DELIVERED BY HAND

October 26, 2006

Board of Commissioners
of Public Utilities
P.O. Box 21040
120 Torbay Road
St. John's, NL A1A 5B2

Attention: G. Cheryl Blundon
Director of Corporate Services
and Board Secretary

Ladies and Gentlemen:

**Re: Newfoundland and Labrador Hydro 2006 General Rate Application**

Please find enclosed the original and ten copies of Newfoundland Power's Prefiled Evidence and Exhibits of Mr. Larry Brockman in respect of Newfoundland and Labrador Hydro's 2006 General Rate Application.

For convenience, the Prefiled Evidence is provided on three-hole punched paper.

A copy of this letter, together with enclosures, has been forwarded directly to the parties listed below. An electronic copy in Adobe format will follow.

If you have any questions regarding the enclosed, please contact the undersigned at your convenience.

Yours very truly,

Gerard M. Hayes
Senior Counsel

c. Gillian Butler, Q.C., & Geoffrey Young
Newfoundland & Labrador Hydro

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**IN THE MATTER OF** the *Public Utilities Act*, (R.S.N. 1990, Chapter P-47 (the "Act"), and

**IN THE MATTER OF** a General Rate Application (the "Application") by Newfoundland and Labrador Hydro for approvals of, under Section 70 of the Act, changes in the rates to be charged for the supply of power and energy to Newfoundland Power, Rural Customers and Industrial Customers; and under Section 71 of the Act, changes in the Rules and Regulations applicable to the supply of electricity to Rural Customers.

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# Prefiled Evidence and Exhibits of Larry Brockman

## Testimony on Behalf of Newfoundland Power

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***Brockman Consulting***

At the hearing into Newfoundland Hydro's 2006 General Rate Application, the Rates and Cost of Service Expert Evidence will be adopted by Larry Brockman, President of Brockman Consulting based in Atlanta, Georgia.

A witness profile for Larry Brockman follows.

**Larry Brockman**
***President of Brockman Consulting***
***Atlanta, Georgia***

Larry Brockman has over 30 years experience as a power system planning engineer, rate designer, regulatory staff member and consultant and specializes in regulatory and generation planning assistance and analysis, as well as the analysis of competitive generation markets.

Mr. Brockman has appeared before the Board of Commissioners of Public Utilities of Newfoundland and Labrador on 8 previous occasions as an expert witness. He has presented evidence on behalf of Newfoundland Power Inc, concerning cost of service, rate design and least cost planning in Newfoundland and Labrador Hydro's 1990, 1992 and 2003 general rate referrals, as well as in Newfoundland and Labrador Hydro's 1992 generic cost of service hearing and the 1995 Rural Rate Inquiry. Mr. Brockman also appeared as an expert witness on cost of service and rate design on behalf of Newfoundland Power in 1996 and 2003 Newfoundland Power General Rate Applications.

A more detailed description of Mr. Brockman's professional background is provided as Exhibit LBB-1 to this evidence.

**Contents**

## 1.0 SUMMARY OF EVIDENCE

On October 20th 2006, the parties to this proceeding reached a Negotiated Settlement concerning most of the Cost of Service and rate design issues with the Newfoundland and Labrador Hydro ("Hydro") 2006 General Rate Application (the "GRA"). As a participant in the negotiations, I agree with, and support the Negotiated Settlement, and recommend that the Board accept it as filed.

Newfoundland Power has asked me to offer my comments and conclusions on the three reports filed by Hydro in relation to Order No. P.U. 14 (2004). The reports are: the NERA Marginal Cost Study (the "Marginal Cost Study"), the Stone and Webster Generation Credit Report (the "Generation Credit Report"), and the Rate Stabilization Plan Report (the "RSP Review").

***The Marginal Cost Study***

The Marginal Cost Study recently performed by NERA for Hydro is generally sound and provides reasonable estimates of the marginal costs for the next 10 years on the Island Interconnected System. The significant differences between marginal costs and embedded costs suggest rates currently based on embedded unit costs should be modified to better reflect marginal costs and promote efficiency.

***The Generation Credit Report***

The Stone and Webster *Review of Newfoundland and Labrador Hydro's Treatment of Newfoundland Power's Generation* offers useful background and a balanced approach to each of the parties' issues on the Generation Credit.

I agree with the following as presented in the Generation Credit Report:

- Compensation to Newfoundland Power for its generation should continue to be based on savings derived from the Cost of Service Study.
- Similar considerations of availability and reliability should be used for both Newfoundland Power and Industrial Customers when considering the credits for generation.
- The Cost of Service Study savings provided to Newfoundland Power for reduced transmission costs related to its thermal generation should be discontinued.

I disagree with Stone and Webster's proposal to change the method of deriving Hydro's system load factor in the cost of service study.

***The RSP Review***

Concerning Hydro's RSP Review and the issues that were not settled with the Negotiated Settlement:

- Hydro's proposal to incorporate risk protection into the RSP in the event of the loss of one of its major customers while ignoring offsetting impacts on revenues and costs is not consistent with general regulatory practice. Hydro's proposal also further complicates an already complicated mechanism. Therefore, Hydro's proposal should not be approved.
- The level of fuel cost protection granted to Hydro through the RSP should be based on an assessment of their overall fuel cost risk and not by looking at their diesel fuel cost risk in isolation. Given the high cost of fuel in the 2007 test year, Hydro's fuel cost risk for 2007 may not be excessive. Hydro's proposal to incorporate diesel fuel and purchased power

cost variability into the RSP should be reviewed in conjunction with the RSP review scheduled for 2007.

