PRE-FILED TESTIMONY OF
P. BOWMAN & A. McLAREN
IN REGARD TO NEWFOUNDLAND & LABRADOR HYDRO
2006 GENERAL RATE REVIEW

Submitted to

The Board of Commissioners of Public Utilities

On behalf of

Island Industrial Customers

Prepared by

InterGroup Consultants, Ltd.
500-280 Smith Street
Winnipeg, MB R2C 1K2

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1.0 INTRODUCTION

This testimony has been prepared for the four continuing Island Industrial Customers and one potential Island Industrial Customer (collectively "IC") of Newfoundland and Labrador Hydro (Hydro or NLH) by InterGroup Consultants, Ltd. (InterGroup) by Mr. P. Bowman and Mr. A. McLaren. It is evidence for the public hearing into an Application (the "Application") by Hydro to the Board of Commissioners of Public Utilities (Board or PUB) dated August, 2006.

The Island IC group includes the four large industrial companies currently operating in Newfoundland and Labrador on Hydro's Island Interconnected System and one potential industrial customer on this system. These companies are:

- Abitibi-Consolidated Company of Canada at Grand Falls;
- Corner Brook Pulp and Paper Limited;
- North Atlantic Refining Limited;
- Aur Resources Inc.; and
- Voisey's Bay Nickel Company Limited which is a potential industrial customer of Hydro.

Mr. Bowman's and Mr. McLaren's qualifications are set out in Attachments A and B respectively. InterGroup was initially retained at the end of June 2001 to assist the IC in addressing the 2001 Hydro Rate Review, and subsequently assisted the Island IC in preparation for the 2003 Hydro Rate Review. Mr. Bowman also submitted evidence on behalf of the IC in the 2003 proceeding.

In preparing this testimony, the following information has been reviewed:

- The Hydro Application filed August 3, 2006, including pre-filed testimony of Hydro staff and witnesses.
- Most of the first round responses to Requests for Information to Hydro from the Board, the IC, the Consumer Advocate (CA), Newfoundland Power (NP) up to approximately "batch 10" filed by Hydro.
- To a limited degree, Hydro's 2007 Capital Budget Application dated July 14, 2006, as well as other regulatory filings available from the PUB website, including the Newfoundland Power (NP) 2007 Capital Budget.

This is the third general review of Hydro's rates by the Board under the new regulatory regime established for Hydro during the mid-1990s. InterGroup has been asked to identify and evaluate issues relating to the following aspects of Hydro's filing, taking into account normal regulatory review procedures and principles appropriate for Canadian electric power utilities:

1. revenue requirements for 2007 as submitted by Hydro;
2. cost of service (COS) and rate design issues; and,
3. the Rate Stabilization Plan (RSP).

This testimony has been prepared with the understanding that most issues related to the cost-of-service study, rate design and the RSP will be fully settled among the parties to the proceeding by way of a negotiated agreement, with some limited exceptions. As such, issues that are part of the negotiated settlement are not addressed in this testimony. Cost of service, rate design and RSP issues not yet addressed by way of the above noted settlement are understood to include the following:

- "Generation Credits" related to the Cost of Service treatment of a customer's own generation;
- The calculation of specifically assigned charges to IC;
- the stabilization of diesel fuel costs and purchased power costs via the RSP; and
- the disposition of the hydraulic production variance in the RSP.

As noted, the review to date has been somewhat limited by the time available, certain availability of responses to the Requests for Information filed by all parties and the quantity of information required for a full understanding of the issues. This initial testimony focuses on summarizing the contents of the Application, identification of key issues related to the above matters and an overview of these issues where possible to date. Following a review and clarification as required of Hydro's responses, further analysis and testimony on these issues may be required.

1.1 SUMMARY

With respect to topics not already addressed by the negotiated settlement, it is apparent that, since 2004, Hydro's system has faced massive overall increases in bulk power costs related to fuel price ($60.6 million[1]) and updated hydro generation average output ($9.8 million). These material increases in fuel cost have occurred despite reduced Holyrood oil consumption due to the closure of a previous IC - Abitibi-Stephenville (approximately 510 GW.h, or $45 million/year of Holyrood generation).

Hydro's application also seeks approvals for cost increases in other areas of Hydro's operations above and beyond fuel and hydrology. The net impact on customer base rates since 2004 is consequently significant – approximately 34% for IC in three years. This submission highlights that over 90% of the rate change proposed for IC is due to factors that are beyond Hydro's control, or that are primarily due to timing. Most uncontrollable costs are today addressed via stabilization mechanisms such as the RSP, as Hydro cannot be reasonably expected to bear this type of cost instability. This type of protection for Hydro should now be expanded to include diesel fuel and related price protection on small non-interconnected systems.

The filing also underlines the importance of the Board's role in ensuring costs that can be controlled by Hydro do not become an exacerbating rate driver at times of major uncontrollable cost escalation (the remaining 10% of the proposed IC rate impact).

Hydro's filing highlights the overall importance of bulk power planning at this time, both for new demand side management activities (DSM) and supply side resources (such as future hydro projects, wind, purchased power, or life extensions of Holyrood). Hydro's proposals with respect to DSM in this filing are

[1] Per Attachment C.

undefined and without specified performance targets. In addition, DSM proposals do not reflect an accounting or regulatory treatment that recognizes the long-term benefits of DSM activities through a proper matching of costs and benefits. Hydro's current supply side resource planning, to the extent it has been outlined in Hydro's filing, fails to reflect reasonable timelines and sequencing needed to allow for proper timely regulatory review and oversight of this important area by the Board.

Focusing specifically on the 2007 Test Year revenue requirement, the filing reflects significant concerns with respect to provision of power to NP to service a planned "Generation Outage" for one of its hydraulic generating stations in 2007. Hydro's approach is to serve this Generation Outage Power via the normal cost of service loads. The net effect of this approach is to have IC and rural customers bear a substantial portion of the associated fuel costs to serve this generation outage (in the range of $0.4 to $0.6 million, and $0.2 to $0.25 million respectively). As a result of this approach, IC and Rural customers will continue to pay rates reflecting this fuel cost each future year until the next GRA, even though this fuel is no longer required to serve the outage. In sharp contrast, when IC who own generation require Generation Outage Power, they are allocated the full fuel cost to serve this load, with no costs allocated to NP or Rural. This is easily addressed by "normalizing" NP's load forecast for cost of service analysis, and treating the power required to service NP's 2007 Generation Outage consistent with IC (i.e., outside the cost of service study).

Hydro's operating and maintenance costs for 2007 in a number of areas do not reflect reasonable regulatory budgeting and normalization of Test Year costs. In particular, although Hydro has proposed reducing its budgeted vacancy rate, a vacancy adjustment for 2007 at the level approved by the Board for the 2004 Test Year remains appropriate. Salary cost allocations to the capital program appear significantly understated in Hydro's Test Year budget. System Equipment Maintenance costs for 2007 are anomalously high reflecting significant overhaul activity in 2007 that only occurs periodically. A suitable approach is required to "normalize" this cost to ensure ratepayers do not have the 2007 Test Year rates reflect this anomaly; absent such normalization, 2007 test year rates reflecting a significant Holyrood overhaul will be effectively applied to future years when no such overhaul is expected (overhauls only occur on a periodic basis).

Hydro continues to propose that NP receive a major cost of service credit to reflect both its hydraulic generation and thermal generation[2]. Hydro has recommended that the level of the credit be approximately cut in half (acknowledging aspects of past IC arguments on this matter). Hydro proposes no comparable credits be provided for IC generation, nor for potential other capacity resources such as loads on Hydro's system that can be curtailed at key times. There remains a solid argument for not providing a cost-of-service credit in respect of the NP thermal generation; however, in the event Hydro's recommendation is adopted, the Board should ensure fair and equal treatment is afforded to other customer-owned generation that Hydro relies upon, including a full credit to relevant IC generation (for example, in the range of 4 MW to Corner Brook Pulp and Paper) and direct Hydro to develop other "curtailable" capacity credit options for customers who are prepared to interrupt their load at these peak times (similar to that currently offered to NP's customers).

[2] Exhibit RDG-2

Finally, in respect of specifically assigned charges, Hydro's approach to calculating these charges remains appropriate in most circumstances. Nonetheless, in the case of Aur Resources, a new IC with recently constructed assets serving them (particularly transmission funded entirely by the customer), the approach appears unduly onerous, and a downward revision in the calculated specifically assigned charges to this customer is appropriate.

A summary of recommendations provided in this submission follows:

1. Hydro's proposal to adopt the updated system hydrology reflecting the "simulation" methodology long-term average output of 4,472 GW.h per year should be approved (section 4.1.1).

2. The NP load forecast in the 2007 test year should be reduced by 44.7 GW.h to reflect the normal hydro output (long-term average hydrology) on NP's system. Currently the load forecast reflects a major additional purchase of approximately 44.7 GW.h from Hydro at embedded cost rates to supply replacement power during a 2007 upgrade project on the NP Rattling Brook hydro station. To the extent Generation Outage power is required by NP for this project, this should be provided at marginal energy rates from Holyrood, comparable to IC's Generation Outage power provision, and not charged to IC or Rural customers (section 4.1.2).

3. The Holyrood fuel efficiency conversion factor for 2007 be set to at least 631.5 kW/h/bbl to reflect the benefits of efficiency projects Hydro has had approved via its Capital Budgets. Consideration should be given to further improvement via a higher 2007 conversion rate (section 4.2.2).

4. A mechanism to fully protect Hydro from diesel fuel price escalation (and prices for purchased power linked to diesel prices) in future years should be established (section 4.2.2).

5. The vacancy rate for 2007 should be retained at the 3.75% ratio approved by the Board for 2004, and consideration should be given to further increases in this ratio to reflect cited current retention and recruitment issues (section 4.2.3).

6. The forecast for capitalized salaries in 2007 should be increased to 25%, rather than 20% as proposed, to reflect Hydro's recent experience (section 4.2.3).

7. Hydro should establish a new provision or deferral account to address Holyrood major overhaul expenses. This account would receive annual appropriations from income at a long-term forecast "normalized" level, and be used to fund all periodic major overhauls of the units. The 2007 System Equipment Maintenance expense should be adjusted downwards accordingly (section 4.2.4).

8. With respect to capital spending, Hydro's record regarding frequent underspending of the full annual capital budget should be reflected in a downward adjustment of ratebase and depreciation related to both 2006 projects and 2007 projects (section 4.2.5).

9. DSM program objectives and targets are required, including consultation with IC in particular to ensure maximum potential load savings (section 4.2.6).

10. DSM expenditures should be capitalized and amortized over 10 years, to reflect the long-term benefits of load reductions (section 4.2.6). DSM expenditures should also be tracked by system and customer class to the extent possible to ensure accurate future allocation via the cost of service study.

11. The Board should carefully assess the proposed specifically assigned charges to Aur Resources, and anomalies arising from the ratio approach to allocation combined with the high "original cost" of Aur's new assets. The potential for a downwards adjustment in the specifically assigned charges should be assessed based on Hydro's methodology over-allocating certain costs to new assets (section 5).

12. Although there remains strong arguments for elimination of the NP Generation Credit for thermal generation, the Board should also assess the option of adopting Hydro's recommended approach (continued credit for generation-related costs, but not transmission and no generation credit adjustment to the system load factor) in combination with:
    a. provision of a fair equivalent generation credit to capacity sources such as Corner Brook Pulp and Paper to reflect their approximately 4 MW of generation that can be made available to the system (and is more readily called upon than NP's thermal generation)
    b. provision of a fair opportunity for Hydro's customers to access capacity credits via "curtailable" rate programs akin to those offered by NP (section 6.3).

13. A firm submission deadline should be established for Hydro to file a full comprehensive long-term Resource Plan and preferred development scenario for the Island Interconnected system with the Board, ideally during the first half of 2008 (section 7).

2.0 INFORMATION ON ISLAND INDUSTRIAL CUSTOMERS

The Island IC group is comprised of large energy customers who operate with high load factors (i.e. they have relatively comparable levels of energy use throughout the day and throughout the year). The group represents all operating industrial customers on the Island Interconnected System, as well as one future industrial customer.

These customers are forecast to require 894.3 GW.h of firm electricity in 2007 (about 14.3% of the firm energy delivered by Hydro to the Island Interconnected system[3]) at a proposed revenue requirement of $44.26 million.[4] Additional purchases of $0.49 million are forecast at non-firm rates. This represents a roughly 32% decrease in energy from 2004 forecast levels[5] and primarily reflects the closure of one of the industrial customers in service at that time – Abitibi-Stephenville. On a simple per kW.h basis, the revenue requirement is proposed to increase by approximately 34% from 3.70 cents/kW.h to approximately 4.95 cents/kW.h.[6] For each of the industrial customers, electricity costs make up a substantial portion of total operating costs.

Industrial Customer concerns typically focus on the following issues:

- Long-term stability and predictability in electricity rates;
- Fair allocation of costs between the various customer classes to be served, including a fair interpretation of the legislative limitation on industrial customer rates from funding the rural subsidy;
- Flexibility to tailor electrical service options to suit their operation to achieve an appropriately firm supply at the lowest cost for the load being served (i.e. using a mix of self-generation, Hydro firm power, Hydro interruptible power, curtailable service, etc.);
- Protection for customers from risky or government-initiated ventures or supply options that are not consistent with the provincial power policy objectives of efficiency and equitable power supply at the lowest possible cost;
- Assurance that all general consumer rates are reasonable within the context of the above considerations and the appropriate long-term financial health of Hydro; and
- Continued reliability of power supply for Island Interconnected customers.

Industrial customer concerns reflect the size of their capital investments in Newfoundland and Labrador, the long-term perspective essential to such investments and the major stake that these investments typically have in continued large-scale power purchases from Hydro. In addition, the industrial customer concerns reflect competitive pressures associated with selling industrial products to external markets.

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[3] RDG-1
[4] RDG-1
[5] Per J.R. Haynes Schedule III.
[6] 3.70 cents is derived by dividing $49.33 million 2004 revenue requirement by 1334.8 GW.h total IC forecast 2004 firm sales. The 2007 value of 4.95 cents is derived by dividing $44.26 million by 894.3 GW.h per RDG-1.

3.0 OVERVIEW OF HYDRO'S APPLICATION

Hydro's Application requests the Board's approval of matters in the following broad areas:

1. The rates to be charged for the supply of power and energy to Hydro's Wholesale Customer (NP), Hydro's Rural Customers and the IC as of January 1, 2007.
2. The rules and regulations applicable to the supply of electricity to Hydro's Rural Customers.

The Application is made pursuant to the Public Utilities Act (R.S.N. 1990, Chap P-47). This is Hydro's third review before the Board since the implementation of the new regulatory regime established for Hydro during the mid-1990s. The first review occurred in 2001, and the second in 2003 (for the 2002 and 2004 test years respectively).

In the past two GRAs, material progress occurred in terms of advancing the regulatory framework, cost of service and rate design approaches and Rate Stabilization Plan. The 2001 GRA was the first opportunity to establish effective regulation of Hydro's rates under the new framework and was also the first GRA in nearly a decade. The 2001 GRA resolved many relatively straight-forward issues (such as facility cost allocation in the COS, removal of the rural deficit from the IC rates as required by law, industrial contract provisions, or outstanding cost of service methodology questions)[7] and set the stage for further discussion of a series of more complex topics at the 2003 GRA. That second proceeding achieved resolution of many of the more difficult or complicated components of Hydro's regulatory regime, such as the Rate Stabilization Plan (RSP), which was materially revised in that hearing, and a reasonable approach to determining Hydro's fair level of Return on Equity.

In contrast, the current proceeding presents far fewer technical or regulatory regime-related issues focused on the Test Year at hand. A review of the current application reveals issues that are focused on and that relate increasingly to the long-term level of rates, health of the utility and system supply. This includes:

- **Normalization of costs:** Regulatory frameworks to "normalize" various inherently unstable or periodic ("lumpy") costs for regulatory and rate setting purposes, in order to better match the timing of costs and revenues, such as overhauls and DSM spending. This includes ensuring that test year hydraulic generation for the utilities (Hydro and NP) reflects a fair long-term average level.

[7] As was to be expected given the large number of issues to be addressed, a number of issues raised in that proceeding were not fully canvassed or finalized by the time of the Board's Order. It was however, a first step in establishing "a stable regulatory environment" , and, as noted by the Board in P.U. 7 (2002-2003) "completes the first phase in the process to effectively regulate NLH" . Specifically, the Board stated "The Board notes as well that this decision sets out several directives which are designed to lay the groundwork for the next phase on regulating NLH" and noted Hydro's actions to "place the Board on notice that financial targets and other measures contained in the Application are temporary and will be fully addressed in the next application, scheduled for 2003" .

