional new high-tension lines would also be required after 2006.

161 HQT-13, doc. 1.2, p. 10.

162 HQT-13, doc. 14, p. 25, R16.1. Though not acknowledged by TransÉnergie, supply- and demand-side alternatives might also substitute for transmission additions which are initiated by the

if HQ-D has requested additional transmission capacity from TransÉnergie, it has already rejected any demand- or supply-side alternatives in its s. 72 supply planning process.

Apparently, then, TransÉnergie's position is that it has no responsibility to examine non-wires alternatives for any upgrade requested by HQ-Distribution. Its response also suggests that, for transmission upgrades resulting either from its own reliability needs or from new point-to-point service requests, it is under no obligation to examine non-wires alternatives either.

However, regardless of the source of the transmission constraint, there may exist supply-side or demand-side alternatives that relieve it at lower cost than would new transmission lines. By our reading of the Act, it is incumbent upon the Régie to ensure that any transmission investments are at lower cost (taking into account economic, environmental and social concerns) than all the alternatives, including not only alternative transmission investments, but also non-wires investments such as energy efficiency or decentralized (distributed) generation. However, it is far from clear that it will be possible to address these issues in proceedings under s. 72.

### *10.5. Recommendation*

In order to ensure that transmission and non-transmission alternatives to Hydro-Québec's proposed expansions are examined with the care they require, we urge that the Régie order that Hydro-Québec to file a long-term transmission plan as part of its next transmission rate case, and to consult the interested public in the preparation of that plan.[163]

Furthermore, to ensure that non-wires solutions are given full consideration in selecting the investments that best reconcile the public interest, consumer protection and the fair treatment of distributors, and that promote the satisfaction of energy needs through sustainable development, the Régie should require that HQ-D participate fully in the consultation process and in the preparation of the transmission plan. It would be desirable that the Régie participate in these consultations as an observer.

Finally, the Régie should specify in advance the fundamental criteria for a satisfactory least-cost planning process, and should also make clear that it will require a specific demonstration by Hydro-Québec as to how these criteria have been met. Otherwise, the rate case itself is likely to become the forum for an extended discussion over approaches to least-cost planning, with a significant possibility that consideration of this important topic will be incomplete, and that the review and approval of these major investments will be based on an inadequate and an unsatisfactory record. The Régie should, to this end, open an initial hearing concerning these criteria, well before the next transmission rate case.

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transmission provider for reliability reasons, or to permit point-to-point service requested by a third party.

[163] A useful analogy might be the DSM plan that Gaz Métropolitain now files as part of its annual rate case.

Once the Régie has begun to exercise its powers under s. 73(1), it is to be expected that the most important transmission planning questions would be addressed in those proceedings rather than in future rate cases. In this regard, we suggest that the Régie make clear to Hydro-Québec that it will not authorize major transmission investments under s. 73(1) except insofar as they form part of a satisfactory long-term transmission plan.

Until that time, however, the rate case will remain the only formal proceeding in which transmission planning issues can be addressed. Similarly, the Régie should make clear to Hydro-Québec that it will not authorize major transmission investments in future rate cases except insofar as they form part of a satisfactory long-term transmission plan.

Procedurally speaking, it may be advisable to regard the review of the long-term transmission plan as a preliminary phase of the rate case. Once the long-term issues are resolved, the regulatory treatment of proposed additions for the current year should not be unduly problematic in the context of the rate case itself.

We therefore recommend that the modalities for the approval of additions or modifications to the transmission rate base in future years include, as a preliminary phase to each future rate case, the review of a long-term transmission plan, developed by Hydro-Québec during the intervening period in consultation with the interested public.

# APPENDIX I

## NARUC
## Summer Committee Meetings
## Resolutions
## July 18-21, 1999

### GUIDELINES FOR COST ALLOCATIONS AND AFFILIATE TRANSACTIONS

Attachment To Resolution Regarding Cost Allocation Guidelines
for the Energy Industry[164]

[164] http://www.naruc.org/Resolutions/summer99.htm#Attachment To Resolution Regarding Cost Allocation Guidelines for the Energy Industry "GUIDELINES FOR COST ALLOCATIONS AND AFFILIATE TRANSACTIONS"

**National Association of Regulatory Utility Commissioners**

## GUIDELINES FOR COST ALLOCATIONS AND AFFILIATE TRANSACTIONS
### Attachment To Resolution Regarding Cost Allocation Guidelines for the Energy Industry