- I recommend that the balance in the Hydraulic Production Variation component of the RSP that existed prior to AUR Resources Inc., an Industrial Customer, going into production mode be used to reduce the Historical Plan balance. This approach better reflects intergenerational equity.

## 2.0 THE NEGOTIATED SETTLEMENT

### 2.1 General

On October 20th 2006, the Parties to this proceeding reached a Negotiated Settlement concerning most of the Cost of Service and rate design issues in the Hydro GRA. Agreement was also reached on certain issues concerning the RSP.

As a participant in the negotiations, I agree with and support the Negotiated Settlement and recommend that the Board accept it as filed.

The major components of the Negotiated Settlement can be summarized as follows:

- The Embedded Cost of Service Study filed by Hydro is in conformance with the Board's prior orders and should be accepted.
- The rate design principles in Attachment A of the Negotiated Settlement are generally sound and should be accepted by the Board.

- Hydro's wholesale rate to Newfoundland Power should continue to have a two block energy rate with the tail block reflecting the marginal cost of fuel at Holyrood.
- Hydro's Demand Rate to Newfoundland Power should be reduced to $4 per kilowatt per month, to reflect the low marginal costs of demand on the Island Interconnected System, as derived in the NERA Marginal Cost Study. Hydro and Newfoundland Power will discuss in the coming year whether the demand pricing signal ought to be spread over more than one winter month.
- The Industrial Customer's rate design should be accepted as recommended in Hydro's filing. However, Hydro and the Industrial Customers will study whether this rate should be similar to Newfoundland Power's rate, with a tail block reflecting the marginal energy cost at Holyrood.
- The current provisions of the RSP should continue as approved for all hydraulic, fuel and load-related components and all recovery calculations, with the exception of the following three issues: 1) the treatment of secondary revenues from the CFB Goose Bay facility; 2) the treatment of potential effects of variations in Rural diesel costs and Rural Purchased Power; and 3) the disposition of the forecast Hydraulic Production Variation balance in the RSP. These issues are discussed in more detail in Section 5.

## 2.2 Rate Design Principles

Attachment A to the Negotiated Settlement includes rate design principles that were agreed upon by all parties.

The rate design principles are briefly summarized as follows:

- Rates will be designed to recover the class revenue requirement derived in the embedded cost of service study and will give consideration to the fairness of embedded cost recovery from individual customers within classes.
- Marginal costs and their trends should be reflected in rates to achieve efficiency.
- Rate design should also consider stability, understandability, gradualism, impact on individual customers, and predictability to the degree practicable.
- Good rate design is a balance of many criteria.

In general, these are the same principles that are used to guide rate making in most jurisdictions in North America and are reasonable.

## 3.0 MARGINAL COST STUDY

### 3.1 General

Marginal costs reflect the economic theory that a society achieves its greatest efficiency when all goods and services are priced at marginal cost.[1] Hydro's marginal costs consist primarily of marginal energy costs and marginal capacity costs. Marginal capacity costs consist of marginal generation and transmission costs.

Marginal costs can be used in conjunction with embedded costs to design rates. When used that way, the embedded costs are used to judge fairness of the rates and their sufficiency to recover

1 This principle is known as "Pareto Optimality" after the Italian economist who popularized the theory.

revenue requirements, while marginal costs are used to adjust the rates to achieve the greatest efficiency.

In Order No. P.U. 14 (2004), the Board ordered Hydro to perform a marginal cost study. This study was performed by NERA and filed by Hydro in May 2006. NERA's method provides reasonable estimates of marginal costs for the next 10 years on the Island Interconnected System. Following are my comments on the study and its implications for rate design.

## 3.2 NERA Marginal Cost Study

### *3.2.1 Marginal Energy Costs*

NERA uses the marginal operating costs of Holyrood (mostly fuel and losses) as the marginal energy costs. This is appropriate as Holyrood supplies any increase in kWh virtually all of the time on the Island Interconnected System. Since Holyrood is essentially on the margin during all hours of the year, there is virtually no seasonal or time of day variation in marginal energy costs.

### *3.2.2 Marginal Capacity Costs - Generation*

To estimate the marginal capacity costs for generation (i.e. marginal demand costs), NERA utilized the results from a generation expansion-planning computer program, STRATEGIST.[2]

2 The computer program was provided to Hydro by my former employer, New Energy Associates (formerly Energy Management Associates), located in Atlanta Georgia.

This program is designed to generate optimal generation expansion plans, based on the input assumptions for fuel, load growth, existing units and other general assumptions. The program was used to identify the next least-cost generation units on the system. Once the next units were identified their capital costs, net of fuel savings[3], were multiplied by the economic carrying charges to get year by year marginal demand costs.

The economic carrying charges of the new units in the expansion plan were then adjusted by the ratio of forecast Loss of Load Hours ("LOLH") in each year to Hydro's LOLH target to express the value of capacity relative to the likelihood of capacity shortages on the system. This approach recognizes that capacity will have increasing value as you approach the time when a plant is needed.

### *3.2.3 Marginal Capacity Costs - Transmission*

The marginal capacity costs for transmission are estimated by calculating the historical and forecast costs of transmission expansion compared to the increase in demand which caused them. Appropriate adjustments are made for administrative loaders, capacity losses and energy losses.

### *3.2.4 Summary of Marginal Cost Study Results*

The results of the study for scenario one[4] are shown in Table 25 A of NERA's report. The average 2007 – 2011 and 2012 – 2020 marginal costs are provided in Table 1.

3 In cases where the units were more efficient and saved fuel costs for the system, the fuel savings were credited against the capital costs.

4 NERA studied two scenarios: scenario one assumes the Island electrical grid remains isolated from Labrador. Scenario two assumes a high voltage transmission interconnection between the island of Newfoundland and Labrador.

