Q. With regard to the response to CA-94-NLH, when is it anticipated that the 2005 Audit report will be available?

A. Please find attached a copy of the 2005 Audit report.

Board of Commissioners of Public Utilities

2005 Annual Financial Review of Newfoundland and Labrador Hydro

CA 209 NLH
2006 General Rate Application
Attachment 1

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 2005 Annual Financial Review of Newfoundland and Labrador Hydro ("the Company")("Hydro").

Scope and Limitations

Our review was carried out in accordance with the following Terms of Reference:

1. Examine Hydro's accounting system and code of accounts to ensure that it can provide information sufficient to meet the reporting requirements of the Board.

2. Review calculation of the return on rate base, return on equity, capital structure and interest coverage ratio.

3. Conduct an examination of operations and administration expenses, fuels, power purchased, depreciation, and interest to assess their reasonableness and prudence in relation to sales of power and energy. The examination of the foregoing will include, but is not limited to, the following:

   a) amortization of deferred charges,
   b) salaries and benefits,
   c) system equipment maintenance,
   d) insurance (including director's liability),
   e) transportation,
   f) building rental and maintenance,
   g) professional services,
   h) miscellaneous,
   i) capitalized expenses,
   j) intercompany charges,
   k) membership fees,
   l) fuels,
   m) power purchased,
   n) depreciation,
   o) interest.

4. Review Hydro's non-regulated activity and assess the reasonableness of adjustments in the calculation of regulated earnings.

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

6. Conduct an examination of the changes to the Rate Stabilization Plan to assess compliance with Board directives.

7. Conduct an examination of the changes to deferred charges and assess their reasonableness and prudence in relation to sales of power and energy.

8. Review Minutes of Board of Directors and Management Committee meetings.

9. Review Hydro's key performance indicators.

10. Review a sample of Contribution in Aid of Construction (CIAC) calculations for accuracy and compliance with approved policy.

The nature and extent of the procedures which we performed in our review varied for each of the items in the Terms of Reference. In general, our procedures were comprised of:

- enquiry and analytical procedures with respect to financial information provided by Hydro;
- examining, on a test basis where appropriate, documentation supporting amounts included in Hydro's records; and,
- assessing Hydro's compliance with Board directives.

The procedures undertaken in the course of our financial review do not constitute an audit of Hydro's financial information and consequently, we do not express an opinion on the financial information as provided by Hydro.

The financial statements of the Company for the year ended December 31, 2005 have been audited by Deloitte & Touche LLP, Chartered Accountants, who have expressed their opinion on the fairness of the statements in their report dated February 14, 2006. 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.

Accounting System and Code of Accounts

Scope: ***Examine Hydro's accounting system and code of accounts to ensure that it can provide information sufficient to meet the reporting requirements of the Board.***

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.

During 2005 Hydro undertook a reconfiguration of its current code of accounts for both its regulated and non-regulated operations. This change to the code of accounts included a new listing of divisions and a revision to the groupings of its departments and business units.

In the table below we have outlined the new divisional structure currently in place for 2005 as compared to the old structure utilized in 2004.

2005	2004
Executive Leadership & Assoc.	Finance
Human Resources & Organizational Effectiveness	Human Resources
Finance/CFO	Transmission & Rural Operations
Engineering Services	Production
Regulated Operations	Internal Audit
	Management

Since a variety of departments and business units were reassigned under the new structure, it is no longer feasible to compare the current divisional structure to the structure utilized in 2004 and prior years. For this reason, the breakdown of expenses within the revenue requirement for the years 2002 to 2004 has been restated to reflect the current divisional structure for comparability purposes.

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. The system allows for adequate flexibility to allow the Company to meet its own and the Board's reporting requirements.

We have reviewed the changes in the chart of accounts since our 2004 review and while the changes are major, they have no impact on the quality of Hydro's financial reporting.

We suggest that Hydro submit its new system of accounts to the Board for their review in accordance with Section 58 of the *Public Utilities Act.*

Return on Rate Base and Equity, Interest Coverage and Capital Structure

Scope: ***Review the calculation of the return on rate base, return on equity, capital structure and interest coverage ratio.***

Return on Rate Base

The Company's calculation of average rate base is included on Return 3 and the calculation of return on rate base is included on Return 12 of the annual report to the Board. The return on average rate base for 2005 was 6.98% (2004 – 7.03%). Our procedures with respect to verifying the reported average rate base and return on rate base included:

- agreeing all carry-forward and component data to supporting documentation;
- checking clerical accuracy of the continuity of the rate base and the return on rate base; and
- reviewing the methodology used in determining average rate base and return on rate base to ensure it is in accordance with Board Orders.

Details with respect to Hydro's calculation of the average rate base and return on rate base are as follows:

(000)'s	**2005**	**2004**	**2003**
Plant investment	$ 1,939,115	$ 1,922,374	$ 1,904,557
Less: Accumulated depreciation	(506,391)	(481,801)	(456,695)
CIAC's	(84,627)	(85,081)	(85,055)
Assets not in service/non-reg	(2,138)	(2,153)	(2,053)
	1,345,959	1,353,339	1,360,754
Balance previous year	1,353,339	1,360,754	1,234,420
Average	1,349,649	1,357,047	1,297,587
Cash working capital allowance	2,711	2,945	3,456
Fuel inventory	21,506	15,611	18,310
Supplies inventoy	20,084	18,615	18,565
Average deferred charges	79,809	82,506	84,494
Average rate base	**$ 1,473,759**	**$ 1,476,724**	**$ 1,422,412**
Regulated net income	$ 3,322	$ 7,322	$ (2,588)
Hydro net interest expense	99,479	96,527	92,138
Return on Rate Base	$ 102,801	$ 103,849	$ 89,550
Regulated rate of return on rate base	**6.98%**	**7.03%**	**6.30%**

The regulated net income component of the return on rate base excludes all non-regulated earnings and expenses of Hydro. In P.U. 14 (2004) the Board approved an allowed Rate of Return on Rate Base of 7.47%. In P.U. 40 (2004) the Board approved a range of return on rate base for Hydro and the definition of excess earnings to be effective January 1, 2005. The range of return approved for Hydro is 30 basis points (± 15 basis points). The reported return of 6.98% falls short due to a lower net income, which primarily resulted from higher depreciation, power purchased, and operations and administration expenses than originally forecast.

As a result of completing our procedures we did not note any discrepancies and therefore conclude that the calculation of average rate base and the rate of return on average rate base included in the Company's annual report to the Board is in accordance with Board Orders and established regulatory practice.

Return on Equity

The Company's calculation of regulated average equity and rate of return on regulated average equity for the year ended December 31, 2005 is included on Return 13 of the annual report to the Board.

Similar to the approach used to verify the rate base and return on rate base, 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 audited financial statements and internal accounting records where applicable;
- agreed component data (dividends, regulated earnings, etc.) to supporting documentation;
- checked the clerical accuracy of the continuity of regulated common equity; and
- recalculated the rate of return on common equity for 2005 and ensured it was in accordance with established regulatory practice.

The return on regulated average equity for 2005 has been calculated at 1.57% as follows:

(000)'s		2005	2004	2003
Shareholder's equity				
	2005	$ 212,530		
	2004	$ 211,012	$ 211,012	
	2003		$ 204,927	$ 204,927
	2002			$ 213,789
Average equity		$ 211,771	$ 207,970	$ 209,358
Regulated earnings		$ 3,322	$ 7,322	$ (2,588)
Return on equity		**1.57%**	**3.52%**	**-1.24%**

During 2005 Hydro experienced a net profit from regulated operations of approximately $3.3 million. This resulted in a return on equity of 1.57%, which is significantly lower than the 5.83% forecast in P.U. 14 (2004). As Hydro does not earn an equity return on its rural assets, 5.57% is effectively the maximum that the Company would have earned had 2005 played out exactly as forecast.