**July 1999**

The following Guidelines for Cost Allocations and Affiliate Transactions (Guidelines) are intended to provide guidance to jurisdictional regulatory authorities and regulated utilities and their affiliates in the development of procedures and recording of transactions for services and products between a regulated entity and affiliates. The prevailing premise of these Guidelines is that allocation methods should not result in subsidization of non-regulated services or products by regulated entities unless authorized by the jurisdictional regulatory authority. These Guidelines are not intended to be rules or regulations prescribing how cost allocations and affiliate transactions are to be handled. They are intended to provide a framework for regulated entities and regulatory authorities in the development of their own policies and procedures for cost allocations and affiliated transactions. Variation in regulatory environment may justify different cost allocation methods than those embodied in the Guidelines.

The Guidelines acknowledge and reference the use of several different practices and methods. It is intended that there be latitude in the application of these guidelines, subject to regulatory oversight. The implementation and compliance with these cost allocations and affiliate transaction guidelines, by regulated utilities under the authority of jurisdictional regulatory commissions, is subject to Federal and state law. Each state or Federal regulatory commission may have unique situations and circumstances that govern affiliate transactions, cost allocations, and/or service or product pricing standards. For example, The Public Utility Holding Company Act of 1935 requires registered holding company systems to price "at cost" the sale of goods and services and the undertaking of construction contracts between affiliate companies.

The Guidelines were developed by the NARUC Staff Subcommittee on Accounts in compliance with the Resolution passed on March 3, 1998 entitled "Resolution Regarding Cost Allocation for the Energy Industry" which directed the Staff Subcommittee on Accounts together with the Staff Subcommittees on Strategic Issues and Gas to prepare for NARUC's consideration, "Guidelines for Energy Cost Allocations." In addition, input was requested from other industry parties. Various levels of input were obtained in the development of the Guidelines from the Edison Electric Institute, American Gas Association, Securities and Exchange Commission, the Federal Energy Regulatory Commission, Rural Utilities Service and the National Rural Electric Cooperatives Association as well as staff of various state public utility commissions.

In some instances, non-structural safeguards as contained in these guidelines may not be sufficient to prevent market power problems in strategic markets such as the generation market. Problems arise when a firm has the ability to raise prices above market for a sustained period and/or impede output of a product or service. Such concerns have led some states to develop codes of conduct to govern relationships between the regulated utility and its non-regulated affiliates. Consideration should be given to any "unique" advantages an incumbent utility would have over competitors in an emerging market such as the retail energy market. A code of conduct should be used in conjunction with guidelines on cost allocations and affiliate transactions.

A. DEFINITIONS

1. Affiliates - companies that are related to each other due to common ownership or control.

2. Attestation Engagement - one in which a certified public accountant who is in the practice of public accounting is contracted to issue a written communication that expresses a conclusion about the reliability of a written assertion that is the responsibility of another party.

3. Cost Allocation Manual (CAM) - an indexed compilation and documentation of a company's cost allocation policies and related procedures.

4. Cost Allocations - the methods or ratios used to apportion costs. A cost allocator can be based on the origin of costs, as in the case of cost drivers; cost-causative linkage of an indirect nature; or one or more overall factors (also known as general allocators).

5. Common Costs - costs associated with services or products that are of joint benefit between regulated and non-regulated business units.

6. Cost Driver - a measurable event or quantity which influences the level of costs incurred and which can be directly traced to the origin of the costs themselves.

7. Direct Costs - costs which can be specifically identified with a particular service or product.

8. Fully Allocated costs - the sum of the direct costs plus an appropriate share of indirect costs.

9. Incremental pricing - pricing services or products on a basis of only the additional costs added by their operations while one or more pre-existing services or products support the fixed costs.

10. Indirect Costs - costs that cannot be identified with a particular service or product. This includes but not limited to overhead costs, administrative and general, and taxes.

11. Non-regulated - that which is not subject to regulation by regulatory authorities.

12. Prevailing Market Pricing - a generally accepted market value that can be substantiated by clearly comparable transactions, auction or appraisal.

13. Regulated - that which is subject to regulation by regulatory authorities.

14. Subsidization - the recovery of costs from one class of customers or business unit that are attributable to another.

## B. COST ALLOCATION PRINCIPLES

The following allocation principles should be used whenever products or services are provided between a regulated utility and its non-regulated affiliate or division.

1. To the maximum extent practicable, in consideration of administrative costs, costs should be collected and classified on a direct basis for each asset, service or product provided.