**Table 1**
**Average Marginal Costs**
**($2007)**

| | **Energy per kWh** | **Generation and Transmission Capacity per kW-mo** | | |
|---|---|---|---|---|
| | | **Winter** | | **Non-Winter** |
| | **All Periods** | **Peak** | **Off-Peak** | **All Periods** |
| **Avg. 2007-2011** | $0.0847 | $1.67 | $0.43 | $0.00 |
| **Avg. 2012-2020** | $0.0858 | $2.51 | $0.59 | $0.01 |

The marginal cost of energy is very high due to the projected high cost of fuel. The marginal cost of capacity on Hydro's system is very low for many years, because the average unit cost of building base load plants is low compared to the high unit cost of fuel. A reduced forecast fuel price would result in higher marginal capacity costs.

NERA also completed a probability of peak analysis to assess the time differentiation of marginal capacity costs. As indicated in Table 1, all marginal capacity costs are incurred in the winter peak period.[5]

**3.3 Implications for Rate Design**

The marginal cost of energy is greater than the average embedded cost of energy on Hydro's system for many years into the future. The embedded cost of energy from Hydro's cost of service study is $0.03811 per kWh excluding the rural deficit. This is significantly lower than the average marginal cost of energy for the 2007 to 2011 period of $0.0847 per kWh.

5 The winter peak period is defined as January to March and December, weekdays, 7:00AM to noon and 4:00PM to 8:00PM.

The marginal cost of demand is less than the embedded cost of demand on Hydro's system for many years into the future. Hydro's 2007 test year embedded cost of demand to Newfoundland Power is $7.49 per kW per month or $89.88 per kW per year. This is significantly higher than the average marginal cost of demand for the 2007 to 2011 period of $2.10[6] per kW for the four winter months or $8.40 per kW per year.

The significant differences between marginal costs and embedded costs suggest rates currently based on embedded unit costs should be modified to better reflect marginal costs and promote efficiency.

Implementation of marginal cost based rates to promote efficiency must be balanced with the principle of fairness in cost recovery and rate stability. The price of fuel, which can be volatile, affects both the marginal cost of capacity and the marginal cost of energy.

## 4.0 THE GENERATION CREDIT

### 4.1 Background

Newfoundland Power's thermal and hydraulic generation serve an important role in Hydro's generation planning and system operations. The generation credit reduces Newfoundland Power's demand allocator in the cost of service study. This reflects Hydro's ability to call upon Newfoundland Power to run its generation when needed.

6 The $2.10 per kW is the sum of the winter peak capacity cost of $1.67 per kW and the winter off-peak capacity cost of $0.43 per kW.

The Board has historically accepted Hydro's method of providing a generation credit to Newfoundland Power for hydraulic and thermal generation. In Order No. P.U. 14 (2004), the Board stated:

> *The Board is not persuaded that NP's thermal generation should be treated any differently than NP's hydraulic generation for the purposes of calculating the capacity credit. Both NP's thermal and hydraulic generation are available to NLH for generation planning and system operations and, as such, NP should be given a credit for this capacity. While NP's thermal generation may not be used to the same extent or for the same purpose as NP's hydraulic generation, primarily because of its higher cost, the thermal generation still comprises available capacity for NLH in terms of the island system capability. Therefore, the Board agrees that NLH should provide a credit to NP for its thermal generation.*

One of the cost of service and rate design issues that has been an area of disagreement among some of the parties since 2001 is the treatment of the generation credit related to Newfoundland Power's thermal generation.

Newfoundland Power currently runs its thermal generation in order to reduce its demand requirements only when requested to do so by Hydro. As a result of this agreement between Newfoundland Power and Hydro, the peak demand assigned to Newfoundland Power through Hydro's cost of service study is net of Newfoundland Power's thermal generation.[7] This practice promotes least cost operation of the thermal generating facilities on the Island Interconnected System and ensures overall efficiency of operations.

7 The thermal generation credit is based on the generation capacity less a reserve percentage estimated by Hydro.

### 4.2 The Stone and Webster Report

In Order No. P.U. 14 (2004), the Board directed Hydro to:

> *… commission an independent study, to be filed with its next general rate application, of the treatment of Newfoundland Power's generation. This study should assess the value of Newfoundland Power's generation to the system and make recommendations on how the generation should be accounted for, both operationally and financially, in the COS study and rate design.*

On February 7, 2006, Hydro filed the *Review of Newfoundland and Labrador Hydro's Treatment of Newfoundland Power's Generation* which was completed by Stone and Webster. Following are my comments on Stone and Webster's review.

Stone and Webster recommends that *"Hydro's costing and billing to Newfoundland Power continue to reflect a set credit for its hydraulic generation, in conjunction with Newfoundland Power's continued obligation to demonstrate the capability of its combined hydraulic and thermal generation"*.[8]

I agree that Hydro's costing and billing to Newfoundland Power should continue to reflect a set credit for its hydraulic and thermal generation.

At page 7 of the review, Stone and Webster conclude that *"the Industrial Customers have more rigid conditions than Newfoundland Power regarding generation availability during peak periods. If conditions were placed on Newfoundland Power to ensure availability of*

8 *Review of Newfoundland and Labrador Hydro's Treatment of Newfoundland Power's Generation*, Stone and Webster, Page 6, Section 4.1.1.

*Newfoundland Power generation, if called upon during peak periods, then both customer classes would be served under more comparable conditions"*.[9]

I agree that similar conditions ought to be placed on both the Industrial Customers and Newfoundland Power to the extent possible. That said, it is important to understand that there are conditions placed upon Newfoundland Power in order to receive the generation credit that do not apply to the Industrial Customers.