- **New Resource Acquisition:** Emphasis on need for near-term consideration of integrated Resource Planning, regarding supply and demand side resources required to help address the myriad of problems associated with Holyrood generation[8]. This includes potential DSM and capacity contributions (such as from curtailable rate programs), as well as supply side options.

- **Enhanced Stabilization of Rates/Revenues:** Further revisions to ensure the proper range of Hydro's costs are addressed by Rate Stabilization mechanisms, both additions to the mechanisms (diesel and purchased power costs[9], as well as updated hydrology) and reductions in scope (load variation, which is properly an item on which the utility retains the risk and is not typically "stabilized"). This is required in part to protect Hydro's future financial health, as well as to ensure Hydro is not driven to require future costly GRAs except where required to address internal cost pressures (rather than just shortfalls related to factors such as diesel fuel escalation which are beyond Hydro's control).

3.1 CONTENTS OF THE APPLICATION

The Application filed by Hydro on August 3, 2006, is comparable in form and presentation to Hydro's 2003 application. Included in the Application are proposed rate schedules for January 2007 and proposed rules and regulations regarding supply of power. The filing also includes Hydro's responses to various Board directives arising from 2003 Application.

Compared to the 2003 Application, there are a number of material changes that are reflected in the contents of Hydro's current Application and proposals, including:

1. **Effective Closure of Abitibi – Stephenville:** Although it remains a customer at very low loads for the 2007 test year, Hydro's application reflects in form and substance the closure of what was previously its largest end-use customer. As set out in CA-109, the rate effects that would be proposed today had Abitibi-Stephenville remained on the system are well beyond those contained in Hydro's application[10]; however, with respect to the overall Province of

[8] This includes issues related to cost of fuel, environmental concerns, and the deteriorating condition of the plant and associated high annual O&M and capital re-investment costs.

[9] Likely only extends to variations in purchased power costs linked in some way to fuel prices, such as priced based on avoided diesel costs, not just inflationary factors.

[10] As set out in the table below, the impacts of rate proposals today had Abitibi-Stephenville remained in service compared to without Stephenville is shown in CA-109, and totals over $3.2 million additional impact on IC had Stephenville remained in service (on a 2007 cost of service of about $44.7 million, this reflects an additional 7.1% increase), and $23.0 million on NP (on a 2007 cost of service of $327.2 million, an additional 7.0% increase)

		per CA-109			
IC	Units - 2007 loads	Without S'ville	With S'ville	change	impact ($000s)
Demand (kW)	1,401,000	6.72	6.27	0.45	630
Energy (MW.h)	894,300	0.03811	0.04249	(0.0044)	(3,917)
			total impact		(3,287)
NP					
Demand (kW)	13,026,840	7.49	6.99	0.50	6,513
1st Block Energy (Mw.h)	3,000,000	0.01917	0.02684	(0.0077)	(23,010)
2nd Block Energy (MW.h)	1,964,000	0.08907	0.08908	(0.0000)	(20)
			total impact		(23,030)

Newfoundland, this beneficial rate impact is a small offset compared to the overall adverse consequences resulting from the closure.

2. **Price of No. 6 Fuel**: While the 2004 test year price of No. 6 fuel effectively averages to $29.58 per barrel[11], Hydro's current application proposes to set rates based on a forecast 2007 price of No. 6 fuel consumed based on the forecast cost of No. 6 fuel for 2007 provided by PIRA, Hydro's fuel consultant. This results in a Test Year cost of $56.12 per barrel[12] which represents an 89% increase in price. For 2007, Hydro proposes to retain the 630 kW.h/bbl forecast Holyrood efficiency adopted for the 2004 Test Year; as a result, the increase in price is not offset by any efficiency gains. The change in fuel price drives material short and long-term changes to Hydro's system in terms of rate levels, DSM potential and opportunities for new non-fuel generation developments, each of which is reflected to some degree in Hydro's application.

   a. **Rate Levels:** Hydro's application reflects material increases to rate levels related to fuel prices since 2004. Due to the operation of the RSP, securing these rate changes via a GRA is of no net consequence to ratepayers compared to allowing them to flow through the RSP. In previous GRAs, the RSP operated to defer and delay the extent to which customers were exposed to these rate signals; however, this was amended in the 2003 GRA to ensure that fuel price signals are fully passed through to customers and energy usage sees the full fuel price signal.

   b. **DSM:** Hydro proposes to initiate a new DSM initiative that goes beyond its nominal "Hydrowise" program undertaken to date, and includes a new $500,000 undefined program in 2007. However, it is not apparent whether $65,000 of spending related to salaries is included in salaries and benefits spending, the $500,000 DSM cost budget, or both – see Section 4.2.6.

   c. **System Development and Opportunities for Non-Fuel Generation:** Hydro appears to be considering the potential of some small sources of new hydro generation (Island Pond hydro at 186 GW.h, Portland Creek hydro at 77 GW.h, Round Pond hydro at 128 GW.h as well as one to potentially 2 new 25 MW wind developments assumed to generate 91 GW.h each); however, IC-168 notes no apparent intentions with regard to initiating project commitment activities and spending on the new hydro projects until the period of about 2011-2012 (although the potential for advancement of these project is noted in one line of Mr. Martin's evidence, at page 16).

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[11] Haynes Schedule VIII indicates 2,826,365 bbls at a total cost of $83,610,000. This is different than the average weighted purchase price of $29.02. Also note that due to changes in the monthly consumption of fuel, the average cost of fuel in 2007 at "2004 prices" (as would be measured via the RSP-type monthly variance accounting) is $29.68/bbl as set out in Attachment C.

[12] Note that Haynes Schedule VIII indicates $55.91 as the average purchase price for fuel in 2007. However, the average price of fuel consumed in 2007 (reflecting inventories outstanding at the end of 2006, as well as monthly purchases and weighted average prices for fuel), is calculated from IC-5 at $56.12. This is also consistent with Haynes Schedule VI which indicates 2,539,144 bbls consumed at a total cost of $142,488,000.

In addition to increasingly uneconomic short-run impacts resulting from Holyrood generation, the evidence also repeatedly emphasizes material long-run concerns with respect to longevity of the plant, required levels of investment and environmental and socio-economic concerns. Despite this, Hydro's focus and planning towards retirement and/or staged reduction in use of this plant appears to be materially inadequate.

3. **No material RSP Balances:** Compared to each of the 2001 and 2003 GRAs, the balance today in the "ongoing" components of the RSP are well within reasonable ranges and operating successfully as intended in the 2003 RSP Negotiated Settlement[13]. In particular, the use of a prospective fuel rider has helped to ensure that large deferred fuel price balances do not accrue as a burden to future customers. In the 2001 and 2003 GRA hearings, considerable time and effort was required to debate means to "crystallize" and defer these large balances (ultimately over $150 million owed from customers at one point). In contrast, despite recent escalations in No. 6 fuel prices, the RSP balances for IC and NP remain in a relatively modest credit position forecast to December 2006 (approximately $20 million combined in the "current" plans, of which about $7 million relates to positive hydraulic variances over 2006 alone). This is a significant improvement over past RSP approaches; as a result, this is the first recent Hydro GRA where RSP discussions are not dominated by a need to consider deferring to future periods recovery of fuel costs related to service provided in the past.

4. **Return on Equity and Automatic Adjustment Mechanism**: Hydro's application reflects a proposal for a 5.20% return on shareholder equity ("ROE"), calculated in a manner consistent with the method approved in P.U. 14 (2004). This is based on long Canada bond yields of 4.65%[14] (which is above the actual levels being recorded in October 2007) plus a "premium" estimated by Hydro's bankers of 0.55%. Hydro is also applying for approval of an automatic adjustment mechanism for its ROE in future years. However, the net effect of this adjustment proposal appears very limited, in that "triggers" will not be engaged unless the measured fair ROE level drifts more than 120 basis points in either direction[15].

5. **Other Increases in System Costs**: Hydro's application reflects material changes to many other revenue requirement categories, including assumptions with respect to the vacancy rate, apparently reduced assumed capitalization of salary costs, and a major overhaul at Holyrood.

6. **Review of Newfoundland Power's Generation Credit**: Hydro has commissioned a study with respect to the treatment of Newfoundland Power's generation in the cost-of-service study and is applying to incorporate the recommended changes from that report into the

[13] This is further set out in Hydro's RSP review, filed with the Board on June 30, 2006 and included in response to PUB-1.

[14] Per CA-96; Hydro notes that this is a forecast of 2007 Bond Yields, but in future appears to propose to use annual October benchmark bond yield actuals to set the ROE.

[15] As noted in IC-107, the measured fair ROE in any given year would have to fall outside the range of 3.92% to 6.41% before the Automatic Adjustment would occur.

cost-of-service study. These changes address approximately half of the concerns raised by IC in the 2003 GRA, but Hydro proposes to retain generous credits to NP on behalf of Island Interconnected customers, with respect to generation that is primarily focused on service to NP rural customers. Hydro also continues to provide no other comparable credits to IC's for potential they have to maximize their own generation when requested by Hydro, nor other capacity-based credits for customers willing to consider interruptible loads (unlike NP, which does provide such credit opportunities to their customers).

7. **System Hydrology – Hydro's Own Generation and NP's:** The application reflects a major update to Hydro's forecast long-term average hydraulic generation. The net effect is to reduce the expected output of the plants by 110 GW.h, or about $9.798 million, in equivalent Holyrood generation in 2007. In contrast, the Application reflects NP hydraulic generation at well below long-term average levels (due to a planned outage of NP's Rattling Brook hydraulic generating station), and in effect seeks to have IC and Rural customers pay for material components of the cost of Holyrood fuel to replace this lost generation (totalling about $4.109 million).

3.2 IMPACT OF APPLICATION ON RATES

The evidence of Mitchell in the application sets out the proposed changes to the overall level of revenue required from rates. This analysis compares rates in place as of December 31, 2006 to those proposed for January 1, 2007[16], and indicates that the impact on Industrial Customers is an 8.2% or $3.857 million increase. Detailed calculations are provided in response to IC-36. In effect, this calculates the cost to IC of purchasing their 2007 forecast load requirements using rates in place at December 31, 2006, and at January 1, 2007. Although this is a proper calculation of the proposed overall rate impact at that point in time, this calculation also effectively includes the impact of other non-GRA changes to the RSP that routinely occur as of January 1 each year, but that are not being driven by the present application[17].

Focusing solely on the present application, Table 3.1 sets out the key variables that drive the IC rate changes proposed by Hydro:

[16] Including RSP rates. See page 14 of the Rates evidence.

[17] This includes impacts related to hydrology transfers, fuel variances from 2006 and prior not yet collected to date, revisions to the historical RSP rates, the cumulative load variation provision and interest.

Table 3.1
Industrial Customer Rate Impact from GRA
Total and Broken out by No. 6 Fuel versus Non-Fuel

	Units	2007 Rates with no GRA		2007 Rates with GRA		
Demand	1,401,000	6.17	8,644,170	6.72	9,414,720	
Energy	894,300,000	0.02675	23,922,525	0.03811	34,081,773	
Specifically Assigned Charges			579,685		760,326	
Total			33,146,380		44,256,819	33.52%
				change	*11,110,439*	
Less: Fuel Impact that will otherwise be recovered via the RSP					8,660,747	26.13%
Less: Hydrology changes that will flow through the RSP					1,401,123	4.23%
Non-Fuel Rate Changes			33,146,380		34,194,949	3.16%
				change	*1,048,569*	

The above table indicates the total impact on IC from the firm rates proposed in this GRA is 33.52% higher compared to the firm rates approved in the previous GRA. Approximately 26.13% of this increase relates solely to the price of No. 6 fuel ($8.661 million), and a further $1.401 million or 4.23% of the increase relates to the changes to the long-term hydrology of the Island Interconnected System. These changes are reviewed in detail in Attachment C, and reflect charges that in any event will be billed or credited to customers via the RSP with or without the present application. These changes are notable and distinct from other cost factors, for two reasons: 1) they are effectively uncontrollable factors for Hydro, and 2) they will be paid by customers regardless of the current GRA (although the timing for the payment may vary, and may ultimately charge/credit interest on deferred amounts).

Although these two major categories of charges (representing over 90% of the rate change since 2004) are not dependent on the current GRA, they represent a clear, unavoidable and onerous rate burden on customers. As a result, the Board should carefully assess Hydro's claims with respect to requiring the additional proposed $1.049 million, or 3.16% in rate impact on industrial customers at this time, to ensure these rate changes do not exacerbate the concurrent fuel and hydrology related impacts on customers.

4.0 REVENUE REQUIREMENT

This section reviews the Hydro sales and loads forecast for 2007, the generation forecast to serve these loads, and the resulting revenue requirement for the test year. It is organized into two sections:

- System Sales and Generation
- Hydro's Test Year Costs

4.1 SYSTEM SALES AND GENERATION

Hydro's application indicates an Island Interconnected system load that is materially reduced from 2004 levels. Total sales of 6,286.2 GW.h in 2007 are 252.1 GW.h, or 3.9%, below 2004 Test Year levels (6,538.3 GW.h):

- **IC:** The largest impact relates to the closure of Abitibi-Stephenville for a net impact of almost 510 GW.h per year compared to 2004 levels. The remaining 2004 IC are up by about 9.6 GW.h or 1.1%, and a new IC (Aur Resources) contributes 64.3 GW.h to the system.

- **Hydro Rural:** Loads are down by 7.8 GW.h or about -2.0%.

- **NP**: 2007 Test Year loads are up by 191.9 GW.h, or over 4.0%; however, as discussed in Attachment C, this apparently includes 44.7 GW.h related to a one-time generation outage in 2007 – on a consistent long-term average system hydrology basis[18] (comparable to Hydro's test year approach) the load growth is 147.2 GW.h or about 3.1% since 2004.

The 252.1 GW.h reduction in sales drives an 18.1 GW.h reduction in losses, for a total reduced generation requirement of 270.2 GW.h. The generation forecast to serve this change in load reflects an increase of 20.9 GW.h from Purchased Power (5.3% increase), a 110 GW.h reduction in hydraulic generation (-2.4%, reflecting the change in the long-term average NLH hydraulic generation methodology since 2004), and a 180.9 GW.h reduction in Holyrood (-10.2%).

4.1.1 Long-Term Island Hydrology

Hydro's revised hydrology currently reflects an updated approach to determining the long-term average output of the Island Interconnected hydro plants. This methodology, referred to as the "simulation approach" is more refined than the previous "spreadsheet approach". IC-130 sets out the net effect of adopting the simulation approach compared to the spreadsheet approach, as well as routine updates to the hydraulic record since 2004,

[18] Long-term average assumed at 426.1, consistent with the 2004 Test Year.

Compared to previous GRAs, the impact of adopting the full hydraulic record is set out Table 4.1:

Table 4.1
Changes to NLH's long-term average hydraulic forecast.

(GW.h)	Hydro's long-term[19] average		30 Year average used by PUB		*Change from previous GRA*	
2002	Pre-GC Plants	4,285	Pre-GC Plants	4,425		
2004	Pre-GC Plants	4,234	Pre-GC Plants	4,358	*Pre-GC Plants*	*(67)*
	Granite Canal	224	Granite Canal	224		
	Total	4,458	Total	4,582		
2007[20]	Pre-GC Plants	4,252			*Pre-GC Plants*	*(106)*
	Granite Canal	220			*Granite Canal*	*(4)*
	Total	4,472			*Total*	*(110)*

As reviewed in the 2003 GRA, typical practice for hydraulic utilities is to use all relevant historic data for determining the long-term average output, basically as proposed by Hydro. The adoption of the full hydraulic record will result in added cost impacts on customers at the time the change is adopted. Nonetheless, the generation balance for 2007 compared to 2004 indicates the benefits of adopting the full hydraulic record today, when overall generation is down by over 270 GW.h since the last GRA (such that the change to hydraulic average need not be made up by increased Holyrood generation in comparison to 2004, but instead through load reductions since 2004).

Consequently, Hydro's proposal to move to a long-term average of 4,472 GW.h, should be approved at this time.

There were material updates to the RSP provisions with respect to hydrology in the 2004 GRA Negotiated Settlement agreement among the parties to the hearing. Hydro has provided a report reviewing this provision in the RSP report attached to PUB-1. That report concludes that the hydraulic provision is operating as intended, which appears fully supported by the evidence to date[21].