2. The general method for charging indirect costs should be on a fully allocated cost basis. Under appropriate circumstances, regulatory authorities may consider incremental cost, prevailing market pricing or other methods for allocating costs and pricing transactions among affiliates.

3. To the extent possible, all direct and allocated costs between regulated and non-regulated services and products should be traceable on the books of the applicable regulated utility to the applicable Uniform System of Accounts. Documentation should be made available to the appropriate regulatory authority upon request regarding transactions between the regulated utility and its affiliates.

4. The allocation methods should apply to the regulated entity's affiliates in order to prevent subsidization from, and ensure equitable cost sharing among the regulated entity and its affiliates, and vice versa.

5. All costs should be classified to services or products which, by their very nature, are either regulated, non-regulated, or common to both.

6. The primary cost driver of common costs, or a relevant proxy in the absence of a primary cost driver, should be identified and used to allocate the cost between regulated and non-regulated services or products.

7. The indirect costs of each business unit, including the allocated costs of shared services, should be spread to the services or products to which they relate using relevant cost allocators.

## C. COST ALLOCATION MANUAL (NOT TARIFFED)

Each entity that provides both regulated and non-regulated services or products should maintain a cost allocation manual (CAM) or its equivalent and notify the jurisdictional regulatory authorities of the CAM's existence. The determination of what, if any, information should be held confidential should be based on the statutes and rules of the regulatory agency that requires the information. Any entity required to provide notification of a CAM(s) should make arrangements as necessary and appropriate to ensure competitively sensitive information derived therefrom be kept confidential by the regulator. At a minimum, the CAM should contain the following:

1. An organization chart of the holding company, depicting all affiliates, and regulated entities.

2. A description of all assets, services and products provided to and from the regulated entity and each of its affiliates.

3. A description of all assets, services and products provided by the regulated entity to non-affiliates.

4. A description of the cost allocators and methods used by the regulated entity and the cost allocators and methods used by its affiliates related to the regulated services and products provided to the regulated entity.

D. AFFILIATE TRANSACTIONS (NOT TARIFFED)

The affiliate transactions pricing guidelines are based on two assumptions. First, affiliate transactions raise the concern of self-dealing where market forces do not necessarily drive prices. Second, utilities have a natural business incentive to shift costs from non-regulated competitive operations to regulated monopoly operations since recovery is more certain with captive ratepayers. Too much flexibility will lead to subsidization. However, if the affiliate transaction pricing guidelines are too rigid, economic transactions may be discouraged.

The objective of the affiliate transactions' guidelines is to lessen the possibility of subsidization in order to protect monopoly ratepayers and to help establish and preserve competition in the electric generation and the electric and gas supply markets. It provides ample flexibility to accommodate exceptions where the outcome is in the best interest of the utility, its ratepayers and competition. As with any transactions, the burden of proof for any exception from the general rule rests with the proponent of the exception.

1. **Generally, the price for services, products and the use of assets provided by a regulated entity to its non-regulated affiliates should be at the higher of fully allocated costs or prevailing market prices.** Under appropriate circumstances, prices could be based on incremental cost, or other pricing mechanisms as determined by the regulator.

2. **Generally, the price for services, products and the use of assets provided by a non-regulated affiliate to a regulated affiliate should be at the lower of fully allocated cost or prevailing market prices.** Under appropriate circumstances, prices could be based on incremental cost, or other pricing mechanisms as determined by the regulator.

3. **Generally, transfer of a capital asset from the utility to its non-regulated affiliate should be at the greater of prevailing market price or net book value, except as otherwise required by law or regulation. Generally, transfer of assets from an affiliate to the utility should be at the lower of prevailing market price or net book value, except as otherwise required by law or regulation. To determine prevailing market value, an appraisal should be required at certain value thresholds as determined by regulators.**

4. Entities should maintain all information underlying affiliate transactions with the affiliated utility for a minimum of three years, or as required by law or regulation.

E. AUDIT REQUIREMENTS

1. An audit trail should exist with respect to all transactions between the regulated entity and its affiliates that relate to regulated services and products. The regulator should have complete access to all affiliate records necessary to ensure that cost allocations and affiliate transactions are conducted in accordance with the guidelines. Regulators should have complete access to affiliate records, consistent with state statutes, to ensure that the regulator has access to all relevant information necessary to evaluate whether subsidization exists. The auditors, not the audited utilities, should determine what information is relevant for a particular audit objective. Limitations on access would compromise the audit process and impair audit independence.

2. Each regulated entity's cost allocation documentation should be made available to the company's internal auditors for periodic review of the allocation policy and process and to any jurisdictional regulatory authority when appropriate and upon request.