In early winter, Newfoundland Power's generation is tested to make sure it can at least provide the level of generation reflected in the credit. If Newfoundland Power fails two tests, billing demand is increased by the amount of generation they are not able to provide based on the tests.

The Industrial Customers use their generation to affect their power on order. If they need to purchased power in excess of their power on order they may be allowed to buy additional power on an interruptible basis at a price based on Hydro's marginal energy costs.

While the two methods are different, the rate structures are also different and it is difficult to say which of the two is more rigid in isolation. I recommend that this issue be studied further after the Industrial Customer's rate structure review is completed.

9 Ibid, Section 4.1.2.

At page 8, Stone and Webster conclude that *"the existing mechanism should continue to credit Newfoundland Power for its hydraulic generation based on capacity net of reserve, but any differences with respect to its hydraulic forecast should continue to be monitored"*.[10]

I agree with this conclusion.

In section 4.2 of the review, Stone and Webster assessed the appropriate value for Newfoundland Power's thermal generation. Stone and Webster concluded that *"Newfoundland Power thermal generation has value to Hydro's Island Interconnected system and contributes to the benefit of all customers"*.[11]

I agree with this conclusion.

Stone and Webster also address a perceived lack of transparency of the thermal generation credit mechanism. To a degree, some compromise in transparency may be unavoidable, given the inherent complexity of the cost of service study.

Stone and Webster recommends that "*compensation for Newfoundland Power's thermal generation should continue as a COS credit, and the notional payment amount should be clearly identified, thus providing greater transparency to the value of generation*".[12]

10 Ibid, Section 4.1.3.
11 Ibid, Section 4.2.1.
12 Ibid, Section 4.2.2.

I agree conceptually, however clarity is required from Stone and Webster as to how this will be accomplished.

Addressing the appropriateness of the credit affecting Hydro's system load factor, Stone and Webster recommends that *"the existing thermal credit mechanism's impact on system load factor and the resulting changes in cost classification should not form part of the compensation because actual system load factor is not impacted"*.[13]

I disagree. The generation credit compensates Newfoundland Power for not using its thermal generation to reduce peak demand. This lowers overall system costs. If Newfoundland Power ran its thermal generation to reduce its peak demand, two things would occur; 1) overall system costs would increase and 2) Hydro's system load factor would in fact change. Therefore, conceptually, the current approach can be justified.

Concerning the appropriateness of the credit for transmission costs, Stone and Webster recommends that *"Hydro should discontinue compensation for transmission because: (1) thermal generation is not forecast to be run during system peak and therefore should not reduce Newfoundland Power's common transmission cost allocation; and (2) Hydro's analysis shows that there is no avoided transmission cost associated with Newfoundland Power thermal generation"*.[14]

13 Ibid, Section 4.2.3.
14 Ibid, Section 4.2.4.

Because Hydro's engineering analysis concluded there is no avoided transmission cost associated with Newfoundland Power's thermal generation, I agree that the thermal generation credit should not reduce Newfoundland Power's common transmission cost allocation.

Stone and Webster also assessed alternatives for valuing Newfoundland Power's generation including:

- Hydro's embedded costs
- Newfoundland Power's internal costs
- Avoided cost
- Cost of a proxy combustion turbine
- Purchase of Newfoundland Power's thermal generation assets

After considering all the alternative methods for compensating Newfoundland Power for its generation, Stone and Webster recommends *"that Hydro's average embedded costs with the recommended changes represents the best balance in consideration of the pros and cons of each alternative, as well as fairness to the parties and practical implications."*[15]

Newfoundland Power is currently being compensated at embedded cost based on its peak demand net of its generation capability.[16] Industrial Customers that have generation are also compensated through the cost of service study based on their peak demand net of their generation reflected in their power on order.

Therefore, I agree with Stone and Webster that the value of Newfoundland Power's generation should continue to be derived through Hydro's cost of service study. However, as previously

15 Ibid, Section 4.2.5.

stated I disagree with Stone and Webster's proposal to change the method of deriving Hydro's system load factor in the cost of service study.

## 5.0. THE RATE STABILIZATION PLAN

### 5.1 Background

The Rate Stabilization Plan (the "RSP") was originally established in 1986 primarily to smooth rate impacts for variations between test year and actual Holyrood fuel costs.

In the late 1990s and early 2000s, the balance in the reserve grew very large as a result of the actual cost of fuel significantly exceeding the test year cost of fuel reflected in customer rates.[17] A number of changes to the RSP have been adopted in recent years to ensure customer rates reasonably match costs incurred on a timely basis.

Reasonable matching of customer rates and costs is necessary to achieve a reasonable degree of intergenerational equity. Intergenerational equity concerns arise when RSP balances grow to such levels to extend the recovery periods that result in a mismatch of rates and costs.

In Order No. P.U. 14 (2004), the Board ordered Hydro to file a report on the operation of the RSP for the period January 1, 2004 to December 31, 2005.

16 Net of a reserve percentage as determined by Hydro.

17 See Hydro's June 2006 report *Review of the Operation of the Rate Stabilization Plan for the Period January 1, 2004 to December 31, 2005*, Page 3, Table 1.

The Order reflected the recommendation of the Board's financial consultants that the new RSP be reviewed after a 24-month period to determine whether any modifications are appropriate. On June 30, 2006, Hydro filed a *Review of the Operation of the Rate Stabilization Plan for the period January 1, 2004 to December 31, 2005* (the "RSP Review").

Most of the conclusions reached in the RSP Review have been dealt with through the Negotiated Settlement in that a further re-design of the RSP will be undertaken in 2007 to better meet its design objectives. The following issues on the RSP were not agreed upon in the Negotiated Settlement.

