Financial Consultants Report
Board of Commissioners of Public Utilities
Newfoundland and Labrador Hydro
2003 General Rate Application

Grant Thornton

Contents

Introduction

This report to the Board of Commissioners of Public Utilities ("the Board") presents our observations, findings and recommendations with respect to our financial analysis of the pre-filed evidence of Newfoundland and Labrador Hydro ("the Company") ("Hydro") which was submitted to the Board in connection with the 2003 Application seeking approval for changes in rates for each of its customers.

Scope and Limitations

The scope of our financial analysis with respect to Hydro's Application and pre-filed evidence is as follows:

1. Review the methodology and assumptions used by the Company for estimating revenues, expenses and net earnings and determine whether the proposed estimates for the years ending December 31, 2003 and 2004 are reasonable and appropriate.

2. Review the proposed energy and revenue forecasts for 2003 and 2004 and verify the calculation of proposed rates necessary to meet the estimated revenue requirement in 2004. Assess the reasonableness of the Company's latest forecast of customer load.

3. Review and verify the Company's various calculations for the cost of capital including the proposed embedded cost of debt, interest coverage, regulated equity and return on equity and weighted average cost of capital for December 31, 2003 and 2004 are reasonable and appropriate.

4. Conduct a review of actual versus estimated capital expenditures for the four years ended December 31, 2002.

5. Review and verify the Company's calculations for rate base and return on rate base for December 31, 2003 and 2004.

6. Conduct a review of forecast energy supply costs including new sources of supply (i.e. Granite Canal and NUGS) to assess its reasonableness and prudence in relation to sales of power and energy.

7. Review Hydro's rates of depreciation and assess their compliance with the 1998 KPMG Depreciation Policy Study. Assess reasonableness of depreciation expense.

8. Conduct a review of forecast interest and other costs to assess their reasonableness and prudence in relation to sales of power and energy and assess compliance with Board Orders where applicable.

9. Examine the Company's financial records to determine whether it complies with the System of Accounts prescribed by the Board.

10. Review the Rate Stabilization Plan (RSP) to access compliance with Board orders.

The nature and extent of the procedures which we performed in our analysis varied for each of the items noted above. In general, our procedures were comprised of:

- enquiry and analytical procedures with respect to financial information in the Company's records;
- examining, on a test basis where appropriate, documentation supporting amounts included in the Company's Application;
- assessing the reasonableness of the Company's explanations; and,
- assessing the Company's compliance with Board Orders.

The procedures undertaken in the course of our financial analysis do not constitute an audit of the Company's financial information and consequently, we do not express an opinion on the financial information.

The financial statements of the Company for the year ended December 31, 2002 have been audited by Ernst and Young LLP, Chartered Accountants, who have expressed their unqualified opinion on the fairness of the statements in their report dated February 14, 2003. In the course of completing our procedures we have, in certain circumstances, referred to the audited financial statements and the historical financial information contained therein.

Forecasting Methodology and Assumptions

The Company's 2003 and 2004 forecast of revenue and expenses were developed through the normal operating budget process which commenced in the spring of 2002 and was essentially completed by the end of that year. Consequently, no actual results for 2003 are incorporated in the forecast. In addition, the 2003 and 2004 forecasts incorporate certain assumptions which reflect Hydro's best estimate of future economic conditions and events.

Our approach in this area of our review focused on the following three objectives:

1. review the methodology used by the Company for forecasting revenues and expenses to ensure it is reasonable and appropriate;
2. review the assumptions made by management with regard to future economic conditions and events; and
3. ensure that these assumptions are properly incorporated into the forecasts.

Methodology

The methodology used by Hydro in preparing the 2003 and 2004 forecasts is consistent with the approach for the 2001 rate hearing and, as noted above is based on the normal budgeting process. The budgeting process followed by Hydro is comprehensive and detailed. The main steps or components in preparation of the operating budget are as follows:

- Budget process commences with the issue of detailed instructions generally in March of each year.
- Operating costs are budgeted at the Business Unit level where each unit prepares its respective budget on an account-by-account basis. Personnel in the individual units enters this information on-line to the JD Edwards system. These budgets are then subject to various levels of review and approval by Managers, Directors, Vice-Presidents and finally Management Committee.
- Load forecasts are prepared by the System Planning department based on forecast information received from Newfoundland Power and the industrial customers. The load forecast is used to generate a revenue budget based on existing rates. For 2004, the proposed new rates were applied to the load forecast to determine the forecast revenue.
- Based on the load forecast, the production department determines the hydraulic/thermal spilt for generation and calculates and prepares the fuel budget. The purchased power estimates from CF(L)Co. and the non-utility generators (NUGS) are also determined at this time.
- The depreciation expense budget is prepared by the Plant Ledger department based on the capital budget and projected in-service dates for construction projects in progress.
- Based on the operating, fuel, revenue and capital budgets, a monthly cash flow is provided to the Treasury department which, based on an interest model, generates a forecast of borrowing requirements and estimates of interest expense and guarantee fees.

- All elements of the operating budget are consolidated at this stage and forecast income statement and balance sheet information is submitted to the Management Committee for their review and approval. After approval at this stage both the operating and capital budgets are submitted to the Board of Directors for final review and approval.

The process as described above was used to generate the 2003 and 2004 forecast revenue and expenses. No inflation factors were used to escalate costs for 2003 or 2004, except for regular salary increases. The various budget elements for the 2003 and 2004 forecast were finalized in the first quarter of 2003 with the revenue requirement determined in the late March to early April time frame, with adjustments occurring in mid August due to the change in proposed return on equity.

As a result of our review, we have determined that the overall methodology used by Hydro for forecasting revenue, expenses and net income is reasonable and appropriate. Our observations with respect to the reasonableness of individual expense estimates and revenue from rates are included within the respective sections of our report that follow.

Review of Assumptions

The key assumptions made by management in developing the test year forecast relate to the following areas:

- the price of No. 6 Fuel for consumption at the Holyrood thermal generating station and price of diesel for consumption at the diesel plants located throughout isolated parts of Labrador and the island;
- a conversion factor of 624 kWh/bbl for average efficiency at the Holyrood thermal plant;
- hydraulic production based on 30-year average water inflows for the existing plants and a power and energy analysis for the Granite Canal plant;
- the expected power purchases from the non-utility generators;
- the hydraulic/thermal production split to meet remaining forecast load;
- the load forecasts for Newfoundland Power, the industrial customers and rural interconnected and isolated customers;
- interest rate projections for short and long-term financing; and
- cost of living adjustment factors for salary costs.

Where appropriate, Hydro has used information from independent sources and/or expert consultants to establish the assumptions for the above noted items. For example, as noted in Mr. Haynes's pre-filed evidence (Production, pg. 23, lines 9-10), Hydro uses the services of the PIRA Energy Group of New York to assist in forecasting the price of No. 6 Fuel.

The nature of some of the assumptions noted above is that they are constantly being revised and updated by the experts (e.g. fuel prices, interest rates). The load forecasts for Newfoundland Power and the industrial customers are also updated periodically. Considering the fact that the key assumptions used by Hydro were developed in 2002 during the forecasting of 2003 and 2004, and that these assumptions may have a significant impact on the 2004 revenue requirement, we recommend that Hydro be requested to update its assumptions and revenue and expense forecasts with more current information as the hearing progresses.

Incorporation of Assumptions into Forecasts

The incorporation of the key assumptions into the forecasts was verified by examination of the various schedules included in the Company's pre-filed evidence and other supporting schedules and information provided. Based upon the results of our procedures we confirm that the assumptions have been appropriately incorporated into the forecasts.

Revenue and Energy Forecasts

Hydro forecasts its revenue based on the total GWh requirements for each of its industrial customers, its utility customer, Newfoundland Power, and its rural customers. These GWh requirements are generally based on operating load forecasts provided in the spring and fall of each year by these customers. The fall's operating load forecast allows Hydro to make its initial projections for the following year. This projection is then updated midway through that year when the spring operating load forecast is received. In addition to the fall and spring load forecasts obtained from its industrial customers and Newfoundland Power, these customers also supply Hydro with expected annual production levels and a five year load forecast. The annual production levels help to explain increases or decreases in the anticipated load whereas the five year load forecast allows Hydro to incorporate potential revenues into its own future budget plans.

In generating the 2003 and 2004 forecast of energy requirements, Hydro was able to rely on the operating load forecasts provided by some of its industrial customers and its utility customer. Past history has shown the short term operating forecasts for these customers to be fairly accurate and adjustments to its load forecasts were not required. For the remaining industrial customers, Hydro used its knowledge of each specific industrial end user as well as historical results as its main guide to forecast its energy requirements.

Forecasting energy requirements for rural customers is largely based on historical data. In preparing this forecast a separate projection is prepared for each area of service, namely the island interconnected, the Labrador interconnected and Labrador and island isolated. In forecasting the energy requirements for the island interconnected, Hydro relies on a long term econometric model. This model uses both current and historical data to calculate GWh requirements for the coming year. Forecasting for the Labrador interconnected is based largely on historical trends as opposed to using an econometric model. These trends are then normalized for any unusual weather patterns such as extremely cold or warm winters. Hydro will also incorporate any relevant factors relating to general service customers that may affect load into its equation such as new requests for service, increases in production levels and the installation of new equipment. When forecasting for rural customers whose energy requirements are produced by diesel, Hydro will use much of the same techniques as used in forecasting the Labrador interconnected. However in doing so, Hydro tends to prepare more detailed forecasts by focusing in on each community.

In order to identify any significant trends and assess the reasonableness of the forecasts we have compared the 2000 to 2002 actual revenues and the 2002 test year with the 2003 and 2004 forecast revenues. The results of this analysis of revenue by customer are as follows:

('000)	2000	2001	2002	Test year 2002	Forecast 2003	Forecast 2004
Industrial						
North Atlantic	$ 7,204	$ 7,518	$ 7,571	$ 7,905	$ 8,054	$ 9,066
Abitibi - GF	4,312	3,376	5,429	5,079	4,566	5,163
Abitibi - Stephenville	16,781	15,634	16,167	18,313	18,282	21,062
Corner Brook	11,979	14,028	15,232	15,527	15,773	16,848
	40,276	40,555	44,399	46,824	46,675	52,139
Canadian Forces Base	3,176	3,476	2,918	3,980	3,057	3,014
Iron Ore Company	4,008	4,011	4,271	4,457	4,471	4,577
Utility	191,688	198,941	210,916	214,791	222,952	258,169
Rural						
Island interconnected	31,267	28,855	30,856	31,600	32,515	34,959
Labrador interconnected	11,921	11,299	12,184	11,317	11,504	12,725
Isolated systems	5,136	5,115	5,725	6,380	6,873	7,406
Lance Au Loup	1,130	1,132	1,218	1,135	1,372	1,497
	49,454	46,401	49,983	50,432	52,264	56,587
Total revenue from rates	$ 288,602	$ 293,384	$ 312,486	$ 320,484	$ 329,419	$ 374,487
Less: Iron Ore Company						(4,577)
Add: Other revenue						1,931
Revenue requirement per J. C. Roberts, Schedule II						$ 371,841

The forecast revenues in 2004 are $62 million higher than 2002 actuals and $54 million higher than the 2002 test year. The significant increase is primarily due to the increase in rates incorporated in the 2004 forecast. The forecast of 2004 revenues using existing rates (September 2002) is $333.6 million. Therefore, $40.9 million of increases noted above are due to the proposed increase in rates. The 2004 forecast revenue at existing rates is $4.2 million (1.3%) higher than the 2003 forecast and $13.1 million (4.1%) higher than the 2002 test year forecast. These increases would be primarily attributable to increases in load.

In order to identify any trends with respect to forecast load and energy sales we have compared the actual energy sales (GWh) for 2000 to 2002, including the 2002 test year, with the forecast energy sales for 2003 and 2004. We have also reconciled the total sales forecast to the total GWh generated through hydroelectric, thermal, diesel and purchases of energy from the NUGS, CF(L)Co and Hydro Quebec. The results of our analysis are as follows:

GWh	2000	2001	2002	Test year 2002	Forecast 2003	Forecast 2004
Industrial						
North Atlantic	220	235	227	233	238	236
Abitibi - GF	158	109	168	177	162	162
Abitibi - Stephenville	553	516	475	557	546	556
Corner Brook	376	443	502	464	472	446
	1,307	1,302	1,372	1,431	1,418	1,400
Canadian Forces Base (CFB)	86	80	78	92	77	77
Iron Ore Company (IOC)	242	199	226	277	251	252
Utility	4,263	4,423	4,589	4,485	4,656	4,741
Rural	899	882	956	938	958	978
	6,798	6,887	7,220	7,223	7,359	7,448
Transmission and distribution losses			274	344	334	338
			7,494	7,567	7,693	7,786
Hydroelectric			3986	4425	4,157	4,582
Thermal			2381	1963	2,263	1,793
Diesel			49	45	50	52
Power purchases						
Star Lake			147	128	141	141
Rattle Brook			17	18	16	16
Corner Brook P&P			-	-	91	100
Exploits River			-	-	27	137
CF(L)Co			899	975	932	948
Hydro-Quebec Lac Robertson			15	13	16	17
			7494	7,567	7,693	7,786

Energy sales are forecast to increase overall in 2004 by 228 GWh or 3.2% from 2002 actuals and 225 GWh or 3.1% from the 2002 test year. Hydro's energy sales are not weather adjusted as is the case with Newfoundland Power. The largest portion of this increase in the number of GWh's in 2004 relates to the forecast for both Hydro's utility customer, Newfoundland Power and the industrial customer Abitibi-Stephenville. Newfoundland Power and Abitibi-Stephenville account for an additional 233 GWh over what was sold in 2002. Forecast increases in rural sales of 22 GWh and sales to IOC of 26 GWh also contribute to the overall increase in GWh's sold. These increases are partially offset by a net decrease in energy sales to other customers, most notably a decrease of 56 GWh for Corner Brook Pulp & Paper.

The increase in the amount of transmission losses is partially a function of the increase in the energy requirement from all of its customers. For 2004 Hydro has forecast approximately 4.5% of the energy requirement to be lost during transmission, whereas in 2002 3.8% of the energy requirement was lost.

Newfoundland Power represents Hydro's largest customer with 64% of total GWh forecast to be sold in 2004. Newfoundland Power's consumption in 2004 is forecast to increase by 152 GWh or 3.3% over the actual GWh sold in 2002 and 5.7% increase over the number of GWh forecast for the 2002 test year. While the energy requirements for the two forecast years are based solely on Newfoundland Power's operating load forecast provided in November 2002, the increases for 2003 and 2004 are reflective of the steady increases in energy requirements from 2000 to 2002.

After reviewing the above table, it is quite evident that the actual number of GWh utilized by each of the industrial customers, including the Iron Ore Company of Canada, has in some cases varied widely from 2000 to 2002. Some of the larger variations in the number of GWh sold during this time period were to Abitibi - Grand Falls and Stephenville. The lowest energy consumption levels for Grand Falls occurred in 2001 when the mill experienced significant down time due to a saturated market for newsprint. While Abitibi in Stephenville also experienced a saturated market for newsprint, the majority of its downtime was experienced in 2002 which prevented the mill from employing all of the energy requirements as set out for the 2002 test year. Due to the unusual downtime experienced in 2001 and 2002, Stephenville is forecasting for 2004 a normal level of operations similar to that experienced in 2000. Abitibi-Grand Falls is expecting an increase in production at the paper mill in 2004 over 2002; however it is also expecting an increase in its own hydraulic generation thus offsetting its reliance on Hydro's supply of energy.