The "regulated" shareholder's equity of Hydro excludes the portion of equity attributable to non-regulated operations. The adjustments for non-regulated operations are as follows:

(000's)	2005	2004	2003
Equity per non-consolidated financial statements	$ 506,900	$ 490,697	$ 474,117
Less: Contibuted capital			
- Lower Churchill Development	(15,400)	(15,400)	(15,400)
- Muskrat Falls Project	(2,165)	(2,165)	(2,165)
Share capital issued to finance investment in CF(L)Co.	(22,500)	(22,500)	(22,500)
Net retained earnings attributable to IOCC	(7,440)	(5,568)	(4,352)
Non-regulated expenses	24,774	24,433	23,186
Net retained earnings attributable to CF(L)Co. (income recorded minus dividends flowed through to government)	(270,464)	(257,425)	(246,767)
Net retained earnings attributable to the sale of recall power to Hydro Quebec (income recorded minus allocation of dividends)	(1,175)	(1,060)	(1,192)
"Regulated Equity"	$ 212,530	$ 211,012	$ 204,927

The calculation in the above table is consistent with the calculation of regulated equity prepared by the Company in Return 13 of the annual report filed with the Board. The adjustments for non-regulated operations are consistent with prior years and in line with expected results.

As a result of completing our procedures, we did not note any discrepancies in the calculation of regulated average equity and rate of return on regulated average equity.

Interest Coverage

Interest coverage for 2005 has been calculated at 1.41 times as follows:

(000's)	2005	2004	2003
Total interest	$ 101,732	$ 98,822	$ 94,303
Less: CF(L)Co	(2,253)	(2,295)	(2,165)
Hydro net interest	99,479	96,527	92,138
Add: Interest earned and IDC			
Power bills	492	403	369
RSP	8,459	10,538	10,333
Sinking funds	9,512	11,715	10,807
IDC	4,296	3,595	7,254
Gross interest	$ 122,238	$ 122,778	$ 120,901
Income from operations	$ 50,485	$ 47,593	$ 18,014[1]
Gross interest	122,238	122,778	120,901
Adjusted income	$ 172,723	$ 170,371	$ 138,915
Interest Coverage	**1.41**	**1.39**	**1.15**

Gross interest costs had been on the rise since 2001, however in 2005 this trend was reversed when interest dipped slightly from 2004 levels. New bond issuances were the primary reason for the past trend of increasing interest costs; however no new bonds have been issued since 2003. While income from regulated operations has not been stable over the past few years, overall income from operations has been strong since 2003 which has resulted in improved interest coverage.

[1] Adjusted for write-down of Labrador River Project of $9.6 million.

Capital Structure

The capital structure of Hydro based on its regulated operations is as follows:

(000)'s	2005	%	2004	%	2003	%
Debt	$ 1,313,584	84.3%	$ 1,357,457	84.9%	$ 1,383,270	85.6%
Employee benefits	32,266	2.1%	29,715	1.9%	26,939	1.7%
Equity	212,530	13.6%	211,012	13.2%	204,927	12.7%
	$ 1,558,380		$ 1,598,184		$ 1,615,136	

During 2005 Hydro declared and paid dividends totaling approximately $55.8 million (2004 - $50.5 million) to the Provincial Government which included:

- $8.4 million (2004 - $8.9 million) dividend based on a partial flow through of CF(L)Co revenue;
- $45.6 million (2004 - $40.4 million) dividend from the sale of recall power to Hydro Quebec;
- $0.4 million dividend from the sale of power to the Iron Ore Company of Canada;
- $0.6 million that was ratified by Hydro's Board in February 2005 relating to non-regulated revenue for 2004; and
- the remaining $0.8 million (2004 - $1.2 million) was based on regulated operations.

Over the past three years Hydro's debt to equity ratio has been improving on a trend towards the 80:20 target ratio.

Revenue Requirement

Scope: ***Conduct an examination of depreciation, fuel, power purchased, operations and administration expenses, and interest to assess their reasonableness and prudence in relation to sales of power and energy.***

The following table provides a breakdown of the revenue requirement for the years 2005 to 2002, including variances between 2005 and 2004:

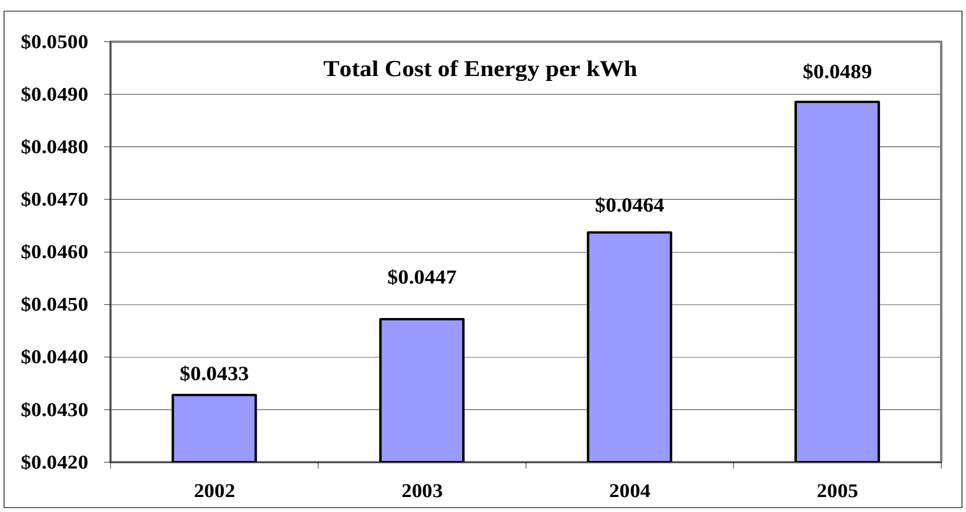
(000)'s	Actuals 2005	Actuals 2004	Actuals 2003	Actuals 2002	Variance 2005 - 2004
Depreciation	$ 35,480	$ 33,799	$ 33,155	$ 31,302	$ 1,681
Fuel	84,502	83,109	84,594	73,248	1,393
Power purchased	36,191	35,342	26,064	15,881	849
Other costs					
Salaries and fringe benefits	66,748	65,151	64,492	64,559	1,597
System equip. maint.	21,351	17,344	18,035	17,179	4,007
Insurance	1,674	1,682	1,655	1,198	(8)
Transportation	2,459	2,307	2,308	2,464	152
Office supplies	1,948	1,846	1,922	1,856	102
Bldg. rentals and maint.	778	752	850	900	26
Professional services	4,241	3,649	4,490	5,318	592
Travel	2,367	2,206	2,233	2,337	161
Equipment rentals	1,128	1,269	1,453	1,372	(141)
Miscellaneous	4,355	4,370	4,191	4,674	(15)
Loss on disposal	3,291	2,812	3,148	2,769	479
Sub-total	110,340	103,388	104,777	104,626	6,952
Allocations					
Other	(3,114)	(2,777)	(2,914)	(2,914)	(337)
Hydro capitalized	(12,608)	(9,655)	(9,956)	(8,623)	(2,953)
C.F.(L) Co.	(1,451)	(2,192)	(1,874)	(2,006)	741
Sub-total	(17,173)	(14,624)	(14,744)	(13,543)	(2,549)
Total	93,167	88,764	90,033	91,083	4,403
Interest	99,479	96,527	92,138	88,547	2,952
Regulated earnings	3,322	7,322	(2,588)	9,742	(4,000)
Revenue requirement	$ 352,141	$ 344,863	$ 323,396	$ 309,803	$ 7,278

From this analysis it is evident that the overall increase in the revenue requirement from 2004 to 2005 of $7.3 million is primarily driven by increases in other costs, interest and depreciation. While the majority of the expense categories within other costs increased over the prior year, the most notable increases occurred in salaries and fringe benefits, system equipment maintenance, professional fees and loss on disposal.