4.1.2 NP 2007 Generation Outage at Rattling Brook Hydro GS

The evidence in this proceeding indicates NP's hydro generation for 2007 is forecast at 381.4 GW.h[22], compared to a long-term average of 426.1 GW.h[23], a reduction of 44.7 GW.h[24]. This reduction appears to

[19] This reflects spreadsheet analysis in 2001 and 2003 GRAs and simulation analysis in the current GRA.
[20] Per NP-35
[21] It is important to note that hydrology variation is a long-term balancing concept, so it is difficult to properly assess the relative success of the provision over just a few years. To date, however, the provision has operated exactly as expected during a period of high water, with the bulk of the "benefits" from this high water period remaining in the RSP to be able to offset the costs of future drought periods.
[22] Per IC-31.
[23] Per IC-31, for the 2004 Test Year.
[24] The outage appears to be limited to summer, so has no impact on NP's coincident peak loads for the year.

reflect a major generation outage planned for NP's hydro generation in 2007 (the Rattling Brook hydro plant) as discussed in NP's 2007 Capital Budget Application[25].

This component of the load forecast gives rise to two major issues:

1. **Inconsistent with Hydro's Test Year approach:** The approach proposed for NP's load forecast reflects a major inconsistency between the methodology for determining NP's hydraulic generation (reflecting a one-time reduced output in 2007) and Hydro's hydraulic output (which is set based on long-term average output levels). As reviewed in Attachment C, the treatment of NP's Generation Outage serves to drive a major increase in costs to IC and Rural customers, as each is effectively being allocated a share of the Holyrood fuel costs to service the NP outage power. It is difficult to provide a precise calculation of the impact without a full Cost-of-Service run, but the impact appears to fall within the range of $0.4 million to $0.6 million to IC and $0.2 million to $0.25 million for rural for the 2007 Test Year (as set out in Attachment C). Since the rates coming out of this GRA are expected to remain in place for a number of years to come, this added burden to IC and to Rural will continue annually long into the future and long after the NP outage has been completed. The resulting return of this hydraulic generation to NP's system in 2008 and thereafter will result in NP receiving major credits for this Holyrood fuel via either reduced second block energy purchases or the RSP load variation component, with IC and Rural continuing to pay material amounts towards this NP credit each year.

2. **Inconsistent with Generation Outage Power provided to IC:** Where the IC have their own generation, Hydro provides a contractual term that allows these customers to purchase "Generation Outage Power" for the exact purposes that NP is seeking to take its hydro generation out of service in 2007. For the IC however, this power must be purchased at a variable rate that reflects the full actual cost of Holyrood at the time of the outage, with no added costs being allocated to any other customer (NP or Rural).

In order to ensure that cost allocation reasonably reflects long-term hydro generation on the Island Interconnected system, and that NP is treated fairly and consistently with IC with respect to generation outage power, the NP Load Forecast for the cost-of-service in Test Year 2007 should be reduced by 44.7 GW.h compared to Hydro's filing, in order to reflect long-term average hydro output. This will result in the power required for NP's outage being purchased at the NP second block rate (reflecting the variable costs of Holyrood) or through NP's load variation RSP, which is comparable to the terms for IC's Generation Outage power.

4.2 HYDRO'S TEST YEAR COSTS

In its application Hydro states that it is forecasting a loss on operations of $12.552 million per Bradbury Schedule II and a negative return on equity in 2007 at existing rates. The proposed rates reflect a target net income of $11.108 million per Bradbury Schedule I, and reflect a difference of $23.660 million.

[25] In particular, note page 2 of 65 of Schedule B; NP's 2007 Capital Budget application, and PUB-4.0 NP from that proceeding.

The overall changes requested to the revenue requirement are reviewed below.

4.2.1 Overview of Proposed Revenue Requirement Changes

The proposed 2007 Hydro revenue requirement set out in Bradbury Schedule III is $443.395 million[26]. This is an increase of $84.243 million or 23.5% from the final 2004 test year revenue requirement of $359.153 million shown in Bradbury Schedule II. Table 4.2 compares the total revenue requirement by category for the 2004 and 2007 test years.

[26] However, note that the Revenue Requirement shown in RDG-1 is $444.268 million. This is explained in part in IC-10 as relating to different treatments of non-regulated revenues in Labrador, as well as other factors.

Table 4.2
Comparison of NLH 2004 and 2007
Revenue Requirements and Revenues from Rates[27]

	2004 Final	August 2007 Proposed	*Increase/ (Decrease)*
Total Depreciation[28]	**35,648**	**40,762**	***5,114***
Fuel			
No. 6 Fuel	83,609	142,488	*58,879*
Diesel Fuel and Other	7,558	13,164	*5,606*
Less RSP Deferral		(38)	*(38)*
Sub-Total Fuel	**91,167**	**155,614**	***64,447***
Purchased Power	**33,594**	**38,348**	***4,754***
Other Costs			
Salaries and Fringe Benefits[29]	62,742	67,666	*4,924*
System Equipment Maintenance[30]	17,440	18,898	*1,458*
Insurance	2,019	2,123	*104*
Transportation	1,759	2,029	*270*
Office Supplies Expenses	1,913	2,109	*196*
Building Rentals and Maintenance	894	851	*(43)*
Professional Services	3,853	4,071	*218*
Travel Expenses	2,395	2,499	*104*
Equipment Rentals	1,756	1,524	*(232)*
Misc Expenses	4,185	4,765	*580*
Deferred Major Extraordinary Repairs		1,901	*1,901*
Deferred Regulatory Costs[31]	600	597	*(3)*
Sub-Total Other Costs	**99,556**	**109,033**	***9,477***
Allocations			
Hydro Capitalized Salary Expense	(7,104)	(8,353)	*(1,249)*
CF(L) Co	(1,858)	(2,899)	*(1,041)*
Non-regulated customer	(2,619)	(2,897)	*(278)*
Sub-Total Allocations	**(11,581)**	**(14,149)**	***(2,568)***
Total Other Costs	**87,975**	**94,884**	***6,909***
Total Return on Ratebase	**110,769**	**113,788**	***3,019***
Total Revenue Requirement	**359,153**	**443,396**	***84,243***
Less: Other Revenues	**1,928**	**2,021**	***93***
Revenue Required from Rates	**357,225**	**441,374**	***84,149***

[27] Figures taken from Bradbury Schedule III Page 2 of 2 unless otherwise cited.
[28] Depreciation expense appears to include losses on disposal of capital assets.
[29] 2004 Salaries and Fringe Benefits and Capitalized Expenses are as reported in Schedule A page 1 of Hydro's May 2004 refiling in response to P.U. 14 (2004). 2007 Salaries and Fringe Benefits and Capitalized Expenses taken from Bradbury Schedule I page 10.
[30] For 2007 Deferred Major Extraordinary repairs broken out from other SEM expenses per Haynes Schedule I.
[31] 2004 Deferred Regulatory Costs are as described in Schedule A page 2 of Hydro's May 2004 refiling in response to P.U. 14 (2004). 2007 Deferred Regulatory Costs are as reported on Haynes Schedule I of the current application, it appears that for 2007 these costs include both regulatory costs related to the General Rate Application as well as costs related to certain studies undertaken by Hydro.

When reviewing the proposed 2007 revenue requirement it is useful to focus in on assessing Hydro's costs in terms of changes from the approved 2004 revenue requirement. Based on Table 4.2, the following areas set out material increases in Hydro's 2007 revenue requirement when compared to the 2004 final approved revenue requirement:

- No. 6 fuel ($58.879 million or 70 per cent of the revenue requirement increase);
- Salaries and Fringe Benefits ($4.924 million or 5.8 per cent of the revenue requirement increase);
- System Equipment Maintenance ($1.458 million or 1.7 per cent of the revenue requirement increase);
- Return on Ratebase ($3.019 million or 3.6 per cent of the revenue requirement increase);
- Depreciation ($5.114 million or 6.1 per cent of the total increase); and
- Miscellaneous Expenses ($0.580 or 0.7 per cent of the revenue requirement increase).

Each of these cost-drivers are reviewed in further detail in the following sections.

4.2.2 Fuel and Purchased Power Costs

Hydro's application and the figures in Bradbury reflect spending on No. 6 fuel and purchased power of approximately $193.962 million.[32] This represents an increase of $69.201 million or 55.5 per cent over 2004 test year forecasts. The cost of No. 6 fuel represents the greatest increase (from $83.609 million in 2004 to $142.488 million in 2007). This is a total increase of $58.879 million or 70.4%. No. 6 fuel currently comprises 32.1 % of the total revenue requirement (compared to 23.3 per cent in 2004). Table 4.3 summarises the derivation of the forecast No. 6 fuel costs.

Table 4.3 indicates a dramatic increase in No. 6 Fuel costs at Holyrood over a period when the total system energy requirement decreased by 270.2 GW.h (approximately 4 per cent). On a per kW.h production basis, fuel costs at Holyrood have increased from approximately 4.70 cents/kW.h in the 2004 Test Year to 8.91 cents/kW.h in the 2007 Test Year forecast. While most of this increase can be attributed to overall higher fuel prices, approximately $6.27 million can be attributed to including 1 per cent sulphur fuel in the forecast instead of 2 per cent sulphur fuel.[33]

[32] See Table 4.2.

[33] This is calculated based on a premium of $2.47/bbl for 1% Sulphur fuel compared to 2% sulphur fuel comparing the $55.91/bbl for 1% fuel cited in Haynes Schedule VIII to the $53.44/bbl for 2% sulphur fuel in IC 8 NLH. This premium was then multiplied by the 2007 forecast bbl of No. 6 fuel required of 2,539,144 bbl from Haynes Schedule VI.

Table 4.3
Comparison of Holyrood No. 6 Fuel Expense
2004 Test Year Forecast vs 2007 Test Year Forecast

	2004 Test Year	2007 Test Year	Difference
Total Energy Requirement (GW.h)	6,759.80	6,489.60	(270.20)
Non-Holyrood Production (GW.h)	4,979.19	4,889.94	(89.25)
Holyrood Production (GW.h)	1,780.61	1,599.66	(180.95)
Holyrood No. 6 Fuel Conversion Factor (kW.h/bbl)	630	630	-
Holyrood No. 6 Fuel Required (bbl)	2,826,365	2,539,144	(286,221)
Average No. 6 Fuel Purchase Price ($/bbl)	$29.02	$55.91	26.89
No. 6 Fuel Production Cost ($ 000)	$83,610	$142,488	$58,878
No. 6 Fuel/kW.h Holyrood Production (cents/kW.h)	4.70	8.91	4.21

With respect to the No. 6 fuel conversion factor, Hydro's application uses 630 kW.h/bbl[34], the same figure approved by the Board for the 2004 test year. Hydro filed actual conversion factor information that showed a somewhat higher actual conversion factor than 630 kW.h/bbl in 2004 and lower conversion factors than 630 kW.h/bbl in 2005 and forecast for 2006.[35] Hydro indicates that the lower conversion factor in 2005 was due to lower Holyrood production requirements.[36] For 2007, Hydro is forecasting Holyrood production requirements that are closer to the 2004 levels when the actual conversion factor was 632 kW.h/bbl.[37] Hydro also provides details regarding two capital projects that are proposed for 2007 which are forecast to reduce fuel consumption at Holyrood[38] and forecasts a combined beneficial impact on fuel costs of $327,000 annually provided by Hydro (or approximately equivalent to 1.5 kW.h/bbl improvement[39] for this factor alone). Absent an improved Test Year Holyrood fuel conversion factor being built into Hydro's revenue requirement above 630 kW.h/bbl, ratepayers will not see any of the benefits from the ongoing improvement work at Holyrood (such as the two above cited projects and work to reduce station service), or any other continuous improvement programs being pursued by Hydro. The evidence therefore supports setting Hydro's test year revenue requirement for Holyrood efficiency above the 630 kW.h/bbl level and the Board should consider increases to at least 631.5 kW.h/bbl if not higher.

Table 4.2 also indicates material escalation in diesel fuel since 2004 (totalling $5.6 million). The bulk of this fuel is used on isolated systems, and not the Island Interconnected system, and as such this is not a material factor in IC rates. However, it is apparent that a substantial component of Hydro's current net income shortfall stems from an escalation in diesel fuel price against which Hydro has no protection.

[34] It appears that this figure represents net Holyrood production after station service, see for example IC 6 NLH which shows that 1,647.56 GW.h production at Holyrood is net of station service.
[35] Refer to Haynes Schedule VI.
[36] Regulated Activities Evidence, page 34.
[37] Refer to Haynes Schedule VI which shows 2004 actual Holyrood conversion factor at 632 bbl/kW.h on production of 1,647.56 GW.h compared to 2007 forecast production of 1,599.66 GW.h.
[38] In IC 136 NLH Hydro indicates that two project planned for 2007 "Turbine & Generator Upgrade Unit 3" and "Air Preheater Steam Condenser Pumps – Unit 3" are forecast to have annual fuel expense savings of $167,000 and $160,000 respectively.
[39] Each 1 kW.h/bbl improvements at Holyrood is equivalent to approximately $225,000 a year in fuel at today's prices.

Although these facilities do not serve industrial customers, it is in the interest of all customers that the utility not be exposed to these unnecessary and uncontrollable risks. In that regard, Hydro's RSP report[40] properly recommends that an RSP-type mechanism be implemented to fully track diesel fuel price variances[41] (perhaps similar to the current RSP No. 6 fuel variance mechanism), to ensure diesel fuel price escalation is passed back to customers in these regions (or NP's customers as part of Rural Deficit reallocation).

4.2.3 Salaries & Benefits

As outlined in Table 4.3, NLH is requesting approval for total salary and benefits expenses of $67.666 million[42] which represents a 7.8% increase or $4.924 million over the 2004 test year forecast. This is partially off-set by an increase in the forecast capitalized salary expense of $1.249 million.

In its evidence, Hydro appears to attribute the increase in its salaries and benefits primarily to a change in its assumptions regarding the vacancy allowance. In the 2004 test year, Hydro originally included $1.0 million for normal vacancies (approximately 2.5% of permanent salaries) and $1.5 million for future improvement savings[43]. In P.U. 14 (2004), the Board ordered Hydro to increase its provision for normal vacancies to $1.5 million (approximately 3.75% of permanent salaries).[44]

In support of the lower vacancy rate forecast, Hydro seeks to indicate that the actual ten year vacancy rate, from 1995 to 2004, was 1.9% and that in recent years the actual vacancy rate was 0.3%[45]. However, significant issues are raised by this data, including the apparent negative vacancy rates in 1999 and 2002[46].

On review, it appears Hydro has adopted terminology that links "vacancy" to all variances in Salaries and Benefits expenses in any given year. In normal parlance, vacancy would solely relate to cost savings due to budgeted positions being unfilled for some period of time. The vacancy concept would not be a catch-all for all Salaries and Benefit cost escalation or budget variances where such variances are unrelated to specific positions being unfilled.

Elsewhere in its filing, Hydro indicates significant concerns about its ability to retain an appropriate baseline resource level, citing an aging workforce, difficulty recruiting personnel for key positions and remote areas and under-compensation for some trades compared to other utilities.[47] These factors would

[40] Provided in PUB-1.

[41] In these communities, to the extent there are other supply sources whose prices are linked to diesel, such as power purchases, these should similarly be tracked to provide Hydro with full and complete protection against fuel price variances.

[42] The sum of lines 2 through 5 from Bradbury Schedule I page 10.

[43] P.U. 14 (2004) page 61

[44] This calculation is based on the ratio of 2.5% to 1.0 million compared to increased vacancy provision of 1.5 million.

[45] Finance and Accounting Evidence, page 22.

[46] It appears that the vacancy rates in CA 135 NLH are calculated as the difference between the budgeted and actual salaries and allowances, which would lead to a negative vacancy rate in years when actual salaries exceeded budgeted salaries. However, on the surface it seems that there could be many reasons beyond a change in the vacancy rate why actual salaries might exceed budgeted salaries.

[47] Corporate Overview Evidence, page 14.

seem entirely inconsistent with Hydro's proposed reduction in the vacancy rate from that last approved by the Board.

The information on the record does not support a change to the vacancy allowance from that last approved by the Board in 2003; therefore, at a minimum, the Board should order Hydro to use the same percentage normal vacancy allowance as approved in P.U. 14 (2004) (3.75%) and further assess the extent to which the other factors cited in Hydro's evidence (such as retention and recruitment issues) should lead to an increase in the forecast vacancy rate for 2007.