The amount of GWh's utilized by Corner Brook Pulp and Paper from 2000 to 2002 has been on an upward climb with 2002 actual levels exceeding the 2002 test year by 38 GWh's. Corner Brook Pulp and Paper has been able to satisfy its energy requirement through purchases from Hydro and by generating its own hydroelectric power from Deer Lake Power. In 2002, due to lower water levels in its reservoir, Corner Brook Pulp and Paper was more dependent on Hydro to meet its energy requirements. However due to the expected completion of its generator upgrades by 2004, which will allow the mill to operate more efficiently and the anticipated increase in its own hydraulic generation through Deer Lake Power, the forecast for 2004 is more consistent with 2001 levels.

The forecast production levels for 2003 and 2004 continue to increase for the iron ore industry. We have compared the forecast for 2003 and 2004 to actual sales from 2000 to 2002, and also for the period 1997 to 1998. The comparison over this period of years shows the energy sales to IOC fluctuating up and down with no real trend apparent. The forecast for 2003 and 2004 is for two years of high energy sales. As noted this forecast is based on higher production levels expected for IOC over this period.

The actual number of GWh utilized by North Atlantic is fairly consistent from year to year, and based on the comparison of 2002 actuals to the 2002 test year; North Atlantic has fallen short of its anticipated budget by 2.6%. The forecast for 2003 and 2004 has increased slightly based on North Atlantic's expected increase in production levels.

Upon receiving the spring load forecasts in 2003 Hydro decided that no changes would be made to the energy requirements forecast for 2003 and 2004 as variations between the 2002 fall and 2003 spring operating load forecasts were considered insignificant. However Hydro is anticipating that the 2003 general rate hearing will coincide with the review of the fall 2003 load forecasts received from its industrial customers and its utility customer. They have advised us that they intend to update the revenue requirement and cost of service for 2004 for any apparent changes in these operating load forecasts.

In addition to the analysis of revenue by customer noted above, we also recalculated the 2004 forecast revenue from rates to ensure the proposed new rates together with the forecast loads agree with the test year revenue requirement. We are able to verify the calculation of revenue for industrial customers and Newfoundland Power on an overall basis and for rural customers on a test basis. No discrepancies were noted in completing these procedures.

Cost of Capital

Capital Structure

Hydro's forecast capital structure for 2004 is detailed in the pre-filed evidence of Mr. J.C. Roberts Schedule V. The projected balance sheet in Schedule VIII of Mr. Roberts' evidence provides the basis for these calculations.

Our procedures performed in this area focused on verifying the calculations of average capital structure, and assessing the reasonableness of the data incorporated in the calculations and the methodology used by the Company. Specifically, our procedures included the following:

- agreed all carry-forward data to supporting documentation;
- agreed all forecast data to supporting documentation to ensure it is internally consistent with the pre-filed evidence and other forecast information; and
- checked the clerical accuracy of the calculations of average capital structure.

The Company's calculation of regulated capital structure for 2001 to 2004 is as follows:

(000)'s	2001	%	2002	%	Forecast 2003	%	Forecast 2004	%
Debt	$ 1,207,149	80.4%	$ 1,364,656	85.1%	$ 1,453,249	86.4%	$ 1,424,143	85.8%
Employee benefits	24,059	1.6%	24,932	1.6%	27,464	1.6%	29,941	1.8%
Equity	269,770	18.0%	213,789	13.3%	200,419	11.9%	205,265	12.4%
	$ 1,500,978		$ 1,603,377		$ 1,681,132		$ 1,659,349	

As can be seen from the above table, the debt to equity ratio has deteriorated from 2001 to 2002 and is forecast to decline further in 2003 and then improve slightly in 2004. This overall deterioration from 2001 can be attributed primarily to the significant dividends declared and paid on regulated operations in 2002 of $65.7 million and the dividends forecast for 2003 of $5.6 million.

The dividend policy approved by the Board of Directors of Hydro on May 12, 2000 provides for the payment of dividends annually up to 75% of net operating income before net recall revenue for that year plus 100% of net recall revenues received provided such payment shall only be made after due consideration has been given by the Board of the impact the payment will have on the debt to equity ratio.

The payment of dividends of $65.7 million from regulated operations was in excess of 75% of net operating income for 2002, which totaled $9.7 million. The minutes of the Board of Directors meeting in which the dividends were approved document the fact that consideration was given to the Company's dividend policy including the impact the payment will have on Hydro's debt to equity ratio.

The appropriateness of Hydro's regulated capital structure and the implications for Hydro's risk profile and credit worthiness will be addressed by the various cost of capital experts presenting evidence related to this Application.

Embedded Cost of Debt

Hydro's calculation of its embedded cost of debt is included in the pre-filed evidence of Mr. J.C. Roberts on Schedule VII. We have checked this calculation as well as vouched the individual components to supporting documentation including checking the Company's calculations of interest, guarantee fee, and amortization of foreign exchange losses and debt discount and issue expenses.

The embedded cost of debt forecast for 2004 compared to the 2002 test year final cost of service is as follows:

	Test Year 2002	Forecast 2004
Interest	$ 98,809	$ 112,289
Amortization of Foreign Exchange Loss	2,157	2,157
Amortization of Debt Discount and Issue Expense	1,062	550
Debt Guarantee Fee	12,434	14,453
	114,462	129,449
Less: Interest on Sinking Fund Assets	(6,305)	(8,117)
CF(L)Co Share Purchase Debt	(1,891)	(2,106)
Net interest	$ 106,266	$ 119,226
Average total debt	$1,301,385	$1,438,696
Embedded Cost of Debt	8.166%	8.287%

The methodology and approach used in calculating the 2004 cost of debt is consistent with 2002. The above table indicates that the embedded cost of debt has increased by 0.12% in comparison to the 2002 test year cost of debt.

Interest Coverage

Overall corporate interest coverage for 2004 has been calculated at 1.37 times as follows:

(000's)	2000	2001	2002	Forecast 2003	Forecast 2004
Total interest	$ 96,034	$ 94,121	$ 90,812	$ 97,742	$ 103,821
Less: CF(L) Co	(1,841)	(2,523)	(2,264)	(1,975)	(2,106)
Hydro net interest	94,193	91,598	88,548	95,767	101,715
Add: Interst earned and IDC					
Power bills	16	1	27	334	369
RSP	3,217	4,361	7,168	10,316	12,081
Sinking funds	5,323	6,382	7,243	7,518	8,117
IDC	3,694	5,151	7,679	7,392	5,057
Gross interest	$ 106,443	$ 107,493	$ 110,665	$ 121,327	$ 127,339
Net income	$ 17,296	$ 40,431	$ 40,815	$ 22,465	$ 46,482
Gross interest	106,443	107,493	110,665	121,327	127,339
Adjusted income	$ 123,739	$ 147,924	$ 151,480	$ 143,792	$ 173,821
Interest Coverage	**1.16**	**1.38**	**1.37**	**1.19**	**1.37**

Gross interest costs have been increasing since 2000. During 2001, Hydro completed two new bond issues in August and December for a total of $250 million. The Company had two more bond issues in April and September 2002 that totaled $250 million. These recent issues are the primary reason for the increased Canadian bond interest costs in 2002. The forecast for 2003 also includes a bond issue of $125 million, thereby further increasing 2003 and 2004 interest costs. The amount of interest capitalized during construction is now decreasing in forecast 2003 and 2004 as Granite Canal was put into service in June 2003. In 2002 Hydro started including the guarantee fee in its interest coverage calculation. The guarantee fee is considered part of the total cost of debt. The calculations for 2001 and 2000 have been revised to reflect this change.

Based upon our review, we did not note any discrepancies in the calculation of interest coverage.

Regulated Equity and Return on Equity

Our procedures in this area focused on verification of the data incorporated in the calculations and on the methodology used by the Company. Specifically, the procedures which we performed included the following:

- agreed all carry-forward data to supporting documentation including the 2002 audited financial statements and internal accounting records, where applicable;

- agreed forecast component data (earnings applicable to common equity; dividends; regulated earnings; etc.) to supporting documentation to ensure it is internally consistent with the pre-filed evidence;

- checked the clerical accuracy of the continuity of regulated common equity as forecast for 2003 and 2004;

- recalculated the rate of return on common equity for 2003 and 2004 and ensured it was in accordance with established practice and P.U. 7 (2002-2003).

In order to provide a basis of comparison for the 2004 average common equity and return on average common equity, we have prepared the following summary for 2000 to 2004:

(000)'s		**2000**	**2001**	**2002**	**2003 Forecast**	**2004 Forecast**
Regulated equity						
	2004					$ 205,300
	2003				$ 200,400	$ 200,400
	2002			$ 213,800	$ 213,800	
	2001		$ 269,800	$ 269,800		
	2000	$ 267,600	$ 267,600			
	1999	$ 289,700				
Average equity		$ 278,650	$ 268,700	$ 241,800	$ 207,100	$ 202,850
Regulated earnings		$ 5,850	$ 11,920	$ 9,740	$ (7,805)	$ 19,385
Return on equity		**2.10%**	**4.44%**	**4.03%**	**-3.77%**	**9.56%**

Hydro proposed in its Application a return on equity of 9.75% for 2004. This differs from the above calculated return on equity of 9.56%. This lower rate of return is primarily due to the fact that Hydro does not earn a return on equity on rural assets. Hydro has provided an explanation of the difference in return in its response to NP-4 and NP-5.

As noted in our 2002 Annual Review Report, the calculation of regulated equity for 2000 and 2001 has also been adjusted from what was previously reported as follows:

- In 2002, Hydro adopted new recommendations from the Canadian Institute of Chartered Accountants with respect to foreign exchange gains and losses. Unrealized gains and losses associated with the First Mortgage Bonds that are not recoverable from Hydro-Quebec under the Power Contract, are included in net income in the current year. Previously, these gains and losses were deferred and amortized on a straight line basis over the remaining life of the debt. This change has been applied retroactively.

- Also in 2002, Hydro started to accumulate the non-regulated costs to be added back to determine regulated equity, similar to the approach used by Newfoundland Power in its calculation of regulated common equity. In its adoption of this approach in calculating regulated equity, Hydro adjusted the regulated equity in 2001 for the non-regulated costs incurred in 2001.

In determining regulated equity Hydro has adjusted its corporate shareholder's equity to eliminate the portion which is attributable to non-regulated operations. These adjustments to Hydro's equity are as follows:

(000's)	2000	2001	2002	2003 Forecast	2004 Forecast
Equity per non-consolidated financial statements	$ 562,899	$ 563,574	$ 493,550	$ 491,649	$ 508,390
Less: Contibuted capital					
- Lower Churchill Development	(15,400)	(15,400)	(15,400)	(15,400)	(15,400)
- Muskrat Falls Project	(2,165)	(2,165)	(2,165)	(2,165)	(2,165)
Share capital issued to finance investment in CF(L)Co.	(22,500)	(22,500)	(22,500)	(22,500)	(22,500)
Net retained earning attributable to IOCC		(1,257)	(2,614)	(3,153)	(3,636)
Non-regulated expenses		134	544	523	575
Net retained earnings attributable to CF(L)Co. (income recorded minus dividends flowed through to government)	(222,783)	(226,327)	(236,654)	(247,442)	(258,985)
Net retained earnings attributable to the sale of recall power to Hydro Quebec (income recorded minus allocation of dividends)	(32,437)	(26,289)	(972)	(1,093)	(1,014)
Regulated Equity	$ 267,614	$ 269,770	$ 213,789	$ 200,419	$ 205,265

Based upon our review, we did not note any discrepancies in the calculations of regulated average equity and regulated rate of return on equity. As previously noted, Hydro has requested a rate of return on equity in this Application of 9.75%. The appropriateness of this requested rate of return will be addressed by the various cost of capital experts presenting evidence related to this Application.

Weighted Average Cost of Capital

The forecast rate of return on rate base is based on the forecast weighted average cost of capital ("WACC"). Hydro's calculation of the WACC is included in the pre-filed evidence of Mr. Roberts on Schedule V. The inputs to this calculation are the average forecast capital structure and the forecast cost of the individual components of invested capital. Our comments with respect to each of these factors have been provided in the preceding sections.

A comparison of the 2004 forecast and the 2002 final test year WACC is included in the table below.

	Test year 2002			Forecast 2004		
	Percent	Cost	WACC	Percent	Cost	WACC
Debt	81.38	8.166%	6.645%	86.14	8.287%	7.138%
Employee Future Benefits	1.56	0.000%	0.000%	1.72	0.000%	0.000%
Equity	17.06	3.000%	0.512%	12.14	9.750%	1.184%
	100.00		7.157%	100.00		8.322%

The WACC for 2004 has increased by 1.165% to 8.322% from 7.157% in the 2002 test year cost of service. The increase in the requested return on equity is the primary reason for the above noted increase in WACC.

Capital Expenditures

From 1998 to 2002, actual capital expenditures have been lower than budget by an average of 14% (high in 1998 of 18.73%; low in 2002 of 9.95%). The following table details the variance percentage of actual expenditures to budget for each category of the capital budget:

	1998	1999	2000	2001	2002	Average
Generation	(24.84%)	(6.19%)	(32.90%)	(27.94%)	(29.18%)	(24.21%)
Transmission and Rural Systems	(23.29%)	(21.40%)	(4.06%)	(12.68%)	(5.30%)	(13.96%)
General Properties	2.47%	(2.11%)	(25.87%)	(9.09%)	(10.42%)	(9.00%)
Total	(18.73%)	(16.70%)	(11.80%)	(13.15%)	(9.95%)	(14.44%)

The capital expenditure and budget information, upon which the variances in the above table are calculated, includes the original approved capital budget plus any new projects and carry-overs from previous years. The capital budget for several of the categories for certain years has been normalized for events that would be considered exceptional. These normalizing adjustments are as follows:

- Transmission in 1998 was adjusted for the delay in projects due to the increased demand for steel during the 1998 ice storm in Quebec. This event resulted in a delay in projects that had a budget of $8.4 million.

- The 1999 budget for rural systems was adjusted by $1.98 million which related to the Nain Plant. This project was delayed in 1999 due to ongoing discussions with the Town Council, however the project was completed in 2000.

- The 2001 budget for rural systems was adjusted by $1.2 million which related to a delay in the construction in the new diesel plant in Nain until 2002.

The 2003 forecast capital expenditures of $35,486,000 have been based on actual expenditures to May 31, 2003 plus expected remaining expenditures for the year. In comparison to the original budget for 2003 of $35,679,000, these expenditures are forecast to be under-budget by 0.54%. The 2004 budgeted capital expenditures total $34,465,000.

According to the above table, actual capital expenditures for the period 1998-2002 were, on average, below budget by approximately 14%. Based on our review, Hydro is probably underspending by approximately 5% on a project basis. Therefore, the remaining 9% variance must be due to delays and carryovers.

In the context of the 2004 forecast revenue requirement, the historical trend of under spending, whether it be actual savings or due to delays and carry-overs, means that certain costs in the forecast year may be overstated. For example, using a 14% downward adjustment to the 2003 and 2004 forecast capital expenditures would result in a reduction in depreciation expense of approximately $85,000 and $169,000 respectively based on the composite depreciation rate of 1.70% in 2003 and 1.74% in 2004, and assuming all projects were put-in-service. A reduction in capital expenditures would also impact the forecast rate base for 2003 and 2004 and consequently the return on rate base included in the revenue requirement.

