

**DEMANDE RELATIVE À LA MODIFICATION DES TARIFS ET CONDITIONS DES  
SERVICES DE TRANSPORT D'HYDRO-QUÉBEC**

**MODALITÉS D'APPLICATION ET D'IMPLANTATION DE  
L'APPROCHE RETENUE PAR LA RÉGIE POUR  
LA TARIFICATION DES ÉCARTS DE RÉCEPTION ET DE LIVRAISON  
ET SUR LE TEXTE DES ANNEXES 4 ET 5 DES TARIFS ET CONDITIONS**

**DOSSIER : R-3669-2008, Phase 2**

**EVIDENCE OF**

**WILLIAM K MARSHALL**

**Imbalance Pricing and Related Issues Relative to FERC Order 890**

**SUBMITTED TO  
THE RÉGIE DE L'ÉNERGIE DU QUÉBEC**

**JUNE 18, 2009**

## TABLE OF CONTENTS

<b>1.</b>	<b>INTRODUCTION.....</b>	<b>1</b>
<b>2.</b>	<b>OBJECTIVES OF THE FERC ORDERS .....</b>	<b>1</b>
	2.1 Non Discriminatory Transmission Access	1
	2.2 Energy and Generator Imbalance Pricing	1
<b>3.</b>	<b>PROXY PRICING FORMULA FOR QUEBEC .....</b>	<b>3</b>
	3.1 Regie Decision of March 5, 2009	3
	3.2 Hydro-Quebec Proposal	3
	3.3 Alternative Proposal	7
	3.4 Recommendation	9
<b>4.</b>	<b>IMPLEMENTATION ISSUES.....</b>	<b>9</b>
	4.1 Service Territory Application	9
	4.2 Maritimes Area Operation	10
	4.3 NBSO Balancing Market	11
	4.4 Imbalance versus Inadvertent	13
	4.5 Requirements for a Quebec Balancing Market	14
<b>5.</b>	<b>RECIPROCITY CONCERNS .....</b>	<b>15</b>
	5.1 FERC Requirements	15
	5.2 Challenge against NB Power Generation	15
	5.3 The risk for non-compliance	16
<b>6.</b>	<b>CONCLUSION .....</b>	<b>16</b>

## Evidence of William K Marshall

### Imbalance Pricing and Related Issues Relative to FERC Order 890

#### 1. INTRODUCTION

William K Marshall was engaged by Brookfield Energy Marketing Inc (BEMI) to review the Hydro Québec R-3669-2008 Phase 2 evidence with regards to FERC Orders 890, 890-A and 890-B (FERC Orders). More specifically, for this report, consideration was to be given to the proposed changes to Schedules 4 and 5 regarding generator and energy imbalances.

#### 2. OBJECTIVES OF THE FERC ORDERS

##### 2.1 Non Discriminatory Transmission Access

The general purpose of Order 890 of the FERC and the follow up re-hearing Orders 890-A and 890-B is “*amending the regulations and the pro forma open access transmission tariff adopted in Order Nos. 888 and 889 to ensure that transmission services are provided on a basis that is just, reasonable and not unduly discriminatory or preferential.*” More specifically the changes in each of the Orders “*are designed to:*

- (1) strengthen the pro forma OATT to ensure that it achieves its original purpose of remedying undue discrimination;*
- (2) provide greater specificity to reduce opportunities for undue discrimination and facilitate the Commission’s enforcement; and*
- (3) increase transparency in the rule applicable to planning and use of the transmission system.”*

##### 2.2 Energy and Generator Imbalance Pricing

FERC’s objective regarding imbalance pricing is to eliminate the variability and confusion that currently exists in the industry while maintaining an incentive for balanced schedules that will preserve reliable operation of the interconnected power systems in a fair and not unduly discriminatory manner. Note the following passages from Order 890.

*“In the NOPR, the Commission noted that the existing energy imbalance charges described in Order No. 2003 are the subject of significant concern and confusion in the industry. The Commission expressed concern about the variety of different methodologies used for determining imbalance charges and whether the level of the charges provides the proper incentive to keep schedules accurate without being excessive. The Commission therefore proposed to modify the current pro forma OATT Schedule 4 treatment of energy imbalances and to adopt a separate pro forma OATT schedule for the treatment of generator imbalances”.* (Order 890, P. 634)

*“The Commission proposed to create new energy and generator imbalance schedules based on the following three principles: (1) the charges must be based on incremental cost or some multiple thereof; (2) the charges must provide an incentive for accurate scheduling, such as by increasing the percentage of the adder above (and below) incremental cost as the deviations become larger; and (3) the provisions must account for the special circumstances presented by intermittent generators and their limited ability to precisely forecast or control generation levels,*

*such as waiving the more punitive adders associated with higher deviations*". (Order 890, P. 635 - Underlines added)

Through the FERC Orders a tiered approach to imbalance pricing based on the above three principles has been adopted for both Energy Imbalance (Schedule 4 in the *pro forma* OATT which is Schedule 5 in the Hydro-Quebec tariff) and Generator Imbalance (a new Schedule 9 in the *pro forma* OATT which is included as Schedule 4 in the Hydro-Quebec tariff).