While Allocations have been fairly consistent from year to year, in 2005 we note a significant increase in transfers of $2.6 million over 2004 levels. The majority of this increase relates to $3 million of additional capitalized expenditures due to an increase in the number of manpower hours for various projects. Additional costs to supply the Iron Ore Company of Canada with extra energy resources over 2004 has also lead to an increase in "other" allocations of $337,000. Overall, the total increase in the Allocation categories of Hydro capitalized expenses and other of $3.4 million was partially offset by reduction in the amount of intercompany charges of $741,000 to CF(L)Co for the year.

As the revenue requirement has been steadily increasing over the past several years with the most notable increases incurring in 2004 and 2005, the total cost of energy per kWh has also progressively been on the rise. In the table and graph below we have provided an analysis of the breakdown of the cost of energy on the basis of the number of kWhs sold for the years 2002 to 2005.

Year	kWh sold and used	Depreciation	Fuel	Purchased Power	Other Costs	Interest	Regulated Earnings	Total Cost of Energy	Cost per kWh
2002	7,158,000	$ 31,302	$ 73,248	$ 15,881	$ 91,083	$ 88,547	$ 9,742	$ 309,803	$ 0.0433
2003	7,231,000	$ 33,155	$ 84,594	$ 26,064	$ 90,033	$ 92,138	$ (2,588)	$ 323,396	$ 0.0447
2004	7,437,000	$ 33,799	$ 83,109	$ 35,342	$ 88,764	$ 96,527	$ 7,322	$ 344,863	$ 0.0464
2005	7,208,000	$ 35,480	$ 84,502	$ 36,191	$ 93,167	$ 99,479	$ 3,322	$ 352,141	$ 0.0489

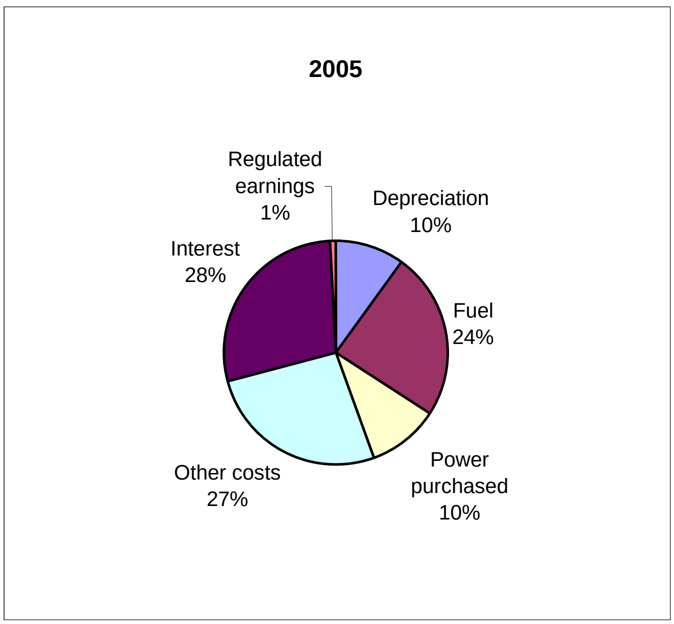


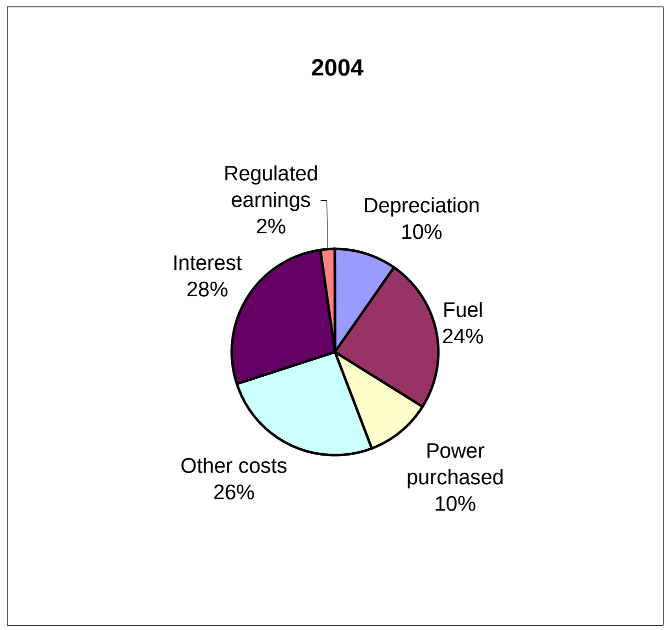
Year over year % chng: 3.2% 3.8% 5.4%

As highlighted in the graph above, the percentage change year over year for the total cost of energy per kWh reached its highest percentage increase in 2005 at 5.4%, with a total cost of $0.489 per kWh.

The following table and charts provide a further breakdown of the expense per kWh by expense category for the years 2004 and 2005.

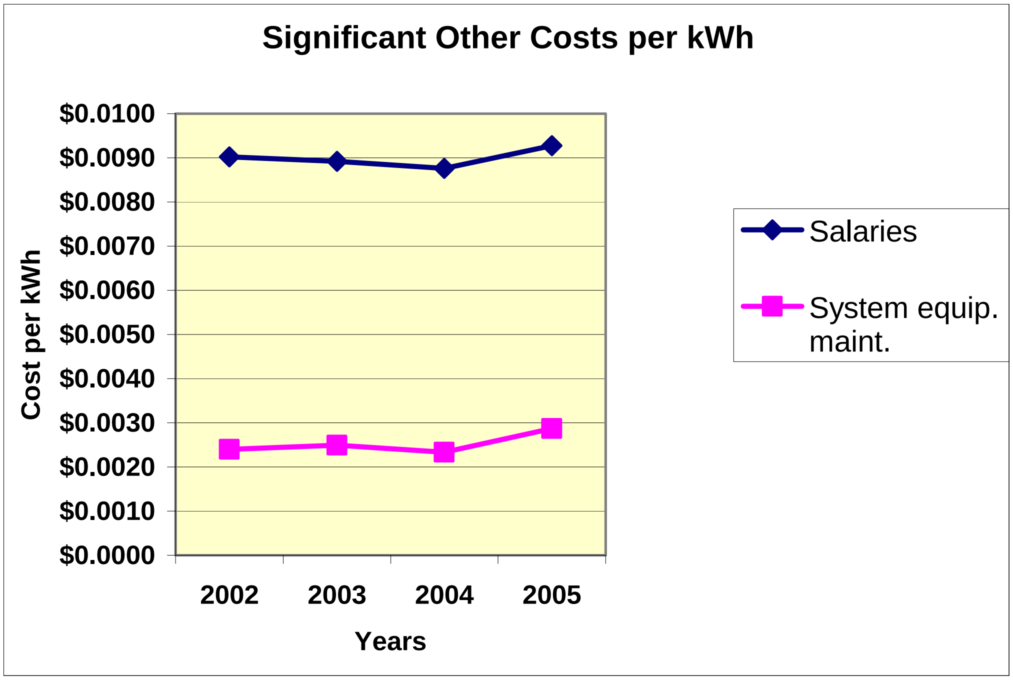
	2005			2004		
kWh sold and used	7,208,000			7,437,000		
	Cost	Cost per kWh	% of Total	Cost	Cost per kWh	% of Total
Depreciation	$ 35,480	0.0049	10.08%	$ 33,799	0.0045	9.80%
Fuel	84,502	0.0117	24.00%	83,109	0.0112	24.10%
Power purchased	36,191	0.0050	10.28%	35,342	0.0048	10.25%
Other costs	93,167	0.0129	26.46%	88,764	0.0119	25.74%
Interest	99,479	0.0138	28.25%	96,527	0.0130	27.99%
Regulated earnings	3,322	0.0005	0.94%	7,322	0.0010	2.12%
Total	$ 352,141	0.0489	100.00%	$ 344,863	0.0464	100.00%