From 1998 to 2002, total capital retirements as a percentage of total capital assets have averaged approximately 0.39%, as detailed in the following table.

	1998	**1999**	**2000**	**2001**	**2002**	**5 year Average**	**Forecast 2003**	**Forecast 2004**
Capital Retirements	5,740	6,676	6,330	6,911	7,743	6,680	2,891	2,654
Capital retirements as a % of total assets	0.35%	0.41%	0.38%	0.40%	0.44%	0.39%	0.15%	0.14%

The retirements for several of the categories for certain years has been normalized for events that would be considered exceptional. These normalizing adjustments are as follows:

- 1999 included an adjustment of $27.8 million related to the retirement of the Roddickton Wood Chip thermal generating station and $2.5 related to telecontrol equipment.
- 2000 included an adjustment of $2.5 million for diesel generation disposals and $2.4 million related to vehicles.
- 2001 was adjusted by $2.3 million related to capital work on transmission lines TL237, TL240 and TL260.
- 2002 retirements were adjusted for $1.1 million associated with the fire loss at Rencontre East as well as $4.2 million related to the write-off of assets at the Holyrood Plant as a result of a physical verification of assets.

Hydro's forecast retirements for 2003 and 2004 appear under budgeted in comparison to the historic trend in retirements as a percentage of total assets. Using a rate of 0.39% of total assets, retirements for 2003 and 2004 would be $7,590,000 and $7,680,000 respectively. In the context of Hydro's forecast revenue requirement, the flow through effect of increasing the retirements would result in a reduction of depreciation expense of approximately $80,000 and $168,000 respectively based on the composite depreciation rate of 1.70% in 2003 and 1.74% in 2004. Such an increase in retirements may also impact the forecast loss on disposal. In addition, an increase in capital retirements would impact the forecast rate base for 2003 and 2004, and consequently the return on rate base included in the revenue requirement.

The Board should consider the above comments relating to the spending variance for capital expenditures and possible under budgeting of capital retirements and assess whether an adjustment to the 2004 revenue requirement is appropriate. The Board has ordered similar adjustments in the past for both Hydro and Newfoundland Power.

Finally it should be noted that the forecast capital expenditures and related depreciation for 2004 are based on Hydro's capital budget which was reviewed at a separate capital budget hearing held recently. The 2004 revenue requirement should be updated for any changes to the 2004 capital budget once the Board's Order related to this hearing has been issued.

Average Rate Base and Return on Rate Base

The Company's calculation of its forecast average rate base and rate of return on rate base for the 2004 test year is included in Schedule III of Mr. J.C. Roberts' pre-filed evidence. Our procedures with respect to verifying the calculation of the average rate base were directed towards the assessment of the reasonableness of the data incorporated in the calculations and the methodology used by the Company. Specifically, the procedures which we performed included the following:

- agreed all carry-forward data to supporting documentation including the 2002 audited financial statements and internal accounting records, where applicable;

- agreed forecast data (capital expenditures; depreciation; etc.) to supporting documentation to ensure it is internally consistent with the pre-filed evidence;

- checked the clerical accuracy of the continuity of the rate base as forecast for 2003 and 2004;

- recalculated the forecast average rate base for 2003 and 2004; and

- reviewed the methodology used in the calculation of the average rate base with reference to the Public Utilities Act, the Hydro Corporation Act and Board Orders.

We have reviewed the items included in rate base and conclude that the inclusion of net plant in service, cash working capital allowance, fuel and supplies inventory, and deferred realized foreign exchange loss plus deferred regulatory costs are reasonable and appropriate in reference to the legislative guidance, normal regulatory practice and existing Board Orders.

Details of the 2004 and 2003 forecast average rate base and return on rate base with comparative data for 2001, 2002 and 2002 test year are presented in the following table:

(000's)	2000	2001	2002	Test year 2002	Forecast 2003	Forecast 2004
Plant investment	$ 1,678,600	$ 1,719,700	$ 1,755,561	$ 1,763,677	$ 1,922,691	$ 1,945,586
Less: Accumulated depreciation	(380,500)	(407,100)	(433,572)	(439,076)	(465,334)	(497,452)
CIAC's	(89,000)	(88,600)	(87,569)	(87,272)	(86,668)	(86,397)
Net capital assets	1,209,100	1,224,000	1,234,420	1,237,329	1,370,689	1,361,737
Balance previous year	1,199,400	1,209,100	1,224,000	1,234,447	1,234,420	1,370,689
Average	1,204,250	1,216,550	1,229,210	1,235,888	1,302,555	1,366,213
Cash working capital allowance	2,945	3,265	3,579	2,942	3,625	3,057
Fuel inventory	20,005	17,230	17,715	13,942	16,292	14,907
Supplies inventory	21,250	20,720	19,966	21,095	19,387	19,387
Deferred realized foreign exchange losses plus regulatory costs	87,300	86,300	85,703	85,703	83,043	81,886
Average rate base	$ 1,335,750	$ 1,344,065	$ 1,356,173	$ 1,359,570	$ 1,424,902	$ 1,485,450
Return on rate base:						
Regulated net income	$ 5,850	$ 11,918	$ 9,742	$ 7,959	$ (7,806)	$ 19,384
Hydro interest expense	96,870	92,800	88,547	88,298	95,767	101,715
Return on rate base	$ 102,720	$ 104,718	$ 98,289	$ 96,257	$ 87,961	$ 121,099
Rate of return on rate base	7.69%	7.79%	7.25%	7.08%	6.17%	8.15%

As detailed above, the average rate base has been increasing each year from 2000 to 2004, with a large increase in forecast 2003. In response to information request CA-127, Hydro has provided an analysis of the increase in average rate base from 2002 to forecast 2004. The increase in rate base is attributable to an increase in net capital assets in service, offset somewhat by a decrease in other rate base components. Granite Canal is the most significant addition to net capital assets in service as can be seen from the following summary:

	000's
2002 Net capital assets	$1,234,420
Granite Canal plant	134,550
2003 and 2004 capital additions net of retirements	55,394
2003 and 2004 depreciation (net)	(63,880)
Net change in other components	1,253
2004 forecast net capital assets	$1,361,737

With regard to the 2002 rate base, it is anticipated that Hydro will request that the Board fix and determine this rate base pursuant to Section 78 of the *Public Utilities Act*. This would be considered normal regulatory practice. Considering this is the first time that Hydro's rate base will be fixed and determined, the Board should consider whether a valuation of the rate base pursuant to Section 64 would be appropriate or necessary. Hydro addressed this issue in its response to information request PUB 110. For reasons stated in this response they believe that a valuation pursuant to Section 64 is not necessary.

In P.U. 7 (2002-2003) the Board ordered that the Company submit, prior to the next rate application, an analysis of the issue of adjusting the cash working capital allowance to reflect the timing difference between the payment of semi-annual long term bond interest and the receipt of the funds for its payment. Hydro's report in response to this order is included in Exhibit JCR-1 of the pre-filed evidence and recommends the Board continue with its methodology for calculating cash working capital allowance. We have reviewed this report and support Hydro's recommendation on this issue. Hydro's approach to forecasting interest automatically adjusts for timing differences or lag between the payment of semi-annual interest and the receipt of revenues. Interest expense in revenue requirement reflects short term interest avoided by the cash flow lag.

In P.U. 21 (2002-2003) the Board ordered a return on rate base of 7.081% for the 2002 test year, however no range of allowed return was established at that time. The Board may wish to consider establishing a range and upper limit of allowed return on rate base for 2004 and future years, together with a definition of an excess earnings account.

As a result of completing these procedures, we can advise that no discrepancies were noted and therefore conclude that the calculation of average rate base and the rate of return on average rate base included in the Company's 2003 general rate application is in accordance with established practice and P.U. 7 (2002-2003).

2004 Revenue Requirement

The forecast revenue requirement for 2004 is $54.8 million higher than the 2002 test year final revenue requirement. Details on Hydro's revenue requirement are included in the pre-filed evidence of Mr. J.C. Roberts, Schedule II, 1st Revision – August 12, 2003. Exhibit 1 of our report reproduces this detail showing a comparison of the 2003 and 2004 forecast to the Company's 2001 and 2002 actual results. In Exhibit 2 we provide a comparison of the 2004 forecast revenue requirement to the 2002 final test year.

In Mr. Wells pre-filed evidence he indicated that Hydro's Application is driven by new sources of supply to meet capacity and energy requirements (Wells, pg.1, lines 15-16). He further states in his concluding comments that, of the approximate $55 million increase in 2004 revenue requirement, approximately $33 million results from new sources of supply and increased cost of No. 6 fuel, $18 million relates to the increase in depreciation and finance charges (excluding those applicable to Granite Canal) with the balance resulting from increases in controllable costs (Wells, pg. 28, lines 23-31).

We have prepared the following summary of the 2004 revenue requirement in comparison to the 2002 test year final revenue requirement. As noted above, a full detailed comparison is included in Exhibit 2 of our report.

	Test year 2002	Forecast 2004	Difference
Depreciation	$ 31,390	$ 33,932	$ 2,542
Fuel	88,616	92,548	3,932
Power purchased	15,100	33,315	**18,215**
Other costs (net)	85,697	90,947	5,250
Interest	88,298	101,715	**13,417**
Return on equity	7,959	19,384	**11,425**
Total Revenue requirement	$ 317,060	$ 371,841	$ 54,781

From this analysis it is evident that the overall increase of $54.8 million is primarily driven by increases in power purchased, interest and return on equity. The increases in power purchased and interest are related to the new sources of supply referenced by Mr. Wells. The increase in return on equity results from the increase in the requested rate of return of 9.75% from 3% in 2002. The impact of the increase in fuel costs is less evident from the table above, however the increase in the price of No. 6 fuel is fairly significant, but this is offset by the reduction in thermal generation and improvement in fuel conversion and the consequent reduction in fuel consumption.

Exhibits 5A and 5B provide an analysis of the major components of the total cost of energy on a per kWh and a percentage basis.

Additional details and analysis of the changes in 2004 revenue requirement are included in the following sections of our report.

New Sources of Supply

During the 2001 general rate hearing, Hydro indicated to the Board that new sources of generation would be required to come into service in 2003 in order for Hydro to meet the capacity and energy requirements of the island interconnected system.

For 2003 and 2004, Hydro's new sources of generation include the following:

- Granite Canal – this is a 40 MW hydroelectric plant with an estimated average annual energy capability of 224 GWh. The in-service date for this project was June 20, 2003.

- Exploits River Hydro Project - this is a power purchase agreement between Hydro and the Abitibi-Consolidated Company of Canada ("ACCC") as the agent for Exploits River Hydro Partnership. The new capacity and energy supply is a result of a new hydroelectric unit at ACCC's Grand Falls generation facility, and an upgrade of ACCC's hydroelectric facility at Bishop's Falls. The total additional capacity and average annual energy available from these projects is 32.3 MW and 137 GWh respectively. This project is scheduled to come in service in 2003.

- Corner Brook Pulp and Paper ("CBPP") - this is a power purchase agreement between Hydro and CBPP. A 15 MW cogeneration unit located at the CBPP mill will produce an average annual energy capacity of 100.2 GWh.

As previously noted, the addition of these new sources of energy is a significant component of the increase in revenue requirement included in Hydro's Application. Hydro is seeking an adjustment in rates to recover the additional costs arising from these new sources of energy required to maintain the island interconnected system.

The following table compares the sources of power and system energy requirements for the island interconnected system in the 2002 test year to the 2004 forecast:

Source of Power	2002 Test Year GWh	2004 Forecast GWh	Variance GWh
Hydroelectric			
Bay d' Espoir	2,703.0	2,657.0	(46.0)
Cat Arm	734.0	733.0	(1.0)
Upper Salmon	586.0	572.0	(14.0)
Hinds Lake	357.0	352.0	(5.0)
Granite Canal		224.0	224.0
Paradise River	38.0	37.0	(1.0)
Other	7.0	7.2	0.2
Total Hydroelectric	**4,425.0**	**4,582.2**	**157.2**
Thermal - Holyrood	**1,963.0**	**1,790.0**	**(173.0)**
Non-Utility Generators			
Star Lake	128.0	141.2	13.2
Rattle Brook	17.9	15.6	(2.3)
Corner Brook	-	100.2	100.2
Exploits River	-	137.0	137.0
Total Non-Utility Generators	**145.9**	**394.0**	**248.1**
Total System Energy Requirements	**6,533.9**	**6,766.2**	**232.2**

Based on the information in the above table, the changes in the various power supply sources can be summarized as follows:

- Hydro's hydraulic energy production for the 2004 test year is expected to increase by 157.2 GWh in comparison to the 2002 test year. This increase is primarily the result of the addition of the Granite Canal project which is forecast to supply 224 GWh. This increase is partially offset by the decreases from the existing hydroelectric plants. These decreases are due to lower average water inflows in recent years which are reflected in the 30 year average used to forecast hydraulic production.

- The supply of power purchased from NUGs is 248.1 GWh greater in comparison to the 2002 test year. The addition of the two new purchase power agreements accounts for the majority of this increase.

- The amount of thermal production at Holyrood is expected to decrease by 173 GWh in comparison to the 2002 test year. This decrease in thermal production is a result of the new sources of generation previously noted.

In the following sections of this report, we will address the impact that each form of new generation has on the overall revenue requirement proposed by Hydro in its Application.

Granite Canal Project

Construction of the hydroelectric plant at Granite Canal commenced in 2000 and, as previously noted, was placed in service in June 2003. The additional costs in 2003 relating to this project are not included in existing rates which are based on the 2002 cost of service; therefore it is being absorbed by Hydro and is partially responsible for the deficit that is forecast for 2003. The Company is proposing that the forecast of the various costs relating to Granite Canal in 2004 be recovered in the rates charged to customers.

In terms of capital expenditures, the original estimate for the project was $134,550,000, which is the Company's latest forecast of the total capital costs. With the project now in service, the impacts on the following costs associated with the project are as follows:

- The return on rate base for this project based on the proposed rate of return on rate base of 8.15% is estimated to be $11.141 million. The portion of this return relating to the cost of debt used to finance the Project is calculated to be approximately $9.544 million and the return on equity portion is approximately $1.597 million. The interest expense forecast for 2004 is $101.7 million, which is $13.4 million higher than interest expense included in the 2002 test year. The interest costs associated with Granite Canal account for 71% of the overall increase in interest expense.

- Depreciation expense relating to Granite Canal for 2004 is estimated at $512,000. The assets included in this project are depreciated using the sinking fund method. Depreciation expense forecast for 2004 is $33.9 million, which is $2.5 million in excess of the 2002 test year. Granite Canal accounts for only 20% of the overall increase in depreciation expense.

- The additional costs included in the operating and maintenance forecast for 2004 are estimated at $52,000. The minimal increase in this category is due to the fact that the operation of this plant does not require any additional employees.

In summary, the portion of 2004 revenue requirement associated with this project is as follows:

Return on rate base	$ 11,141,000
Depreciation	512,000
Operating and maintenance	52,000
Total expenses	**$ 11,705,000**

The other factors relating to the increase in the interest and depreciation expense for the 2004 test year in comparison to the 2002 test year will be addressed later in this report.
It is also important to note that while this new supply of energy is increasing the specific cost components of the revenue requirement noted above, the project is also contributing to a decrease in the cost of fuel that would otherwise be required if this source of generation was not available to the system.