*"Specifically, imbalances of less than or equal to 1.5 percent of the scheduled energy (or two megawatts, whichever is larger) will be netted on a monthly basis and settled financially at 100 percent of incremental or decremental cost at the end of each month. Imbalances between 1.5 and 7.5 percent of the scheduled amounts (or two to ten megawatts, whichever is larger) will be settled financially at 90 percent of the transmission provider's system decremental cost for overscheduling imbalances that require the transmission provider to decrease generation or 110 percent of the incremental cost for underscheduling imbalances that require increased generation in the control area. Imbalances greater than 7.5 percent of the scheduled amounts (or 10 megawatts, whichever is larger) will be settled at 75 percent of the system decremental cost for overscheduling imbalances or 125 percent of the incremental cost for underscheduling imbalances"* (Order 890, P 664)

Regarding the definition of "*incremental and decremental costs*" the final ruling of FERC is that energy imbalance pricing for both load and generator imbalances is to be based on the "*incremental cost of the last 10 MW dispatched for any purpose, e.g., to serve native load, correct imbalances, or to make off system sales.*" Furthermore, there is to be no distinction between incremental and decremental costs. As stated in the *pro forma* schedules for both energy and generator imbalances

*"For purposes of this Schedule, incremental cost and decremental cost represent the Transmission Provider's actual average hourly cost of the last 10 MW dispatched for any purpose, e.g., to supply the Transmission Provider's Native Load Customers, correct imbalances, or make off-system sales, based on the replacement cost of fuel, unit heat rates, start-up costs (including any commitment and redispatch costs), incremental operation and maintenance costs, and purchased and interchange power costs and taxes, as applicable".* (*pro forma* OATT, Schedule 4 and Schedule 9)

While FERC does not specifically include opportunity costs or the use of market proxy pricing in its *pro forma* definition of incremental cost it is prepared to consider their use on a case by case basis.

*"Several entities complain that the Commission's definition of incremental cost does not properly allow for recovery of opportunity costs. The determination and calculation of opportunity costs associated with providing imbalance service will vary based on the circumstances of the transmission provider and, as such, we do not believe that it is appropriate to amend the definition of incremental cost in the pro forma OATT to address opportunity costs. We will therefore continue to consider proposals to include recovery of legitimate and verifiable opportunity costs on a case-by-case basis consistent with Commission precedent. Such proposals must clearly explain how opportunity costs would be determined and demonstrate that the recovery of opportunity costs would not lead to over-recovery of costs".* (Order 890-A, P. 311. Underlines added).

*“We do not believe it appropriate to require transmission providers to use market proxy pricing to calculate incremental costs in the pro forma OATT. The feasibility of using market proxies must be considered on a case-by-case basis, given the characteristics of each market. If proposed, the proxy price must represent a valid alternative to the incremental cost calculation, reflecting competitive, transparent and liquid conditions similar to those that would exist in the seller’s market”. (Order 890, P.692. Underlines added).*

This allowed use of a market proxy price and opportunity costs is important to a hydro dominated market like Quebec that both exports and imports power to adjacent markets. If it was not allowed the incremental cost of the last 10 MW in Quebec based on the *pro forma* definition would often be zero as there are no fuel costs, heat rates or start up costs to consider. This is not reasonable as an incremental cost of zero does not reflect the opportunity value of the balancing energy. It would encourage “leaning” on the system which is counter to FERC’s objective “*to reduce opportunities for undue discrimination*”.

### **3. PROXY PRICING FORMULA FOR QUEBEC**

#### **3.1 Regie Decision of March 5, 2009**

The Regie in its March 5, 2009 Decision D-2009-015 takes a similar position to FERC regarding the use of a market proxy price for imbalance. It ordered that HQT develop a reference price for energy imbalance that is based on the hourly market prices in adjacent areas. As a predominantly hydro system that trades large quantities of energy to adjacent markets the incremental cost (or value) of the last 10 MW dispatched by Hydro-Quebec is either the opportunity cost value of that energy in the adjacent market or the purchase price of energy from an adjacent market. As such using a market proxy price from an adjacent market is a reasonable way to price imbalances in Quebec. The following extract from Decision D-2009-015 (p. 111) is clear on establishing a formula that is based on hourly market prices in adjacent areas:

*« La Régie considère que l'utilisation d'un prix de marché satisfait l'objectif d'offrir une juste compensation au fournisseur du service, sans créer d'opportunités d'arbitrage pour les clients du Transporteur.*

***La Régie est d'avis que le prix de référence doit refléter les prix horaires sur les marchés limitrophes, ajustée des coûts de transport. »***

#### **3.2 Hydro-Quebec Proposal**

Hydro-Quebec filed its evidence May 29 and proposed to apply the tiered imbalance structure set out in the FERC Orders. It includes deviation bands from the scheduled transaction of up to 1.5% (min 2 MW) for Band 1, between 1.5% and 7.5% (or over 2 to 10 MW) for Band 2 and over 7.5% for Band 3. Settlement for each band is also consistent with the FERC pro forma by applying no adder to incremental cost for Band 1, a +/- 10% adder to the incremental cost for Band 2, a +/- 25% adder for Band 3, and exempting intermittent resources from Band 3.

Hydro-Quebec proposes to determine incremental and decremental prices using proxy market prices from Ontario (using the HOEP price), from New York (using the Zone M price) and from ISO-New England (using the Phase 2 price). The formulae proposed to get incremental and decremental prices from each market are as follows:

NY incremental price = NY Zone M less 0.16 \$/MWh less HQT hourly tariff (NY Inc)  
NY decremental price = NY Zone M plus 4.50 \$/MWh (NY Dec)  
NE Incremental price = ISO-NE (Ph2) less 6.00 \$/MWh less HQT hourly tariff (NE Inc)  
NE decremental price = ISO-NE (Phase II) plus 8.00 \$/MWh (NE Dec)  
Ontario Incremental price = HOEP (ON Inc)  
Ontario decremental price = HOEP plus 4.00 or 5.00 \$Ca/MWh (off-peak or on-peak)  
(ON Dec)

The incremental and decremental prices for each band prior to application of a +/- 10% adder for Band 2 and a +/-25% adder for Band 3 are proposed as follows:

Band 1 Incremental price = highest price of NY Inc, NE inc or ON Inc  
Band 1 Decremental price = lowest price of NY Inc, NE inc or ON Inc  
Band 2 Incremental price = highest price of NY Inc, NE inc, ON Inc or \$Ca100/MWh  
Band 2 Decremental price = lowest price of NY Inc, NE inc, ON Inc or \$Ca 25/MWh  
Band 3 Incremental price = highest price of NY Inc, NE inc, ON Inc or \$Ca100/MWh  
Band 3 Decremental price = \$Ca 0/MWh