With respect to the capitalized portion of salaries and benefits expense, Hydro states that it has forecast the capitalized salaries and benefits amount at approximately 20 per cent of its 2007 capital program, and notes that this is consistent with the amount approved for the 2004 Test Year (approximately $7.1 million or 20 per cent of the $34.5 million capital program[48]) as well as recent experience. In IC-12 Hydro was asked to provide the data to support the ratios experienced in recent years; Table 4.4 compares the data from that IC-12 response, reflecting both actual and forecast capitalized salaries and benefits and capital expenditures for the actual years 2002 through 2005 and the 2004 and 2007 test years.

Table 4.4
Comparison of NLH Actual and Forecast
Capitalized Salaries and Capital Expenditures from IC-12[49]

	Actual 2002	**Actual 2003**	**Actual 2004**	**Actual 2005**	***Actual 4-year Average***	**Test-year 2004**	**Test-year 2007**
Capitalized Salaries	7,098	8,120	7,727	10,314	8,315	7,100	8,353
Capital Expenditures	40,217	32,506	27,984	33,952	33,665	34,500	41,421
Per cent of Capital Expenditures	17.6%	25.0%	27.6%	30.4%	24.7%	20.6%	20.2%

Table 4.4 indicates that in the four actual years from 2002 through 2005, the capitalized portion of salaries reflects between 17.6% and 30.4% of the capital expenditures in the year. The four year average is 24.7% of the capital expenditures. In short, the evidence provided by Hydro does not support Hydro's forecast of 20% (which it claims is based on recent actual experience), and consequently the forecast should be revised to 25% for a reduction in Test Year Salaries and Benefits of approximately $2 million.

[48] Finance and Accounting Evidence, page 23.
[49] 2002 through 2005 information taken from IC 12 NLH. 2004 test-year information is as summarised on page 23 of the Finance and Accounting Evidence. 2007 capitalized salaries information is taken from Bradbury Schedule I page 10. 2007 capital expenditures are as stated on page A-1 of NLH's 2007 capital budget application dated July 14, 2006. Capitalized Salaries figures all appear to be net of capitalized overtime. However, the 2002 capital expenditures figures do not agree with NP-19 NLH from the 2003 General Rate Application, but no attempt has been made to reconcile the two sets of figures. Further, the totals referred to as "capitalized salaries" on Bradbury Schedule I page 10 are broken out as "capitalized salaries" and "capitalized overheads" in IC-12.

4.2.4 System Equipment Maintenance

Hydro's application forecasts System Equipment Maintenance (SEM) for the 2007 test-year at $18.898 million (indicated in Table 4.2). This is an increase of $1.458 million or 8.4 per cent over 2004 approved levels. Hydro is also seeking $1.901 million in its 2007 revenue requirement for deferred major extraordinary repairs.[50] Combined, these SEM-related expenses total $20.799 million or a 19.2 per cent increase over 2004 test year levels.

A significant portion of these expenses relates to maintenance expenditures at the Holyrood generating station. Table 4.5 summarises the forecast Holyrood SEM expenditures from 2006 through 2015 from Hydro's Capital Budget filing.

[50] Hydro indicates this is made up of approximately $1.5 million related to the asbestos abatement program and $0.4 million related to the Holyrood Boiler #2 tubing per Table 3 of the Finance and Accounting evidence and the response to IC 119 NLH.

Table 4.5

Forecast System Equipment Maintenance Expense at Holyrood ($000)[51]

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Units 1, 2, 3 Preventive - Yearly	450	459	468	477	489	501	510	522	534	546
Units 1, 2, 3 Corrective	870	888	906	924	945	966	987	1,011	1,032	1,053
Units 1, 2, 3 Turbine Valve Overhaul	331		344	352	360	368		384		401
Units 1, 2, 3 Boiler Annual Overhaul	2,400	2,448	2,496	2,553	2,607	2,664	2,724	2,787	2,847	2,907
Units 1, 2, 3 Turbine Major Overhaul		1,377					1,532		1,602	
Units 1, 2, 3 Operating Projects	414	1,586	666			534	546	558	570	582
Common Equipment	2,404	2,260	2,579	4,284	4,081	1,642	1,678	1,716	1,754	1,791
Buildings and Grounds	894	692	581	615	498	687	702	718	734	750
WT Plant	241	161	164	240	297	231	237	242	247	253
WWT Plant	18	5	43	19	6	19	19	19	20	20
Environmental Monitoring	171	175	178	182	186	180	184	188	192	196
Total Holyrood SEM	**8,193**	**10,051**	**8,425**	**9,646**	**9,469**	**7,792**	**9,119**	**8,145**	**9,532**	**8,499**

[51] Taken from Appendix 1, page 13 of Plan of Projected Operating Maintenance Expenditures 2006-2015 for Holyrood Generating Station filed as Section G of Hydro's 2007 Capital Budget Application dated July 14, 2006. Totals do not agree precisely due to rounding.

The Table 4.5 figures from Hydro's Capital Budget filing indicate that there is a Major Turbine Overhaul scheduled in 2007 which will cost approximately $1.377 million. Note however that this is in contrast to figures Hydro cites in its evidence in this GRA that indicate the total cost of the Major Turbine Overhaul scheduled for 2007 is estimated at $2.7 million[52] and in other locations as $1.8 million[53]. Regardless of the specific forecast, the following is noted from a review of Table 4.5:

- Major Turbine Overhauls appear to be a key driver in the overall level of SEM costs. Two of the three years with the highest forecast SEM costs are years when major overhauls are scheduled.
- 2007 has the highest Holyrood SEM expense forecast for any year from 2006 through 2015 and is more than $1.6 million higher than forecasts for 2006 and 2008.
- After 2007, there is no Major Turbine Overhaul forecast until 2012.

In the event Table 4.5 underestimates the current proposal for the unit #3 overhaul, the concerns noted above are only exacerbated.

Focusing on the appropriate regulatory and rate setting treatment for this type of routine but periodic or "lumpy" expense, it would be beneficial to mitigate the variability in the SEM expense forecast caused by these expensive but relatively infrequent major overhauls. Hydro has indicated that its accounting policy is to expense overhauls in the year that they occur.[54] An alternative is provided by NP-18, where NP questions whether it would be reasonable to amortize these costs over a certain number of years[55]. In a rate-setting context (as opposed to strictly GAAP accounting), this approach merits further consideration.

1. **Accounting Policy re: Deferrals:** With respect to certain material cost items in Test Years, regulators can and do apply non-GAAP standards with respect to cost deferral. The standard code of accounts from various regulators tribunals[56] allow for "regulatory assets" and "regulatory liabilities" to serve this purpose with respect to the utility accounts. This deferred cost treatment is similar to that suggested by NP in its question NP-18 to Hydro.

   In response to IC 138 NLH, Hydro indicated that its policy with respect to expensing overhauls was appropriate since overhauls are a normal repair expenditure and therefore they are not considered for deferral and amortization. However, a $2.7 million 2007 Major Overhaul at Holyrood is of sufficient size to give rise to concerns over rate stability and the

[52] Finance and Accounting Evidence Page 23.

[53] Appendix 4 page 16 of the Plan of Projected Operating Maintenance Expenditures 2006-2015 for Holyrood Generating Station filed as Section G of Hydro's 2007 Capital Budget Application dated July 14, 2006. In addition, Hydro indicates in IC 28 NLH that this overhaul is a $1.85 million overhaul.

[54] IC 137 NLH.

[55] NP-18 NLH.

[56] Examples include the Federal Energy Regulatory Commission in the United States (Uniform System of Accounts), and the Ontario Energy Board Accounting Procedures Handbook, as follows with respect to "Other Regulatory Assets": "The amounts included in this account are to be established by those charges which would have been included in net income determinations in the current period under the general requirements of this Uniform System of Accounts but for it being probable that such items will be included in a different period(s) for purposes of developing the rates that the utility is authorized to charge for its utility services" available at: http://www.oeb.gov.on.ca/documents/cases/usoa/USOA1.pdf

degree to which the 2007 Test Year forecasts are representative of the years to which the proposed rates are expected to apply. As a result, this GAAP accounting justification for expensing the entire work package (and consequently building the entire cost into 2007 revenue requirement) is not compelling.

2. **Regulatory Approaches (including review of other relevant jurisdictions):** The major concerns with respect to the Holyrood overhaul in 2007 is the role 2007 forecast costs play in establishing rates that are expected to be in place for a number of years to come. As a result, regulatory approaches to addressing such large inconsistent costs have been developed in some cases. In Newfoundland, such approaches are already used for inconsistent expenses such as fuel related to hydrology variances in any given year via the RSP. For other Canadian jurisdictions that have thermal overhauls as a major and inconsistent[57] component of their revenue requirement, such as Northwest Territories and Yukon, similar related deferral approaches have been implemented[58] as set out in Attachment D.

The treatment for the 2007 major overhaul expense proposed by NP could help smooth the impact of this major overhaul on rates. A related but permanent on-going option for the treatment of such costs would be to establish a deferral account that captures all such future major Holyrood overhaul costs. The Revenue Requirement in any given Test Year would then be set so as to allow for a standard annual appropriation to this account, with future GRAs providing the opportunity to adjust the annual appropriation as required (in the event it was initially set too high or too low – not unlike the hydrology component of the RSP). This would smooth the costs over the longer term while allowing NLH to recover all prudently incurred maintenance costs. Such treatment also has regulatory precedent in Canada at Northwest Territories Power Corporation (refer to Attachment C).

Based on the evidence available to date, it would be an appropriate regulatory approach to ensure Hydro's 2007 Revenue Requirement is not based on the anomalous 2007 Holyrood overhaul (and as such become part of rates for multiple years); instead some form of mechanism should be established to either defer or normalize these costs. Based solely on the data in Table 4.4 above, one estimation of the long-term amount for major overhauls is $450,000 per year ($4.5 million over 10 years); however, given the clear inconsistencies with respect to the apparent budget for the 2007 overhaul, resolving the specific annual amount and resulting impact on 2007 revenue requirement may require further review of Hydro's filed materials and further data from Hydro.

4.2.5 Return on Ratebase and Depreciation

Table 4.2 indicates that depreciation expense has increased from $35.648 million in the 2004 test year to $40.762 million in the 2007 test year – an increase of $5.114 million or 14.3 per cent. Return on ratebase

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[57] In many utilities with a large number of generating units or very large systems, overhauls are not deferred and amortized reflecting the extent to which they are in these cases not lumpy or not of major size in relation to the system's revenue requirement. This is different for smaller utilities with a small number of thermal generating units, like Northwest Territories Power Corporation and Yukon Energy, which are described in Attachment D.

[58] This can take the form of either a simple cost deferral to income for any given overhaul over a given number of years, or a permanent "deferral account" to normalize costs over the long-term.

has increased by $3.019 million or approximately 2.7 per cent. Hydro indicates that depreciation expense tends to increase over time due to expansion of the system, as well as the addition of relatively short-lived assets and the increasing costs of new assets.[59] Return on ratebase will also be influenced in the test years to some degree by the capital forecasts for 2006 and 2007.

Hydro was asked in IC-139 to provide the forecast and actual capital additions for each year from 2002 through 2005. Table 4.6 summarizes this data, and indicates that during this period Hydro's actual capital additions have been only 90 %, or lower, of the budgeted amount. Further, Hydro indicates that as of September 30, 2006 it has spent only 48 % of its capital budget for 2006.[60]

The Board should be cognizant of this budgeting history and experience to date in 2006 when evaluating the reasonableness of Hydro's capital additions, ratebase and depreciation figures. Consideration should be given to a downward adjustment to the 2007 Ratebase and Depreciation expense forecasts to reflect the likelihood of there being "unspent" capital budget for each of 2006 and 2007.

Table 4.6

Forecast and Actual Capital Additions by year ($000)[61]

	2002	2003	2004	2005	4-Year Avg
Total Capital Additions - Budget	44,660	36,122	31,435	47,760	39,994
Total Capital Additions - Actuals	40,217	32,506	27,984	33,952	33,665
Actual Spending as per cent of Budget	90.1%	90.0%	89.0%	71.1%	84.2%

In addition, NP-32 indicates that Hydro has set a very aggressive capitalization forecast for 2007 (only one project is forecast to be incomplete at year end – the contaminated water treatment project at Holyrood for $276,000. This is well below the levels of carry-overs seen in recent years (2004 at $2.65 million, 2005 at $7.38 million and 2006 forecast at $6.2 million). To the extent such carry-overs arise in 2007, they would serve to lower the rate base from that set out in the Application. The extent to which this forecast may not be reasonable should be carefully assesses in setting the 2007 Test Year rates.

A review of the Return on Ratebase materials also highlights a key concern with respect to the reported average cost of Hydro's debt. This calculation has indicated a consistent and material upward movement in the average cost of debt, which is generally inconsistent with the current low long-term interest rates and the recent low rate financing undertaken by Hydro. It appears a key part of the mathematics relates to the means used to isolate "non-regulated debt" (which appears to result in lower average cost debt being assigned to non-regulated operations and higher average cost debt being assigned to ratepayers)

[59] NP 26 NLH.

[60] NP 105 NLH.

[61] Taken from page 2 of the response to IC 139 NLH. It should be noted that these figures do not agree with the percentages reported in NP 104 NLH – however that response generally points to underspending of Hydro's approved capital budget in most years and it is not possible at this time to reconcile the difference Hydro has calculated between the two responses.

and the ongoing requirement for sinking funds on a number of the instruments (which are today invested at relatively low yields).

At this time, there is not sufficient information or time to fully assess this issue. In the event there is further information or conclusions that can be put on the record to assist the Board, supplementary evidence will be provided.

4.2.6 Miscellaneous expenses

Table 4.2 shows that miscellaneous expenses have increased by $0.580 million or 13.9 per cent from the 2004 Test Year to the 2007 forecast. Hydro attributes nearly all of this increase to $500,000 in proposed spending for conservation efforts.[62] This $500,000 in spending is in addition to approximately $100,000 in Hydrowise spending. Hydro also indicates that $65,000 of the $500,000 relates to salaries, though it is unclear why any salary component would be captured on the Miscellaneous Expenses line item of Bradbury Schedule III and not in the Salaries and Fringe Benefits line item. In assessing the reasonableness of Hydro's revenue requirement, consideration should be given to ensuring that this Salaries and Benefits expense is not double-counted.

The 2007 proposed DSM spending represents a material increase over recent experience. Hydro indicates that its forecast for 2006 includes the $100,000 Hydrowise spending (as well as approximately $25,000 in additional salary costs[63] related to Hydrowise for a total of $125,000) plus the $500,000 amount noted above. Hydro was asked to provide more details on the conservation targets associated with this spending and the proper accounting treatment for such expenditures.[64] Hydro's only response was that it was currently evaluating many different types of initiatives and that such programs would be targeted to all consumers and targets would include both capacity and energy savings as appropriate.[65]

Given the current cost of fuel and maintenance expenses for Holyrood, efforts to reduce the generation required from that facility can certainly benefit ratepayers. Hydro's proposed spending on DSM does not seem out of proportion with other regulated utilities[66]; however, the Board and Hydro's ratepayers should be wary of such a material increase in proposed spending absent further clarification regarding the types of programs and initiatives being considered, the types of reasonable performance targets that should be implemented to ensure that spending is effective and that performance can be evaluated and how those costs will be treated for accounting and cost of service purposes.

Two specific comments are provided in respect of Hydro's proposals:

1. **Development of Objectives:** As part of the initial stages of the DSM program, Hydro should be directed to develop objectives and load reduction targets for the program as

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[62] CA 163 NLH.
[63] IC 1 NLH.
[64] See for example CA 167 NLH; IC 2 NLH and IC 145 NLH.
[65] IC 2 NLH.
[66] For example, Manitoba Hydro's 2000/01 and 2001/02 Annual Power Smart Review reported utility Power Smart program costs of $7.293 million on domestic electricity revenues of $797 million in 2001/02. Since that time, it is understood that DSM program spending has grown materially.

quickly as possible, potentially for review by the Board. This will allow both tracking of the program achievement, and a focus on the best means to achieve the targets. In seeking to maximize the value of the program, Hydro should include consultation with Industrial Customers regarding the best means to achieve conservation objectives in their operations. Experience in other jurisdictions indicates that it may be optimum to implement DSM for large industrial customers focused on a) funding technical and feasibility work to confirm the potential for customer savings via the implementation of new technologies or process improvements – once such data is available the customers themselves can typically proceed to implement the improvements without much further utility involvement, and b) curtailable rate programs with respect to interruptible capacity.