The direct fuel cost that is not included in the 2004 test year due to an increase in the hydraulic production can be estimated as follow:

Annual average energy from Granite Canal	224 GWh
Fuel conversion factor (proposed by Hydro)	624 KWh / bbl
Number of barrels of fuel required	358,974
Forecast price of No.6 fuel consumed	$29.42 / bbl
Estimated No. 6 fuel costs avoided	$10,561,015

Based on the above information, the incremental increase for Granite Canal exceeds the estimated avoided fuel cost by $1.1 million ($11.7 -$10.6 million). This simplified analysis does not take into consideration all of the factors that may influence costs if Granite Canal were not available.

New Power Purchase Agreements

The costs associated with the power to be purchased as a result of the new agreements with the Exploits River Hydro Project and the cogeneration unit at Corner Brook Pulp and Paper is included in the "power purchased" expense. As with the Granite Canal Project, Hydro is also incurring the additional costs relating to these agreements in 2003 and is requesting that these costs be included in rates for 2004 and future years.

The power purchased expense in 2004 is forecast to be $33.3 million in comparison to $15.1 million included in the 2002 test year. The increase in this cost of $18.2 million represents approximately 33% of the increase in the overall revenue requirement for 2004 in comparison to the 2002 test year.

The cost attributable to the total purchase of 237.2 GWh from these two projects in 2004 is forecast to be $18.4 million which basically represents the increase when comparing the total purchased power expense in each test year.

For the past several years, Hydro has been purchasing power from two other NUGs: Star Lake Hydro Partnership and Algonquin Power. The average annual cost per MWh under each of these contracts in comparison to the two new contracts for the 2004 test year is summarized below based on the information provided in CA-35:

Corner Brook Pulp and Paper	$77.4 / MWh
Exploits River Hydro Partnership	$77.0 / MWh
Star Lake	$70.5 / MWh
Rattle Brook	$75.2 / MWh

The direct fuel cost that is avoided in the 2004 test year due to the purchase of power from the new NUG's, as opposed to using thermal production to generate the additional requirements, can be estimated as follows:

Annual average energy from new NUG's	237.2 GWh
Fuel conversion factor (proposed by Hydro)	624 KWh / bbl
Number of barrels of fuel required	380,128
Forecast price of No.6 fuel consumed	$29.42 / bbl
Estimated No. 6 fuel costs avoided	$11,183,366

Based on the above information, the incremental cost for the new power purchase agreements is $7.2 million ($18.4 - $11.2 million). As previously noted, this simplified analysis does not take into consideration all of the factors that may influence costs if the supply of power from these agreements was not available.

Fuel Costs

Fuel expense for the 2004 test year is forecast to increase by $3.9 million (4.4%) in comparison to the 2002 test year. The increase is primarily driven by an increase in the cost associated with No. 6 fuel and diesel fuel (No. 2). The increase in No. 6 fuel of $3.2 million is primarily due to an increase in the forecast market price of No.6 fuel per barrel in comparison to 2002 test year, offset by a decrease in thermal production and the change in the conversion factor. The increase in diesel fuel of $870,000 is primarily related to the forecast increase in load due to growth in sales forecast for the isolated systems in comparison to the 2002 test year. These increases are offset by a net decrease in the other components of this expense of $111,000.

No.6 Fuel

The forecast of No.6 fuel expense takes into account a number of factors including: the price of fuel; the estimated energy to be generated using thermal production at Holyrood; and the fuel conversion factor (i.e the number of kWh generated per barrel of No.6 fuel). The impact of each of these factors relating to the 2004 test year revenue requirement is summarized below:

Increase in the price of No.6 fuel/bbl	$12,681,169
Decrease in thermal production	(8,271,551)
Change in conversion factor	(1,235,140)
Net increase in No.6 fuel expense	$ 3,174,478

Price per barrel:

In P.U.7 (2002-2003), the Board set the cost of No.6 fuel in Hydro's rates at an average price of $25.88 per barrel, which was forecast to be the average market price for 2002. In its current application, Hydro is forecasting an average market price of $29.20 per barrel for 2004. Hydro has obtained this forecast information from PIRA, based on PIRA's forecasts of January 8, 2003. However, when the 2004 opening value of fuel inventory is taken into consideration, the consumption price per barrel of No.6 fuel is $29.42 for 2004.

To calculate the incremental increase in fuel cost associated with the price per barrel of fuel, we have used the forecast barrels of fuel to be consumed per the 2002 test year and multiplied it by the price of fuel for each test year.

Number of barrels of No.6 fuel to be consumed in 2002: (Schedule VII – JRH)	3,191,969
Average fuel price for barrels consumed-$29.423/bbl	$93,917,304
Average fuel price for barrels consumed-$25.45/bbl	81,235,611
Increase relating to fuel price per barrel	$12,681,169

Fuel Conversion Factor

Hydro is proposing a conversion factor of 624 kWh/barrel in the 2004 test year as compared to a factor of 615 kWh/barrel used in the 2002 test year. The increase in this factor means that Hydro will require fewer barrels of fuel to generate the same amount of energy. The conversion factor proposed by Hydro will be discussed later in this section of the report.

To calculate the impact that this change has on the revenue requirement for 2004 in comparison to 2002, we have used the forecast net production of thermal energy in 2004, calculated the difference in the number of barrels of fuel that would be required for each conversion factor and multiplied the result by the forecast price of fuel for 2004.

Net thermal production forecast for 2004:	1,790.15 GWh
Number of barrels @ 624 kWh/barrel	2,868,830
Number of barrels @ 615 kWh/barrel	2,910,813
Decrease in number of barrels	(41,983)
Price per barrel consumed	$29.42
Decrease in fuel cost relating to conversion factor	$(1,235,140)

Net Thermal Production

As previously noted, the introduction of new sources of energy supply during 2003 has also decreased the production requirement of thermal energy from Holyrood. Thermal production in 2004 is forecast to decrease by 172.91 GWh in comparison to the 2004 test year.

To calculate the impact that this change has on the revenue requirement for 2004 in comparison to 2002, we have used the difference in forecast net production of thermal energy between 2002 and 2004, and calculated the decrease in the number of barrels of fuel that would no longer be required using the previous conversion factor of 615 kWh/barrel.

Net decrease in forecast thermal production (1,963.06-1,790.15)	172.91 GWh
Decrease in barrels required @ 615 kWh/barrel	281,154
Price per barrel consumed	$29.42
Decrease in fuel cost relating to decreased thermal production	$(8,271,551)

Diesel Fuel (No.2)

The $870,000 forecast increase in diesel fuel expense for 2004 in comparison to the 2002 test year is primarily related to the forecast sales growth within the isolated systems. The diesel production forecast for the isolated systems included in the 2004 test year is 51,664 MWh in comparison to 45,229 MWh in the 2002 test year; an increase of 6,435 MWh or 14.2%.

According to the information filed by Hydro in NP-39, the cost of service number of litres of diesel fuel in 2002 was 14,846,003 at a cost of $6.46 million ($0.435 average per litre) and the 2004 forecast includes 16,890,713 litres of fuel at a cost of $7.31 million ($0.433 average per litre). Therefore, the increase in this fuel cost is attributable to the increase in the number of litres of fuel required to meet the increase in the energy forecast as a result of the sales growth anticipated within the isolated systems.

No.6 Fuel Conversion Factor

In P.U 7 (2002-2003), the Board ordered Hydro to use a fuel conversion factor of 615 kWh per barrel in setting rates based on its 2002 revenue requirement. This was an increase from a factor of 605 kWh/bbl that was used prior to 2002. In its current application, Hydro is proposing to increase the conversion factor to 624 kWh/bbl. As previously explained, the increase in the conversion factor decreases the number of barrels required in the production of thermal energy and in turn decreases the fuel expense.

In the pre-filed evidence of Mr. J R Haynes, it is noted that Hydro has initiated a number of operating changes to enhance productivity and efficiency with regards to the operation of the Holyrood Plant and it is also noted that there is a relationship between unit loading at Holyrood and efficiency.

In its response to IC-252, Hydro indicated that there were three specific projects in the last five years that will contribute to a higher efficiency of the Holyrood plant over the status quo. These include a water lance installation of Unit No. 3; reheater tubing of Unit No. 3; and the continuous emissions monitoring system.

Hydro estimated that the water lance installation and the reheater tubing projects should approximate a 1% boiler efficiency improvement for Unit No. 3, and assuming that Unit No.3 produces a third of the plant production, it would equate to a plant efficiency improvement of approximately 2 kWh/bbl.

The Continuous Emissions Monitoring system is being installed in 2003; Hydro has indicated that this system will provide more data to the operations staff and allow more tuning of the combustion process through direct feedback of the exit gas conditions. This project will not be functional until the Holyrood units return to service in the fall of 2003. However, Hydro has anticipated that the net effect of this will be a 0.5% increase in plant efficiency or 3 kWh/bbl.

Hydro has also indicated that the monthly conversion factor is influenced by a number of other factors other than average unit load. Other examples were provided in response to IC-317. These include:

- Operating Unit- the efficiency of all units is different
- Load Level – the range of loads the units carry during the month influences the efficiency of the plant
- Unit Fouling – efficiency can be affected by the state of the boiler, air heaters, heat exchangers and other systems in the stem cycle
- Fuel Consumption Measurements – there are inherent inaccuracies in the measurement of bulk storage tanks that can lead to variances from month to month
- Heat Content of the Fuel – the monthly conversion factor does not consider the variance in the heating value of the fuel. If the oil has a different heating value, the conversion factor of a barrel of oil to electrical energy will be different.
- Ambient Conditions –the efficiency of the plant can be affected by ambient conditions. Air temperatures affect the combustion process and the water temperature can affect the cooling efficiency. These conditions change monthly and by season.

Taking these items into consideration and the combined effort of the initiatives within Systems Operations and the Holyrood plant, Hydro is proposing to increase the conversion factor to 624 kWh/bbl. According to the response to NP-74, this factor is calculated using the weighted average conversion factor for the period 1996 to 2002. Hydro chose this period because it represents the period of time since the Company installed the controllable losses program (ETAPRO), which was in 1995. This program was designed to assist the operator to optimize unit performance.

The data used to determine the 624 kWh/bbl conversion factor is included in the table below (source – NP-74).

Year	Net Energy Produced (GWh)	No.6 Fuel Consumed (Barrels)	Conversion Factor (kWh/bbl)
1996	1,403,596	2,297,258	611.0
1997	1,531,301	2,432,538	629.5
1998	1,263,264	2,041,605	618.8
1999	919,802	1,593,932	577.1
2000	970,283	1,591,586	609.6
2001	2,098,490	3,315,853	632.9
2002	2,385,262	3,678,183	648.5
Total	**10,571,998**	**16,950,955**	**623.7**

Based on actual results in 2003 (January to June), the year to date conversion rate is 639 kWh/bbl. Including the actual year to date results in 2003, and assuming a rate of 624 kWh/bbl for July to December, along with the information in the table above, the weighted average conversion factor is estimated at 633kWh/bbl (NP-208).

Hydro has also indicated in its response to NP-198, that 2001 and 2002 have more months with the average unit loading in the upper range (130 MW) and 1999 and 2000 have more months with loading in the lower range (73 MW average). The Company has indicated that in order to predict the average conversion factor over the range of hydraulic generation that may occur in the system, they recommend using the average conversion factor over an extended period of time to capture some historic variability, and the period from 1996 to 2002 provides a balance of these conditions.

It can be argued that if it is the weighted average conversion factor since 1995 that is used to calculate the proposed conversion factor, the following items should also be considered in determining the appropriateness of the proposed factor:

- The impact of the Continuous Emissions Monitoring System is not included in the data from 1996 to 2002. Hydro has estimated that this initiative will increase efficiency by 3 kWh/bbl.

- The actual year to date factor for 2003 is currently 639 kWh/bbl as of June 2003.

- Including all actual results from 1996 to June 2003 and 624 kWh/bbl from July to December would result in a factor of 633 kWh/bbl.

Depreciation

Our procedures with respect to depreciation were focused on reviewing the depreciation amounts and rates incorporated in the 2003 and 2004 forecast to ensure compliance with the 1998 KPMG Depreciation Policy Study, and on assessing the overall reasonableness of depreciation expense.

The specific procedures which we performed on the Company's estimates of depreciation expense included the following:

- recalculated depreciation for 2003 and 2004 for both depreciation methods (sinking fund and straight line) on a test basis and compared the estimated service lives used in the calculations to the Depreciation Policy Study.

- reviewed the interest rates used in calculating sinking fund depreciation for reasonableness.

- assessed the overall reasonableness of the estimates of depreciation for 2003 and 2004.

Hydro's forecast of depreciation expense for 2003 and 2004 is as follows:

Asset Class	Method	2004 Net Cost	2004 Expense	2003 Net Cost	2003 Expense
Hydraulic stations Terminal stations Transmission lines	Sinking Fund	$1,130.9 million	$13.0 million	$1,135.3 million	$11.7 million
All other classes	Straight Line	$232.9 million	$20.9 million	$237.5 million	$21.1 million
		$1,363.8 million	$33.9 million	$1,372.8 million	$32.8 million

The majority of Hydro's high dollar value capital assets, such as Granite Canal, are depreciated using the sinking fund method. As noted above this method is applied to hydraulic stations, terminal stations and transmission lines which account for approximately 83% of the net cost of all capital assets. Depreciation on the remaining classes of assets is calculated using the straight line method.

Under the sinking fund method, depreciation is very low in the early years of an asset's life and increases with time such that it is very high in the final years. The underlying rationale in support of this methodology by Hydro is that the combined charge of depreciation plus interest on the long-term debt required to finance the asset should be equal over the short and long term to minimize fluctuations in operating income. The straight-line method results in equal amounts of depreciation being charged to each period/year over an asset's useful life.

A comparison of the depreciation expense from 1998 to 2002, including forecast 2003 and 2004 is detailed in the following table. The table also calculates depreciation costs as a percentage of total assets.

(000's)	Forecast 2004	Forecast 2003	2002	2001	2000	1999	1998
Sinking fund	$13,000	$11,700	$11,300	$ 9,800	$ 9,700	$ 8,100	$ 8,200
Straight line	20,900	21,100	19,800	22,400	25,800	28,000	23,900
Total Depreciation	$33,900	$32,800	$31,100	$32,200	$35,500	$36,100	$32,100
Total assets (cost)	$1,947,700	$1,924,800	$1,757,700	$1,721,900	$1,680,800	$1,643,100	$1,639,800
Depreciation % of assets	1.74%	1.70%	1.77%	1.87%	2.11%	2.26%	1.96%

As indicated in the table above, the depreciation expense for 2003 is forecast to be $1.7 million higher than 2002 and 2004 is forecast to be a further $1.1 million higher than 2003, for a total increase in 2004 over 2002 of $2.8 million. The increases in depreciation reflect the annual capital additions to be placed in service net of disposals of $164.2 million for 2003 ($29.7 million net of Granite Canal) and $22.9 million for 2004. The major capital items placed in service in 2003 and 2004 and the related 2004 depreciation expense is as follows:

	Cost	**2004 Depreciation**
Microwave System Interconnection	$ 8,941,700	$ 894,000
Granite Canal	134,550,000	512,000
Vehicles	4,299,000	527,000
End User Infrastructure Evergreen Program	3,206,900	331,000
Enterprise Storage Infrastructure	1,363,900	273,000
Total	$ 152,362,000	$ 2,537,000

Depreciation as a percentage of total assets has been decreasing since 1999 with the largest decrease occurring in 2001. This again is a reflection of the annual capital expenditures incurred each year. For 2001, the actual capital expenditures were approximately $10 million higher than average annual capital expenditures. The total assets in 2003 and 2004 include the costs for Granite Canal of $134.5 million. If these costs and related depreciation were removed, then depreciation as a percent of assets would increase to 1.81% in 2003 and 1.84% in 2004. Finally, 2002 depreciation decreased as a result of changes to the useful lives of certain assets based on adoption of the recommendations for the 1998 Depreciation Policy Study.