These formulae proposed by Hydro-Quebec to determine incremental cost and decremental cost applicable for each deviation band is not compatible with the FERC Orders for several reasons as discussed below:

1. Hydro-Quebec do not propose to use one formula to calculate a proxy incremental cost that would be used to settle both positive and negative deviations, that is one cost to be both for incremental settlement and decremental settlement. Rather they propose to use two completely separate formulae, one for incremental cost and one for decremental cost. While FERC allow consideration of a market proxy as we discussed above it is clearly to determine a “proxy price” (not prices) that “must represent a valid alternative to the incremental cost calculation” which produces one cost to be used for both incremental cost and decremental cost.
2. It is not just that Hydro-Quebec proposes different prices for incremental cost and decremental cost. They actually propose different prices for decremental cost at each of Band 1, 2 and 3 and a different price for incremental cost at Band 1 than at Bands 2 and 3. The same cost is only proposed to be used for incremental costs at Bands 2 and 3. For the same reasons discussed above this is not comparable to the requirements in the FERC Orders. Actually given the magnitude of the differences in band prices one could argue that the proposal is unduly discriminatory.
3. Hydro-Quebec proposes to add a fixed price floor of \$100/MWh to incremental cost for negative deviations in both Bands 2 and 3, a fixed price maximum of \$25/MWh to decremental cost for positive deviations in Band 2 and \$0/MWh payment for positive deviations in Band 3. This effectively sets the price owing for deficient energy provided to the Transmission Customer equal to \$100/MWh or higher and the price paid to the Transmission Customer for surplus energy provided equal to \$25/MWh or less for Band 2

and equal to \$0/MWh for Band 3. This is counter to the FERC Orders because it effectively adds a penalty price even for Band 2 that is as much as +/-60% or more. It is counter to FERC's intention to use incremental cost plus the deviation band adders of +/-10% and +/-25%. Note FERC's intention regarding penalty prices below

*"The Commission recognizes the need to provide transmission customers with the appropriate incentives not to intentionally dump power on the system or lean on other generation. We do not believe, however, that separate penalties for intentional deviations need to be generically imposed in the pro forma OATT. The tiered imbalance penalties adopted in this Final Rule generally provide a sufficient incentive not to engage in such behavior."* (Order 890, P. 676. Underlines added)

FERC recognizes the need to include all cost components in the determination of incremental cost but there is no room for added costs that are not actually incurred as stated below.

*"We believe including charges for unit commitment costs (e.g., start-up and minimum load costs) and O&M costs is necessary to ensure that both energy and generation imbalance charges reflect the full incremental costs incurred by the transmission provider. We emphasize, however, that such costs should only be the additional costs incurred by the transmission provider due to the imbalance".* (Order 890, P. 689. Underlines added)

These excessive penalty charges are not just greater than actual incurred costs due to imbalance and thus counter to the FERC Orders. They can also be argued to be unduly discriminatory against third party Transmission Customers and preferential to Hydro-Quebec's Production and Distribution divisions. HQP is proposed not to be subject to imbalances because it will be supplying the balancing services and HQD is only to be subject to the imbalance charges for sale of its surplus energy. Its supply to native load is to be exempt.

The formulae proposed by Hydro-Quebec for imbalance charges is questionable for other reasons as well. This can be illustrated by reviewing the results of the application of the Hydro-Quebec formulae to some real historic data.

Examples of prices determined by the Hydro-Quebec formulae are given in Table 1 below. They cover a range of operating situations –a summer peak in the export markets when exports are high (Case 1), a winter peak in Quebec when Quebec is importing (Case 2), an April day with export and import (Case 3) and an off peak period with import and export (Case 4). Details regarding data and the determination of these prices are provided in Appendix A and in Appendix C.

**Table 1  
Hydro-Quebec Proposal Imbalance Rates**

Time/Band	Incremental Cost			Decremental Cost		
	Market	MW Flow*	\$/MWh	Market	MW Flow*	\$/MWh
<b>July 8/08 Hr 11</b>						
Band 1	ISO-NE	-1376	271.79	NYISO	-1156	153.42
Band 2	ISO-NE	-1376	298.97	N/A	N/A	25.00
Band 3	ISO-NE	-1376	339.74	N/A	N/A	0.00
<b>Jan 16/09 Hr 8</b>						
Band 1	Ontario	348	395.21	NYISO	953	125.64
Band 2	Ontario	348	434.73	N/A	N/A	25.00
Band 3	Ontario	348	494.01	N/A	N/A	0.00
<b>April 16/09 Hr 16</b>						
Band 1	Ontario	184	27.98	NYISO	-973	30.39
Band 2	N/A	N/A	100.00	N/A	N/A	25.00
Band 3	N/A	N/A	100.00	N/A	N/A	0.00
<b>July 29/08 Hr 6</b>						
Band 1	NYISO	555	67.69	Ontario	237	36.36
Band 2	N/A	N/A	100.00	N/A	N/A	25.00
Band 3	N/A	N/A	100.00	N/A	N/A	0.00

\*: Positive means a net import into Québec.

Note: N/A for the market means that the price come from the fixed price component of the proposed formula, not from a neighboring market and therefore, there is no nets flows available.

The resulting Incremental Price that would apply on April 16 for negative imbalances is \$Cdn 27.98/MWh while the resulting Decremental Price that would apply for positive imbalances is \$Cdn 30.39/MWh. This result would have Hydro-Quebec paying for the surplus energy from a long schedule at a higher price than they would charge for the deficient energy in a short schedule.