- Whether there should be any limitations on the potential effects of the full or partial closure of the CFB Goose Bay facility on Hydro's net income;
- Whether there should be any limitations on the potential effects of variations in Rural diesel fuel costs and Rural power purchase costs on Hydro's net income; and
- The disposition of the forecast hydraulic production variation balance in the RSP.

Following are my comments on each of these issues.

**5.2 CFB Goose Bay Secondary Revenue**

In Hydro's 2006 General Rate Application, Hydro is proposing to remove the allocated portion of the forecast CFB Goose Bay Secondary Revenue Credit from Newfoundland Power's revenue requirement and provide the credit based on actual sales to CFB Goose Bay through the RSP. This reduces risk to Hydro related to a possible reduction in net income from secondary sales to CFB Goose Bay.

Hydro has identified two aspects of risk on this issue; 1) fuel price variability, and 2) the sales forecast uncertainty related to the future operations of CFB Goose Bay.

If fuel price declines then the secondary revenue from CFB Goose Bay will also decline. In isolation this can be perceived as a significant financial risk to Hydro. However, if fuel price declines then the cost of supplying diesel fuel to the isolated systems will also likely decline. This fuel cost decline would provide savings to Hydro which can, to some degree, offset the lost secondary revenue from CFB Goose Bay.

If CFB Goose Bay ceased operations, the lost sales would reduce Hydro's regulated revenues. However, Hydro has confirmed in Request for Information NP-54 NLH that "*if secondary sales to CFB Goose Bay do not materialize that Hydro's non-regulated revenues will increase through increased sales to Hydro Quebec*." The Board will have to assess the dynamics of transfers between regulated and non-regulated revenues and whether there is a real risk to Hydro in the event that operations discontinue at CFB Goose Bay.

Hydro's proposal to incorporate risk protection into the RSP in the event of the loss of one of its major customers while ignoring offsetting impacts on revenues and costs is not consistent with general regulatory practice. Hydro's proposal also further complicates an already complicated mechanism. In the unfortunate event that CFB Goose Bay discontinues operations, Hydro can apply to the Board to deal with this matter at that time.

Therefore, I disagree with Hydro's proposal.

**5.3 Rural Diesel Fuel Costs**

In the RSP Review, Hydro presented its position that its financial exposure due to variations in the uncontrollable price of diesel fuel, affecting both diesel fuel and power purchase costs for isolated systems, presents an unreasonable net income risk to Hydro. Therefore, Hydro is requesting additional protection through the RSP.

The diesel fuel cost and the purchased power cost for isolated systems (that is also linked to the price of diesel fuel) have increased significantly from the 2004 test year cost currently reflected in rates.[18] The portion of this increased fuel cost related to price increases is not immediately offset by increased revenues. Therefore, it is understandable that Hydro would request some protection through the RSP.

While I agree that Hydro deserves a reasonable degree of protection from fuel cost risk, it is most appropriate that all fuel cost components be reviewed as a package in assessing the level of fuel cost protection provided through the RSP. Given the high cost of fuel in the 2007 test year, Hydro's fuel cost risk for 2007 may not be excessive depending on actual fuel prices.[19] Hydro's proposal to incorporate diesel fuel and purchased power cost variability into the RSP should be reviewed in conjunction with the RSP review scheduled for 2007.

18 See *Review of the Operation of the Rate Stabilization Plan for the Period January 1, 2004 to December 31, 2005*, Table 16.

19 If the actual diesel fuel price declines from the price in test year, Hydro's earnings will benefit.

## 5.4 Disposition of the Hydraulic Production Variation Balance

### *5.4.1 Background*

Unlike the balance of other components of the RSP which are either recovered or repaid to customers over a 1-year period, there is no definitive period for disposition of the balance in the Hydraulic Production Variation component. Twenty-five per cent of the year-end balance is reflected in the RSP adjustment to be included in customer rates each year. The RSP Review indicated the balance in the Hydraulic Production Variation account continues to represent a level which Hydro is willing to carry on its balance sheet.

The response to Request for Information NP-42 NLH provided estimates of the *pro forma* balances in the Hydraulic Production Variation component for the period 1990 to 2006 based on actual hydraulic production versus the test year cost of service hydraulic production used in the RSP. The *pro forma* balances at year-end for each year are provided in Table 2.

**Table 2**
***Pro Forma* RSP Hydraulic Production Variation Balances**
**($000s)**

| | **Cumulative Variation Net of 25% Allocation** |
|---|---|
| **Opening Balance** | - |
| **1990** | 29,995 |
| **1991** | 16,345 |
| **1992** | 11,628 |
| **1993** | (6,434) |
| **1994** | (60,365) |
| **1995** | (57,362) |
| **1996** | (67,091) |
| **1997** | (78,057) |
| **1998** | (73,205) |
| **1999** | (94,832) |
| **2000** | (125,065) |
| **2001** | (76,966) |
| **2002** | (46,941) |
| **2003** | (28,264) |
| **2004** | (33,392) |
| **2005** | (37,570) |
| **2006F** | (45,184) |

The *pro forma* results of the analysis on actual hydraulic production data indicates that the balance in the Hydraulic Production Variation component for the period 1990 to 2000 would have reached $125 million by the year 2000. This illustrates the potential for intergenerational equity concerns with the existing recovery mechanism.

### *5.4.2 Intergenerational Equity*

Under the principle of intergenerational equity, ratepayers in a given period should pay only the costs necessary to provide them with service in that period. The RSP Review identifies concerns with intergenerational equity if recovery of the Historical Plan balance is extended. The concern relates to the disposition of a large balance to a customer base that differs from those that created the balance.