As a result of completing our procedures, no significant discrepancies were noted and therefore, we report that depreciation expense for forecast 2003 and 2004 appears reasonable. Also, we conclude that in forecasting depreciation expense, Hydro is in compliance with P.U. 7 (2002-2003).

Power purchased

The Company's "power purchased" expense for the 2004 test year is forecast to increase by $18.2 million in comparison to the 2002 test year. As indicated in a previous section of this report, the addition of the two new power purchase contracts in 2003 has increased this expense by $18.4 million in the 2004 test year.

In addition, the cost relating to the power purchased from the two existing NUG's (Star Lake and Rattle Brook) has increased by $1.1 million in the 2004 test year in comparison to the 2002 test year. This is due to an increase in the contract price for each NUG and a forecast increase in energy supplied of 10.9 GWh in comparison to 2002.

The increases relating to the new and existing power purchase contracts is partially offset by the expiration in March 2003 of a ten year contract with Abitibi – Stephenville for the right to interrupt a portion of its power supply should Hydro need the power to meet its own demand. This was a ten year contract for approximately $1.3 million per year.

In summary, the changes in power purchased expense are as follows:

	(million's)
New purchased power contracts	$18.4
Increase cost from existing NUGs	1.1
Expiration of interruptible power supply contract	(1.3)
	$18.2

Interest

Interest expense for 2004 is forecast to increase by $13.2 million overall compared to 2002. The following is a summary of interest expense for 2004 as compared to actual 2002 and 2002 test year:

(millions)	Forecast 2004	Actual 2002	Test year 2002
Gross interest	$ 112.3	$ 97.4	$ 98.8
Debt guarantee fee	14.4	12.2	12.4
Amortization of debt discount and financing costs	0.6	1.2	1.1
Foreign exchange losses	2.2	2.2	2.1
	129.5	113.0	114.4
Less:			
Interest earned	(20.6)	(14.5)	(16.2)
Interest attributable to CF(L)Co share purchase	(2.1)	(2.3)	(1.9)
Interest capitalized during construction	(5.1)	(7.7)	(8.0)
	$ 101.7	$ 88.5	$ 88.3

Gross interest costs are forecast to increase $14.9 million over 2002. This increase is primarily attributed to interest incurred on new bond issues. In 2002, the Company completed two bond issues in April and September that totaled $250 million and has forecast a bond issue in mid 2003 totaling $125,000 at a rate of 6.65%. The forecast for 2004 reflects the full year interest costs for all three bond issues which accounts for $12.3 million of the increase in gross interest.

The issuing of bonds in 2002 and 2003 was driven by the accumulating balance in short term debt. In managing the promissory notes balance, which is largely driven by the rate stabilization plan and capital expenditures, Hydro's uses a calculation called the targeted weighted average term to maturity to determine when a bond issue may be necessary.

Gross interest for 2004 reflects a further increase of approximately $3.0 million related to forecast interest on short term debt. Interest rates for short term debt are forecast to average 5% in 2004 compared to 3% in 2002.

The debt guarantee fee for 2004, which is based on 2003's forecast of long term debt less any sinking funds, has also increased by $2.2 million over 2002 due to the additional bond issues in 2002 and 2003.

However, offsetting increases in gross interest costs is the increase in the forecast for interest earned. The three main categories included in interest earned are power bills, the rate stabilization plan and sinking funds. For 2004, an increase in the interest forecast to be earned on the RSP of $4.9 million and an increase in the interest forecast to be earned on sinking funds of $0.9 million account for the majority of the $6.1 million increase over 2002.

The amount of interest capitalized during construction for the 2004 forecast has decreased from 2002 by $2.6 million. The total interest capitalized during construction is driven by the amount of capital expenditures incurred in that same time period. The decrease in 2004 is mainly a function of completing construction on Granite Canal in 2003. Construction of this hydroelectric plant commenced in 2000 and resulted in an estimated project cost of $134.5 million.

Other Costs

Schedule II of Mr. Roberts pre-filed evidence contains details of Hydro's Other costs forecast for 2003 and 2004 with comparative data on 2002 final test year and 2002 actual. Exhibit 1 of our report provides similar information and also includes 2001 comparative data. Exhibit 2 provides a comparison of forecast 2004 with 2002 final test year only. In Exhibit 1 we see that total Other costs are forecast to decrease by $3,496,000 (3.3%) for 2004 relative to 2002 actual. On a net basis the forecast decrease is only $136,000 (0.2%), due primarily to the reduction in capitalized expenses forecast for 2004 compared to 2002.

In Exhibit 2 we see that total other costs are forecast to increase by $4,478,000 (4.6%) for 2004 compared to the 2002 final test year. On a net basis the increase is $5,250,000 or 6.1%. Relative to the 2002 final test year, the most significant changes for forecast 2004 are in salaries and fringe benefits, insurance and the productivity allowance. The productivity allowance of $2 million was a requirement in Board Order P.U. 7 (2002 – 2003). The Board gave Hydro the discretion to allocate this allowance among the various expenditure categories, however, in order to expedite finalization of the 2002 revenue requirement, Hydro presented the $2 million allowance as a separate line item in the 2002 final test year forecast. The increases in salaries and fringe benefits and insurance together with variances in other categories are discussed in the following sections of our report.

Hydro has also presented details on other costs or operating expenses on a departmental basis in its pre-filed evidence. This departmental breakdown can be found as follows: Production – Haynes, Schedule VI; Transmission and Rural Operations – Martin, Schedule V; and Finance and Corporate Services – Roberts, Schedule XIII. In Exhibit 3 of our report we have summarized this departmental breakdown and provided a comparison of the 2004 forecast to the 2002 actual and 2002 final test year. Variances in forecast departmental costs are referenced throughout our comments on the overall expense categories which follow.

In Exhibit 5C we provide an analysis of total other cost on a kWh's sold basis for the years 2000 to 2004. This Exhibit shows that on a KWh basis, other costs are declining over the period noted.

Salaries and benefits

Gross payroll costs forecast for 2003 are $63.605 million and $63.237 million for 2004. In 2004 overall costs are 2.1%, or $1.322 million lower than 2002 levels. The salaries and benefits costs are summarized by category in Exhibit 4A.

Our review of salaries and benefits included an analysis of the variances from year-to-year, an analysis of the trends in salary costs, and discussions with Company officials.
Hydro has indicated that for 2003 and 2004, its forecast is prepared based on FTE's (i.e Full Time Equivalents) as opposed to budgeting based on a permanent workforce supplemented by temporary/seasonal employees. Therefore, the Company did not budget separately for permanent salaries and temporary wages. The comparative figures for the prior years in Exhibit 4A have been adjusted to reflect both permanent salaries and temporary wages in the "salaries" grouping.

As noted in Exhibit 4A, salaries are forecast to decrease in 2004 from 2002 actuals by $381,000. The net decrease is attributable to two offsetting factors. The Company has indicated that there will be annual savings of $2.6 million in salaries due to the elimination of 46 positions during 2002. However, the Company has also forecast increases in union and non-union wages for 2003 and 2004 which offsets the savings obtained from the reduced workforce. The breakdown of salaries by division is summarized in Exhibit 4B.

Included in the salary forecast is a vacancy credit of $1 million and $2.5 million for 2003 and 2004 respectively. This compares to a $1.5 million vacancy credit included in the 2002 test year. According to Hydro's response to CA-43, the intent of this vacancy adjustment is to "estimate the amount of savings due to vacancies in salaries." It also notes that there are always "a number of positions that become vacant during a particular year due to retirements, terminations, long-term disability etc. which results in salary savings because of the period of time which elapses between the date of vacancy and the date of hiring the replacement."

Per review of Exhibit 4A the most significant variances between 2003 and 2004 forecasts and 2002 actuals occur in the following categories of salaries:
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- Decrease in overtime for 2003 and 2004.
- Increase in the vacancy adjustment in 2003 and 2004.
- Increase in employee future benefits
- Increase in group insurance

As noted above, the Company has forecast increases in salary scales in comparison to 2002. Based on information provided by Hydro (CA-41), the forecast increases are as follows:

- A general scale increase of 2.5% is provided to all union staff effective March 31, 2003 and non-union staff including the management committee effective January 1, 2003.
- An additional general scale increase of 2.5% is provided to all union staff effective September 29, 2003 and non-union staff, including the management committee effective July 1, 2003.
- A general scale increase of 3% is provided to all union staff effective March 29, 2004.

With respect to the FTE's, Hydro has provided information in response to NP-10 which indicates that the number of FTE's for 2003 and 2004 are 932 and 922 respectively. These are lower than the 2002 FTE number included in our 2002 annual report of 1,014. According to Hydro the number of FTE's for 2004 reflects changes in staffing levels to August, 2003 and that it does not reflect anticipated future staff reductions. These anticipated future staff reductions are reflected in the 2004 forecast through the vacancy adjustment of $2.5 million. We have recalculated the average salary per FTE for 2003 and 2004 and determined that the average salary per FTE has increased on a percentage basis comparable with salary increases forecast by Hydro for 2003 and 2004.

The forecast for salaries is based on planned or expected work requirements by the various business units. In using this approach, the forecasts would not include any amounts for extraordinary or unexpected maintenance requirements whereas actual salaries for prior years would include any additional costs associated with such items.

Overtime costs for 2004 are forecast to decrease in comparison to 2002 actual by $1.046 million or 26.7%. While it is difficult to forecast the amount of overtime that is likely to incur in a year, these costs are generally linked to the maintenance requirements in the TRO and Production divisions and requirements related to capital projects. Hydro has indicated that for 2003 and 2004, there is a conscious effort by the Company to reduce overtime costs. They plan to use less staff internally to complete capital projects which should reduce the amount of overtime costs incurred.

Employee future benefits consist of two components: 1) the current service portion, and 2) an interest portion. The cost of the interest portion can vary depending on the average balance of the pension benefit obligation or liability. Employee future benefits are forecast to increase by $1.282 million from 2002 to 2004. This increase is due to the fact that actuarial estimates have shown higher projected costs. According to the Company, the increased valuation is due to increases in the cost of health care benefits and increases in usage by retirees.

Group insurance expense is forecast to increase by $827,000 from 2002 to 2004. This is attributable to an increase in corporate group benefits which are a result of higher group insurance rates. The group insurance rates have also increased due to increased utilization of the plan, higher costs for drugs and expanded coverage for temporary employees.

Fringe benefits expense has been forecast to increase by approximately $480,000 in 2004 in comparison to 2002. Fringe benefits were approximately 13.15% of salaries and hourly wages in 2002. For 2003 and 2004, the forecasts are 14.22% and 14.24 % respectively. These increases are attributable to items such as escalating Canada Pension Plan rates.

Exhibit 4C indicates the allocation of gross payroll costs from 2001 to forecast 2004 between operations and capital. The payroll costs charged to capital are forecast in 2004 to decrease from 2002 by $2.653 million. The main reasons provided by Hydro for the declining capitalized salaries are:

- There were some significant capital projects completed in 2002 including the Granite Canal and the Avalon Upgrade. These accounted for a large portion of capitalized salaries in 2002.

- There is also an initiative by the Company to reduce the number of internal staff utilized on capital projects in the future.

Executive salaries for the years 2000 to 2002 are as follows:

	Base Salary	Incentive Base Pay & Special bonus	Fringe Benefits	**Total**
2002				
Total executive group	$ 820,755	$ 99,550	$ 50,408	$ 970,713
Average per executive (5)	**$ 164,151**	**$ 19,910**	**$ 10,082**	**$ 194,143**
2001				
Total executive group	$ 817,737	$ -	$ 44,867	$ 860,354
Less: retirement	(47,740)		(2,250)	(49,990)
Add: Annualize replacement	11,455			11,455
	$ 781,452		$ 42,617	$ 821,819
Average per executive (5)	**$ 156,290**	**$ -**	**$ 8,523**	**$ 164,363**
2000				
Total executive group	$ 793,415	$ -	$ 45,163	$ 838,578
Average per executive (5)	**$ 158,683**	**$ -**	**$ 9,033**	**$ 167,716**
% Average increase 2002 vs 2001	**5.0%**	**100.0%**	**18.3%**	**18.2%**

In the completion of our 2002 annual financial review, Hydro provided several reasons for the increase in executive compensation in 2002. Firstly, a study was conducted in 2001 to review executive compensation which led to the introduction of a performance-based system as part of the Company's compensation structure. The incentive payments for the 2001 fiscal year were included in the total salary and benefits figures for 2002. Secondly, there were two 2.5% increases in base salary for executives to coincide with the union and non-union wage increases during the year. Thirdly, the Vice-President of Production retired in 2001, leaving the position vacant for a period before it was filled. Finally, the Board of Directors approved a "special bonus" of $17,000 each for three of the Vice-Presidents in 2002 to compensate them for their work relating to the 2001 General Rate Hearing.

With respect to the 2003 and 2004 forecast for executive salaries, Hydro has advised us that the 2002 actual salaries were used to develop salary forecasts with scaling factors applied to these amounts consistent with other staff categories. Hydro has also advised that the 2004 forecast does not include any incentive payments relating to the incentive based program. However, the pilot project noted above will continue for 2003 and 2004.

We have reviewed overall salaries for reasonableness and based on the scaling factors noted in CA-41 indicating two 2.5% increases for all staff in 2003 and another 3% increase for union staff in 2004, there is nothing to indicate that the executive salaries are inappropriately forecast.

The comparison of gross salary costs between the 2004 test year and the 2002 test year (Exhibit 2) indicates an increase of $1.3 million. This increase can be summarized as follows:

	(000's)
Decrease in salaries (net of vacancy adjustment)	($1,166)
Increase in employee future benefits	1,294
Increase in fringe benefits	684
Increase in group insurance	270
Increase in overtime costs	248
Net increase	$1,330

As previously indicated, the decrease in salaries is due to the elimination of 46 positions in 2002 offset by the scale increases forecast for 2003 and 2004. The vacancy adjustment for 2004 is also $2.5 million in comparison to $1.5 million for the 2002 test year.

The explanations for the increase in employee future benefits, fringe benefits, and group insurance previously explained in the comparison of 2002 actual costs with the 2004 test year would also be relevant for these variances. The increase in overtime costs is a portion of the overall salary costs allocated to capitalized expenses.

System equipment maintenance

System equipment maintenance costs forecast for 2003 and 2004 are fairly consistent with prior year totals. The forecast cost for 2004 relative to 2002 shows an increase of $240,000 as per Exhibit 2. Although the expense is fairly consistent over the past several years, there are a number of items to note that have been forecast for the 2003 and 2004 year ends.