In Phase 1 Hydro-Quebec argued that HQP should not be subject to imbalance charges because they are providing the balance service. This is not quite correct. Consider a case where BEMI are short on their schedule by 10 MW and NL Hydro (or their agent) are long on their schedule by 10 MW. There would be no net imbalance for HQP to offset yet HQT propose to charge imbalance to both BEMI and NL Hydro. Because the incremental and decremental rates are different with extreme variations this would amount to a windfall gain to Hydro-Quebec when no service was provided. A single fair balancing price is required and in addition the ability to trade imbalances so that charges are only for the net total imbalance should be implemented.

### 3.3 Alternative Proposal

As discussed above in Sections 2.1 and 3.1 the use of a market proxy price is valid for Quebec and has been recognized by the Régie in its decision D-2009-015. Furthermore, it is the opinion of this writer, that without implementation of an independently administered balancing market, it is the only mechanism that could be applied in Quebec to be comparable with the FERC Orders. At issue is not the use of the tiered band structure as proposed by Hydro-Quebec. It is simply the determination of incremental and decremental costs that needs consideration and much of the proposal presented by Hydro-Quebec is useful in determining a mechanism that will be comparable with the FERC requirements.

Firstly, there can not be two prices in the same hour (one for incremental cost and one for decremental cost) so a mechanism is required to decide which formula approach should be used. The following is proposed:

- If Hydro-Quebec is a net importer of energy in the hour of concern<sup>1</sup> it is acting as a purchaser so the markets from which it is purchasing determine its incremental cost. Unlike the Hydro-Quebec proposal the last 10 MW would not come from the lowest priced market. Rather, Hydro-Quebec would purchase as much lower priced energy as possible and the last 10 MW would come from the highest priced market from which it is importing plus delivery costs to get it to Quebec. Even if this import is for a wheel through to a different export market it is still the cost to Hydro-Quebec of the last 10 MW dispatched. Recall the FERC definition for incremental cost which is the “*actual average hourly cost of the last 10 MW dispatched for any purpose, e.g., to supply the Transmission Provider’s Native Load Customers, correct imbalances, or make off-system sales.*” (Underlines added for emphasis). If a Transmission Customer is long and provides surplus energy Hydro-Quebec pays the same price as it did to purchase its last 10 MW. If the Transmission Customer is short then it pays the same price as the export market from which Hydro-Quebec obtained the energy and Hydro-Quebec is kept whole.
- If Hydro-Quebec is a net exporter of energy in the hour of concern then it is acting as a seller so the markets to which it is exporting determine its opportunity cost value. Again, unlike the Hydro-Quebec proposal the last 10 MW would not come from the highest priced market. Rather, Hydro-Quebec would sell as much energy as possible to the highest priced markets and the last 10 MW dispatched would be destined for the lowest priced market to which it is exporting. By using this lowest priced export market as a proxy we can determine the net back opportunity cost for energy in Quebec. If a Transmission Customer is short energy Hydro-Quebec supplies it at the same opportunity value that it is making for its last 10 MW of off system sales. If the Transmission Customer is long and supplies surplus energy to Hydro-Quebec it gets paid the same value that Hydro-Quebec would have received. Hydro-Quebec does not lose money and gets to keep its energy for use in another hour.

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<sup>1</sup> This can be determined from the Hydro-Quebec OASIS by summing all the flows on the interconnections to HQT. As exports are negative and imports are positive a net positive total determines that HQ is a net importer. Conversely, a net negative total indicates that HQ is a net exporter. In doing the calculation an adjustment needs to be made for the Labrador interface. Only the energy scheduled by NLH or its agent is to be considered as an import. The remainder of the flow is a designated resource for HQD and is to be considered as generation internal to Quebec.

Once an incremental cost is determined using the above method it would be subject to the tiered structure with adders of +/-10% for Band 2 and +/-25% for Band 3.

Our proposed formulae was applied to the same historical hourly price data as used above with the Hydro-Quebec proposed formulae in Section 3.2. The results are provided in Table 2 and the details of the calculations are provided in Appendix A. Our proposed formula requires information regarding the export/import status of Hydro-Quebec which is summarized for the four cases as follows:

- Case 1 - Quebec is exporting to the three proxy markets (Ont, NY and NE)
- Case 2 - Quebec is importing from the three markets
- Case 3 - Quebec is both importing and exporting but in total is a net exporter
- Case 4 - Quebec is both importing and exporting but in total is a net importer

**Table 2  
Alternative Proposal Imbalance Rates**

Time/Band	Incremental Cost			Decremental Cost		
	Market	MW Flow*	\$/MWh	Market	MW Flow*	\$/MWh
<b>July 8/08 Hr 11</b>						
Band 1	NYISO	-1156	140.49	NYISO	-1156	140.49
Band 2	NYISO	-1156	154.54	NYISO	-1156	126.44
Band 3	NYISO	-1156	175.61	NYISO	-1156	105.37
<b>Jan 16/09 Hr 8</b>						
Band 1	Ontario	348	408.47	Ontario	348	408.47
Band 2	Ontario	348	449.32	Ontario	348	367.62
Band 3	Ontario	348	510.59	Ontario	348	306.35
<b>April 16/09 Hr 16</b>						
Band 1	NYISO	-973	16.50	NYISO	-973	16.50
Band 2	NYISO	-973	18.15	NYISO	-973	14.85
Band 3	NYISO	-973	20.63	NYISO	-973	12.38
<b>July 29/08 Hr 6</b>						
Band 1	NYISO	555	80.73	NYISO	555	80.73
Band 2	NYISO	555	88.80	NYISO	555	72.66
Band 3	NYISO	555	100.91	NYISO	555	60.55

\*: Positive means a net import into Québec.

The above historical analysis utilizes the HOEP price as proposed by Hydro-Quebec and the LAW interconnection as it is the most flexible and least constrained at this time. When the new HVDC interconnection is operational the actual hourly price at that interconnection point in Ontario should be used.