An example of the intergenerational equity issue with large balances to be recovered in the RSP is currently before the Board. Hydro's AUR Resources Inc. ("AUR") Application is requesting the Board to exempt AUR from paying the current RSP adjustment related to the Historical Plan balance. AUR was not a customer and did not use the energy that created the balance owing.

The AUR case should be instructional to all parties to ensure that RSP provisions exist for the disposition of balances over a reasonable period of time. It is my understanding that another large customer, Voisey's Bay Nickel Company, is expected to become a customer of Hydro in a few years. It is desirable that the Board not have to deal with a similar application for Voisey's Bay Nickel Company as is currently before the Board for AUR. This situation has the potential to occur if the method for dealing with the balances in the Hydraulic Production Variation component is not modified.

### *5.4.3 The Current Balance*

The current balance in the Hydraulic Production Variation component (the "Hydraulic Balance") at the end of August 2006 is an approximate $16 million credit balance to the benefit of customers. From an intergenerational equity perspective it is desirable to clear this credit balance in as short a time frame as reasonable without creating rate volatility. However, there is also a debit balance of approximately $84 million in the Historical Plan balance.[20] Approximately $21 million of the Historical Plan balance is related to Industrial Customers and $63 million is related to Retail Customers. From an intergenerational equity perspective, the most practical approach would be to use the Hydraulic Balance to reduce the Historical Plan balance. The net effect is to clear the Hydraulic Balance and reduce the Historical Plan balance to be recovered from customers.

This approach would also address the type of intergenerational equity issue that was raised in the case of AUR. AUR should neither be required to pay the Historical Plan balance nor benefit from the Hydraulic Balance that accumulated without a material contribution from AUR.

AUR was connected to the system in January 2006. However, based on the response to Request for Information IC-41 NLH, AUR appears to be increasing their load significantly in September and even further in October 2006 to a level that will remain for all of 2007. This data indicates that AUR's production mode was forecast to begin in September 2006.[21] Based on this data, I would use the Hydraulic Balance of approximately $16 million reported in the August 2006 RSP Report to reduce the Historical Plan balance.

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20 July 2006 Rate Stabilization Report. This amount is before the $10 million contribution provided by the Provincial Government announced in October 2006 to cover the portion of the Historical Plan balance related to the loss of the Abitibi mill in Stephenville.

21 Response to Request for Information IC-41 page 10 of 16.

This approach would reduce the Historical Plan RSP rate adjustment to be in effect for Industrial Customers for the period January 1, 2007 to December 31, 2007 and for Retail Customers for the period July 1, 2007 to June 30, 2008.

If the Board approves Hydro's AUR Application, AUR will be exempt from paying the RSP adjustment related to the Historical Plan Balance currently reflected in rates. In the interest of intergenerational equity, the Board should also deny AUR the benefits of the savings in the Hydraulic Balance. Therefore, I recommend that the Board use the Hydraulic Balance to reduce the Historical Plan balance that existed prior to AUR going into production mode.

#### *5.4.4 The Recovery Provision*

The current provision for recovery of the Hydraulic Production Variation uses a declining balance approach.[22] Use of the declining balance approach increases the likelihood of plan balances increasing significantly if there are consistent trends in hydraulic production variances from the test year forecast as was illustrated in Table 2.

The RSP clause should be modified so that the Hydraulic Balance is amortized annually over a fixed recovery period or straight line approach. The fixed period approach will limit growth in RSP balances.

22 Methods of disposition of RSP balances were described by the Board's Financial Consultant in Supplemental Evidence for the 2001 Hydro General Rate Proceeding.

A recovery period of more than 1-year is required to avoid rate volatility due to potentially large fuel cost fluctuations due to hydraulic production level variability. However, to minimize intergenerational equity concerns, I do not recommend exceeding a 3 year recovery period. The details of the revised RSP wording necessary to reflect the fixed recovery approach can be settled in the review of the RSP scheduled for 2007.

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| ***Personal Profile*** | |
| **Name** | Larry B. Brockman |
| **Present Position** | President, Brockman Consulting |
| **Education** | Mr. Brockman earned a bachelor's degree in engineering from the University of Florida in 1973. He subsequently completed 35 quarter-hours towards a master's degree in electrical engineering, with a minor in regulatory economics at the University of Florida. |
| **Qualifications Summary** | Mr. Brockman has over 30 years experience as a utility planner, consultant, regulatory staff member, educator, rate designer, and expert witness. He specializes in strategic planning, regulatory assistance, competitive market assessments, bid evaluation processes, merger and acquisition analysis, cost of service, and rate design, and computer simulation, to help utilities and IPPs meet their strategic goals and maintain competitive advantage. |
| **Prior Experience** | During his career, Mr. Brockman has helped perform, and manage numerous consulting projects, including:<br><br>***Cost of Service and Rate Design***<br>Numerous cost of service and rate design investigations for Canadian and US utilities, examining the utilities' marginal and embedded cost-of-service and rate design procedures for their ability to meet the utilities' strategic and regulatory goals. In many of these examinations, Mr. Brockman has appeared as an expert witness.<br><br>Analysis of methods and witness support used by Georgia Power Company for inclusion of Purchased Power Expenses for a 2006 Fuel Adjustment Clause Proceeding.<br><br>Review of a restructured utility's shared services costs of service separation study to allocate the costs between regulated and unregulated subsidiaries, and procedures for tracking the costs in the future. |