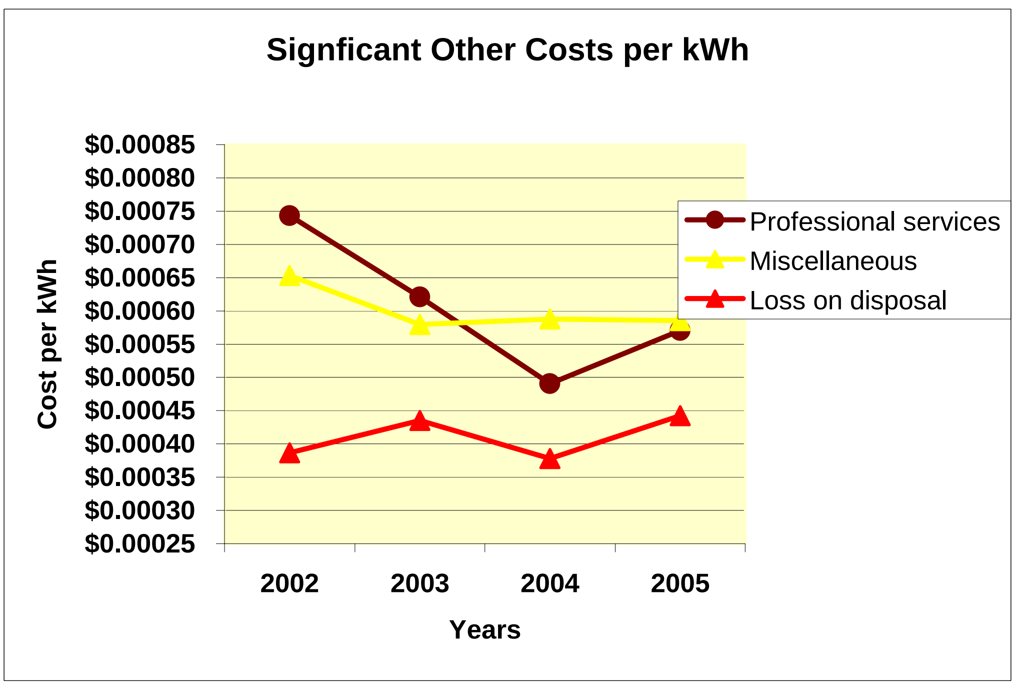




For 2005 and 2004 the percentage of cost per kWh by category is almost identical with the exception of the slight variance in other costs and regulated earnings.

An analysis of the most significant accounts within other costs for the years 2002 to 2005 has been provided below in the following two graphs:





The first graph clearly demonstrates that the cost for salaries and system equipment maintenance were fairly level from 2002 to 2004 but trended upward in 2005. However, in the second graph considerably more fluctuations are noted from year to year. The cost category loss on disposal tends to be a more cyclical expense with a decrease one year followed by an increase the next, whereas, miscellaneous costs appeared to have declined after 2002 only to level out from 2003 to 2005. Professional fees seem to have experienced the greatest variance over the period 2002 to 2005. In 2002, professional fees were at an all time high due in part to the 2001 General Rate Hearing followed by a sharp decline in 2003 and 2004 and subsequent increase for 2005.

We have reviewed the various expense categories in more detail on an individual basis and our observations and comments are noted below for your consideration.

Depreciation

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

Our procedures with respect to depreciation were focused on reviewing the rates of depreciation used and assessing their compliance with the 1998 Depreciation Study and also assessing the overall reasonableness of depreciation expense.

During 2005 Hydro reported depreciation expense of $35.5 million compared to $33.8 million in 2004. The increase in depreciation expense for the year is largely attributed to the net additions to capital assets of $41.5 million in 2005 and $35 million in 2004. The breakdown of depreciation expense for 2005 is as follows:

Location	Asset Class	Net Cost	Method	2005 Expense
Hydro	Hydraulic stations Terminal stations Transmission lines	$1,126.4 million	Sinking Fund	$14.9 million
Hydro	All other classes	221.7 million	Straight Line	20.6 million
		$1,348.1 million		$35.5 million

The majority of Hydro's high dollar value capital assets 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 84% 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.

In completing our procedures, we recalculated depreciation for both methods on a test basis and compared the estimated service lives used in the calculations to the 1998 Depreciation Study**.** We also reviewed the interest rates used in calculating sinking fund depreciation for reasonableness**.**

As a result of completing our procedures, no significant discrepancies were noted and therefore, we report that depreciation expense for 2005 appears reasonable.

We also reviewed the depreciation study performed by Gannett Flemming Inc. as of December 31, 2004 related to electric generation, transmission and distribution systems. The study was finalized and released to Hydro in December 2005. The study resulted in recommendations that included the discontinuation of the sinking fund method currently in place as this method is not providing appropriate matching of expenses and consumption and is resulting in losses on asset retirement. It was recommended that Hydro switch to a straight line method of depreciation for these assets and that a transitional approach be developed.

It is expected that Hydro will address the recommendations contained in this new depreciation study in a future Application to the Board.

Fuels

Fuel expense in 2005 totaled $84.501 million compared to the 2005 budget of $98.447 million and $83.109 million in 2004. The increase in fuel expense over 2004 levels was $1.393 million. However, in comparison to budget the 2005 actual costs were $13.9 million lower. The breakdown of costs within the fuel category is noted below for the years 2005 to 2002:

(000)'s	**2005**	**2005 Budget**	**2004**	**2003**	**2002**
No.6 Fuel	**$80,305**	$101,732	$80,845	$114,800	$112,534
Fuel Additives	**236**	196	212	204	251
Fuel Costs Indirect	**62**	107	84	66	147
Environmental Handling Fee	**25**	16	20	28	88
Ignition Fuel	**250**	127	127	89	116
Gas Turbine Fuel	**275**	479	101	245	153
Diesel Fuel Rural	**9,643**	7,745	7,654	6,663	6,766
Rate Stabilization Plan (RSP)	**(6,295)**	(11,955)	(5,934)	(37,501)	(46,807)
	$84,501	**$98,447**	**$83,109**	$84,594	$73,248

No. 6 Fuel

At $80.3 million in 2005, the cost of No. 6 Fuel, which is the largest component of fuel expense is quite comparable to 2004 levels. The more significant fluctuation in the cost of No. 6 fuel occurred between 2005 actual and budget. Savings of $21.427 million is the result of a decrease of approximately 929,000 barrels consumed in 2005 in comparison to budget. While the drop in thermal production for the year should have led to even greater savings, the increase in the average cost per barrel of fuel of $4.40 ($37.59 - $33.19) partially offset this decrease in cost.

Rate Stabilization Plan (RSP)

Net of RSP adjustments, the cost of No. 6 Fuel for 2005 drops to $74.0 million compared to $74.9 million in 2004 and $89.8 for the 2005 budget. The variation in the RSP consists of four main components: fuel variation, hydraulic variation, load variation and Labrador interconnected.

(000)'s	2005	2005 Budget	2004	Variance 05-05B	Variance 05-04
Water Variation	**$8,646**	($4)	$7,362	$8,650	$1,284
Load Variation	**1,442**	(672)	(590)	2,114	2,032
Fuel	**(16,289)**	(11,085)	(12,665)	(5,204)	(3,624)
Labrador Interconnected	**(94)**	(194)	(41)	100	(53)
	($6,295)	**($11,955)**	**($5,934)**	$5,660	($361)

As noted in the table above, the most significant of these variations contributing to the net RSP adjustment of $6.3 million in 2005 is fuel. The fuel variation is calculated using the actual cost of No. 6 fuel relative to the cost of service (COS) price applied to the number of barrels of fuel consumed. The calculation of this fuel variation is provided in the table below.