### **3.4 Recommendation**

It is recommended that the Alternative proposal detailed in 3.3 above and in Appendix A be implemented for both energy and generator imbalance. To do so requires changes to the wording proposed by Hydro-Quebec for both Schedules 4 and 5. Wording to accommodate this end is provided in Appendix B and it is recommended that it be approved by the Regie.

## **4. IMPLEMENTATION ISSUES**

### **4.1 Service Territory Application**

In the Hydro-Quebec proposal there is reference to different terms that connote different service territories which is at times confusing. This also can have an influence over application of imbalance charges under the tariff so it is worth clarifying.

The terms of interest and their connection with service territory are as follows:

1. Quebec Interconnection – This is the total power system that includes all elements synchronized together covering the territory of Quebec. It also includes portions of Labrador and at times radial loads and generators in adjoining provinces and states that are synchronized to the Hydro-Quebec system.
2. Reliability Coordinator (RC) – This is a North American Electric Reliability Corporation (NERC) term that makes Hydro-Quebec, as the Reliability Coordinator, responsible for the reliable operation of the bulk power system within the Quebec Interconnection. Note that it is our understanding that Newfoundland and Labrador are not a member of NERC nor have any agreement with NERC but NLHydro through its interconnection agreement with Hydro-Quebec would be subject to NERC and Regie reliability standards.
3. Control Area – This is an old NERC term that has been replaced with Balancing Area for NERC purposes. However it is still used by FERC as a carryover from pre Balancing Area times so in FERC’s eyes control area should be interpreted as balancing area. Control Area is also still used by NPCC and is also shortened to Area and refers to the five areas of NPCC, namely, Quebec, Ontario, Maritimes, New York and New England.
4. Balancing Area – This is a NERC term for the synchronized area within which all generation and load must be balanced according to NERC balancing standards. It is our understanding that the Hydro-Quebec Balancing Area encompasses the entire Quebec Interconnection today but in future a sub portion of the interconnection could also be a separate balancing area.
5. Transmission Provider area – This is the footprint of the transmission system over which transmission service is provided. In Quebec it is the territory shown on the Hydro-Quebec OASIS. It does not include transmission systems owned by others unless there is an agreement between Hydro-Quebec and the other transmission owner that would enable the third party system to be included under the HQ OATT. Obviously such an agreement and its inclusion in the HQ OATT would require approval of the Regie. At this point in time

transmission systems in Quebec that are not in the HQT area include the Alcan system and the Énergie La Lièvre system.

6. Transmission Owner area – This is the area covered by the transmission system of a particular owner. In Quebec it includes the Alcan area, the Énergie La Lièvre area and the HQT area.

The key point of this section is that the Hydro-Quebec OATT is for service on the HQT system which is only a subset of the Quebec Interconnection, the RC footprint, the HQ Control Area, and the HQ Balancing area. Similar differences exist in the Maritimes Area so an explanation of its operation regarding energy imbalance is offered for consideration of the Regie.

#### **4.2 Maritimes Area Operation**

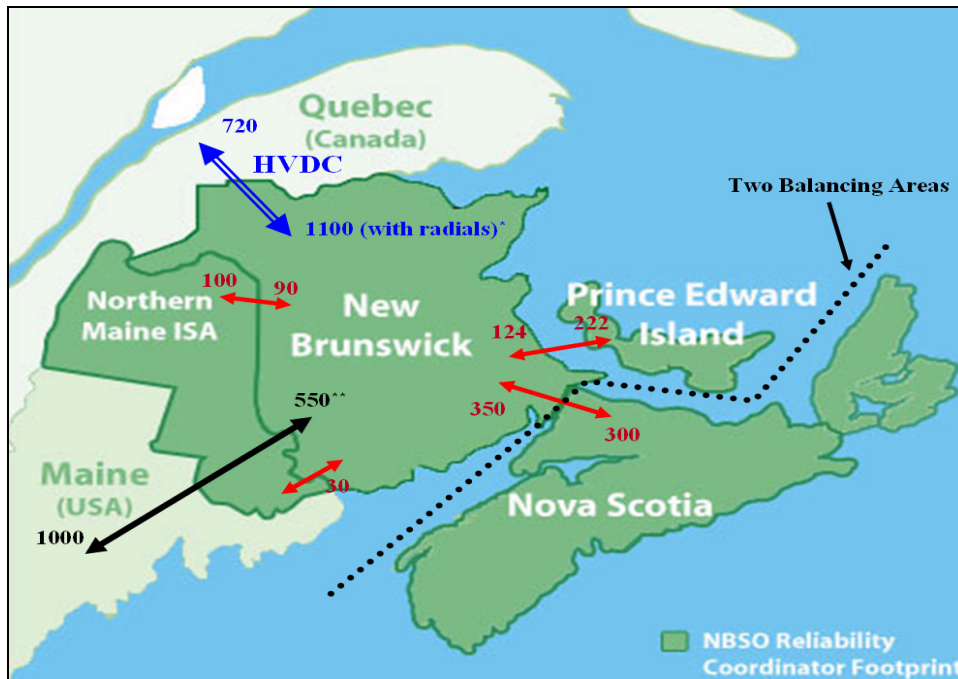
The Maritimes Area is comprised of the power systems in Nova Scotia (NS), New Brunswick (NB), Prince Edward Island (PEI) and Northern Maine (NMe). The NB system is the hub with each of NS, PEI and NMe connected radial from NB. In addition NB has significant interconnections to both Quebec and New England as shown in Figure 1. The New Brunswick System Operator (NBSO), an independent NB government statutory corporation, operates the NB system and is the NERC recognized Reliability Coordinator for the entire Maritimes Area.