2. **Recognize Long-Term Value:** DSM programming is typically implemented as a means of securing new resources to meet system load over more than one year. As a result, accounting approaches for DSM can reflect this longer-term benefit. For example, in Manitoba, Manitoba Hydro defers and amortizes its "Power Smart" DSM expenses over 15 years[67]. Given Newfoundland Hydro's DSM programming is relatively new and undefined, it would be appropriate today to adopt a deferral over a shorter period, such as 10 years, for further review at a later date.

There are currently no major concerns with respect to Cost-of-Service methodologies for tracking DSM spending, given the relatively modest amortization on the deferred amounts that would occur in 2007 (if amortized over 10 years). Nevertheless, it is recommended that Hydro should be directed to begin tracking DSM spending by system and customer class, such that DSM accounts can be assigned in this fashion in future cost of service studies.

[67] Per Manitoba Hydro - Notes to Consolidated Financial Statements, 2005/06.

5.0 SPECIFICALLY ASSIGNED CHARGES

Specifically assigned charges to NP and each of the IC reflect assets and related O&M costs for components of Hydro's system that are solely used by the customer in question.

Hydro's proposal for specifically assigned charges for IC for 2007 have been updated from the 2004 test year to reflect several asset additions[68]. The largest change in respect of the existing IC is to Corner Brook Pulp and Paper, related to major investment in the Frequency Converter. The Board has previously ruled that the Frequency Converter is to be directly assigned to Corner Brook, so these charges appear reasonable and consistent with the investment expected.

In respect of the new IC, Aur Resources, the specifically assigned charge reflects primarily the new 45 kilometre transmission line TL264[69] of $5.455 million original cost consisting of $4.2 million of transmission and $1.255 million of terminal stations. However, as the line costs were fully contributed by Aur Resources, there is no return on rate base or depreciation related to these assets. As a result, the Aur Resources specifically assigned charge totals $0.19 million per year, comprised of $0.025 million in depreciation of common assets (such as feasibility studies) and $0.167 million in operating and maintenance costs.

With respect to the calculation of the specifically assigned operating and maintenance expense, Hydro appears to allocate the share of operating and maintenance costs on the basis of the share of gross plant by function per IC-34. For example, the calculation of the specifically assigned portion of transmission line expense for Aur Resources is as follows:

$$\frac{\text{Customer Transmission Plant in Service}}{\text{Total NLH Transmission Plant in Service}} \times \text{NLH Transmission Lines O\&M} = \text{Sp Assigned}$$

$$\frac{4,200,000}{302,529,988} \times 2,465,736 = 34,232$$

As per the above calculation, Aur is allocated $34,232 of Hydro's $2.465 million transmission line O&M based on the gross book value of plant in service for Aur compared to the entire system. Presumably this reflects transmission maintenance costs such as brushing, replacement of insulators and other maintenance activities. Similar calculations are used for each category of O&M, to ultimately allocate the full $0.167 million in O&M costs to Aur, as well as the $0.025 million of depreciation.

This approach to allocation is consistent with the approach to specifically allocating costs to the other customers on Hydro's system. It reflects the use of basic ratios similar to a number of components of the

[68] IC 34 NLH.
[69] Per Schedule JRH-2-II

Cost of Service study. However, in respect of Aur specifically, the approach raises concerns due to two factors:

1. **Gross Book Value Allocation:** The approach is effectively based on a rough assumption that operations and maintenance costs for transmission lines and other plant are incurred in direct proportion to their gross book value (original cost). However, there is no means to adjust these book values to reflect the era in which the investment was made. For example, transmission lines built today compared to in past years reflect gross book value costs that will incorporate considerable inflation, and as a result likely attract more of the "ratio-based" costs than similar assets built in past periods.

2. **Operating and Maintenance Expenses on New Assets:** For new transmission lines, it would be expected that operating and maintenance costs would be well below the system average (particularly for such components as brushing) due to their recent construction. As a result, any standard ratio-based allocation of operating and maintenance costs likely overstates the costs to Hydro in 2007 related to these specific new assets.

In addition, the life of the Aur Resources Duck Pond mine is understood to be only about 8 years.

It is difficult to quantify the combined effect of the above factors in over-estimating the fair level of costs to Aur. However, although ratio approaches remain reasonable in a cost-of-service context, given this is a small customer which appears to being unduly burdened by the ratio approach, the Board should consider applying a subsequent ratio to the calculated specifically assigned charge to Aur to ensure they are not being overly burdened by these average system charges on the $5.455 million transmission line and terminal station they are already fully funding via customer contributions.

6.0 NP AND OTHER GENERATION CREDITS

Pursuant to the Board's direction in Order P.U. 14 (2004) from the 2003 GRA, Hydro commissioned a study into the appropriate cost of service treatment of the "NP Generation Credit" (provided in Exhibit RDG-2). The issue relates to the approach used by Hydro to "credit" NP amounts via the cost of service study to recognize that NP owns generation that Hydro at times uses in support of the entire grid. Hydro has argued in past proceedings that such a credit is appropriate for NP hydraulic and thermal generation as the NP generation is of value, and absent such a credit the benefits it provides to the integrated grid (particularly the benefits of NP's thermal generation[70]) would go uncompensated by Island Interconnected customers.

Conceptually, the NP Generation Credit is a means whereby Hydro compensates NP (and consequently charges all Island Interconnected customers) amounts in recognition of the role NP's remote thermal generation can, at times, play in helping meet overall system peaks.

There are a number of tools available to system planners and operators with regard to meeting system peaks, through both 'dispatchable' short-term generation (such as NP's thermal generation) and similarly through dispatchable short-term reductions in demand, such as curtailable rates programs. In contrast to NP who offers curtailable rate options and associated credits for its customers that can interrupt their load on short notice and consequently help to meet system peaks, Hydro does not provide any of its customers other than NP with the opportunity to access such a credit mechanism for either dispatchable generation or load reductions (and has continued to ignore the opportunity to re-instate past conservation "demand credit" programs such as its previous "Interruptible B" offering[71] that was cancelled on Abitibi Stephenville leading into the 2003 GRA).

6.1 BACKGROUND ON THE NP GENERATION CREDIT ISSUE

In the 2001 GRA and the 2003 GRA, the IC indicated concern over the degree of credit being provided to NP via the generation credit. The essential points raised in the IC position were as follows:

1. **Units focused primarily on rural service:** Rates for IC in Newfoundland should reflect the overall bulk power system providing high-voltage service (including major generation and core backbone transmission) based on normal cost of service principles so as to not cross-subsidize the cost of providing power to rural customers in Newfoundland. The NP thermal generation has a primary role of providing reliability to rural areas, with at most a

[70] NP's hydraulic generation is actually forecast to operate at peak times, so NP in effect receives a "credit" for this generation in any event, similar to IC-owned hydro generation. This is because NP's hydraulic generation is netted off of the total NP "native" peak to determine the peak to be imposed on Hydro's system. As the thermal generation is not forecast to operate at peak times, no similar credit is embedded in NP's load forecast.

[71] The specific details of the Interruptible B rate program are as follows: this program was in place under a contract from December, 1993 to March, 2003, and provided Hydro with the ability to call upon Abitibi Stephenville, at any time during the four winter months between the hours of 0800 and 2200, to reduce their power consumption by up to 46 MW for up to 10 hours. The interruption could be initiated on one hour's notice. This type of program is similar to interruptible capacity rate offerings by other utilities.

much lesser role in providing capacity support to the Island Interconnected System. As such, the costs of the thermal generation are primarily a rural service cost, and under normal cost of service principles should not result in added charges via the IC rates.

2. **Credit higher than Costs – credit far more generous than needed to compensate NP for their costs:** At the 2003 Hydro GRA, the IC evidence reviewed how, in effect, the IC and Rural customers were being allocated 59% of the NP annual costs for their thermal generation (annual costs in NP's revenue requirement of $1.691 million, of which $0.995 million was credited back to NP and charged to IC and Rural). This was far above the IC and Rural share of the overall system demand, at about 20% at that time. In other words, units which had a single role in supporting the system peak demand would only be allocated 20% to IC and Rural – presumably units which had a double role, of which only the lesser was supporting broad system demand (the larger being supporting NP rural reliability) would be allocated far less than 20% to IC and Rural based on loads at that time, and certainly not 59%.

3. **Credit higher than Value - higher than full cost for new, reliable, ideally located units:** Hydro already pays NP for all variable costs to run this thermal generation when it is required for system support. As such, the NP Generation Credit is at most a type of payment towards their capital cost to retain the option for Hydro to call upon the units when needed. Given new capacity could at the time (the 2003 GRA) be secured for $100/kW/year for new simple cycle turbines, the maximum economic value to IC at that time for new, reliable, ideally located capacity was $12.64/kW, since IC was 12.64% of the system peak. By contrast, the cost-of-service approach adopted by Hydro cost IC $16.23/kW for NP's older, remotely located units which were not even primarily focused on this role. In other words, the net "payment" to NP imposed on IC did not reflect the value (in terms of avoided capacity costs) that these units provided.

4. **Credit does not reflect ongoing need/benefit to the system at that time:** Prior to the 2003 GRA, one IC operation (Abitibi - Stephenville) had participated in a program to offer Hydro interruptible capacity (46 MW) that Hydro could call on to help meet peak loads (i.e., as an effective source of supply). This rate – called Interruptible B – played the exact same role in Hydro's operations as NP's generation[72]. However, as a result of new Power Purchases and the in-service of Granite Canal at that time, Hydro cancelled that Interruptible B program (and the corresponding $1.3 million annual payment to Abitibi Stephenville) as it indicated it no longer needed the capacity. In contrast to the assertion that capacity was not required at that time, Hydro continued to propose maintaining the credit to NP for its thermal generation (in fact to slightly enhance the credit via reduced system reserves[73]).

[72] Arguably, Interruptible B is of much higher value than new generation, as 1) it is guaranteed to be available (there is no risk of unit failures or being out-of-service), 2) it is directly on the backbone transmission, and 3) along with the 46 MW, Hydro also saves the losses on this capacity (so more than 46 MW benefit) – with the dispatch of NP generation the net benefit to the system will typically be the value of the generation less the incremental losses.

[73] At the 2003 GRA, Hydro reduced the system reserve from 18.5% to 16%, which in effect increased the credit to NP for its generation.

Further detail on the IC argument from the 2003 GRA is provided in Attachment E.

In the 2003 GRA, the Board accepted the existing methodology but directed Hydro to conduct a study of the appropriate treatment of NP's generation following the 2003 GRA.

6.2 HYDRO'S PROPOSAL IN THIS GRA

In the current GRA, Hydro provided the directed study and has proposed a material modification to the NP Generation Credit as set out in detail in Exhibit RDG-2. Hydro has assessed the value of NP's generation and determined that this generation in effect contributes to the system both through reducing the LOLH in the test year, and through allowing over the long-term an opportunity to defer additions of new plant (per RDG-2 Exhibit 6). Although this conclusion is entirely at odds with the NERA report, which concludes capacity is of no material current or long-term economic value on Hydro's system[74], the evidence provided in RDG-2 indicates that the presence of NP's generation allows deferral of future investment in system generation, and IC-55 further indicates that additional new sources of capacity beyond NP's generation can further extend the time before new generation is triggered (in that case assumed to be focused capacity contributions via curtailable rates such as the old Interruptible B).

The study (exhibit RDG-2) did conclude that various components of the Generation Credit, as it had been applied to date, were not appropriate. Consequently, Hydro now proposes to reduce the value of the NP Generation Credit compared to the approaches used in the 2001 and 2003 GRAs, pursuant to the recommendations of the study. This adjustment relates to removing any credit related to the transmission system, and ensuring the provision of the credit does not result in erroneous system load factor calculations[75]. The net cost effect of the proposal is set out in Table 6.1 below (using 2007 Test Year results).

[74] NERA indicates, essentially, that the present price of No. 6 fuel will drive new investment in economic wind and hydraulic generation plant for energy reasons, that will in effect bring capacity along with it at basically no added cost.

[75] The system load factor for the purposes of classifying hydraulic and purchased power costs to demand and energy is based on the overall sales (numerator) and the peak loads (denominator). In the approach used to date, the NP Generation Credit was mathematically applied to artificially reduce the system peak loads (reduce the denominator) to erroneously arrive at an artificially high system load factor.

Table 6.1
NP Generation Credit – Net Effect of 2003 Approach and Hydro's Proposed Approach on Test Year 2007

($millions)	2003 GRA Approach (Per RDG-1, revised as per NP-67)	Hydro's Proposed Approach (per NP-67)	No Generation Credit (per IC-38)
Fully Allocated Cost to Serve NP	290.859	291.104	291.452
effect of credit	*(0.593)*	*(0.348)*	-
Fully Allocated Cost to Serve IC	44.565	44.367	44.174
effect of credit	*0.391*	*0.197*	-
Fully Allocated Cost to Serve Rural Island Interconnected	56.796	56.749	56.594
effect of credit	*0.202*	*0.155*	-

The above table demonstrates that Hydro's proposed approach provides some degree of relief from the cost impacts of the Generation Credit on IC (from $0.391 million to $0.197 million) and Hydro Rural customers (from $0.202 million to $0.155 million). As noted in Table 6.2 below, Hydro's proposed approach more accurately reflects the limits on the value the NP Generation brings to the Island Interconnected System (as opposed to its own rural systems) compared to past practice.

Table 6.2
NP Generation Credit – Effective cost per kW to the Island Interconnected System Customers

($millions)	2007 Test Year		2004 Test Year
	2003 GRA Approach (Per RDG-1, revised as per NP-67)	Hydro's Proposed Approach (per NP-67)	
Cost to IC	0.391	0.197	0.738
Notional "full cost" of NP Thermal Generation Credit (IC at 8.08% of system in 2007, 12.64% in 2004)	4.839	2.438	5.839
Effective kW of thermal generation	37,826	37,826	45,500[76]
Cost per kW "compensation" to NP	$127.9/kW	$64.5/kW	$128.3/kW

[76] From RDG-2 from the 2003 GRA, Appendix 3

The values in Table 6.2 indicate in the first row the costs to IC from Table 6.1 of the old approach (2003 GRA, for the 2004 Test Year) and Hydro's proposed approach (in the middle column). These costs to IC are equivalent in each case to a system cost (effectively a payment to NP) of the amounts in the second row (the values between $2.438 million under the Hydro proposed approach, up to $4.839 million under the old approach applied to the 2007 test year – for reference this value was $5.839 million in the 2004 Test Year). As NP's thermal generation only provides 37.8 MW (45.5 MW in 2004), this is equivalent to a payment to NP as shown in the bottom row - $127.9/kW/year under the old approach, and $64.5/kW/year under Hydro's proposed 2007 approach.

Table 6.2 indicates impacts on IC costs that are a marked improvement compared to the 2003 approach; however, overall charges remain high compared to the relative role and value of the NP Generation:

- **Role:** The units in question remain old and in locations driven primarily by the provision of local rural load support (not being on main 230 kV backbone transmission). Further, as suggested in the recent marginal cost reports, continued pursuit of cost-effective energy in order to displace Holyrood generation may serve to bring future capacity to the system at very little to no incremental cost[77].

- **Value:** NP has not updated in this proceeding the cost of these units to its annual revenue requirement. However, in the 2003 GRA, NP indicated (IC-187 from the 2003 GRA) that the annual revenue requirement for the thermal units was $1.691 million in 2001, presumably lower in 2007 with ongoing depreciation[78]. In contrast, the approach proposed by Hydro today continues to credit NP with an effective $2.438 million in 2007 from all Island Interconnected Customers in 2007 (of which IC pays $197,000 consistent with its 8.08% share of system peak).

- **Fairness:** Compared to this generous credit to NP for installed capacity, Hydro today offers no credit to other customers who own generation that can be dispatched to help meet the system peak loads. In particular, the standard operating procedure for the Island Interconnected System does indicate Hydro plans to use these resources. For example, Corner Brook Pulp and Paper provide Hydro with the opportunity to have CBPP increase its Deer Lake generation at peak times to aid in meeting system peak loads. In addition, Hydro no longer offers an "Interruptible B" rate (an option offering to industrials to allow them to curtail their loads at peak times in exchange for an annual "credit") despite this type of conservation rate being routinely among the most successful capacity DSM programs offered by other utilities. In each case (CBPP generation at Deer Lake, and the former Interruptible

[77] This conclusion, however, is quite a dramatic change from the conclusions of RDG-2 and the value that RDG-2 determines for capacity on the system. Before considering accepting such a dramatic change as computed by NERA (that capacity is of basically no value on the system), further serious consideration should be given to the issue.