The costs for 2001 to 2004 for the system equipment maintenance portion of this expense only (excluding tools and equipment, freight and lubricants, gases and chemicals) are broken down by department as follows:

(000)'s	2001	2002	2002 Test Year	2003 Forecast	2004 Forecast
Transmission and rural operations	$ 5,946	$ 7,042	$ 6,522	$ 5,530	$ 5,950
Production	9,230	7,773	8,063	9,121	9,117
Human Resources & Legal	814	800	865	856	825
Finance	138	120	127	139	139
Other	22	63	37	26	26
	$ 16,150	$ 15,798	$ 15,614	$ 15,672	$ 16,057

In 2002, there was a significant increase in the TRO division which was primarily due to certain non-recurring extra maintenance costs in the Central and Northern regions. The extra maintenance requirements in these areas included inspections and replacement of wood poles, reconditioning transformer oil at the Bay D'Espoir site, repairs to air blast circuits at Sunnyside, repairs to diesel plant units due to a leak in the exhaust manifold, radiator and generator failure and an overhaul on a diesel unit. In 2003, the costs for these regions are expected to decline to prior year levels. Hydro indicates that this decline is primarily due to a change in maintenance philosophy with the adoption of a Reliability Centered Maintenance (RCM) program and a decrease in the number of operating projects. The RCM program essentially places emphasis on reliability, and therefore, not all of the systems are treated the same with respect to the frequency of maintenance. Hydro has advised that the intent of this program is to create a more effective maintenance program and to promote more efficient use of resources in the maintenance area. The forecast amounts for 2003 and 2004 for TRO are $5.530 million and $5.950 million respectively. This means a decrease of approximately $1.092 million or 15.5% in maintenance costs from 2002 to 2004.

This decrease in costs in TRO is offset by an increase in the Production department for 2003 and 2004. In 2002, the Production department costs decreased from $9.230 to $7.773 million, primarily due to the fact that there were no major overhauls at the Holyrood plant in 2002. In 2001, there was a major overhaul done on Unit#3 in Holyrood whereas in 2002 only minor overhauls were completed on all three units.

Production department maintenance costs have been forecast to increase to $9.121 million and $9.117 million in 2003 and 2004, a net increase of $1.343 million compared to the 2002 actual. For 2003, there is a major turbine overhaul forecast for Unit #1 at Holyrood, which accounts for approximately $1 million in increased costs. In 2004, there are no major overhauls planned for the three units in Holyrood, however, several significant operating projects are forecast for that year. These projects include: Heat Tracing Refurbishment ($203,000), Fuel Oil Tank Cleaning and Repair ($665,000), Asbestos Abatement Program ($175,000), Roof Replacement ($215,000) and Fire Protection Purging Valves Relocation ($200,000).

The above comments all relate to thermal generation costs. Maintenance costs for hydro generation are forecast to decline by approximately $277,000 from 2002 to 2004. The forecast expense is lower in 2004 because 2002 included special projects beyond routine maintenance which totaled $293,000. These projects included resurfacing the lower turbine seal on Unit 2 in Bay d'Espoir, repairs to breaker at Hinds Lake, governor repairs/modifications on Units 3, 5 and 6 in Bay d'Espoir and crushed rock at Granite Canal. These projects were non-recurring and they are not forecast for future years.

Overall, the net variance in the Production and TRO departments from 2002 to forecast 2004 is $251,000 ($1.343 million - $1.092 million). The remaining variances in system equipment maintenance are not significant and further analysis and commentary on these components is not considered necessary.

Miscellaneous

The breakdown of items included in the miscellaneous expense category for 2001 and 2002 actuals and forecast 2003 and 2004 are as follows:

	Actual 2001	Actual 2002	Test Year 2002	Forecast 2003	Forecast 2004
Staff Training	$ 1,051,515	$ 658,037	$ 840,805	$ 932,719	$1,012,649
Contribution	182,838	185,251	193,500	194,000	194,000
Sundry costs	299,399	107,837	83,538	88,198	81,818
Diesel fuel Hydro	92,318	53,669	94,550	95,300	39,400
Demand side management	13,917	20,934	45,000	45,000	100,000
Employee expenses	306,889	276,239	340,176	331,686	322,526
Collection fees	8,421	6,190	25,000	8,520	8,520
Bad debt expense	386,197	1,036,772	300,000	324,996	324,996
Inventory gain/loss	1,075,488	288,092	594,000	370,000	420,000
Municipal and payroll tax	2,198,438	2,231,281	2,074,700	2,224,694	212,040
	$ 5,615,420	$ 4,864,302	$ 4,591,269	$ 4,560,819	$ 4,678,603
Less: Non-Regulated	(182,000)	(190,000)	(193,500)	(194,000)	(194,000)
Total (as per Exhibit 2)	$ 5,433,420	$ 4,674,302	$ 4,397,769	$ 4,366,819	$ 4,484,603

The procedures performed in this expense category included a comparison of the forecast amounts to prior years, investigation of any unusual fluctuations and assessing the overall reasonableness of the forecast amounts.

For purposes of the 2003 and 2004 forecast, all of the amounts forecast for contributions are considered non-regulated. These have been removed from the chart as noted above.

Miscellaneous expense for the years 2002 to forecast 2004 is fairly consistent overall reflecting a decrease of $189,699 or 4.1%. In comparison to the 2002 test year there is a forecast increase of $86,834 or 2%. While the total expense is fairly consistent, within the sub-categories of miscellaneous there are a couple of significant fluctuations to note.

The bad debt expense forecast for 2003 and 2004 of $324,996 is consistent with the bad debt expense of 2001 ($386,197). The large increase in 2002 of $650,575 was primarily due to the write-off of accounts related to isolated customers in Labrador.

Staff training costs for the 2003 and 2004 forecast have increased from 2002, however, they are comparable to 2001. The decrease in staff training in 2002 was related to several factors. In the Human Resources division there was a Diesel Plant Operations Training program that was an initiative for 2000 and 2001. It had much lower costs than anticipated in 2002, however an increase in these training costs is forecast for 2003 for new diesel system representatives and retraining of others. Also, during 2002 there were reduced training costs in the Central Region ($75,000), the IS & T department ($61,000) and the Financial Planning and Customer Services department ($28,000). The staff training costs in 2002 were also lower than in 2001 because other work commitments, such as the Business Process Improvement study, prevented various departments from completing the training which was originally planned. This training was rescheduled for 2003 and 2004.

The employee expenses have been forecast to increase in 2003 and 2004. However, they are comparable to 2001. This category increase includes a provision for the purchase of newly required personal protective equipment.

The inventory gain/loss account decreased substantially in 2002 to $288,092. It was $1,075,488 in 2001 and it has been forecast to be $420,000 in 2003 and $370,000 in 2004. As noted in our 2002 report, there was a large initiative in 2001 to identify excess and obsolete inventory items and to remove them from inventory. As a result, there was a write-off of approximately $1 million in 2001 for inventory losses. For 2002, the anticipated write-offs did not totally materialize resulting in a substantial decrease in this category. For 2003 and 2004, the forecast figures are slightly higher than in 2002 to account for the anticipated write-off of obsolete telecontrol equipment.

The municipal tax/payroll tax account is scheduled to decrease in 2003 and then increase in 2004 so that the 2004 forecast of $2.224 million is consistent with the 2002 and 2001 actual amounts of $2.231 million and $2.198 million respectively. The decrease in 2003 is attributable to lower salary levels because of the elimination of 46 positions in 2002, whereas the increase in 2004 is due to higher anticipated salary levels after the wage scale increases in 2003. In addition, the municipal taxes are projected to be higher in 2004 due to higher rural revenues.

The demand side management expense is forecast to increase in 2004 because of higher costs related to the HYDROWISE conservation program.

Professional services

For 2003 and 2004, we compared the forecast amounts to prior years, investigated any unusual fluctuations and assessed overall reasonableness of the forecast amounts. Professional services costs from 2001 to 2004 are as follows:

(000's)	**2001**	**2002**	**Test Year 2002**	**Forecast 2003**	**Forecast 2004**
Professional services	$ 1,880	$ 3,315	$ 2,561	$ 2,395	$ 2,013
Regulatory related costs	2,470	806	1,600	1,000	1,150
Software acquistions & maintenance	1,180	1,202	1,179	1,267	1,340
Non-regulated		(5)	(397)	(21)	
Total professional fees	$ 5,530	$ 5,318	$ 4,943	$ 4,641	$ 4,503

The high costs in the professional services category for 2002 related primarily to the Business Process Improvement project. This initiative alone accounted for $1,010,000 in consulting fees. The forecast decrease for 2003 and 2004 is attributable to the removal of these fees.

For 2002, regulatory related expenses totaled approximately $806,000 which was a large decrease compared to 2001. This significant decrease is primarily related to costs for the 2001 rate hearing. While this hearing did extend into 2002, the majority of the costs had been accrued in 2001. Hydro had anticipated regulatory related costs of approximately $1,203,000 for the 2002 test year, however all of these costs did not materialize as budgeted due in part to the deferral approved in P.U. 16 (2002-2003).

In P.U. 16 (2002-2003), the Board approved a deferral of a portion of the costs relating to the 2001 hearing. The Order indicated that external regulatory costs in excess of $1 million were permitted to be deferred and amortized over a sixteen month period commencing September 2002. The total external costs for the Hearing totaled $1,805,000 and the amortization of $202,000 relating to the four month period ending December 31 2002 was included in the depreciation expense for that year. Amortization of the remaining $603,000 in deferred costs is not included in the regulatory expenses for 2003. To be consistent with 2002, it has been included in the depreciation expense. Regulatory related expenses are forecast to increase in 2003 because of the anticipated costs from the general rate hearing.

For purposes of the 2003 general rate hearing, the company has estimated that there will be $1.2 million in external regulatory costs related to the Board and intervenors. Hydro is proposing that these costs be amortized over a three-year period beginning in 2004 and it has factored one year of amortization (i.e. $400,000) into its regulatory related costs forecast of $1.15 million for 2004. This treatment is consistent with prior hearings and it also consistent with the treatment ordered by the Board for Newfoundland Power. Based on this information, we conclude Hydro's proposal to defer and amortize regulatory costs related to the 2003 hearing appears reasonable.

The forecast fees for software acquisitions in 2003 and 2004 are above 2002 levels. There is an increase of $65,000 in 2003 and another $73,000 in 2004. Hydro advises that this is due to the escalating prices for the cost of software.

While the professional services expense category has exhibited a significant upward trend over the past four years (65% increase from 1997 to 2002), the forecast for 2004 reflects a decrease of 15.3% compared to 2002 actuals and 8.9% compared to the 2002 final test year forecast.

Travel and conferences

The travel and conference costs for 2001 and 2002 actuals and forecast 2003 and 2004 are noted in the table below.

	2001	2002	Test Year 2002	Forecast 2003	Forecast 2004
Travel	$2,599,000	$2,213,000	$2,069,000	$2,079,000	$1,922,000
Conferences	179,000	124,000	306,000	169,000	217,000
	$2,778,000	$2,337,000	$2,375,000	$2,248,000	$2,139,000

The forecast costs for travel show a decrease of $134,000 in 2003 compared to 2002 and an additional decrease of $157,000 in 2004. Hydro advises that the total forecast decrease over two years of $291,000 reflects efforts by the company to reduce travel costs. The largest variance for departmental travel is in TRO where costs are projected to decline approximately $339,000 from 2002 to 2004. The company's adoption of the RCM program combined with its initiative to use less internal staff for capital projects have reduced travel cost forecasts. Also, there were two significant capital projects (i.e. Granite Canal and Avalon Upgrade) that were completed during the year and will reduce the demand for travel in 2003 and 2004. This reduction in travel is partially offset by a projected increase of approximately $70,000 from 2002 to 2004 in Human Resources and Legal travel. The travel in this department is forecast to increase because of costs attributable to the 2003 general rate hearing.

Conference costs are forecast to increase by $93,000 from 2002 to 2004. This is due to the fact that various departments have anticipated more conference expenses including IS &T where more technical conferences are being attended. The 2004 forecast is consistent with 2001 and 2000 levels.

The procedures performed for travel and conference included comparing the forecast amounts to prior years and investigating any unusual fluctuations.

Other Costs Categories

In addition to the various categories of expenses commented on above, the other categories of operating expenses by breakdown were also analyzed for any unusual variances.

	2001	2002	Test Year 2002	Forecast 2003	Forecast 2004
Insurance	$ 949	$ 1,198	$ 977	$ 1,614	$ 2,019
Transportation	1,858	1,979	1,923	1,955	2,044
Office supplies	1,872	1,856	1,864	1,972	1,913
Building rentals and maintenance	703	900	626	898	894
Equipment rentals	1,369	1,372	1,558	1,526	1,636
Loss on disposal	1,839	2,769	890	628	541

From this analysis, the following observations were made with respect to these expenses:

- Forecast insurance expense for 2004 is more than double the 2002 test year and 69% higher than 2002 actuals. Insurance premiums for 2003 and 2004 are increasing on an annual basis due to several factors. Overall changes in insurance markets worldwide over the past several years have resulted in significant premium increases across all industries. In addition, Hydro adds gross assets of approximately $35 million a year and these new capital items require insurance coverage.

- The trend in transportation expense is fairly consistent over the years 2001 to 2004. The above expenses are net of capital fleet allocations of $473,546 (2001), $485,470 (2002), $400,000 (2003) and $300,000 (2004). The primary reason for the increase in 2002 transportation was that casual helicopter rates increased approximately 20%. In addition, there was an increased usage of helicopters in Labrador for emergency response requirements and in the Central area on TL206 for lightning arrestors. In 2003, expenses are consistent with 2002 but as noted above, they are forecast to increase $65,000 when comparing 2002 to 2004. This is because there is a forecast decrease in the utilization of vehicles on capital projects in 2004.

- The office supplies expense is consistent from 2001 to 2004 with no significant variances to note.

- Building rentals and maintenance is forecast to remain consistent in 2003 and 2004 compared to 2002. The increase in 2002 was a result of safety clothing, in the amount of $184,000, being reallocated to this expense category.

- The increase in equipment rentals is attributed to the increasing cost of leasing communication circuits, Internet connection costs and some licensing costs. More specifically, there is an increase of computer costs of $109,000 from 2002 to 2004. This is due to the increase in computer costs mainly related to the extra disk space required for the disaster recovery plan. There is also an increase of $139,000 from 2002 to 2004 forecast for rentals which is attributable to higher costs for the IS & T department in the area of network services such as VHF trunking and digital data.

- The loss on disposal account has decreased by $2.2 million. The loss in 2002 of $2.8 million was primarily due to the write off of diesel plants destroyed in the fire at Recontre East and the disposal of several assets from the Holyrood Plant. Forecast amounts for 2003 and 2004 appear reasonable. The nature of this account makes it very difficult to determine a precise amount and the account does not appear overstated.

Intercompany charges

Intercompany charges to CF(L)Co. for 2004 have decreased by $229,163 or 11.4% compared to 2002. The breakdown of intercompany charges by department is as follows:

	2001	2002	Test Year 2002	Forecast 2003	Forecast 2004
Production	$629,714	$589,199	$621,074	$621,074	$571,074
Finance	406,755	462,315	387,780	378,780	378,780
Transmission and Rural Operations	73,921	67,387	135,500	37,000	37,000
Internal Audit	36,211	33,961	67,957	71,637	71,637
Management	29,421	179,917	120,024	120,024	120,024
Human Resources and Legal	590,413	673,171	577,906	577,906	598,272
	$1,766,435	$2,005,950	$1,910,241	$1,806,421	$1,776,787

These charges are for the provision of services in accordance with a Services Agreement between Hydro and CF(L)Co. Hydro's methodology for determining intercompany charges utilizes specific work orders in most situations to capture the actual costs of providing services to CF(L)Co. According to the report prepared by Hydro relating to its methodology for determining intercompany charges, costs recoveries such as salary and overhead charges are determined as follows using the JD Edwards integrated suite of applications and a Lotus Notes Time Reporting application:

a) Departments track salaries, overtime, temporary wages and employee expenses through time reporting.
b) Departments use the percentage calculated from the time reporting to allocate other costs such as membership dues and conferences.
c) Interest and depreciation costs for Hydro Place are based on the equivalent complement percentage. This percentage is used to allocate the costs of providing administrative services such as telephone, maintenance materials, janitorial, etc.
d) "Information Systems and Telecommunication" costs are allocated based on the ratio of personal computers assigned to CF(L)Co. to the total number of personal computers corporate-wide. This percentage is applied to computer costs and software acquisition and maintenance cost accounts.
e) All specific costs are recorded directly into the CF(L)Co. accounting system.