Fuel Variation		2005	2004	Variance
Actual barrels adjusted for non firm sales		2,111,293	2,543,990	(432,697)
Average Actual Fuel		37.59	31.02	
Average COS Fuel		29.58	25.94	
Annual fuel price variance		$ (8.01)	$ (5.08)	$ 2.93
Fuel Variation	1	$ (16,289,228)	$ (12,664,904)	$ 3,624,324

	Production	Average Price	Variance
Fuel Price Variance Increase	2,111,293	2.93	6,186,088
Volume Decrease	(432,697)	(5.08)	(2,198,101)
Annualized calculated variance 2			3,987,988

1 This number has been calculated on a monthly basis
2 Calculation is done on an annualized basis for comparision purposes and will lead to slight differences from a monthly basis.

In the table above, the average cost of No. 6 fuel for 2005 exceeded the average price in the COS by $8.01 per barrel. This increase in fuel prices resulted in a fuel variation of approximately $16.3 million to the Plan in 2005 compared to $12.7 million in 2004. The change in fuel consumption together with a change in the fuel price variation has led to an increase in the RSP fuel adjustment of $3.6 million (calculated on a monthly basis) for 2005 compared to 2004.

In addition to the fuel variation, hydraulic production in 2005 also contributed to the RSP adjustment, but as a savings to the Plan.

Hydraulic Variation		**2005**	**2004**	**Variance**
Average COS Fuel (A)		29.58	25.94	3.64
Actual Hydraulic Production		4,769,629	4,726,355	
COS Hydraulic Production		4,582,150	4,543,840	
Annual hydraulic production variance (B)		187,479	182,515	4,964
Hydraulic variation	1 2	$ 8,646,000	$ 7,362,000	$ 1,284,000
		Production	Average Price	Variance
Fuel Price Increase		187,479	3.64	1,110
Hydraulic Production Variance Increase		4,964	29.58	237
Annualized calculated variance **(000's)**	3			1,347

1 Holyrood conversion factor in COS is 615 kWh/bbl for 2002 COS and 630 kWh/bbl for 2004 COS.
2 This number has been calculated on a monthly basis
3 Calculation is done on an annualized basis for comparision purposes and will lead to slight differences from a monthly basis.

These savings in 2005 occurred as the result of an increase in hydraulic generation of 187.5 GWh over the COS in 2005. An increase in hydraulic production together with an increase in the average COS fuel price has led to an increase in the RSP hydraulic adjustment of $1.3 million (calculated on a monthly basis) for 2005 compared to 2004.

The load variation for 2005 also contributed positively to the Plan in the amount of $1.4 million. Due to a drop in load requirements for industrial customers, the sale of GWh in 2005 was 98 GWh below the COS.

Diesel Fuel Rural

The next most significant variance between actuals for 2005 and budget as well as the variance between 2005 and 2004 levels occurred in Diesel Fuel Rural. In 2005, the cost of diesel fuel increased to $9.643 million compared to a budget of $7.745 million and $7.654 million in 2004. Although Hydro experienced a decrease in the load requirements in island isolated and

Labrador isolated in 2005 compared to budget and 2004, the increase in the average price of diesel fuel of $0.15 per litre offset the savings attributed to a reduction in diesel generation. In 2005 diesel generation was down 3GWh compared to 2004 and 7GWh compared to the 2005 budget.

Gas Turbine Fuel

Gas turbine fuel expense experienced an increase in cost of approximately $174,000 over 2004 but a decrease of approximately $205,000 from budget. The volume of gas turbine fuel consumed each year can vary based on plant and operational requirements. In 2005 the volume of gas consumed was 157% above 2004. A higher demand from the Island Power System created a greater production demand at Hardwoods and Stephenville. The decrease in 2005 from budget is largely due to certain loading and contingency conditions that were budgeted but never materialized with a slight offset in savings due to a rise in average fuel prices.

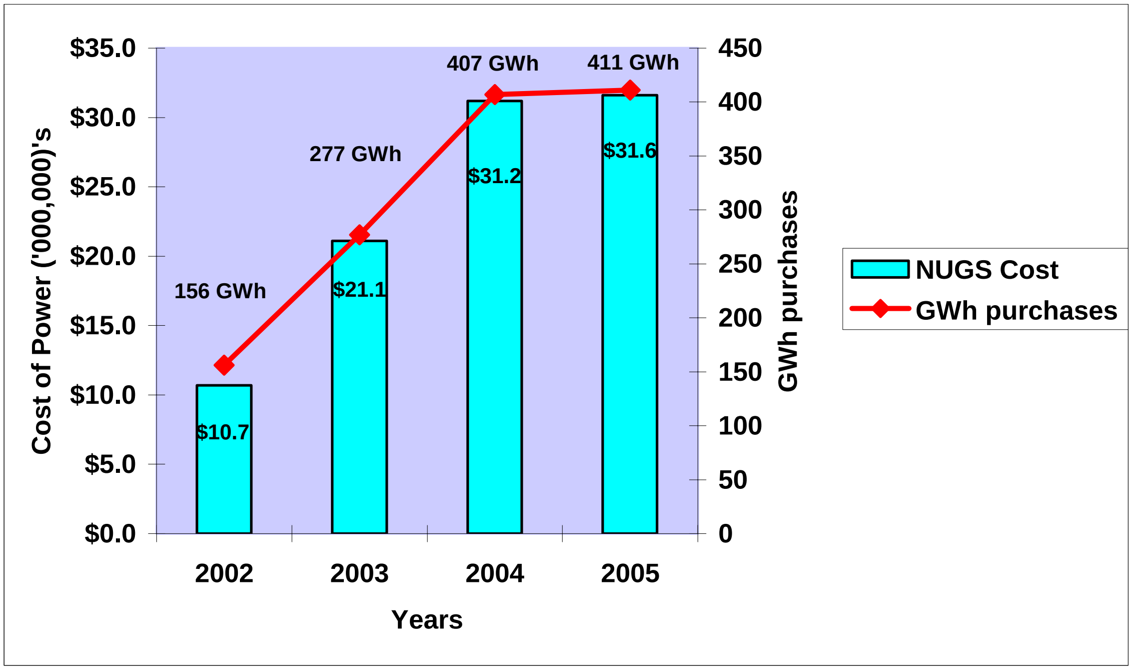
Power purchased

Overall, power purchased (excluding all non-regulated activity) increased by $0.85 million over 2004 which represents an increase of approximately 2.4%.

The breakdown of power purchased by category is as follows:

(000)'s	2005	2004	2003	Variance 05-04
L'Anse au Loup	$1,308	$974	$796	$334
Ramea Wind	82	21		61
Secondary energy	79	91	344	(12)
Demand & energy - CF(L)Co	2,375	2,296	2,332	79
CFLCO Interest	66	80	104	(14)
Interruptible - Abitibi Stephenville			981	0
Energy Costs - NUGS	31,560	31,169	21,098	391
Capacity Expansion	292	201	116	91
Island wheeling	429	510	293	(81)
	$36,191	$35,342	$26,064	$849

Energy purchases from Non-Utility Generators (NUGs) represents the most significant component of purchased power. This category increased by $391,000 in 2005 compared to 2004. The following graph depicts the changes in energy purchases in terms of GWh and costs over the period 2002 to 2005.