The Area encompasses the transmission systems of six different transmission owners – NS Power in NS, NB Power and WPS Generation Canada in NB, Maritime Electric in PEI and Maine Public Service and Eastern Maine Electric Cooperative in NMe. The NB Power and WPS transmission provide service under a joint tariff that is independently administered by NBSO. Each of the other transmission systems have separate tariffs under separate regulators. All are based on the FERC *pro forma* OATT.

There are two balancing areas as shown on Figure 1; one for Nova Scotia and one for NB, PEI and NMe. Schedule imbalances between NB and NS are handled as inadvertent up to a specified amount (usually about 16 MW) and as energy imbalance under the NBSO OATT above that amount. Schedule imbalances with both Quebec and New England are handled as inadvertent and paid back in kind. This is a continuation of the historic practice within the Maritimes and between these NBCC areas.

Schedules between NB and PEI and between NB and NMe (except for EMEC who utilize network service) utilize point-to-point service and imbalances are handled as energy imbalance under the NBSO OATT. This has not historically been the case. Prior to 2000 with the implementation of the Northern Maine Market under the Northern Maine Independent Administrator (NMISA) the interface to Maine Public Service was handled as inadvertent. With the market implementation NMISA requested and negotiated with NB Power to have the interface settled by one hourly imbalance price. This was done and then subsequently replaced by imbalance under the NBSO balancing energy market. There is no hourly market in PEI but similar to NMe the historically negotiated settlement method was replaced by the NBSO balancing market in 2004.

**Figure 1  
Maritimes Area**



### 4.3 NBSO Balancing Market

The New Brunswick Electricity market is a physical bilateral market with a balancing and re-dispatch market based on the NBSO OATT that is compatible with the FERC Order 888 *pro forma* tariff. NBSO is currently in the process of updating the OATT to establish compatibility with FERC's more recent Order 890, 890-A and 890-B, which improve the basic components of the Order 888 *Pro Forma* tariff.

Load-serving entities contract with suppliers for the energy and capacity necessary to serve their load and maintain system reliability. Similar to Quebec where HQD is the dominant supplier of local load, the dominant supplier in New Brunswick is NB Power Distribution and Customer Service Corporation (NB Disco) who supply 99% of the native load. Also similar to Quebec the vast majority of the generation supply for NB Disco is through heritage contracts with NB Power Generation Corporation and NB Power Nuclear Corporation (Collectively NB Genco).

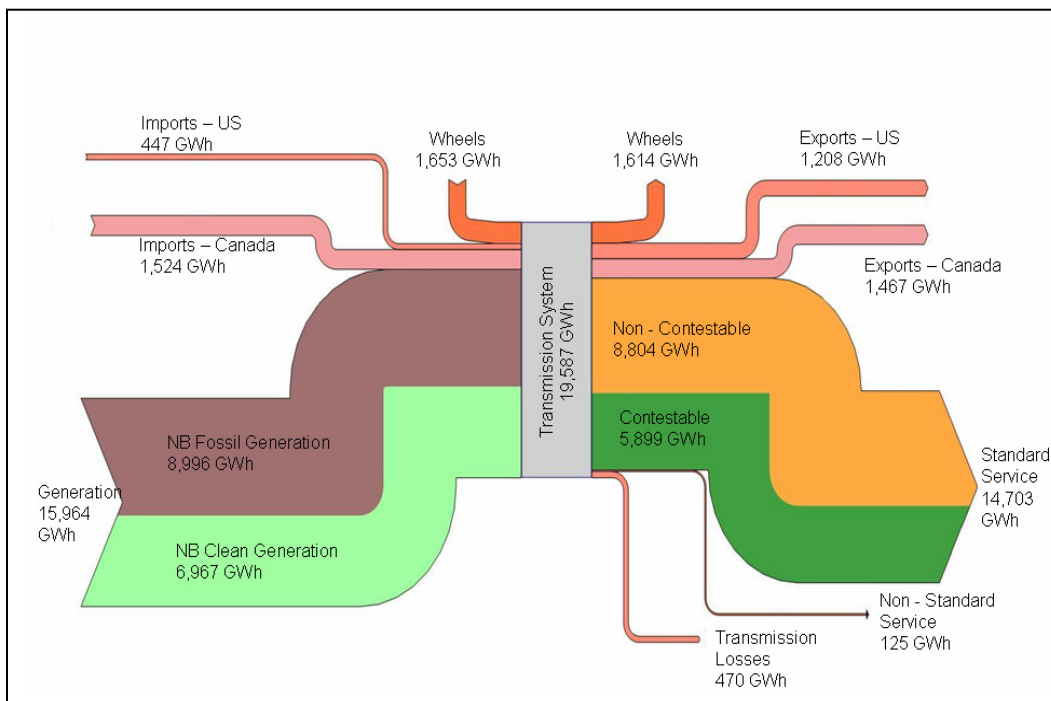
NB Disco, other suppliers and point-to-point Transmission Customers are required to provide balanced schedules to NBSO for each hour on a day ahead basis. These transactions are scheduled with NBSO as the independent system operator responsible for the Open Access Transmission Tariff and Market Rules governing the use of the transmission system in New Brunswick. In addition all generators are required to submit price quantity pairs (P-Q pairs) by which their generator can be dispatched. Changes to balanced schedules and P-Q pairs can be made up to 30 minutes before the hour of operation. NBSO then performs an optimized security-constrained economic dispatch of generation and loads using the P-Q pairs.

The final hourly marginal cost (FMHC) resulting from the dispatch is used to settle all deviations from schedules whether long or short. Unlike Quebec this includes load forecast errors of NB Disco, scheduling errors of each generating station (including NB Genco generators), all schedule imbalances of point-to-point transmission reservations including wheel throughs and wheel outs, and external resources dispatched to wheel in for native load. Trading of imbalances is available for facilities contracted through the same market participant. This enables NB Disco and NB Genco to net out imbalances to reduce the amount of money changing hands. There are no +/-10% or +/-25% adders so there is no penalty money for NBSO. Essentially all short participants pay the long participants for the energy that they take from the system at the FMHC.