3. Any jurisdictional regulatory authority may request an independent attestation engagement of the CAM. The cost of any independent attestation engagement associated with the CAM, should be shared between regulated and non-regulated operations consistent with the allocation of similar common costs.

4. Any audit of the CAM should not otherwise limit or restrict the authority of state regulatory authorities to have access to the books and records of and audit the operations of jurisdictional utilities.

5. Any entity required to provide access to its books and records should make arrangements as necessary and appropriate to ensure that competitively sensitive information derived therefrom be kept confidential by the regulator.

F. REPORTING REQUIREMENTS

1. The regulated entity should report annually the dollar amount of non-tariffed transactions associated with the provision of each service or product and the use or sale of each asset for the following:

a. Those provided to each non-regulated affiliate.

b. Those received from each non-regulated affiliate.

c. Those provided to non-affiliated entities.

2. Any additional information needed to assure compliance with these Guidelines, such as cost of service data necessary to evaluate subsidization issues, should be provided.

# APPENDIX II

# PROPOSED MODIFICATIONS TO REG. 659

## A. Priority of service for native load

The following proposed modifications to s. 13.6 are described in section 9.1.

| **13.6 Curtailment of Firm Transmission Service:** | **13.6 Réduction du service de transport ferme:** |
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| In the event that a Curtailment on the Transmission Provider's Transmission System, or a portion thereof, is required to maintain reliable operation of such system, Curtailments will be made on a non-discriminatory basis to the transaction(s) that effectively relieve the constraint. ~~If multiple transactions require Curtailment~~ To the extent practicable and consistent with Good Utility Practice, Curtailments will be proportionally allocated among ~~the Transmission Provider's Native Load Customers, Network Customers, and~~ Transmission Customers taking Firm Point-To-Point Transmission Service before being applied to Native Load customers, whether or not they are served under a Network Integration Service Agreement, or to other load-serving entities taking Network Integration Service. All Curtailments will be made on a non-discriminatory basis, however, Non-Firm Point-To-Point Transmission Service shall be subordinate to Firm Transmission Service. When the Transmission Provider determines that an electrical emergency exists on its Transmission System and implements emergency procedures to Curtail Firm Transmission Service, the Transmission Customer shall make the required reductions upon request of the Transmission Provider. However, the Transmission Provider reserves the right to Curtail, in whole or in part, any Firm Transmission Service provided under the Tariff, including service to Native Load, when, in the Transmission Provider's sole discretion, an emergency or other unforeseen condition impairs or degrades the reliability of its Transmission System. The Transmission Provider will notify all affected Transmission Customers in a timely manner of any scheduled Curtailments. | Si une réduction dans le réseau de transport du transporteur, ou une partie de celui-ci, est nécessaire pour maintenir une exploitation fiable du réseau, des réductions seront faites de façon non discriminatoire à la transaction (aux transactions) qui a(ont) pour effet d'alléger les contraintes. ~~Si plusieurs transactions doivent être réduites,~~ Dans la mesure du possible et conformément aux pratiques usuelles des services publics, les réductions s'appliqueront aux clients du réseau intégré et aux clients du service de transport utilisant un service de transport ferme de point à point avant qu'elles ne soient appliquées aux clients de charge locale du transporteur, qu'ils soient desservis par le biais d'un contrat en réseau intégré ou non, ou par d'autres services publics utilisant le Service de transport en réseau intégré. Toutes les réductions seront faites sur une base non discriminatoire; toutefois, le service de transport non ferme de point à point est subordonné au service de transport ferme. Quand le transporteur établit qu'il existe une urgence de nature électrique dans son réseau de transport et met en oeuvre des procédures d'urgence pour réduire le service de transport ferme, le client du service de transport doit faire les réductions requises à la demande du transporteur. Toutefois, le transporteur se réserve le droit de réduire, en tout ou en partie, le service de transport ferme prévu au Contrat du service de transport, incluant le service en réseau intégré, si, à sa seule discrétion, un état d'urgence ou toute autre condition imprévisible compromet ou détériore la fiabilité de son réseau de transport. Le transporteur avisera en temps opportun tous les clients du service de transport touchés des réductions programmées. |

## B. Obligation to expand or upgrade the network

The following proposed modifications to ss. 13.5 and 15.4 are described in section 9.2.