In 2002, NUG purchases were approximately $10.7 million, in 2003 they rose to $21.1 million, in 2004 these costs increased to $31.2 million and then began to level off in 2005 at $31.6 million. The increase from 2002 to 2003 is attributed to the commencement of the Corner Brook Pulp and Paper Co-Generation Project which started operating on January 30, 2003. The cost of NUGs power continued to increase from 2003 to 2004 with the Exploits River Hydro Partnership coming on stream in November 2003 contributing to a full year of power in 2004 compared to only two months in 2003. In 2005, Hydro incurred additional expense of approximately $0.4 million for 4 additional GWh of power from the NUGs. While the amount of energy purchased from NUGs has increased significantly over the period the average cost per GWh of power has remained relatively consistent at $77,000 per GWh since 2003.

The next largest variance experienced in power purchases was noted in the category L'Anse au Loup. The cost of power for this region of the province has been continuing to rise for the past couple of years. In 2004, the cost of power increased by $178,000 over 2003 and then in 2005 the cost spiked again to create an increase of $334,000 over 2004 levels. This increase is due primarily to a higher purchase price from Hydro Quebec which is driven by the market price for No 2 diesel fuel.

Though the costs relating to Ramea Wind of $82,000 is not significant in relation to the total cost of purchased power, the project is worthy of discussion since it represents the province's first wind-diesel demonstration project in Ramea. This project commenced production in September 2004 and up to December of that year Hydro purchased 108,390 kWh at a cost of $21,000. Then in 2005, after a full year in operation, Hydro purchased an additional 419,000 kWh of power at an average cost of $0.197 per kWh ($82,000/ 419,000 kWh). This is still considered a demonstration project and is being monitored closely by Hydro to evaluate its potential for application elsewhere.

The variance in other components of this expense category was less significant on a net basis in 2005 compared to 2004 and no further analysis was conducted.

Salaries and fringe benefits

Gross payroll costs for 2005 were $66,748,000, which was slightly higher than 2004 levels by $1,597,000 or 2.4%. The increase in 2005 over 2004 is due to various fluctuations within the salaries and fringe benefits cost grouping. These fluctuations are outlined in the table below which summarizes salaries and fringe benefits costs incurred from 2002 to 2005.

(000)'s	2005	2004	2003	2002	Var 05-04
Salaries	**$ 49,535**	$ 48,892	$ 48,460	$ 50,323	**$ 643**
Directors fees	**51**	46	41	23	**5**
Overtime	**4,353**	3,657	3,954	3,910	**696**
Employee future benefits	**4,300**	4,281	3,614	2,445	**19**
Fringe benefits	**6,851**	6,775	6,910	6,630	**76**
Group insurance	**1,557**	1,411	1,421	1,123	**146**
Labrador travel benefit	**101**	89	92	105	**12**
	$ 66,748	$ 65,151	$ 64,492	$ 64,559	**$ 1,597**

As noted in the table above, all categories within salaries and benefits experienced some level of increase in 2005 over 2004. The main categories to account for the $1.6 million increase relate to additional costs incurred in salaries, overtime and group insurance. The increase in overtime costs for the year is in direct correlation to the increase in additional maintenance requirements in the regulated operations division of $3.7 million and the increase in capitalized overtime of $143,000. The increase in group insurance of $146,000 from 2004 to 2005 is due to increases in premiums and an adjustment to short term disability resulting from a review of the related liability account. Increases to these two areas were partially offset by an increase in collections from retirees to cover their group insurance costs.

The salaries category peaked at $50.3 million in 2002, and then experienced a decrease of $1.9 million in 2003 dropping back to levels more comparable to 2000 and 2001. In 2004 and continuing into 2005, the salaries category experienced a modest upward trend. Though the increase in 2005 over 2004 of $643,000, or 1.3%, is not overly significant, the fluctuations between divisions in 2005 are much more notable.

Based on the new divisional structure in place for 2005, the salaries divisional breakdown has been revised for the years 2004 to 2002. The breakdown by division is as follows:

(000)'s	2005	2004	2003	2002	Var '05-04
Executive Leadership & Assoc.	**$ 3,007**	**$ 1,921**	$ 1,834	$ 1,614	$ 1,086
Human Resources & Org. Effect.	**2,552**	**3,368**	3,080	3,297	(816)
Finance/CFO	**9,358**	**11,007**	10,287	10,778	(1,649)
Engineering Services	**5,895**	**5,180**	5,207	5,229	715
Regulated Operations	**29,458**	**27,796**	28,314	29,506	1,662
Recharged salaries	**(735)**	**(380)**	(262)	(101)	(355)
	$ 49,535	**$ 48,892**	$ 48,460	$ 50,323	$ 643

Major salary fluctuations were noted within all the divisions from 2004 to 2005. While Hydro underwent a complete reconfiguration of its current code of accounts including divisions and departments in 2005, further restructuring within most of the divisions was ongoing throughout the year.

The divisional restructuring included the reallocation of 40 customer service positions in January 2005 and 20 network service positions in October 2005 from the Finance/CFO Division and 4 meter shop positions in October 2005 from the Engineering Services Division to the Regulated Operations Division. This movement of 64 positions into the Regulated Operations Division accounted for $1.63 million of the increase in salaries to this division.

The second largest variance in salary costs between 2005 and 2004, which primarily offsets the increase in the Regulated Operations Division, was the decrease in the Finance/CFO division of $1.65 million. Similar to the Regulated Operations Division, the decrease in this Division is primarily due to the transfer of existing positions within the Finance/CFO Division out to other divisions. As previously discussed, 60 positions within the departments for customer service and network service were transferred out to the Regulated Operations Division and an additional 9 telecontrol engineer positions were transferred out to the Engineering Services Division.

The remaining variances in salary costs between 2005 and 2004 for the Executive Leadership & Associates, the Human Resources and the Organization Effectiveness and Engineering Services Divisions are described below:

- the increase in the Executive Leadership & Associates Division of $1.1 million is due primarily to executive redundancy payments and retiring allowances for three former Vice-Presidents and a retiring allowance for the President.
- restructuring within the Engineering Services Division contributed to a net increase in this division of $715,000. In January 2005, Engineering Services received 6 properties positions from the Human Resources and Organizational Effectiveness Division and 9 telecontrol engineers were reallocated from the Finance/CFO Division in October 2005. These

transfers net of the 4 meter shop transfers to the Regulated Operations Division along with redundancy payments to 3 engineering directors increased salary costs for the year for this division by $724,000.

- the decrease in the Human Resources and Organizational Effectiveness Division of $816,000 was largely due to the transfer of 6 positions to the Engineering Services Division and a reduction in apprentice wages due to timing of recruitment.

Recharged salaries consist of an employee's time being charged to another division when he/she is working on a project that is not budgeted in his/her current division. Generally recharged salaries should net to $Nil for the year; however, because of recharges to non-regulated activities, a credit balance will normally remain in this account.

A detailed comparison of the number of full-time equivalent (FTE) employees by division for 2005 to 2002, including the budget for 2005, would provide a better visual picture of the new divisional restructuring that took place in 2005 including the various positions transfer as discussed above. However, Hydro was unable to recast FTE numbers of prior periods based on the new division structure in 2005, therefore a divisional comparison of FTEs to prior years was deemed ineffective. A comparison of total FTEs over the period 2002 to 2005 is as follows:

	2005	2005B	2004	2003	2002
Executive Leadership & Assoc.	**20**				
Human Resources & Org. Effect.	**47**				
Finance/CFO	**163**				
Engineering Services	**79**				
Regulated Operations	**532**				
Total	**841**	**868**	**849**	**891**	**949**

In comparison to 2004 the total FTEs for 2005 was reduced by 8 full time positions. While Hydro incurred moderate savings from the reduction of its workforce, additional costs related to redundancy pay and severance packages for directors and executive vice-presidents offset the decrease in salary expense, resulting in an overall increase of $643,000. As part of our review we completed an analysis of the average salary per FTE, including and excluding executive compensation. The salary costs as detailed earlier in the report have been normalized for special payments outside of regular wage expense. The results of our analysis for 2005 to 2002 are included in the table below:

(000)'s

	2005	2004	2003	2002
Salary costs	$49,535	$48,892	$48,460	$50,323
Less: Retiring allowances and redundancy pay	(1,798)	(801)	(374)	(1,109)
Retiring allowance and redundancy pay for executives	(1,188)			
Short term incentive payout, special bonuses and supplementary pension benefits for executive employees	(110)	(157)	(48)	(99)
	46,439	47,934	48,038	49,115
Less: Executive compensation	(1,029)	(915)	(863)	(821)
	$45,410	$47,019	$47,175	$48,294
FTEs (including executive members)	841	849	891	949
FTEs (excluding executive members)	835	839	881	941
Average salary per FTE	**$55,219**	**$56,459**	**$53,915**	**$51,754**
% increase	**-2.20%**	**4.72%**	**4.18%**	
Average salary per FTE (excluding executive members)	**$54,383**	**$56,042**	**$53,547**	**$51,322**
% increase	**-2.96%**	**4.66%**	**4.34%**	

For the first time in several years the above analysis indicates a decrease in the number of FTEs and a drop in the average salary per FTE excluding executive members. This decrease appears to be primarily related to type of job classifications that are being maintained or eliminated in the staff complement and the age demographics of the remaining workforce. For example, in 2004 Hydro paid out retiring allowances to 31 employees at an average cost of $28,304. However in 2005 Hydro paid out retiring allowances to 38 retirees (excluding executives) at an average cost of $32,399. The increase in the average retiring allowance signifies an increase in years of service for each retiree and the result is generally a younger workforce.

Executive salaries for the years 2005 to 2002 are as follows:

	Base Salary	Incentive Base Pay & Special bonus	Fringe Benefits	Total
2005				
Total executive group	$905,673	$73,609	$37,096	$1,016,378
Average per executive (5) [1]	**$184,831** [2]	**$15,022**	**$7,571**	**$207,424**
2004				
Total executive group	$914,700	$157,543	$42,783	$1,115,026
Average per executive (5)	**$182,940**	**$31,509**	**$8,557**	**$223,005**
2003				
Total executive group	$863,430	$47,895	$43,508	$954,833
Average per executive (5)	**$172,686**	**$9,579**	**$8,702**	**$190,967**
2002				
Total executive group	$820,755	$99,550	$50,408	$970,713
Average per executive (5)	**$164,151**	**$19,910**	**$10,082**	**$194,143**
% Average decrease (2005 vs 2004)	**1.03%**	**-52.32%**	**-11.52%**	**-6.99%**
2004 vs 2003	**5.94%**	**228.93%**	**-1.67%**	**16.78%**
2003 vs 2002	**5.20%**	**-51.89%**	**-13.69%**	**-1.64%**

1 Actual FTE for the year is 4.9 since two vice presidents left prior to December 31, 2005

2 Balances do not include the VP of Churchill Falls since 100% of his salary is charged out to a non-regulated division

The table above highlights an increase in base salary of 1.03% in 2005 over 2004. The reason for the slight increase in base salary is primarily related to the differences in salary scale for new executives.

However, with regard to average total salary for 2005 compared to 2004, we note a decrease in the average balance. This decrease is largely attributed to special bonuses that were distributed in 2004 to the executives in recognition of their extra effort and hours worked on the 2003 general rate hearing. Bonuses ranging from $21,000 to $24,000 were paid out to the four VPs for a total of $91,000.

A performance-based system introduced in 2001, which forms a part of the Company's compensation structure, provided payments in 2005 which were comparable to the 2004 amounts. The major areas that were selected for the evaluation of corporate performance included financial performance, improvement in system reliability and safety. The weighting of the incentive payments to be assigned to the total of these areas is 100% for the President and CEO, 70% for Vice-Presidents, 40% for Directors, and 30% for Regional Managers. In addition, to these three areas, divisional and departmental targets have been established and assigned to each vice-president and director. All payments related to the performance-based incentive system in 2005 related to Company and individual performance in 2004.

Based on the performance achieved in 2004 in relation to the established targets, a total of $105,258 was paid out in 2005 to the sixteen individuals who participated.

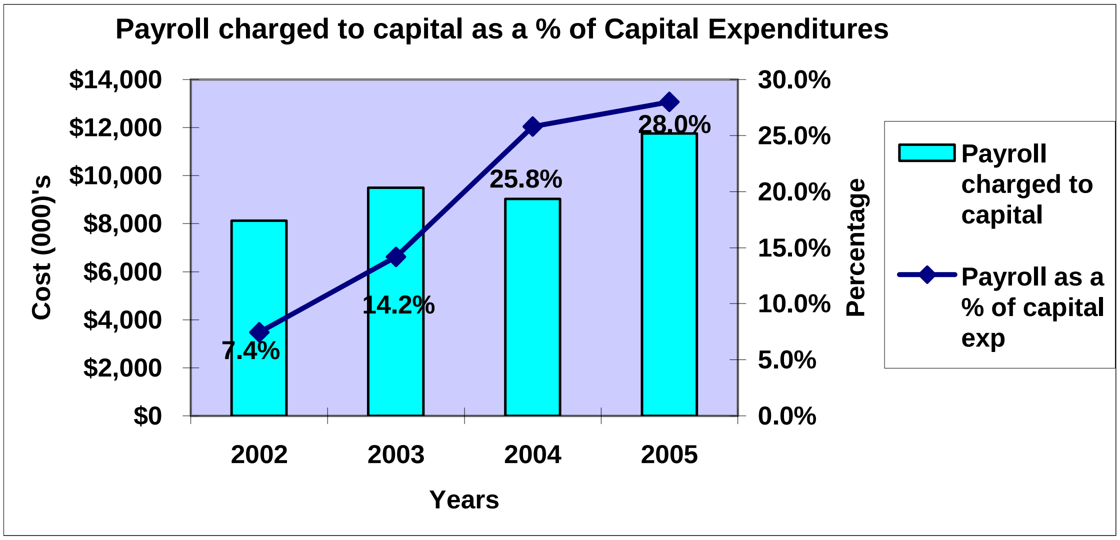
Capitalized salaries include the salaries and benefits of the Company's employees whose time is charged directly to capital projects, as well as departmental and non-departmental overhead. The gross payroll costs for 2002 to 2005 were allocated to operations and capital as follows:

(000)'s	**2005**	**2004**	**2003**	**2002**	**Var 05-04**
Payroll charged to operating	**$54,989**	**$56,122**	$54,997	$56,443	($1,133)
Payroll charged to capital	**11,759**	**9,029**	9,495	8,116	2,730
	$66,748	**$65,151**	$64,492	$64,559	$1,597

Payroll costs charged to capital in 2005 of $11.8 million represents the highest amount of salaries charged to capital expenditures in the last ten years. The amount of capitalized salaries can vary widely from year to year depending on the type of capitalized projects and their requirement for manpower versus machine power. The percentage of capital salaries in relation to the amount of capital expenditures can also fluctuate from year to year.

The following table and graph illustrate the relationship between payroll charged to capital and capital expenditures for the period 2002 to 2005.

(000)'s	2005	2004	2003	2002
Capital expenditures	**$42,000**	**$35,000**	$67,000	$109,000 [1]
Payroll charged to capital	**$11,759**	**$9,029**	$9,495	$8,116
Payroll as a % of capital exp	**28.0%**	**25.8%**	**14.2%**	**7.4%**



1 - includes capital expenditures for Granite canal

The increase in capitalized salaries can also be the result of the number of projects on-going during in any given year. In 2005, at least 29 separate projects containing salary costs at a minimum of $50,000 were in progress compared to 23 projects in 2004. Some of these projects are continuations of the larger projects capitalized in 2004 such as the Granite Canal Development, replacement of the Energy Management System and service extension and upgrading to the Central, Labrador and Northern Regions. Other capital projects such as Duck Pond power supply, wood pole line management, Lower Churchill and Rencontre East interconnection represent some of the new projects started in 2005 which also contributed significantly to capitalized salary costs.