[78] Exhibit RDG-2 appears to indicate NP's calculations of the cost of the units at $3.704 million; however this is entirely inconsistent with earlier NP data.

B), the resources are higher in Hydro's stacking order (per Exhibit JRH-3 of the 2003 GRA)[79] meaning they are dispatched more frequently than NP's thermal generation.

In this proceeding, it is necessary to critically assess the extent of Hydro's range of capacity credits, and a fair and efficient distribution of these credit opportunities to customers. In a marked contrast to Hydro's elimination and continued rejection of any "capacity credits" to any customer other than NP, the evidence in this hearing is that NP has expended its curtailable rate offering[80] (similar to Hydro's former Interruptible B, but for smaller customers) in part to respond to the demand-price signal imposed by Hydro's two-part rate.

6.3 TWO OPTIONS TO ADDRESS GENERATION CREDIT IN THIS GRA

Based on the above discussion, there would appear to be two reasonable means to address dispatchable demand resources in this application:

1. **The first option is to eliminate the NP Generation Credit entirely for its thermal resources**, and retain the credit for hydraulic resources the same way IC customer generation is treated.

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[79] the System Operating Instruction in Appendix A of Exhibit JRH-3 of the 2003 GRA indicates the following measures that are to be applied in the sequence set out below in times of system constraints:

1. Approach maximum on Hydro's hydraulic and steam generation
2. Request NP to maximize their hydraulic generation
3. Request Deer Lake Power and NUGS to maximize production
4. Notify industrial customers that non-firm power rates will start to be based on gas or diesel costs (higher cost than Holyrood). Ask NP to curtail their interruptible loads.
5. Start using standby generation
    a. Hardwoods gas turbine (54 MW)
    b. Stephenville gas turbine (54 MW)
    c. Curtail Interruptible B load (46 MW)
    d. Holyrood gas turbine (10 MW)
    e. Hawke's Bay diesel and St. Anthony diesel (13 MW)
    f. Two NP gas turbines (25 MW and 40 MW)
    g. Roddickton diesel (1.7 MW), NP mobile gas turbine (7 MW), various NP diesels (6.9 MW)
6. Interrupt non-firm industrial energy
7. Re-confirm steps 1-6
8. Reduce voltage at Hardwoods and Oxen Pond
9. Request industrial customers to shed non-essential loads
10. Request industrial customers to shed additional load
11. Request NP to start rotating feeders and start rotating Hydro rural feeders.

The above sequence beyond step 4 reflects activities that are infrequent at best. For example, exhibit JRH-3 of the 2003 GRA notes that St. Anthony and Hawke's Bay diesels (step 5e) had to that time been dispatched only once since the 1996 interconnection .

[80] IC-58

2. **A second option is to ensure a fair and reasonable credit and opportunity for all customers to benefit from both their own generation and their own potential to offer curtailable demand,** as follows:

   a. ***Adopt Hydro's recommendation in respect of NP Generation:*** Adopt the recommendations of RDG-2, which ensures the Generation Credit will not apply to transmission, and will not be allowed to erroneously distort the system load factor.

   b. ***In addition, provide equivalent fair credit to other capacity sources:*** For example, with respect to Corner Brook Pulp and Paper, ensure a generation credit is provided to reflect the Corner Brook (Deer Lake) generation as a resource available to Hydro. For 2004, CBPP provided an answer to an RFI in the 2003 GRA (NLH-226-IC) as to the magnitude of capacity they are likely able to make available to Hydro at peak times, which has been updated here for 2007 based on information received from CBPP:

   > Corner Brook Pulp and Paper's native peak load requirement is 162 MW, comprising 142 MW at 60 Hz and 20 MW at 50 Hz. Peak generation at Deer Lake Power's facilities is 80 MW at 60 Hz and 40 MW at 50 Hz for a total of 120 MW, assuming all units available and a full head on the Deer Lake plant. Accounting for Losses of 5.4 MW, this produces net peak generation of 114.6 MW. The difference between Deer Lake Power generation and mill requirements at peak is 47.4 MW. Allowing a margin to avoid exceeding the Power on Order results in a CBP&P Power on Order request of 52 MW for 2007[81].
   >
   > When Hydro requests Deer Lake Power to maximize generation, the production available will depend upon the load requirements of the mill at the time. At peak load, there should be approximately 4.6 MW available to the grid. If the mill is not at peak load the available power could be significantly higher.

   Further, for the purposes of cost of service, Hydro in effect assumes that the mill will not be at peak load during system peaks, by way of using only a 89.6% coincidence factor for this load. As a result, based on this information it is appropriate for the Board to ensure a fair Generation Credit is included for IC in the COS study, of at least 4 MW net of reserves[82] (approximately 1/10 the credit provided to NP for their thermal generation).

   c. ***Finally, provide opportunity for future Curtailable Load credit:*** The Board should ensure Hydro, in the context of proposed expanded DSM programming, is required to develop a Curtailable Rate program for its retail and industrial Island Interconnected customers prior to the next GRA. This program should be coordinated with and linked in terms of fair value with the NP Curtailable rate offering.

Either of the above two approaches would reflect a fair and consistent treatment of all capacity resources on the system. In addition, the second approach offers a fair treatment of Hydro's customers compared

[81] Note that the GRA filing indicates a Power on Order of 54 MW. This is understood to be a recent update which presumably will be reflected in the final COS.
[82] Hydro plans on reserves of 15% (Haynes, page 32) which reduces 4.6 MW to approximately 4 MW.

to NP's in respect of load curtailment "credit" opportunities, and as a result should be accepted by the Board.

7.0 LONG TERM SYSTEM PLANNING

Since test year 2004, Hydro's use of Holyrood has decreased by approximately 180 GW.h (from approximately 1,780 GW.h in 2004 to approximately 1,600 GW.h in 2007); however, the sole contributor to this reduction is the closure of Abitibi-Stephenville, which reduced Hydro's net load at generation by about 525 GW.h[83]. Overall system generation is expected to grow by approximately 600 GW.h over the next 5 years and with the exception of an as yet unallocated $500,000 DSM program in 2007[84], this application contains no specific measures to address reductions in the use of Holyrood. Indications of potential future activities to occur outside the 2007 Test Year include a proposal to secure 25-75 MW of wind (totalling 91-273 GW.h), as well as a brief reference in Mr. Martin's evidence to giving greater consideration to the potential advancement of up to three hydro projects such that they can be completed by early in the next decade (each in the range of 77-186 GW.h). Even combined, all potential wind and hydro projects noted reflect less energy than expected load growth during the intervening period to potential final project in-service, and will therefore provide no net contribution towards reducing Holyrood generation compared to today's levels.

In sharp contrast, CA-19 indicates that at today's retail rates (NP's and Hydro's) electric space heating and water heating in particular remains a reasonably cost competitive source of energy on the Island Interconnected System, that is expected to contribute to load growth on NP's system and Hydro's Rural Island Interconnected systems. While there are clear concerns over the thermodynamic inefficiencies related to the substantial losses on steam generation and transmission systems of oil-fired electricity being used for space and water hearing (compared to using oil or other fuels directly for heating), at a broader public policy level, the overall Newfoundland economy is not well served by failing to use this opportunity to develop enhanced local sources of supply, such as Island or Labrador hydro generation (with the attendant in-feed, depending on construction costs).

It is clear that regulation of Hydro over the coming years will need to focus heavily on assessing new sources of supply. System planning on non-interconnected systems is not an easy exercise, as major costs are typically involved, timelines from the time of commitment through to first power can be long, commitments made will drive costs for decades to come, and there is never perfect information on which to base decisions.

It is also clear that at the present time, there are strong incentives that need to be considered – Holyrood is expensive to operate, increasingly expensive to maintain and potentially requires very substantial capital to address emissions issues. Island sources of new supply are suggested to be limited, and even under very optimistic scenarios (all 3 of the 25 MW wind projects, plus Island Pond, Portland Creek and Round Pond are developed), the new non-Holyrood supplies will only serve to help meet ongoing load growth, without materially contributing to actual reductions in the use of Holyrood generation. Finally, major supply options such as Labrador infeed (with or without new Labrador generation) are clearly of substantial capital cost.

[83] Per CA-109.
[84] Some wind monitoring capital spending is also included in Hydro's 2007 Capital Budget, at $33,000.

On a non-interconnected system, a strong coordinated planning role is needed to ensure a complete and balanced mix of resources are secured (e.g., dispatchable versus non-dispatchable, hydro versus resources not subject to drought risk, geographic distribution, DSM versus supply-side resources, and incorporating seasonal variability considerations, load forecast risk, and other similar considerations). This involves an ongoing assessment of opportunities and supply options, and weighing risks and benefits of many facets related to long-term supply. Much of this role in Newfoundland can only practically be fulfilled by Hydro.

Past experience with new bulk power developments in Newfoundland do not provide a positive record with respect to ensuring proper, timely regulatory review by the PUB pursuant to what Hydro refers to as the Board's "authority and responsibility to ensure that proper planning of generation sources occur" per CA-43. Ignoring for a moment the inherent difficulties in this concept as it is described by Hydro (that the PUB is the body responsible for planning the system, a role for which the utility would normally be expected to have the lead role, as it has the funds, expertise, specific knowledge and data to carry out system planning; under the supervision of the Board[85]), past practice from Newfoundland with regard to new supply sources provides no indication of this PUB role being successfully achieved. In particular, approvals for both the recent power purchase agreements and the approval of Granite Canal generating station were provided by the Government of Newfoundland and not the Board[86] due to the time constraints imposed by deferring decisions on these projects until immediately before commitment decisions were required. The Board has recognized this in Decision P.U. 14 (2004) at pages 147-149, where the Board noted the contrast between the type of regulatory review contemplated by the Act compared to recent practice.

The evidence provided by Hydro outlines roughly the utility's future plans for the next source of supply. This appears to reflect a project planning and regulatory review process that is inadequate with respect to the Board's jurisdiction and role, similar to the regulatory review deficiencies that occurred in the case of Granite Canal. In this vein, the process may ultimately lead to the same time-driven constraints on proper and thorough review of resource planning before the Board. This concern is heightened by increased fuel prices, which may support a significant economic opportunity for advancement of Hydro's hydraulic generation projects (or a Labrador infeed) compared to that assumed by Hydro; whereas the Board has no obvious near-term opportunity planned by Hydro for it to review and potentially drive such an advancement. In particular, the following key points are noted:

- **Holyrood Condition Assessment**: Hydro's 2007 Capital Budget seeks approval of a major condition assessment of Holyrood generating station ($3.335 million). The results are intended to allow comparison of various supply options to the costs of extending the life of Holyrood and continued use of the plant. Hydro indicates that the results of this work, will not be available until year-end 2007 (per PUB-13.0 from the 2007 Hydro Capital Budget Application).

[85] The Board clearly retains a major oversight and review role with respect to resource planning on Hydro's system. As an example, the scope for a current Yukon Resource Plan regulatory review before the Yukon Utilities Board is provided in Attachment F, which is the Minister's letter enabling the review (in Yukon, unlike Newfoundland, the legislation does not provide YUB jurisdiction over these matters absent such a Ministerial direction).

[86] This was reviewed in some detail at the 2001 Hydro GRA.

Although there is understood to be an ongoing regulatory process with respect to the Holyrood Condition Assessment, to determine if it is required in 2007 and at what scale, the evidence appears to be that Hydro sees this project as a first step in the longer-term system planning exercise. This type of sequence is consistent with proceeding from existing system assessment, to determining system requirements as a next step, and then to determine resource options and select a preferred resource, in this type of linear fashion. Clearly alternative sequences can exist based on the fact that Holyrood physically is not at end-of-life[87]. These alternatives may involve a major focus on new economic supply options and incremental progress on developing non-Holyrood generation as the first step (followed in a number of years by serious Condition Assessment of Holyrood once it is physically closer to end-of-life). In any event, Hydro's capital budget proposal does not embrace such an alternative approach.

- **Call for Proposals:** In CA-42, Hydro indicates that before it commits to further resource acquisition the expected course of action will involve a 12 month process of competitive supply RFPs with regard to determining its preferred resource options. Given the apparent Hydro approach noted above, this would presumably follow the determination of system requirements coming out of the Holyrood Condition Assessment (which would yield information on the capabilities and costs of operating or life-extending Holyrood into the future). Consequently, even under the most optimistic circumstances it may be assumed that this RFP process under Hydro's plan will take up to one year following the Holyrood Condition Assessment, from 2008 through to 2009 (note also that Hydro's 2007 Revenue Requirement includes no apparent costs to conduct such an RFP process[88]). Presumably by the end of that RFP process, Hydro would expect to have full knowledge of its existing system longevity and of non-utility generation options available to it, against which to assess its own supply options such as new NLH hydro, for ultimate review by the Board.

- **Island Pond and other NLH hydraulic generation projects:** Although Mr. Martin indicates Hydro may consider advancing Island Pond or other hydraulic generation projects, the current plan is to have this generation in service by 2014, with construction beginning in 2011[89]. While various factors would influence the process, it would be routinely expected that at least 2 years of detailed engineering and environmental field studies and licencing activities will be required in advance of starting construction[90]; further time may be required

[87] A quick review of the evidence in the 2006 Capital Budget proceeding indicates debate over the degree to which Holyrood's current operating hours are within the range normally assumed by utilities for major life assessment and life extension activities; this issue has not been reviewed in detail in the current proceeding.

[88] In contrast, note that Hydro is able to proceed quickly with RFPs for new wind generation based on this being a potentially economic source of new supply to the system. There would appear to be no prohibition on further investigating and committing to other new (wind or non-wind) supply options in the near-term prior to the Holyrood Condition Assessment being completed, if that were determined to be required.

[89] IC-63 and IC-168.

[90] In contrast, Hydro appears to indicate two incompatible schedules in CA-42 and IC-168. In CA-42, Hydro indicates that all planning, licencing and construction of potential resource options can be completed over "18 to 42 months, depending on the resource chosen"; however in IC-168, Hydro indicates that for Island Pond, construction alone would take 3.5 years (42 months) with no apparent additional time provided for planning, environmental licencing, activities, etc. in advance of construction.

if significant fish or habitat issues must be addressed (as suggested by IC-127). In other words, committed activity may be required by no later than 2008/09 to protect the planned 2014 in-service date (other projects, such as Portland Creek, appear to be behind Island Pond in terms of knowledge today).

Starting with the sequence of activities currently underway, Hydro's approach appears to result at best in an opportunity for the Board to review a comprehensive integrated resource plan for the Island system by no earlier than some point in 2009. In contrast, working back from the Island Pond in-service date that is required to meet Hydro's load forecast, such regulatory activity would ideally be scheduled no later than 2008 in advance of significant commitments of time and funds towards environmental licencing and design of Island Pond, with full PUB involvement occurring considerably sooner if Mr. Martin's proposed "advancement" scenario is to be pursued.

Hydro's intentions with respect to potential advancement of Island Pond or other hydraulic generation in order to avoid No. 6 fuel costs are prudent and justified; however, there appears to be no firm and coherent schedule or iterative sequence for integrating the various pieces noted above. This may in part reflect Hydro's view set out in CA-190 that it "does not prepare a complete integrated resource plan". Although Hydro may be correct that "such a plan would require input from all energy sectors", it is not clear that there is any practical alternative to Hydro to prepare such a plan for PUB review. As an example, Manitoba Hydro has prepared at least 2 Power Resource Plans for the Manitoba power system for regulatory review[91] despite there being one other utility owning generation in Manitoba (during the 1990 review) and despite actively pursuing non-utility generation (during the 2004 review) – neither prevented Manitoba Hydro from playing this key role.

A firm schedule is required at this time to ensure that proper planning and regulatory review is not minimized. In its Order for this proceeding, the Board should ensure that there is a firm submission timeline set for a Long-term Island Interconnected System Resource Plan and clarity that Hydro has the lead role in preparing that plan for PUB review. The plan should include proposed preferred development scenarios (potentially along the lines of the scope provided in Attachment F, with respect to Yukon's current 20-year Resource Plan review), ideally in the first half of 2008 to allow Island Pond or other new generation or infeed commitment activities to proceed forthwith in the event they are determined to be justified. In the event the Holyrood Condition Assessment proceeds in 2007, Hydro should be encouraged to develop preliminary conclusions as early as possible in 2007 for integration into resource planning activities.

[91] One such plan was reviewed by the PUB in 1990, when the Conawapa project was proposed; the second was in 2004 before the Clean Environment Commission under a somewhat different framework as part of a review of the proposed Wuskwatim project – "Justification, Need for and Alternatives to" the project.