It is also important to note that Hydro does not carry a receivable for cost recoveries from CF(L) Co. CF(L) Co. pays Hydro on a monthly basis based on the budgeted amount set for the year. The actual amounts are determined at year end and any adjustments are processed at that time. Furthermore, there is no interest charged on these amounts.

As can be seen in the table above, in comparison to 2002 actual the recovery of costs for services provided to CF(L)Co has decreased by $200,000 in 2003 and by another $30,000 in 2004. With these decreases the 2004 forecast charges are then fairly consistent with the $1.766 million in 2001. In 2002, the Human Resources and Legal department had increased charges of $83,000 and the Management department had increased charges of $150,000. The increase in the Human Resources and Legal department was primarily attributable to charges for severance and redundancy payments for terminated employees who regularly provided services to CF(L)Co. The increases in management charges were due to the Company's involvement in the Business Process Improvement initiative. Since these charges were non-recurring, the 2003 and 2004 forecast reflect normalized recoveries.

Capitalized expenses

Capitalized expenses are forecast to be $6.805 million in 2003 and $5.764 million in 2004.

The breakdown of capitalized expenses is as follows:

	2001	2002	2002 Test Year	2003 Forecast	2004 Forecast
Salaries	$ 8,977,207	$ 8,116,250	$ 5,722,500	$ 6,405,373	$ 5,463,951
Fleet expense	473,546	485,670	300,000	400,000	300,000
Travel direct work orders	115,693	21,341	108,640		
	$ 9,566,446	$ 8,623,261	$ 6,131,140	$ 6,805,373	$ 5,763,951

The methodology employed by Hydro with respect to capitalizing expenses is outlined below. This methodology changed slightly in 2002 relating to travel direct work orders. During 2002, Hydro began charging these expenses directly to the capital job. This change is the reason for the decrease in this sub-category for 2002 compared to 2001 and the elimination in forecast 2003 and 2004.

Capitalized salaries include the salaries and benefits of the Company's employees whose time is charged directly to capital projects, as well as departmental and non-departmental overhead. The benefits component is determined by applying a pre-determined percentage to the gross salaries, which are capitalized directly. The departmental overhead component is allocated to the capital projects as a percentage of direct salaries and benefits depending on the employees' responsibilities. Finally, the non-departmental overhead component includes costs of departments which are not directly related to the capital program but which are considered necessary to support the various capital projects throughout the year. The non-departmental overhead charge is determined by applying a pre-determined percentage to the total cost of capital projects as per the work orders.

Fleet expense and travel direct work orders encompass fleet costs and costs associated with smaller work orders related to the Company's distribution system. These costs were primarily capitalized using standard rates developed by the Company; however during 2002 Hydro began charging these expenses directly to the capital job.

All categories of capitalized expenditures other than capitalized direct salaries are allocated to work orders using percentages or standard rates developed by the Company. These allocations are intended to ensure that capital projects are adequately charged with the cost of support functions such as accounting and finance, engineering, and other such expenses which cannot be directly charged to specific capital projects.

For 2002, the percentages used to capitalize fringe benefits and overhead costs were as follows:

Benefits (% of direct salaries)	
Island	33.0%
Labrador	43.0%
Departmental overhead	
Non-field (% of direct salaries and benefits of engineers and office staff)	37.6%
Field (% of salaries and benefits of crews)	19.8%
Non-departmental overhead (% of work order total costs)	6.0%

The forecasts for 2003 and 2004 illustrate a continuing trend of decreased capitalized salaries. This is because Hydro is planning to reduce the number of staff used in the capital program. In addition, the forecasts for 2003 and 2004 project lower capitalized salaries due to the completion of a few large capital projects including Granite Canal and Avalon Upgrade. The forecast capitalized expenses for 2003 and 2004 are 18% and 16% of capital expenditures respectively. This appears reasonable compared to prior years which have ranged from 7% to 19% since 1998.

Other Items

Rate Stabilization Plan

In P.U.7 (2002-2003), the Board ordered that the RSP in existence at the time of the 2001 General Rate Hearing (the "old" RSP) be fixed as of August 31, 2002 and recovered from the retail and industrial customers over a five year period on a straight line basis. On September 1, 2002 the "new" RSP commenced which incorporated the orders of the Board set out in P.U. 7 (2002-2003). The balance in this "new" plan will be recovered over a two year period (straight line) beginning January 1, 2004 for the industrial customers and July 1, 2004 for the retail (Newfoundland Power) customers.

The balance in the "new" Plan as of December 31, 2002 was $20.496 million. The fuel price variation represented $13.7 million and the hydraulic production variance represented approximately $7 million. For the six months ended June 2003, the plan has accumulated an additional balance of $32.063 million (excluding interest), of which $31.3 million was the result of the fuel price variation.

In P.U.7 (2002-2003), the Board set the price of No.6 fuel at the price based on the most recent forecast from PIRA, which was approximately $26/barrel. However, due to world events since the inception of this new plan, the price of No.6 fuel has escalated to $44 per barrel and has averaged approximately $37 over the past ten months (September 2002 to June 2003). Hydraulic production has also been lower than estimated in the 2002 Cost of Service which is contributing to the balance in this plan.

Based on the information provided in Schedule XII (J.C. Roberts-1st Revision), Hydro is forecasting the "new" RSP balance to accumulate to $67 million as of December 31, 2003; based primarily on an average forecast price of No.6 fuel of $34.80 for 2003 compared to the cost of service price of $26. The balance at December 31, 2004 is forecast to be $52.1 million. The only activity that is included in the 2004 forecast for the "new" RSP is the interest charges and the recovery of a portion of the 2003 balance. The activity relating to the remaining factors is considered to be equal to the cost of service for 2004.

Hydro has proposed in its Application that the factors included in the RSP for 2004 be rebased to reflect the proposed forecast price of No.6 fuel, the 30 year hydraulic production forecast, the 2004 load forecast and the fuel conversion factor of 624 kWh/bbl.

The only activity occurring in the "old" RSP plan during the 2003 and 2004 forecast years is the recovery from the consumers and the interest that is being charged to the plan. The forecast balance of the "old" RSP for 2003 and 2004 is $94.1 million and $79.4 million, respectively. The five year recovery period commenced January 1, 2003 for industrial customers and July 1, 2003 for retail customers.

In 2003, both plans are incurring interest costs based on an annual weighted average cost of capital of 7.157%, which was approved in P.U.7 (2002-2003). For forecast 2004, interest is calculated using the proposed weighted average cost of capital of 8.322%.

Methodology for Forecasting Hydraulic Production

Hydro's hydroelectric production facilities consists of nine generating stations, with the Bay d'Espoir plant being the largest. This includes the addition of the Granite Canal project in 2003.

Hydro's forecast of the amount of hydraulic energy to be produced in the 2004 test year is based on a 30 year average for water inflows with the exception of Granite Canal. According to Hydro, the estimate for Granite Canal was obtained from a power and energy analysis for that plant.

The use of the 30 year average for forecasting hydraulic production was ordered by the Board in P.U.7 (2002-2003). The Board also ordered the Company to have an independent study completed with regards to its hydraulic production forecast methodology. SGE Acres ("SGE") was retained to complete this study and Hydro included a copy of this study in its Application. The SGE study includes a number of recommendations and Hydro has indicated that they endorse the recommendations included in the study, and with Board approval will implement them to forecast hydraulic production for future rate applications.

One particular recommendation provided by SGE is that the longest reliable reference inflow sequence (period of record) should be used for all of Hydro's operation planning and rate setting purposes. In Hydro's response to NP-70, they have noted that "the recommendation to use the longest reliable reference record is made because, in the absence of long term trends, the irregular variability of hydrology means that the longer the record, the less the sampling error, and the better the estimate." It is also noted that SGE "recommends using data and methodology that will give the best estimate; and can see no reason to use an estimate other than the best available for any purpose." The response also makes reference to a survey of utilities completed by SGE that suggested other utilities and regulators agree with this approach.

As noted above, Hydro is using a 30 year average for water inflows for its 2004 forecast even though SGE is recommending the use of the longest available record. As indicated in Table 7 of J.R Haynes pre-filed evidence (Page 30), the hydraulic forecast based on the recommended full historic record would be 124 GWh lower than the results of the 30 year average used in the 2004 forecast. If the recommended method was used in this Application, the requirements for thermal production would be increased to compensate for the lower hydraulic production. According to Hydro, this would have resulted in an increase of $5.97 million in No.6 fuel expense, which in turn would cause an increase in the 2004 revenue requirement by the same amount.

Accounting Systems and Code of Accounts

Section 58 of the *Public Utilities Act* states that the Board may prescribe the form of all books, accounts, papers and records to be kept by Hydro and that Hydro shall comply with all such directions of the Board.

The objective of our review of Hydro's accounting system and code of accounts was to ensure that it can provide information sufficient to meet the reporting requirements of the Board. We have observed that the Company has in place a well-structured, comprehensive system of accounts and organization / reporting structure. Hydro was able to meet all our requests for information and reports on a timely basis during our review. Our review also indicated that there were very few changes to the chart of accounts and these changes were not of a significant nature.

In P.U. 7 (2002-2003), the Board approved Hydro's code of accounts pursuant to Section 58 of the *Act*. This Decision also included a requirement for Hydro to file its written policies and procedures for the accounting of all intra and inter-corporate transactions, identifying what is to be included in regulated versus non-regulated activities.

Hydro filed these written policies and procedures with the Board by December 31, 2002. With respect to the accounting and reporting of non-regulated activities, Hydro uses separate business units within the JD Edwards accounting system to capture this information. No other changes have been made to the current accounting system during 2003.

Newfoundland and Labrador Hydro **Exhibit 1**
Revenue Requirement
2001 to 2004

(000)'s	2001 Actuals	2002 Actuals	2003 Forecast	2004 Forecast Revenue Requirement
Depreciation	$ 32,175	$ 31,302	$ 32,786	$ 33,932
Fuel	50,207	73,248	91,159	92,548
Power purchased	15,600	15,881	25,288	33,315
Other costs		-		
Salaries and fringe benefits	61,729	64,559	63,605	63,237
System equip. maint.	17,445	17,179	17,024	17,419
Insurance	949	1,198	1,614	2,019
Transportation	2,332	2,464	2,355	2,344
Office supplies	1,872	1,856	1,972	1,913
Bldg. rentals and maint.	704	900	898	894
Professional services	5,530	5,318	4,641	4,503
Travel	2,778	2,337	2,248	2,139
Equipment rentals	1,369	1,372	1,526	1,636
Miscellaneous	5,433	4,674	4,367	4,485
Loss on disposal	1,839	2,769	628	541
Sub-total	101,980	104,626	100,878	101,130
Allocations				
Other	(2,753)	(2,914)	(2,914)	(2,642)
Hydro capitalized	(9,567)	(8,623)	(6,805)	(5,764)
C.F.(L) Co.	(1,766)	(2,006)	(1,807)	(1,777)
Sub-total	(14,086)	(13,543)	(11,526)	(10,183)
Total	87,894	91,083	89,352	90,947
Interest	92,788	88,547	95,767	101,715
Regulated earnings	11,918	9,742	(7,806)	19,384
Revenue	$ 290,582	$ 309,803	$ 326,546	$ 371,841

Newfoundland and Labrador Hydro **Exhibit 2**
Revenue Requirement
2002 test year vs 2004
(000)'s

	Test Year	Forecast	
	2002 Revenue Requirement	2004 Revenue Requirement	Difference ($)
Depreciation	$ 31,390	$ 33,932	$ 2,542
Fuel			
No. 6 Fuel	81,237	84,410	3,173
Additives and Indirects	178	240	62
Environmental Fee	124	56	(68)
Ignition Fuel	123	113	(10)
Gas Turbine Fuel	446	351	(95)
Diesel Fuel	6,508	7,378	870
	88,616	92,548	3,932
Power purchased	15,100	33,315	18,215
Other costs			
Salaries and fringe benefits	61,926	63,237	1,311
System equip. maint.	16,763	17,419	656
Insurance	977	2,019	1,042
Transportation	2,223	2,344	121
Office supplies	1,864	1,913	49
Bldg. rentals and maint.	626	894	268
Professional services	4,943	4,503	(440)
Travel	2,484	2,139	(345)
Equipment rentals	1,558	1,636	78
Miscellaneous	4,398	4,485	87
Productivity allowance	(2,000)		2,000
Loss on disposal	890	541	(349)
Sub-total	96,652	101,130	4,478
Allocations			
Other	(2,914)	(2,642)	272
Hydro capitalized	(6,131)	(5,764)	367
C.F.(L) Co.	(1,910)	(1,777)	133
Sub-total	(10,955)	(10,183)	772
Total	85,697	90,947	5,250
Interest	88,298	101,715	13,417
Regulated earnings	7,959	19,384	11,425
Revenue requirement	$ 317,060	$ 371,841	$ 54,781

Newfoundland and Labrador Hydro **Exhibit 3**
Operating Expenses by Department

		2002 Test Year		2002 Actual		2004 Forecast		2002 Test Year vs. 2004		2002 Actual vs. 2004
SALARIES										
Production	$	18,710	$	19,706	$	20,160	$	1,450	$	454
TRO		21,967		21,901		21,349		(618)		(552)
Finance and Corporate Services		15,527		14,836		16,264		737		1,428
	$	56,204	$	56,443	$	57,773	$	1,569	$	1,330
SYSTEM EQUIPMENT MAINTENANCE										
Production	$	8,521	$	8,493	$	9,777	$	1,256	$	1,284
TRO		7,009		7,411		6,449		(560)		(962)
Finance and Corporate Services		1,233		1,275		1,193		(40)		(82)
	$	16,763	$	17,179	$	17,419	$	656	$	240
OTHER EXPENSES										
Production	$	5,982	$	5,635	$	5,433	$	(549)	$	(202)
TRO		4,558		5,193		4,840		282		(353)
Finance and Corporate Services		8,124		8,784		9,360		1,236		576
	$	18,664	$	19,612	$	19,633	$	969	$	21
RECOVERIES										
Production	$	(621)	$	(589)	$	(571)	$	50	$	18
TRO		(136)		(67)		(37)		99		30
Finance and Corporate Services		(1,153)		(1,350)		(1,169)		(16)		181
	$	(1,910)	$	(2,006)	$	(1,777)	$	133	$	229
NET OPERATING EXPENSES										
Production	$	32,592	$	33,245	$	34,799	$	2,207	$	1,554
TRO		33,398		34,438		32,601		(797)		(1,837)
Finance and Corporate Services		23,731		23,545		25,648		1,917		2,103
	$	89,721	$	91,228	$	93,048	$	3,327	$	1,820
RECONCILIATION TO J. ROBERTS SCHEDULE II										
Less : Non Regulated Customer		(2,914)		(2,914)		(2,642)				
Less: Productivity Allowance		(2,000)		0		0				
Add: Loss on Disposal		890		2,769		541				
TOTAL OPERATING EXPENSES	$	85,697	$	91,083	$	90,947				