Because Northern Maine, Nova Scotia, and Prince Edward Island are only connected electrically to the remainder of North America via New Brunswick, the New Brunswick market, in many ways, serves as a wholesale market for the region. As stated earlier in section 4.2, imbalances for NME and PEI are settled through the NB balancing market. Also some generators in these markets participate in bidding P-Q pairs for the NBSO dispatch. HQP, NS Power and market participants in New England also are eligible to bid P-Q pairs as an externally dispatchable facility.

The best source of information on the evolving development of the NB electricity market is the NBSO document “**State of the Market Report - April 2007 to March 2008**” (“NBSO Market Report”). It provides details on the nature of the market, the volume of transactions, the number of various types of market participants and points towards increasing future market activity. Figure 2 came from this report and illustrates the source and destination of all energy transacted through NBSO for the fiscal year 2007/08. Of the 19,587 GWh scheduled, about 18% came from sources outside New Brunswick and about 22% was delivered to parties who were not NB Power Standard Service customers.

**Figure 2  
NBSO Bilateral Market Transactions for 2007/08**



The level of growing activity in the NB bilateral market is also indicated by the number of registered facilities and the control of those facilities. When the market first opened in October 2004, there were 27 registered in province facilities all controlled by the NB Power group and one external dispatchable facility (“EDF”). At that time NB Power Generation was the only market participant submitting P-Q pair data. As of March 2008 there were 35 registered facilities of which 6 are non NB Power affiliated and 7 are EDFs.

Development of the hourly re-dispatch balancing market is crucial to supply efficient competitively priced energy to settle imbalances in bilateral transactions in a fair and not unduly discriminatory manner. The continued introduction of additional market participants in the re-dispatch market and increased volume of bidding and dispatch of multiple players will keep competitive pressures on bidding. This will increase balancing capability for anticipated wind generation growth, reduce the dependency on market monitoring and reduce the burden on NB Power Generation as the sole supplier of balancing energy.

In summary, while there have been no exits from standard service there is marginal but growing activity in the re-dispatch balancing market. This is an important component for the efficient development of the Energy Hub. NBSO has gained valuable experience and has demonstrated its ability to operate both a bilateral market and a balancing energy re-dispatch market that supports the Maritimes Area.

Finally, it is important to note that the design of the NB physical bilateral market is more resistant to market power abuse than other designs such as pure pool arrangements. This is especially appropriate for the Maritimes context with such a small number of active wholesale market suppliers. It would also be appropriate for Quebec because of the dominance of HQP. In a bilateral market pricing decisions are made over longer time frames and there is less ability to influence price than real time markets. The majority of market stakeholders support this view and they see no reason to move away from the current bilateral design, albeit they support development of a more efficient re-dispatch market.

#### **4.4 Imbalance versus Inadvertent**

Not all settlement of imbalances at interconnection points are handled via imbalance charges through a tariff. Usually imbalances between balancing areas are handled as inadvertent energy and some settlement between different transmission systems are also handled as inadvertent.

Inadvertent energy is essentially settled similar to Band 1 but without the financial payout at the end of the month. The amount of deviations from schedules are recorded and paid back with energy at a latter time that is usually scheduled between the respective operators.

FERC recognize the historic treatment of inadvertent and did not impose through 890 that it should be changed to settlement via energy imbalance through the *pro forma* OATT.

*The Commission proposed in the NOPR to continue to allow inadvertent energy to be treated differently from energy and generator imbalances, explaining that these two types of service are not comparable. The Commission noted that, given the nature of inadvertent energy and historical practices, transmission providers pay back inadvertent energy imbalances and that*

*the Commission has accepted this practice as just and reasonable. (Order 890, P.693. Underlines added))*

*Historically, transmission providers have paid back inadvertent interchange imbalances in kind, which has not, as a general matter, proven to be problematic. Our primary concern with respect to inadvertent energy is to avoid incentives that could degrade reliability. (Order 890, P. 703)*

*Our primary concern with respect to inadvertent energy continues to be avoidance of incentives that could degrade reliability. To date, the return-in-kind approach to inadvertent energy has proven adequate as a general matter. Petitioners do not present any evidence that in-kind payment of inadvertent energy is no longer sufficient to maintain reliability or allows certain entities to lean on the grid to the detriment of other entities. We disagree that this treatment of inadvertent energy is inconsistent with Order No. 2000. There the Commission required both control area operators and transmission customers within an RTO to clear imbalances through a real-time balancing market. In the absence of a real-time balancing market, we continue to believe it is appropriate for transmission providers operating under the pro forma OATT to treat inadvertent interchange differently than customer imbalances. (Order 890-A, P. 318. Underlines added))*

Historically all energy deviations from schedule at the Maclaren interconnection between HQT and Énergie La Lièvre have been handled as inadvertent. In the March 5 decision, the Regie has indicated that BEMI may be subject to imbalances, as the case may be, “*lorsque le Transporteur est en mesure de déterminer qu’elle est responsable de l’écart observé*” (D-2009-015, p. 107). Given the potential for imbalances, the onus is on the Regie to establish a fair market based mechanism to handle same. Ideally it should be a real-time balancing market as suggested by FERC and this should be sought in the future. In the interim fair treatment of BEMI and other transmission customers require that the proxy market balancing alternative proposed in this paper be adopted by the Regie.

#### **4.5 Requirements for a Quebec Balancing Market**

Quebec could implement a balancing market similar to NBSO. Essentially Quebec is supplied by a bilateral market today with two dominate players HQP and HQD. But Quebec also has numerous large interconnections that would enable a significant amount of activity in a redispatch balancing market. In addition to the Ontario, NY and NE markets with their many market participants there are the BEMI, Alcan and NLH facilities that would participate.