ATTACHMENT A

Resume – Patrick Bowman

EDUCATION: **University of Manitoba**
MNRM (Natural Resource Management), 1998

Prescott College
BA (Human Development and Outdoor Education), 1994.

PROFESSIONAL HISTORY:

InterGroup Consultants Ltd. **Winnipeg, MB**

1998 – Present *Research Analyst/Consultant/Principal*

Regulatory economic analysis and socio-economic impact assessment experience, primarily in the energy field.

Utility Regulation

Conducted research and analysis for regulatory reviews of electrical and gas utilities in four Canadian provinces. Prepare evidence and review testimony for regulatory hearings. Assist in utility capital and operations planning to assess impact on rates and long-term rate stability.

- **For Yukon Energy Corporation (1998-present)**, analysis and support of regulatory proceedings and normal regulatory filings before the Yukon Utilities Board. Appear before YUB as expert on revenue requirement matters. Prepare analysis of major capital projects, financing mechanisms to reduce "rate shock" to ratepayers, as well as revenue requirements.

- **For Yukon Development Corporation (1998-present)**, prepare analysis and submission on energy matters to Government round table on competitiveness of Yukon economy. Coordinate development of options for government rate subsidy program. Assist with review of debt purchase, potential First Nations investment in utility projects, and corporate governance.

- **For Northwest Territories Power Corporation (2000-present)**, provide technical analysis and support regarding General Rate Application. Assist in preparation of evidence, filings before the Northwest Territories' Public Utilities

Board, and related issues. Appear before PUB as expert in cost of service and rate design matters, and on system planning (Required Firm Capacity) review.

- **For Manitoba Industrial Power Users Group (1998-present)**, prepare analysis and evidence for regulatory proceedings before Manitoba Public Utilities Board representing large industrial energy users. Appear before PUB as expert in cost of service and rate design matters in rate proceedings, as well as cost-of-service methodology hearing. Assist in regulatory analysis of the purchase of local gas distributor by Manitoba Hydro. Assist industrial power users with respect to assessing alternative rate structures and surplus energy rates.

- **For Industrial Customers of Newfoundland and Labrador Hydro (2001-present),** prepare analysis and evidence for Newfoundland Hydro GRA hearings before Newfoundland Board of Commissioners of Public Utilities representing large industrial energy users. Appear before PUB as expert in cost of service and rate design matters.

- **For NorthWest Company Limited,** review rate and rider applications by Nunavut Power Corporation (Qulliq Energy), provide analysis and submission to rate review before Utility Rates Review Council.

- **For Nexen Chemicals, Inc. (2000)**, review options for subscribing to curtailable service rates.

- **For Columbia Power Corporation/Columbia Basin Trust and Municipal Interveners (2000),** review evidence and prepare analysis on major transmission line project for Public Convenience and Necessity hearing before the British Columbia Utilities Commission.

- **For the City of Yellowknife (1999)**, prepare preliminary analysis of policy options and planning process for development of a municipal piped propane distribution system.

- **For the Government of the Northwest Territories (1999)**, prepare analysis of policy alternatives to facilitate supply of natural gas to local communities in the event of a Mackenzie Valley pipeline being constructed.

- **For INCO Manitoba Division (1998-present)**, prepare analysis of energy costs under various alternative industrial rate options. Provide recommendations on preferred energy rate options.

Socio-Economic Impact Assessment and Mitigation

Provide support in development of local investment opportunities or socio-economic impact mitigation programs for energy projects, including northern Manitoba, Yukon, and NWT. Socio-economic assessment work related to forestry planning in Manitoba and Saskatchewan. Support to two local communities in development of negotiation position for resolving outstanding compensation related to hydro projects in Northern BC. Also conducted assessment of socio-economic impacts of policy options for floodplain management, and strategic planning for resource management board.

- **For Northwest Territories Energy Corporation (2003-present)**, provide analysis and support to joint company/local community working groups in development of business case and communication plans related to potential new major hydro and transmission projects.

- **For Kwadacha First Nation and Tsay Keh Dene (2002-2004):** Support and analysis of potential compensation claims related to past and ongoing impacts from major northern BC hydroelectric development. Review assessment of options related to energy supply, including change in management contract for diesel facilities, potential interconnection to BC grid, or development of local hydro.

- **For Manitoba Hydro Mitigation Department (1999-2002)**, provide analysis and process support to implementation of mitigation programs related to past northern generation projects. Assist in preparation of materials for church-led inquiry into impacts of northern hydro developments.

- **For International Joint Commission (1998)**, analysis of current floodplain management policies in the Red River basin, and assessment of the suitability of other floodplain management policies.

- **For Nelson River Sturgeon Co-Management Board (1998 and 2005)**, an assessment of the performance of the Management Board over five years of operation and strategic planning for next five years.

Government of the Northwest Territories **Yellowknife, NT**

1996 - 1998 *Land Use Policy Analyst*

Conducted research into protected area legislation in Canada and potential for application in the NWT. Primary focus was on balancing multiple use issues, particularly mining and mineral exploration, with principles and goals of protection.

Natural Resources Institute **Winnipeg, MB**

1996 - 1998 *Researcher*

Conducted research on surface rights allocation and access for mining, with particular emphasis on implications of government actions undermining mineral rights tenures. Also undertook analysis of Manitoba's Registered Trapline System and implications for Aboriginal trappers; also, an economic assessment of the property rights system inherent in the provincial Registered Trapline System policy and its implications on efficiency in allocation of the furbearer resource.

PUBLICATIONS:

G*overnment Withdrawals of Mining Interests* in Great Plains Natural Resources Journal. University of South Dakota School of Law. Spring 1997.

Legal Framework for the Registered Trapline System in Aboriginal Trappers and Manitoba's Registered Trapline System: Assessing the Constraints and Opportunities. Natural Resources Institute. 1997

Land Use and Protected Areas Policy in Manitoba: An evaluation of multiple-use approaches. Natural Resources Institute. (Masters Thesis). 1998

Electrical Rates in Yukon. Submission by Yukon Development Corporation to Yukon "Government Leader's Economic Forum Series" on Tax Reform and Competitiveness. 1999.

Review of Red River Basin Floodplain Management Policies and Programs. Prepared for Red River Basin Task Force of the International Joint Commission. 1998.

Patrick Bowman Utility Regulation Experience

Utility	Proceeding	Work Performed	Before	Client	Year	Testimony
Yukon Energy Corporation	Final 1997 and Interim 1998 Rate Application	Analysis and Case Preparation	Yukon Utilities Board (YUB)	Yukon Energy	1998	No
Manitoba Hydro	Curtailable Service Program Application	Analysis, Preparation of Intervenor Evidence and Case Preparation	Manitoba Public Utilities Board	Manitoba Industrial Power Users Group (MIPUG)	1998	No
Yukon Energy	Final 1998 Rates Application	Analysis and Case Preparation	YUB	Yukon Energy	1999	No
Westcoast Energy	Sale of Shares of Centra Gas Manitoba, Inc. to Manitoba Hydro	Analysis and Case Preparation	Manitoba Public Utilities Board	Manitoba Industrial Power Users Group (MIPUG)	1999	No
Manitoba Hydro	Surplus Energy Program and Limited Use Billing Demand Program	Analysis and Case Preparation	Manitoba Public Utilities Board	Manitoba Industrial Power Users Group (MIPUG)	2000	No
West Kootenay Power	Certificate of Public Convenience and Necessity - Kootenay 230 kV Transmission System Development	Analysis of Alternative Ownership Options and Impact on Revenue Requirement and Rates	British Columbia Utilities Commission (BCUC)	Columbia Power Corporation/Columbia Basin Trust	2000	No
Northwest Territories Power Corporation (NTPC)	Interim Refundable Rate Application	Analysis and Case Preparation	Northwest Territories Public Utilities Board (NWTPUB)	NTPC	2001	No
NTPC	2001/03 Phase I General Rate Application	Analysis and Case Preparation	NWTPUB	NTPC	2000-02	No
Newfoundland Hydro	2002 General Rate Application	Analysis, Preparation of Intervenor Evidence and Case Preparation	Board of Commissioners of Public Utilities of Newfoundland and Labrador	Newfoundland Industrial Customers	2001-02	No
NTPC	2001/02 Phase II General Rate Application	Analysis, Preparation of Company Evidence and Expert Testimony	NWTPUB	NTPC	2002	Yes
Manitoba Hydro/Centra Gas	Integration Hearing	Analysis and Case Preparation	Manitoba Public Utilities Board	Manitoba Industrial Power Users Group (MIPUG)	2002	No
Manitoba Hydro	2002 Status Update Application/GRA	Analysis, Preparation of Intervenor Evidence and Expert Testimony	Manitoba Public Utilities Board	Manitoba Industrial Power Users Group (MIPUG)	2002	Yes
Yukon Energy	Application to Reduce Rider J	Analysis and Case Preparation	YUB	Yukon Energy	2002-03	No
Yukon Energy	Application to Revise Rider F Fuel Adjustment	Analysis and Case Preparation	YUB	Yukon Energy	2002-03	No
Newfoundland Hydro	2004 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	Board of Commissioners of Public Utilities of Newfoundland and Labrador	Newfoundland Industrial Customers	2003	Yes
Manitoba Hydro	2004 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	Manitoba Public Utilities Board	Manitoba Industrial Power Users Group (MIPUG)	2004	Yes
NTPC	Required Firm Capacity/System Planning hearing	Analysis, Preparation of Company Evidence and Expert Testimony	NWTPUB	NTPC	2004	Yes
Nunavut Power (Qulliq)	2004 General Rate Application	Analysis, Preparation of Intervenor Submission	Nunavut Utility Rate Review Commission	NorthWest Company (commercial customer intervenor)	2004	No
Nunavut Power (Qulliq)	Capital Stabilization Fund Application	Analysis, Preparation of Intervenor Submission	Nunavut Utility Rate Review Commission	NorthWest Company (commercial customer intervenor)	2005	No
Yukon Energy	2005 Required Revenues and Related Matters Application	Analysis, Preparation of Company Evidence and Expert Testimony	YUB	Yukon Energy	2005	Yes
Manitoba Hydro	Cost of Service Methodology	Analysis, Preparation of Intervenor Evidence and Expert Testimony	Manitoba Public Utilities Board	Manitoba Industrial Power Users Group (MIPUG)	2006	Yes
Yukon Energy	2006-2025 Resource Plan Review	Analysis, Preparation of Company Evidence and Expert Testimony	YUB	Yukon Energy	2006	Pending

ATTACHMENT B

Resume – Andrew McLaren

InterGroup CONSULTANTS

ANDREW McLAREN
CONSULTANT

EDUCATION: **Natural Resources Institute, University of Manitoba**
MNRM (Master's of Natural Resources Management), 1999

University of Manitoba
Bachelor of Science (Environmental Science), 1996

PROFESSIONAL HISTORY:

InterGroup Consultants Ltd. **Winnipeg, MB**

2000 - Present *Research Analyst/Research Consultant/Consultant*

Regulatory economic analysis and socio-economic impact assessment experience, primarily in the energy and water resource management fields.

Utility Regulation

Conduct research analysis for regulatory reviews, primarily of electric utitilies. Prepare evidence and regulatory filings and review testimony for regulatory proceedings.

- **For Northwest Territories Power Corporation (2000-present)**, primary responsibility for coordinating and developing all aspects of the ratebase section for the 2006/08 General Rate Application. Provided technical analysis regarding the Corporation's 2001/03 General Rate Applications and ongoing regulatory support. Responsibilities have included the preparation of evidence and filings before the Northwest Territories Public Utilities Board. Other responsibilities have included assistance on economic evaluation of major capital projects.

- **For Manitoba Industrial Power Users Group (2001-present)**, prepare analysis for regulatory proceedings before Manitoba Public Utilities Board representing large industrial energy users, including expert testimony before the Manitoba Public Utilities Board in the 2006 Cost-of-Service Study hearing..

- **For Yukon Energy Corporation (2001-present)**, Review secondary and interruptible industrial sales options from other jurisdictions in Canada. Provide technical analysis and support regarding applications to the Yukon Energy Board.

- **For Yukon Development Corporation (2001-present),** prepare analyses of rate options and rate subsidy program impacts as well as contribute to discussion papers on modifications and options for on-going subsidy program.

- **For Industrial Customers of Newfoundland and Labrador Hydro (2001-present),** assist in the preparation of analysis and evidence for Newfoundland Hydro GRA hearings before Newfoundland Board of Commissioners of Public Utilities representing large industrial energy users.

- **For NorthWest Company Limited (2004-2005),** review rate application and rider applications, provide analysis and filing before the Nunauvt Utility Rates Review Council.

- **For Government of Northwest Territories (2005),** prepare modeling tools and provide analysis and discussion paper on forecast spending for the Territorial Power Support Program.

Socio-economic Impact Assessment

- **For Manitoba Floodway Authority (2003-2005)**, managed the field program for the socio-economic impact assessment of the proposed Floodway Expansion, a project to improve flood protection for the City of Winnipeg. Responsibilities included planning, conducting and supervising field work and key-person interviews, analysis of potential socio-economic pathways of environmental effects based on the results of engineering and bio-physical studies and drafting and editing the socio-economic chapter of the Floodway Expansion environmental impact statement. Participation in the project also involved responding to interrogatories and supporting expert testimony on socio-economic impacts at the Clean Environment Commission hearings on the project.

- **For Province of Manitoba (2000-2002),** conducted quantitative and qualitative assessment of socio-economic impacts related to proposed flood control alternatives for the City of Winnipeg. Included key-person interviews with stakeholders and presentation of results at public meetings.

- **For two Northern British Columbia First Nations,** Provide support and analysis related to potential claims for past and ongoing effects from major hydroelectric development. Review economic casework related to changes to energy supply options for the communities including potential for interconnecting to the BC Hydro grid or development of local hydroelectric or wind generation.

ATTACHMENT C

CALCULATION OF FUEL PRICE IMPACT - 2007 TO 2004

The 2007 Fuel price is reported in Haynes Schedule VI as $55.91. As shown in NP-58, this is solely the weighted average purchase price in 2007, and is not the average cost to ratepayers of the fuel consumed. This is for two reasons: 1) fuel consumed in the beginning of the 2007 year is actually fuel purchased in 2006, and 2) fuel purchased at the end of 2007 will not be consumed in 2007 but in 2008. To determine the proper fuel price being charged to customers in 2007, consistent with the monthly approach used in the RSP, the data required is provided in IC-5. This data also allows determination of the average price per barrel using 2004 monthly values weighted for 2007 consumption, as shown in Table C1 below:

Table C1
Calculation of Monthly and Average Annual No. 6 Fuel Price per bbl
2007 and 2004 based on 2007 monthly weightings

	2007 Holyrood production (GW.h) per IC-5	2007 Holyrood consumption (000s bbls) at 630 kW.h/bbl	2007 Cost of Fuel per IC-5	Average Price per bbl 2007	Average Price per bbl 2004
Jan	263.1	417.7	24,266	58.10	31.85
Feb	237.7	377.3	21,409	56.75	31.00
Mar	219.3	348.1	19,338	55.56	30.28
Apr	169.8	269.5	14,971	55.56	30.28
May	109.6	174.0	9,669	55.56	28.66
Jun	57.3	90.9	5,052	55.56	28.66
Jul	0.0	0.0	0		28.66
Aug	0.0	0.0	0		28.66
Sep	21.2	33.7	1,871	55.55	28.66
Oct	109.6	174.0	9,761	56.09	27.99
Nov	169.8	269.5	14,952	55.49	27.75
Dec	242.3	384.6	21,198	55.12	28.00
				weighted annual average price based on 2007 consumption	
Total	1,599.7	2,539.1	142,487	56.12	29.68

The volume of fuel forecast for the 2007 GRA reflects three major factors:

1. **Change to Average NLH hydraulic forecast:** As set out in Haynes section 7.3 and IC-130, the NLH system long-term average annual hydraulic generation is proposed to be revised from 4,582 GW.h per year (2004 test year) to 4,472 GW.h per year (2007 tear year). At an average Holyrood generation of 630 kW.h per bbl, this 110 GW.h adjustment is equivalent to 174,600 barrels of No. 6 fuel oil, or $9.798 million in 2007 based on the average test year price of $56.12/bbl.