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| | ***Expert Litigation Assistance***<br>Project manager of an anti-trust case involving investigation of all phases of power supply planning covering a 40 year historical period and a successful defense against over $3 Billion damage suit over alleged actions by an investor owned utility.<br><br>Managed a successful defense against a cogenerator seeking to convince regulators that a utility's ratepayers should pay over $1.5 Billion in unnecessary and uneconomic new generation avoided costs by the cogenerator.<br><br>Project manager for a precedent setting FERC case defending a utility from an attempt to abrogate a long term bulk power contract worth over $400 Million. Mr. Brockman's team was able to convince the FERC that contract abrogation was not in the public interest, that the plaintiff was not going bankrupt, and that the plaintiff's difficulties were the result of arbitrary and capricious state regulation.<br><br>***Financial Analysis and Asset Valuation***<br>Construction of detailed utility financial simulation models to forecast regional bulk-power prices and profits for use by Independent Power Producers (IPPs) and power marketers to judge market entry positions and create successful negotiating strategies for purchases and sales in unregulated generation markets.<br><br>A profitability study for an electric utility to assess effects on shareholder returns and economic value added (EVA), of various marketing activities of the utility. These studies resulted in re-engineering the marketing department to yield higher returns and be more consistent with corporate goals.<br><br>Several asset valuation studies for electric utilities to determine whether a market existed to sell existing generating assets, what they were worth, and whether they would be competitive with existing and new generation in the region. Results were presented to senior management and used to revise the strategic planning direction.<br><br>***Competitive Market Assessments***<br>Expert testimony to the Arkansas and Louisiana Public Service Commissions on the market clearing prices for generation in a competitive market, and the relative competitive positions of |

many of the generating companies in the SPP and ERCOT regions. To perform this work, Mr. Brockman used sophisticated computer models and a database containing over 120,000 MW of capacity in the region.

A study on the effects of retail competition on the states of North and South Carolina, presented to the South Carolina Legislature and performed for Carolina Power and Light Company. The study required research on the behavior of prices in other formerly regulated industries and detailed modeling of the market prices and financial effects on the utilities, as well as the effects on state and local taxes.

An independent review of the effectiveness and reliability of a large Mid-Western utility's Power Marketing and Purchases Department in deregulated generation markets, performed as a joint project with the utility and the state's attorney general. Numerous market outlook and generator profitability studies of the ERCOT, Eastern Interconnect, and WSCC markets for merchant plant developers, using the GEMAPS transmission-constrained production cost simulation tool.

An analysis for a large Canadian utility of the profitability of increased transmission line investments to move power into various competitive markets in the US and Canada.

***Strategic Planning***
Analysis and witness support of Duke, Progress Energy, and Dominion North Carolina's 2005 Integrated Resource Plans for reasonableness and conformance with accepted Commission policy.

A strategic planning project for a large South Eastern electric utility identifying strengths, weaknesses, opportunities, and threats, in competitive open-access power markets. For each utility in the region, the project identified which customers would be gained and lost, and assessed the impacts of alternative transmission, and contracting strategies. The entire South Eastern US generating and major transmission systems were simulated. Over $1.5 Billion of potential customer revenue migration was identified at the client utility. Strategies for maintaining the utility's profitability were recommended and accepted by senior management.

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| | Development of several successful strategies and power supply bid evaluation procedures for use by investor owned and rural electric cooperatives, to ensure that winning bids are consistent with the utility's business goals and objectives.<br><br>***Computer Simulation of Power Systems***<br>Mr. Brockman is an expert in the use of utility simulation software for: resource planning; operations; and financial analysis including: PROMOD; PROVIEW; PROSCREEN II; PMDAM; EVALUATOR; GEMAPS, IREMM, and power flow programs.<br><br>***Operational Studies***<br>A salt dome natural gas storage study for a South Central electric utility. The study identified the hourly operational characteristics necessary for favorable economics of the required storage facility. Estimated savings in excess of $100 Million were identified. The facility was constructed and has been successfully benchmarked against the study results.<br><br>***Merger and Acquisition Analysis***<br>Mr. Brockman has participated in several merger and acquisition studies assessing the production cost and planning and operational synergies arising from the merger. He testified before the FERC on the accuracy and appropriateness of computer simulations a merger application. He also participated in a regulated/non-regulated cost separation study for a shared services group of a major utility.<br><br>***Prior Positions Held***<br>Managing Consultant PA Consulting, 2000-2002. Mr. Brockman managed a group of consultants engaged in the analysis of transmission-constrained competitive generation markets, as well as managing several litigation cases involving electric utilities.<br>President of Brockman Consulting 1997-2000. Mr. Brockman assisted clients with strategic planning and regulatory assistance.<br><br>Managing Director and Vice President 1994-1996, EDS Management Consulting Services. Responsible for annual revenues of $3.5 Million in the Atlanta office, engaged in providing technical consulting services in planning, regulatory assistance, marketing, competitive assessments, reliability, bid evaluation, financial simulation, and expert testimony.<br>Vice President Energy Management Associates (EMA) Consulting Department 1985-1994. Started as lead consultant and rose to position of Vice President. He marketed and provided |