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| **13.5 Transmission Customer Obligations for Facility Additions or Redispatch Costs:** In cases where the Transmission Provider determines that the Transmission System is not capable of providing Firm Point-To-Point Transmission Service without (1) degrading or impairing the reliability of service to Native Load Customers, Network Customers and other Transmission Customers taking Firm Point-To-Point Transmission Service, or (2) interfering with the Transmission Provider's ability to meet prior firm contractual commitments to others, the Transmission Provider will be obligated to expand or upgrade its Transmission System pursuant to the terms of Section 15.4. <u>However, this obligation will be without effect until the date of coming into force of the first regulation under subparagraph 1 of the first paragraph of section 73 of the Act concerning the Régie de l'énergie.</u> The Transmission Customer must agree to compensate the Transmission Provider for any necessary transmission facility additions pursuant to the terms of Section 27. To the extent the Transmission Provider can relieve any system constraint more economically by redispatching the Transmission Provider's resources than through constructing Network Upgrades, it shall do so, provided that the Eligible Customer agrees to compensate the Transmission Provider pursuant to the terms of Section 27. Any redispatch, Network Upgrade or Direct Assignment Facilities costs to be charged to the Transmission Customer under the Tariff will be specified in the Service Agreement prior to initiating service. | **13.5** Obligations du client du service de transport pour les frais reliés à des installations additionnelles ou à une nouvelle répartition: Dans les cas où le transporteur établit que le réseau de transport ne peut pas fournir de service de transport ferme de point à point (1) sans compromettre ou réduire la fiabilité du service pour les clients de charge locale, pour les clients du réseau intégré et pour les autres clients du service de transport utilisant un service de transport ferme de point à point ou (2) sans nuire à la capacité du transporteur de satisfaire à ses engagements contractuels fermes antérieurs envers d'autres, le transporteur sera contraint d'étendre ou d'améliorer son réseau de transport en vertu de l'article 15.4. <u>Cependant, cette obligation sera sans effet jusqu'a la date d'entrée en vigueur du premier règlement pris en vertu du paragraph 1o du premier alinéa d l'article 73 de la *Loi sur la Régie de l'énergie.*</u> Le client du service de transport doit accepter de dédommager le transporteur pour les additions nécessaires aux installations de transport aux termes de l'article 27. Dans la mesure où le transporteur peut alléger une contrainte du réseau de façon plus économique en ayant une nouvelle répartition des ressources du transporteur au lieu de construire des améliorations du réseau, il doit le faire à condition que le client admissible accepte de dédommager le transporteur, conformément à l'article 27. Les frais relatifs à une nouvelle répartition, à l'amélioration du réseau ou à des installations d'attribution particulière qui seront facturés au client du service de transport en vertu du Contrat du service de transport seront précisés dans la convention de service avant le début du service. |

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| **15.4 Obligation to Provide Transmission Service that Requires Expansion or Modification of the Transmission System:** If the Transmission Provider determines that it cannot accommodate a Completed Application for Firm Point-To-Point Transmission Service | **15.4 Obligation de fournir un service de transport exigeant l'expansion ou la modification du réseau de transport:** Si le transporteur établit qu'il ne peut pas répondre favorablement à une demande complète visant un service de transport ferme de point à point à cause |

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| because of insufficient capability on its Transmission System, the Transmission Provider will use due diligence to expand or modify its Transmission System to provide the requested Firm Transmission Service, provided the Transmission Customer agrees to compensate the Transmission Provider for such costs pursuant to the terms of Section 27. The Transmission Provider will conform to Good Utility Practice in determining the need for new facilities and in the design and construction of such facilities. The obligation applies only to those facilities that the Transmission Provider has the right to expand or modify, and this obligation will be without effect until the date of coming into force of the first regulation under subparagraph 1 of the first paragraph of section 73 of the Act concerning the *Régie de l'énergie*. | de l'insuffisance de capacité sur son réseau de transport, le transporteur agira avec diligence pour étendre ou modifier son réseau de transport afin de fournir le service de transport ferme réclamé, à condition que le client du service de transport accepte de payer les coûts s'y rapportant au transporteur, conformément aux conditions de l'article 27. Le transporteur se conformera aux pratiques usuelles des services publics pour décider de la nécessité de nouvelles installations et en ce qui concerne la conception et la construction de ces installations. L'obligation vise seulement les installations que le transporteur est en droit d'étendre ou de modifier, et cette obligation sera sans effet jusqu'a la date d'entrée en vigueur du premier règlement pris en vertu du paragraph 1o du premier alinéa d l'article 73 de la *Loi sur la Régie de l'énergie.* |