2. **Newfoundland Power, Generation Outage of Rattling Brook hydro GS:** In 2007, Newfoundland Power proposes to do major service to their Rattling Brook hydraulic

generating station, as set out in detail in the NP 2007 Capital Budget and PUB-4.0 from that Capital Budget Proceeding. This is proposed to remove 38 GW.h of hydro generation from the NP supply to the Island Integrated System in 2007, and to ultimately enhance the output of the station by 6.2 GW.h. The net loss to 2007 generation is set out at IC-31 as the difference between NP long-term average hydro generation (426.1 GW.h from the 2004 GRA) and the 2007 forecast (381.4 GW.h) for a net loss of generation (increase purchases from Hydro) of 44.7 GW.h. This loss would appear to necessitate 46.1 GW.h of increased Holyrood generation including losses[92].

The impact of the above two changes, as well as fuel price changes since 2004 and related impacts by customer class is set out in Table C2 below:

Table C2
Impact of 2007 NLH Hydrology Changes, NP Generation Outage and Price Changes on No. 6 Fuel Cost[93]

	GWh	bbls (000s)	Total Cost ($000s) at $56.12/bbl	*estimate of impact (see note 1)*		
Total Holyrood	1,599.7	2,539.1	142,487			
Hydrology	110.0	175	9,798	*NP*	*79.36%*	*7,776*
				IC	*14.30%*	*1,401*
				Rural	*6.27%*	*614*
				Interruptible	*0.08%*	*8*
NP outage at Rattling Brook	46.1	73	4,109	*NP*	*79.36%*	*3,261*
				IC	*14.30%*	*588*
				Rural	*6.27%*	*258*
				Interruptible	*0.08%*	*3*
Other Holyrood	1,443.5	2,291.3	128,580			
total cost at $29.68/bbl			*68,015*			
total impact of #6 fuel cost changes			*60,565*	*NP*	*79.36%*	*48,064*
				IC	*14.30%*	*8,661*
				Rural	*6.27%*	*3,797*
				Interruptible	*0.08%*	*48*

As indicated in the above table, the total Holyrood generation in the 2007 Test Year of 1,599.7 GW.h reflects 1,443.5 GW.h of core Island Integrated System generation consistent with the 2004 approach, plus 110 GW.h for the revision to Hydro's long-term average hydrology, plus 46.1 GW.h related to NP's

[92] NP energy supplies are at transmission – at generation additional losses of 3.2% are added in per PUB-2.

[93] Note 1: The impact on individual customers of the NP Generation Outage is approximate, as the outage will result in changes to both overall costs ($4.1 million) as well as NP's share of the system costs (as their purchases will be higher) and the system load factor (as it changes the amount of annual energy, but not system peak). As a result it is likely that the $0.588 million impact estimated above for IC is overestimated to some degree, that can only readily be confirmed by running a full adjusted Cost of Service case (a quick assessment indicates the full impact on IC maybe ultimately more in the range of $400,000 than $588,000).

generation outage (which results in variances from the long-term average hydrology from the approach used in 2004). These impacts drive costs to each of the customer groups as follows:

- **NLH Hydraulic Long-Term Average:** The update to the NLH long-term average generation results in added costs to the entire system of $9.798 million at today's fuel prices, or about $1.401 million to IC. However, these costs are solely a timing impact – under both the 2004 approach and the 2007 proposed approach, the RSP in effect ensures that ratepayers only pay for the actual fuel required[94] as a result of hydraulic variances, regardless of the "average" used in the last GRA. Increasing revenue requirement by $9.798 million in 2007 solely serves to reduce the average annual level of charges to the RSP (or, if the hydraulic estimate today is too high, increase the annual credits to the RSP) by this same amount.

- **NP Generation Outage:** In contrast to the NLH long-term average hydraulic change, the NP generation outage power forecast for the 2007 Test Year results in a net cost to the system of $4.109 million, of which IC pays $0.588 million before reallocations[95], Rural $0.258 million and NP $3.261 million. In future years (non-test years 2008 and beyond), however this annual cost to IC and Rural will continue each year, but NP will see a credit approximating the full $4.109 million (via either reduced 2nd block rate purchases, and/or RSP load adjustments), for a net benefit to them of on the order of $0.8 million each following year at IC and Rural expense. This issue is further addressed in Section 4.1.2.

- **Changes in the cost of No. 6 Fuel:** Net of the two above changes, the price impact on No. 6 fuel is approximately $60.565 million, or a net cost to IC of $8.661 million.

[94] At a consistent 630 kW.h/bbl conversion factor.

[95] As noted in Note 1 above, reallocations related to the NP share of the system, and changes to the system load factor may ultimately result in a reduction of about 1/3 of this cost to IC, but full COS analysis will be required to determine the exact break-down.

ATTACHMENT D

AMORTIZATION OR NORMALIZATION OF MAJOR MAINTENANCE AND OVERHAUL COSTS IN OTHER JURISDICTIONS

This attachment reviews and summarises approaches used in other regulated jurisdictions for normalizing irregular or "lumpy" operating expenses such as overhaul expenses.

NORTHWEST TERRITORIES POWER CORPORATION

The Northwest Territories Power Corporation (NTPC) operates diesel generating stations in 25 communities in its service area and hydro units at 6 plants. Rates are set in each community based on individual community-level revenue requirements. Given the small size of many of the communities NTPC serves, overhauls can be a significant portion of a community's revenue requirement in the years they occur.

In the negotiated settlement related to its 2001/03 Phase I GRA, NTPC and the intervenors agreed that NTPC would establish a regulatory deferral account for overhauls for each community, and this settlement was approved by the NTPC PUB in Decision 1-2002. An appropriation to the deferral account was included in the test year revenue requirement based on the seven year average of overhaul expenses. This same appropriation occurs each year. Actual overhaul expenses are charged to the deferral account as they arise and the balances are tracked for each community, and adjusted at subsequent GRAs as required. The deferral account is tracked in NTPC's financial statements as either a "regulatory asset" or "regulatory liability" depending on the balance at any given point in time.

In the 2001/03 Phase I Negotiated Settlement NTPC specifically defined that Diesel Engine Overhauls for the purposes of the normalized account include labour and materials for planned major maintenance based on operating hours. NTPC also noted that overhaul requirements vary with engine size, speed, make and operating conditions but typically are required at 5,000 hour intervals for minor overhauls, 15,000 hours for top overhauls and 30,000 hours for major overhauls. The engine overhaul deferral account does not capture minor routine maintenance.

YUKON ENERGY CORPORATION

Yukon Energy Corporation operates nineteen diesel generating plants in the Yukon territory, eight hydro units and two wind units.

During the 1993/94 General Rate Application, the Yukon Utilities Board (YUB) reviewed expenses related to two overhauls at Aishihik hydro. In decision 1993-8, the YUB noted that while overhauls are not capital in nature, they are significant in magnitude and not a recurring annual expense. The Board directed

Yukon Energy Corporation (YEC) to defer and amortize the overhaul expenditures over five years, during which time it allowed a return on the unamortized balance.

Since the Board's 1993 decision, YEC has continued to defer and amortize all major overhauls. Where activities related to overhauls have been determined to extend the useful life of the asset, these activities are capitalized.

ATTACHMENT E

SUMMARY OF NP GENERATION CREDIT EVIDENCE FROM IC IN 2003 GRA

In the IC evidence from 2003 (evidence of Osler and Bowman), a key item of discussion was Newfoundland Power's own generation. In order to consider an appropriate treatment of the NP generation, the evidence noted that there are two types of generating plant that NP maintains on the Island Interconnected system:

- **NP Hydraulic generation**: Comparable to Hydro's small hydraulic generation, NP's plants provide energy to the grid, and play some role in meeting demand peaks[96]. The hydraulic generation is presumably dispatched in almost all cases to maximize energy output, which would be consistent with the normal practices for economic dispatch of small hydro plants.

  As a result of their hydro generation being available to service a portion of their load from both an energy and capacity perspective, NP imposes a smaller burden on Hydro's network (and likely on Hydro's costs) than if NP did not possess the hydraulic generation and Hydro had to serve NP's full native load. Within a cost-of-service perspective it would be the normal practice to net the hydraulic energy off of the forecast total native energy NP required in determining the energy they require from Hydro's system. In addition, it would be normal practice to net the capacity that NP's hydraulic plant can reasonably provide off of NP's native peak to determine their peak demand for the purposes of cost allocation.

- **NP Thermal generation**: In contrast to hydraulic generation, NP's thermal generation plays no role in meeting the system energy requirements, either on a forecast basis under normal water flows (i.e., a test year) or in terms of firm energy for system planning (i.e., during a drought year). The NP thermal generation capacity is considered in determining the Island Interconnected capacity requirements, reflecting its ability to be operated at peak times. However, as noted above, the system is presently indicated to be in a state of capacity sufficiency. In addition, the NP thermal generation is clearly located on the grid primarily to service radial loads in order to increase their local reliability[97], similar to the GNP generation that Hydro maintains. In addition, IC-295 from the 2003 GRA indicated that NP's thermal generation is very far down the list of available resources at times of system constraints, and is only dispatched after all Hydro's gas turbines, the St. Anthony diesel plant and the Hawke's Bay diesel plant have been brought on-line and Deer Lake Power output maximized.

[96] Per Haynes, Schedule II from the 2003 GRA, NP hydraulic generation has a normal output of 424 GW.h and a firm generation of 323 GW.h. with a maximum peak capacity of 93.2 MW.

[97] As of the 2003 GRA, the Board was presented with evidence that the following NP thermal generation was in service: the NP Greenhill 25 MW gas turbine is located on the radial transmission line on the Burin Peninsula, the Wesleyville 15 MW gas turbine is located well off the main 230 kV grid on a long 69 kV radial line, and the "mobile" 7 MW gas turbine appears to be located on the Doyles-Port aux Basques radial line. The NP diesel appears to be located at Port aux Basques (2.5 MW), Port Union (0.5 MW) on the long Bonavista radial transmission line, with then remaining 4 MW located in St. John's or as portable units. Some portion of these units have since been de-rated or potentially retired.

The 2003 evidence reviewed the various cost and operational considerations and consequences of the NP generation, and concluded, in summary, that there are only two potential rationales that could be offered as to why NP's thermal generation might be considered as a credit to NP in the cost of service study:

- ***NP's thermal generation could realistically be needed for dispatch/interruption at peak:*** One rationale for netting certain loads off of cost of service peaks is that they are not firm load that the utility has to supply at critical peak times. For example, the CFB Goose Bay secondary power is properly not included in the Labrador Interconnected cost of service capacity allocations[98] as secondary power does not place any firm demand peaks on the system (it is readily interrupted at the time of system peak). Applying this rationale to the NP thermal generation, however, does not indicate that they should be netted off of NP's firm loads based on overall assumptions adopted for the cost of service. First, the NP thermal generation units are well down in the capacity shortage dispatch sequence (below other capacity sources that are not netted off in the cost of service, such as increased Deer Lake Power output and the former Interruptible B capacity). In addition these units are not dispatched until after St. Anthony and Hawke's Bay diesels have been put into service. Hydro has confirmed that between 1996 and 2003, the St. Anthony and Hawke's Bay diesels were only used once in support of the Island Interconnected grid[99], and that was before Granite Canal and the new PPAs were in service. In summary, there is little credible basis to suggest that these units provide any material benefit to the Island Interconnected grid or would likely be needed for dispatch or interruption at this system's peak, other than in extreme emergencies which are not the basis for normal Cost-of-Service analysis.

- **Considering NP's thermal generation as a credit in the cost of service study prevents uneconomic dispatch or peak shaving by NP:** At times Hydro indicates that NP should be given a generation credit is that giving NP a full generation credit as if all their thermal capacity was operating at peak, in order to prevent NP from actually choosing to run these units at uneconomic times to peak shave[100]. In other words, Hydro is asserting that if NP is already provided with the benefit reflecting 100% of the output of these units, there is no additional need for NP to actually run them at peak in order to reduce their own costs charged by Hydro – and that running them at peak would be less advantageous for all customers since it represents an uneconomic dispatch of the system generation. This rationale ignores the legislative framework for regulation by the Board. Any consideration of NP's generation, and any reduced rates or reduced bills that might arise as a result of this generation plant, need to first recognize the clear power policy of Newfoundland, as outlined in the EPCA, 1994 at section 3(b). Specifically, the Board must ensure all utility generation is operated in such a way as to "result in the most efficient production, transmission and distribution of power"[101] and "result in power being delivered to consumers in the province at

[98] Per RDG-1.
[99] JRH-3 page 15 from the 2003 GRA
[100] Such as at RDG-2, page 12.
[101] EPCA, 1994 section 3(b)(i).

> the lowest possible cost consistent with reliable service"[102]. In other words, the provision of a "generation credit" for NP in order to prevent them from dispatching their generation in a way that lowers the overall system efficiency (and increases overall system costs) is simply unnecessary and inappropriate. The legislative direction to the Board already appears to ensure the Board will not allow NP to profit (at the expense of others) from reducing the efficiency of power generation in the Province.

As a result of this review, The IC evidence in the 2003 GRA concluded that there did not appear to be a reasonable basis to provide NP with the generation credit as proposed by Hydro to reflect the thermal generation plant NP has in service. The evidence concluded that it remained appropriate to provide such a credit for NP's hydraulic generation, but only to reflect the peak capacity that NP would provide to the system based on economic dispatch to maximize energy output (not full dispatch that is reflective of system capacity shortage conditions).

[102] EPCA, 1994 section 3(b)(iii).

ATTACHMENT F

SCOPE OF REGULATORY REVIEW FOR YUKON ENERGY'S 20-YEAR RESOURCE PLAN

Dennis Lemke

Yukon
Office of the Minister
Box 2703, Whitehorse, Yukon Y1A 2C6

June 5, 2006

from Linda Dixon

Yukon Utilities Board
19 1114 1st Ave
Whitehorse, Yukon
Y1A 1A3

Dear Mr. Morris

I have recently received a copy of Yukon Energy Corporation's 20 Year Resource Plan 2006 – 2025The Government of Yukon feels that it is imperative that the Plan be subjected to a detailed and thorough review by the Yukon Utilities Board as has been the practice in the past.

Accordingly, I would request that the Board carry out a review and hold a hearing on the Plan as follows:

1) The Yukon Utilities Board (the "Board") be assigned the duty of reviewing, at a public hearing, Yukon Energy Corporation's 20 Year Resource Plan regarding proposals in respect of major electrical generation and transmission requirements in Yukon during the period 2006 to 2025 with emphasis on:

   a) those projects related to the 20 Year Resource Plan which require commitments by Yukon Energy Corporation before the year 2009 for major investments with anticipated costs of $3 million or more for feasibility assessment and engineering, environmental licensing, or construction; and,

   b) planning activities related to the 20 Year Resource Plan which Yukon Energy may be required to carry out in order to commence construction on other projects before the year 2016 to meet the needs of potential major industrial customers or other major potential developments in Yukon.

2) This review shall include consideration of the following:

a) significant utility spending commitments related to the generation and transmission of power in the Yukon that would affect long term utility costs and rates;

b) the effect of the proposed spending commitments on electricity rates to be charged to Yukon consumers;

c) with regard to generation or transmission projects, the necessity for the proposed spending commitments and, to the extent currently known, their physical and engineering characteristics and their economic consequences with emphasis on:

(i) effects relating to electrical load forecast requirements, including requirements related to potential new major industrial customers or other major potential developments in Yukon, and the need for the spending commitments to meet such load forecast requirements;

(ii) the capability of existing generation and transmission facilities to provide reliable electrical power generation to meet the load forecast requirements in (i), taking into consideration capacity planning criteria appropriate and adequate to establish requirements for such electrical power generation capacity in accordance with principles established in Canada by regulatory authorities of the Government of Canada or of a province or of a Territory regulating hydro and non-hydro electric utilities;

(iii) evidence that all reasonable alternative options have been considered and that the proposed spending commitments have been selected on reasonable grounds, i.e. technical feasibility, cost efficiency, and reliability; and

(iv) the analysis by Yukon Energy Corporation of potential risks from all causes, including but not limited to economic and financial risks, and including possible modifications to design or schedule resulting from environmental review and related regulatory approvals.

3) The Board shall hear submissions from any persons or groups or classes of persons who, in the opinion of the Board, have an interest in the matter.

4) The Board shall forward its report on its findings to the Commissioner in Executive Council, and make it public, not later than October 31, 2006.

I am advised that YEC would by practice be required to pay the Board's costs for holding a hearing and conducting its review of the Resource Plan.

I would appreciate you undertaking your review in a timely manner and I look forward to receiving your report.

Sincerely,

John Edzerza
Minister of Justice