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| | strategic planning, regulatory assistance, and operational consulting to electric and gas utilities worldwide.<br><br>Assistant Director Electric and Gas Department, Florida Public Service Commission 1981-1985. Supervised 48 employees engaged in all phases of electric and gas regulation. Made recommendations to the Commission on rate cases and resource planning dockets for all electric and gas utilities in Florida. Responsible for financial and management audit scopes, prudence reviews of rate base, expenses, revenue requirements, and final rate design. Also advised Commission on economic effects of regulatory and energy policy actions.<br><br>Corporate Planning Engineer 1979-1981, Gainesville Regional Utilities. Developed, analyzed, and presented to senior management and the City Council, ideas, plans, and studies affecting the growth, financial well-being and efficient operation of the city owned electric system. Performed detailed simulations and studies of new generation, substations, transmission lines, voltage conversions, re-conductoring, and power factor correction. Mr. Brockman conducted public hearings and testified before the City Council on proposed transmission lines, substations, and rate designs.<br><br>Special Consultant 1979-1980, University of Florida Public Utilities Research Center. Under a grant from Florida Power Corporation and the Florida Public Service Commission, performed a detailed review of marginal cost study techniques for electric utilities and completed a marginal cost study for Florida Power Corporation.<br><br>Transmission Planning Engineer 1973-1976, Jacksonville Electric Authority. Responsible for bulk transmission planning, including extensive use of power-flow, fault current, and transient stability computer programs. Chairman of the Florida Electric Coordinating Group's Long Range Transmission Planning Task Force 1974.<br><br>Adjunct Faculty Member 1976, University of North Florida. Taught courses in industrial and commercial building wiring design and conformance with National Electrical Codes. |

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| **Expert Witness Appearances** | City of Gainesville City Council, 1980, testified on behalf of Gainesville Regional Utilities concerning a joint utility and citizen's collaborative effort on rate design.<br>City of Gainesville City Council, 1981, testified concerning a Long-Range Transmission and Distribution Plan and proposals to construct a new substation.<br><br>Florida Public Service Commission, Florida Power and Light, 1981 Docket No. 810002, Rate Case, testified on cost-of-service.<br>City of Tallahassee - Surcharge Outside the City Limits, 1983. Testified concerning marginal and embedded costs inside and outside the city limits.<br><br>Florida Public Service Commission, 1988, West Florida Natural Gas Company. Testified on cost-of-service and rate design and why the utility needed flexibility to meet competition.<br>Oklahoma Corporation Commission, 1988, Avoided Cost Proceeding. Testified on the appropriate use of computer models to determine avoided cost of generation.<br><br>Nova Scotia Board of Commissioners of Public Utilities, 1989, Nova Scotia Power Rate Case. Testified on cost of service and rate design.<br><br>Nova Scotia Board of Commissioners of Public Utilities, 1990, Nova Scotia Power Rate Case. Testified on integrated resource planning, cost of service and rate design<br><br>Nova Scotia Board of Commissioners of Public Utilities, 1993, Nova Scotia Power Rate Case. Testified on cost of service and rate design.<br><br>Board of Commissioners of Public Utilities of the Province of Newfoundland and Labrador, 1990. Newfoundland and Labrador Hydro rate case. Testified on integrated resource planning and rate design.<br>Board of Commissioners of Public Utilities of the Province of Newfoundland and Labrador, 1992, Newfoundland and Labrador Hydro rate case. Testified on Cost of Service and Rate Design.<br><br>Board of Commissioners of Public Utilities of the Province of Newfoundland and Labrador, 1992, Generic Hearing on Cost of Service and Rate Design. |

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| | Board of Commissioners of Public Utilities of the Province of Newfoundland and Labrador, 1995, In the Matter of an Inquiry Into Issues Relating to Rural Rate Subsidies.<br>Public Service Commission Colorado, 1994, testified on behalf of Public Service Company of Colorado on the proper use of dynamic programming models in the utility's integrated resource planning process.<br><br>Federal Energy Regulatory Commission, 1994, Merger Case, Testified on behalf of Central and Southwest utility concerning production cost merger benefits.<br><br>Nova Scotia Board of Commissioners of Public Utilities, 1995, Nova Scotia Power Rate Case. Testified on cost of service and rate design.<br><br>Board of Commissioners of Public Utilities of the Province of Newfoundland and Labrador, 1996, Newfoundland Power Rate Case, testified on cost of service and rate design.<br><br>Arkansas Public Service Commission, 1997, Arkansas Power and Light Rate Case, testified concerning the market clearing prices for power in deregulated markets and the relative competitive positions of various generators in such markets.<br><br>Board of Commissioners of Public Utilities of the Province of Newfoundland and Labrador, 2001, Newfoundland and Labrador Hydro rate case. Testified on Cost of Service and Rate Design.<br><br>Board of Commissioners of Public Utilities of the Province of Newfoundland and Labrador, 2003, Newfoundland Power rate case. Testified on Cost of Service and Rate Design |
| **Clients Served** | Mr. Brockman's clients have included:<br>Ahlstrom Pyro Power<br>Alabama Electric Cooperative<br>Alberta Power Company<br>Balch and Bingham<br>Black and Veatch<br>California Energy Commission<br>Carolina Power and Light Company<br>Central and Southwest Company<br>Central Vermont Power Company<br>Chugach Electric Cooperative<br>Cincinnati Gas and Electric Company |

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| | Citibank<br>Commonwealth Edison Company<br>Duke Power Company<br>Enron<br>Entergy<br>Florida Public Service Commission<br>Georgia Power Company<br>Gainesville Gas Company<br>Hawaiian Electric Company<br>Howery and Simon<br>Hydro One<br>McKinsey and Company<br>Mission Energy<br>Nevada Power Company<br>New Brunswick Power Company<br>New York State Electric and Gas<br>Newfoundland Power<br>Niagara Mohawk<br>Nova Scotia Power Company<br>Oklahoma Gas and Electric Company<br>Ontario Power Generation<br>Pacific Gas and Electric Company<br>Public Service Company of Colorado<br>Public Service Company of New Mexico<br>Rochester Gas and Electric<br>SCANA<br>Southern California Edison<br>Tampa Electric Company<br>The City of Austin<br>The Southern Company<br>TransEnergie<br>West Florida Natural Gas Company<br>The World Bank |