While HQP is very large relative to other potential players it would not have market power contrary to some expectations. Because of its in province bilateral obligations a major portion of its resources are allocated. Competition in a redispatch balancing market only occurs at the margin and there are enough marginal resources to provide efficient competition.

Such a market has many benefits. It would not only meet the reciprocity obligations but would signal to the region that Quebec is open for business in a way that would encourage new independent power developments. It would increase the utilization of the HQT system for wheeling and as such increase transmission revenues for the benefit of all transmission customers in particular HQD.

## 5. RECIPROCITY CONCERNS

### 5.1 FERC Requirements

In our previous paper **Order 890 Requirements For a Coordinated, Open and Transparent Transmission Planning Process** FERC's policy regarding reciprocity was explained in detail. In summary it requires any non public utility (including foreign utilities like Hydro-Quebec) that makes use of open access transmission service (as does Hydro-Quebec in all its adjoining market areas) to provide reciprocal transmission access under comparable conditions. This reciprocity condition applies to all aspects of the *pro forma* OATT including energy and generator imbalance provisions as stated by FERC as follows.

*“As such, the Commission will modify the current pro forma OATT Schedule 4 treatment of energy imbalances and adopt a new separate pro forma OATT Schedule 9 for the treatment of generator imbalances, each based on the tiered structure described above. To the extent a transmission provider wishes to deviate from these revised pro forma provisions, it may demonstrate in an FPA section 205 proceeding that the proposed changes are consistent with or superior to the pro forma OATT as modified by this Final Rule. However, we note that proposed alternative provisions must comply with the three imbalance charge principles addressed in the NOPR and adopted in this Final Rule and be consistent with or superior to the specific imbalance charges set forth in the pro forma OATT.”* (Order 890, P. 668. Underlines added)

The above statement by FERC is clear. It is not just the “*tiered structure*” that is required but also the “*specific imbalance charges.*” Given that Hydro-Quebec has proposed an alternative method to determine “*incremental and decremental cost*” it is incumbent on Hydro-Quebec to demonstrate that its proposal is “*consistent with or superior to*” the determination of incremental cost as set out in the *pro forma* OATT.

It is the opinion of this writer that the Hydro-Quebec proposal for “*specific imbalance charges*” is inferior to the *pro forma* and does not fulfill Hydro-Quebec's reciprocity obligation.

### 5.2 Challenge against NB Power Generation

The issue of a potential challenge against Hydro-Quebec that was raised in the previous section is real as evidenced by a complaint laid by Integrys Energy Services Inc (IES) against NB Power Generation Corporation (NB Power) this February.

NB Power was a winning bidder in a Maine Public Utilities Commission (MPUC) solicitation to serve a portion of the standard offer service to retail customers in the territory of the Northern Maine Independent System Administrator (NMISA). IES had previously served that load and filed a complaint with FERC that NB Power did not have the right to serve that retail load in the NMISA territory because it had not demonstrated that it does not possess market power in the Maritimes Area. NB Power argued that FERC has no jurisdiction over supply of retail load in NMISA territory by a Canadian utility. It also argued that FERC's jurisdiction over interstate commerce did not apply to Northern Maine because Northern Maine is electrically connected only to Canada and is isolated from the rest of the United States.

FERC, in its June 10 order, agreed with NB Power that it has no jurisdiction over retail sales into NMISA from a Canadian utility but it also agreed with IES that NB Power must provide a market power analysis for the Maritimes Area if it wishes to retain its market-based rate authority. FERC also disagreed with NB Power that its wholesale transactions into Northern Maine are outside FERC's jurisdiction because there are frequent transactions between Northern Maine and the rest of the US through New Brunswick transmission that are interstate commerce transactions and are under FERC jurisdiction.

The challenge in this case was not about reciprocity as the NBSO tariff meets all the reciprocity requirements of FERC. The challenge was about market power which is the second requirement in order to obtain a market-based rate authority from FERC for participation in US markets. However, it indicates that FERC will consider very seriously any complaints regarding access to US markets by foreign utilities. Considering that Hydro-Quebec is in competition with other generators in supplying US markets it is not out of the question to expect that a competitor would file a complaint with FERC that Hydro-Quebec does not meet the reciprocity provisions in the *pro forma* OATT.

### **5.3 The risk for non-compliance**

By not meeting the reciprocity requirements laid out in the FERC Orders, Hydro-Quebec is open to challenge before FERC from other participants in the US markets and thus may put itself at risk. A successful challenge could eliminate its market-based rate authority status in the United States and force all transactions to be executed at the border under regulated conditions. Such an occurrence could reduce the net back value that Hydro-Quebec receives from export sales and correspondingly reduce both contributions to in province rates and dividends to the government. Either could increase the burden on Quebecers through increased electricity rates or higher taxes.

## **6. CONCLUSION**

This paper has reviewed the proposal of Hydro-Quebec for Schedules 4 and 5 regarding generator and energy imbalances and found them wanting. The proposed changes of Hydro-Quebec are unacceptable because the pricing of energy imbalances is punitive and unduly discriminatory against Transmission Customers other than HQP and HQD. Furthermore the changes proposed do not meet FERC reciprocity obligations and will put the current US export operations of Hydro-Quebec at risk of challenges before FERC.

For the longer term future it is recommended that a re-dispatch balancing market similar to that operated by NBSO be implemented in Quebec. In the immediate term an alternative Proxy Quebec pricing mechanism is proposed that will provide fair treatment and meet the reciprocity requirements of FERC.

### **ATTACHMENTS:**

#### **APPENDIX A – ENERGY IMBALANCE CHARGES**

#### **APPENDIX B – AMENDED SCHEDULES 4 AND 5 OF HQT'S TARIFF**

#### **APPENDIX C – SUPPORTING DATA**