Newfoundland and Labrador Hydro 2003 Rate Hearing **Exhibit 4A**
Salaries

Gross Salaries

(000)'s	2001	2002 A	2002 F	2003	2004
Salaries	$ 47,865	$ 50,323	$ 50,108	$ 48,986	**$ 49,942**
Directors fees	35	23	62	62	**62**
Temporary					
Overtime	3,987	3,910	2,616	2,969	**2,864**
Employee future benefits	2,411	2,445	2,433	3,631	**3,727**
Fringe benefits	6,192	6,630	6,426	6,965	**7,110**
Group insurance	1,129	1,123	1,680	2,000	**1,950**
Labrador travel benefit	110	105	101	101	**99**
Unregulated				(109)	**(17)**
Vacancy adjustment			(1,500)	(1,000)	**(2,500)**
	$ 61,729	$ 64,559	$ 61,926	$ 63,605	**$ 63,237**

Salaries by Department

Exhibit 4B

(000)'s	2001	2002 A	2002 F	2003	2004
Finance	$ 3,880	$ 4,349	$ 5,391	$ 4,097	**$ 4,035**
Human resources and legal	4,182	4,734	4,280	4,598	**4,731**
Transmission and rural operations (TRO)	21,201	21,951	21,554	21,004	**21,322**
Production	17,365	17,960	17,562	17,941	**18,472**
Internal audit	270	269	278	276	**284**
Management	971	1,070	1,043	1,070	**1,098**
Unregulated	(4)	(10)			
	$ 47,865	$ 50,323	$ 50,108	$ 48,986	$ 49,942

Newfoundland and Labrador Hydro 2003 Rate Hearing **Exhibit 4C**

Salaries

Capitalized salaries

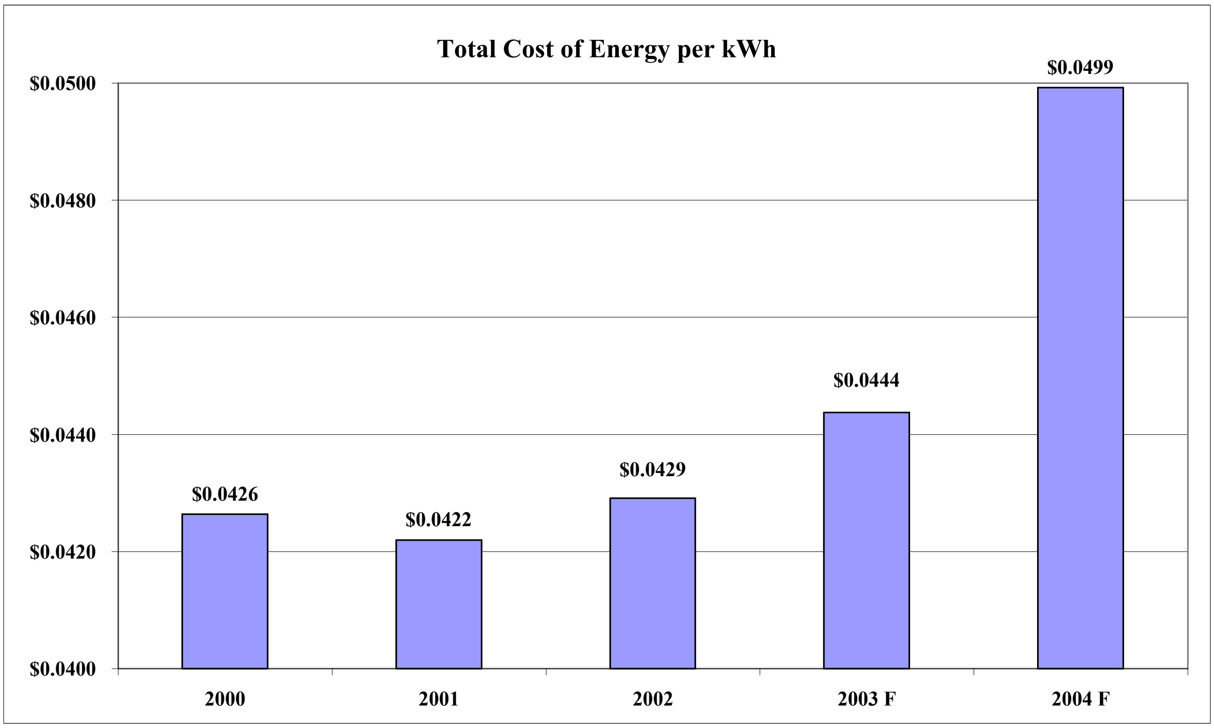
(000)'s	2001	2002 A	2002 F	2003	2004
Payroll charged to operating	$ 52,752	$ 56,443	$ 57,703	$ 57,200	$ 57,774
Payroll charged to capital	8,977	8,116	5,723	6,405	5,463
	$ 61,729	$ 64,559	$ 63,426	$ 63,605	$ 63,237

Newfoundland and Labrador Hydro **Exhibit 5A**

Comparison of Total Cost of Energy to kWh Sold and Used

(000)'s

Year	kWh sold and used	Depreciation	Fuel	Purchased Power	Other Costs	Interest	Regulated Earnings	Total Cost of Energy	Cost per kWh
2000	6,798,000	$ 35,469	$ 42,568	$ 15,961	$ 93,144	$ 96,868	$ 5,850	$ 289,860	$ 0.0426
2001	6,887,000	$ 32,175	$ 50,207	$ 15,600	$ 87,894	$ 92,788	$ 11,918	$ 290,582	$ 0.0422
2002	7,220,000	$ 31,302	$ 73,248	$ 15,881	$ 91,083	$ 88,547	$ 9,742	$ 309,803	$ 0.0429
2003 F	7,359,000	$ 32,786	$ 91,159	$ 25,288	$ 89,352	$ 95,767	$ (7,806)	$ 326,546	$ 0.0444
2004 F	7,448,000	$ 33,932	$ 92,548	$ 33,315	$ 90,947	$ 101,715	$ 19,384	$ 371,841	$ 0.0499



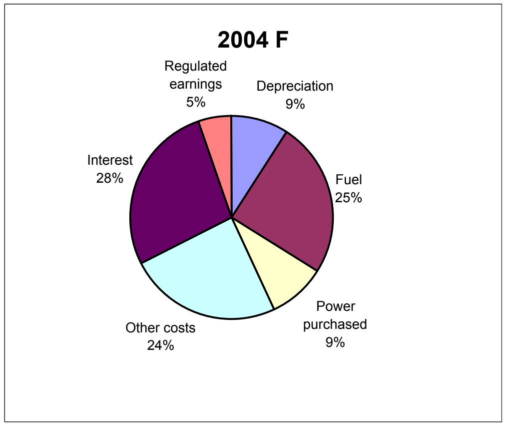
Newfoundland and Labrador Hydro **Exhibit 5B**

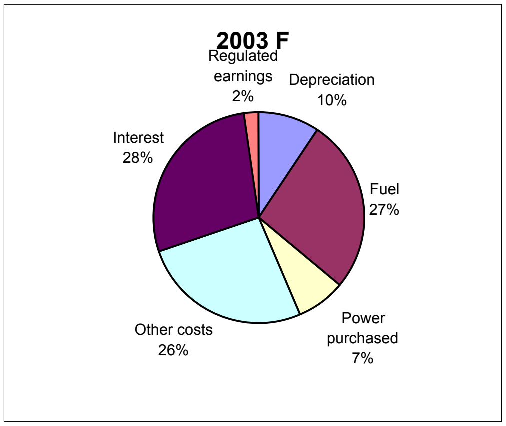
Comparison of Costs as a Percentage of kWh Sold and Used

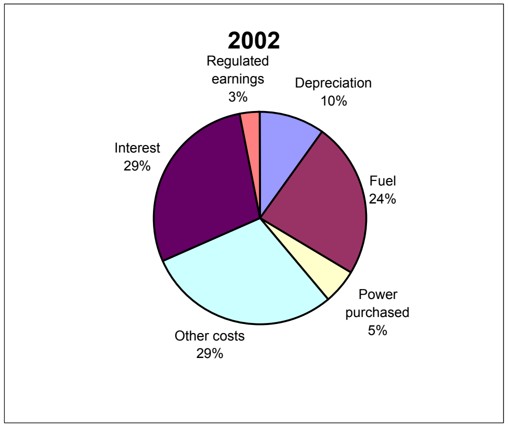
	2000			2001			2002			2003 Forecast			2004 Forecast		
kWh sold and used	6,798,000			6,887,000			7,220,000			7,359,000			7,448,000		
	Cost	Cost per kWh	% of Total	Cost	Cost per kWh	% of Total	Cost	Cost per kWh	% of Total	Cost	Cost per kWh	% of Total	Cost	Cost per kWh	% of Total
Depreciation	$ 35,469	0.0052	12.24%	$ 32,175	0.0047	11.07%	$ 31,302	0.0043	10.10%	$ 32,786	0.0045	10.04%	$ 33,932	0.0046	9.13%
Fuel	42,568	0.0063	14.69%	50,207	0.0073	17.28%	73,248	0.0101	23.64%	91,159	0.0124	27.92%	92,548	0.0124	24.89%
Power purchased	15,961	0.0023	5.51%	15,600	0.0023	5.37%	15,881	0.0022	5.13%	25,288	0.0034	7.74%	33,315	0.0045	8.96%
Other costs	93,144	0.0137	32.13%	87,894	0.0128	30.25%	91,083	0.0126	29.40%	89,352	0.0121	27.36%	90,947	0.0122	24.46%
Interest	96,868	0.0142	33.42%	92,788	0.0135	31.93%	88,547	0.0123	28.58%	95,767	0.0130	29.33%	101,715	0.0137	27.35%
Regulated earnings	5,850	0.0009	2.02%	11,918	0.0017	4.10%	9,742	0.0013	3.14%	(7,806)	- 0.0011	-2.39%	19,384	0.0026	5.21%
Total	$ 289,860	0.0426	100.00%	$ 290,582	0.0422	100.00%	$ 309,803	0.0429	100.00%	$ 326,546	0.0444	100.00%	$ 371,841	0.0499	100.00%

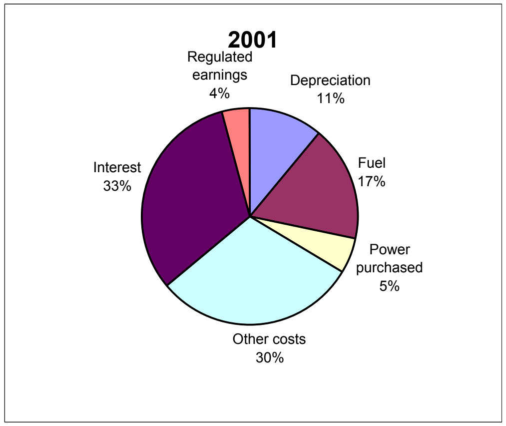
Newfoundland and Labrador Hydro **Exhibit 5B**

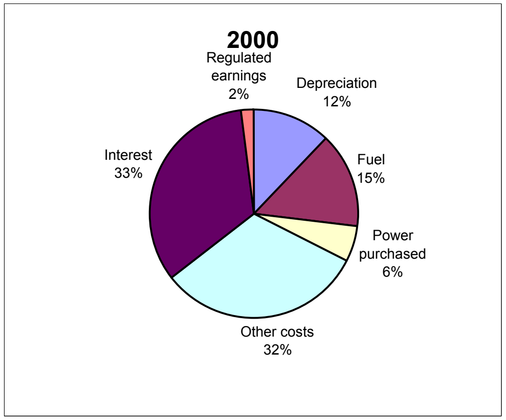
Comparison of Costs as a Percentage of kWh Sold and Used











Newfoundland and Labrador Hydro
Comparison of Other Costs by Breakdown
2000 to 2004

Exhibit 5C

	2000			2001			2002			2003 Forecast			2004 Forecast		
kWh sold and used	6,798,000			6,887,000			7,220,000			7,359,000			7,448,000		
	Cost	Cost per kWh	% of Total	Cost	Cost per kWh	% of Total	Cost	Cost per kWh	% of Total	Cost	Cost per kWh	% of Total	Cost	Cost per kWh	% of Total
Salaries	$ 61,267	0.00901	100.00%	$ 61,729	0.00896	100.00%	$ 64,559	0.00894	100.00%	$ 63,605	0.00864	100.00%	$ 63,237	0.00849	100.00%

	2000			2001			2002			2003 Forecast			2004 Forecast		
kWh sold and used	6,798,000			6,887,000			7,220,000			7,359,000			7,448,000		
	Cost	Cost per kWh	% of Total	Cost	Cost per kWh	% of Total	Cost	Cost per kWh	% of Total	Cost	Cost per kWh	% of Total	Cost	Cost per kWh	% of Total
System equip. maint.	$ 18,976	0.00279	45.84%	$ 17,445	0.00253	43.34%	$ 17,179	0.00238	42.88%	$ 17,024	0.00231	45.67%	$ 17,419	0.00234	45.97%
Insurance	1,037	0.00015	2.50%	949	0.00014	2.36%	1,198	0.00017	2.99%	1,614	0.00022	4.33%	2,019	0.00027	5.33%
Transportation	2,892	0.00043	6.99%	2,332	0.00034	5.79%	2,464	0.00034	6.15%	2,355	0.00032	6.32%	2,344	0.00031	6.19%
Office supplies	2,081	0.00031	5.03%	1,872	0.00027	4.65%	1,856	0.00026	4.63%	1,972	0.00027	5.29%	1,913	0.00026	5.05%
Bldg. rentals and maint.	998	0.00015	2.41%	704	0.00010	1.75%	900	0.00012	2.25%	898	0.00012	2.41%	894	0.00012	2.36%
Professional services	3,815	0.00056	9.22%	5,530	0.00080	13.74%	5,318	0.00074	13.27%	4,641	0.00063	12.45%	4,503	0.00060	11.88%
Travel	2,835	0.00042	6.85%	2,778	0.00040	6.90%	2,337	0.00032	5.83%	2,248	0.00031	6.03%	2,139	0.00029	5.64%
Equipment rentals	1,400	0.00021	3.38%	1,369	0.00020	3.40%	1,372	0.00019	3.42%	1,526	0.00021	4.09%	1,636	0.00022	4.32%
Miscellaneous	5,179	0.00076	12.51%	5,433	0.00079	13.50%	4,674	0.00065	11.67%	4,367	0.00059	11.72%	4,485	0.00060	11.84%
Loss on disposal	2,186	0.00032	5.28%	1,839	0.00027	4.57%	2,769	0.00038	6.91%	628	0.00009	1.68%	541	0.00007	1.43%
Total	$ 41,399	$ 0.00609	100.00%	$ 40,251	$ 0.00584	100.00%	$ 40,067	$ 0.00555	100.00%	$ 37,273	$ 0.00506	100.00%	$ 37,893	$ 0.00509	100.00%

Grand Total	$ 102,666	$ 0.01510	100.00%	$ 101,980	$ 0.01481	100.00%	$ 104,626	0.01449	100.00%	$ 100,878	0.01371	100.00%	$ 101,130	0.01358	100.00%

Newfoundland and Labrador Hydro **Exhibit 5C**
Comparison of Other Costs by Breakdown
2000 to 2004