In addition to the increase in capital salaries, increases were also experienced in capital overtime and departmental and non-departmental overhead allocated to the capital projects. The table below provides a breakdown of these costs.

(000)'s	2005	2004	2003	2002
Capital salaries	$8,223	$6,308	$6,273	$4,785
Capital overtime	1,445	1,302	1,375	1,018
Capital overhead	2,091	1,419	1,847	2,313
	$11,759	$9,029	$9,495	$8,116

Like capitalized salaries, capitalized overtime can also vary due to unforeseen circumstances such as time delays and overruns; however, when we compare 2005 to 2004 the variance in capital overtime is not overly significant. Instead, the larger variance between 2005 and 2004 is the rise in the amount of capital overhead of $672,000. This increase in capital overhead is directly linked to the fringe benefits and departmental overhead cost components for capital salaries.

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. Therefore any increase in capitalized salaries would directly result in an increase in capital overhead. In addition, the mix of employees utilized in each project will also have a direct impact in the overhead charge, i.e. Newfoundland versus Labrador projects and field versus non-field employees. While all of these variables will change with the progress of each project, each of these variables contributed to the increase in capitalized overhead costs in 2005 over 2004.

The final component of capitalized overhead, which is non-departmental overhead, includes the 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.

Within the categories of capitalized expenditures capitalized fringe benefits and overhead costs 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 2005, the percentages used to capitalize fringe benefits and overhead costs were unchanged from 2004.

System equipment maintenance

In 2005 System equipment maintenance costs increased significantly over 2004 levels by approximately $4.0 million or 23%. While every sub-category within system equipment maintenance experienced an increase in cost in 2005 over 2004, the most significant increase occurred in Maintenance material at $3.7 million. The following table summarizes System equipment maintenance costs incurred from 2005 to 2002 by sub-category.

(000)'s	2005	2004	2003	2002	Var 05-04
Maintenace material	**$ 19,884**	$ 16,155	$ 16,769	$ 15,798	**$ 3,729**
Tools and operating supplies	**358**	282	312	470	**76**
Freight expense	**525**	339	312	294	**186**
Lubricant, gases & chemicals	**584**	568	642	617	**16**
	$ 21,351	$ 17,344	$ 18,035	$ 17,179	**$ 4,007**

While most of the increase in 2005 occurred in the category maintenance material, the Company also experienced an increase in the cost of freight. In 2005, Hydro decided to discontinue the utilization of its own transportation department to move freight. This decision along with an increase in the volume of materials shipped by the Company in 2005 created an increase in freight expense of approximately $186,000 over 2004 and $223,000 over the 2005 budget.

The increase in Maintenance material of approximately $3.7 million over 2004 represents one of the largest variances since 2000. While Maintenance material costs are incurred throughout all divisions the majority of the costs are incurred in Regulated Operations. The following table provides a breakdown of Maintenance material by division which has been restated for the years 2002 to 2004 based on the new divisional structure currently in place for 2005.

(000)'s	2005	2004	2003	2002	Var 05-04
Executive Leadership & Associates	**$ 73**	$ 55	$ 37	$ 63	$ 18
Human Resources & Org. Effect.	**67**	40	29	40	27
Finance/CFO	**986**	1,094	1,050	1,228	(108)
Engineering Services	**165**	142	(48)	172	23
Regulated Operations	**18,593**	14,823	15,701	14,295	3,770
	$ 19,884	$ 16,154	$ 16,769	$ 15,798	$ 3,730

Most of the departments within the Regulated Operations Division had previously fallen under the old divisions of Production and Transmission and Rural Operations. These departments incurred large increases between 2004 and 2005 which account for the significant increase in this division. The following table provides a departmental breakdown of Maintenance material costs in the Regulated Operations Division.

(000)'s	**2005**	2004	2003	2002	**Var 05-04**
System Operation	**$128**	$115			**$13**
Hydro Generation	**1,202**	1,010	1,080	1,372	**192**
Thermal Holyrood	**9,944**	7,132	8,266	5,568	**2,812**
Central operations	**4,731**	4,427	4,639	5,102	**304**
Labrador operations	**1,602**	1,170	1,015	1,158	**432**
Northern operations	**986**	969	577	960	**17**
	$18,593	$14,823	$15,577	$14,160	**$3,770**

The increase in costs in Hydro Generation in 2005 over 2004 related primarily to additional maintenance for the cooling water piping, the exciter fault, governor adjustment and inspection, Burnt Dam road and the environmental monitoring stations.

Additional costs of $304,000 were expensed in Central Operations in 2005 due to extra maintenance requirements on the microwave radio system and microwave tower inspections, additional brush cutting requirements and higher than normal corrective maintenance costs for standby diesel fuel at the Hardwoods gas turbine including an assessment of high exhaust gas temperature problems at the Hardwoods and Stephenville gas turbine.

The Labrador operations also incurred an increase in maintenance material costs of $432,000 due to a bearing replacement at the Happy–Valley gas turbine, an overhaul of Unit G6 at Goose Bay North Plant and additional operating projects for diesel engine overhauls.

However, the most significant increase for 2005 occurred in the Thermal Holyrood department where costs were $2.8 million higher than 2004. The costs in this department largely relate to the annual maintenance requirements on each of the three thermal units in Holyrood plus routine maintenance requirements on the structures and equipment around and in the plant. A breakdown of costs at the Holyrood thermal plant is as follows:

(000)'s	**2005**	2004	2003	2002	**Var 05-04**
Unit # 1 overhaul	**$1,108**	$1,240	$3,371	$1,109	**($132)**
Unit # 2 overhaul	**4,288**	1,142	983	1,404	**3,146**
Unit # 3 overhaul	**1,135**	1,248	1,000	963	**(113)**
Annual routine maintenance	**3,413**	3,502	2,912	2,331	**(89)**
	$9,944	$7,132	$8,266	$4,530	**$2,812**

Maintenance costs at Holyrood are subject to a high degree of variability. For 2005 the main contributing factor to the overall increase in thermal plant costs over 2004 is the major overhaul that was completed on Unit #2. Based on information provided by the Company Unit # 1 had a major overhaul in 2003 and minor overhauls in 2002, 2004 and 2005 with an unscheduled repair to #3 valve spindle in 2004. Unit # 2 had minor overhauls completed from 2002 to 2004, with additional costs relating to work performed on the valves in 2002. The major overhaul on Unit #2, which is the first one completed since 1999 revealed excessive stack breaching damage, unforeseen turbine overhaul work beyond normal repair scope and additional fuel tank cleaning resulting from roof corrosion deposit. These extra maintenance requirements plus the major overhaul work on Unit # 2 were the main reasons for the variance increase of $3.1 million from 2004 to 2005. With respect to Unit # 3, minor overhauls were completed on this unit in 2002 to 2005 with valve work conducted in 2004.

The annual routine maintenance category includes the maintenance on Holyrood buildings and sites, common equipment, water treatment plant equipment and administration equipment. In 2005 the routine maintenance costs actually decreased from 2004 levels reversing the upward trend experienced over the prior three years. Costs relating to structures and equipment are incurred on a project-by-project basis, and costs incurred for regular routine maintenance can vary greatly depending on the type of maintenance projects that are completed. Due to the age of the plant and the surrounding grounds some years are much more costly than others. Some of the more significant projects incurred in 2005 include fuel oil tank inspection and replacement, replacement of machine shop roof and warm air make-up coil replacement.

While the Regulated Operations Division accounts for the majority of the costs in the Maintenance material category as well as the variance experienced for 2005 compared to 2004, a small decrease in the Finance/CFO division marginally offset this variance. The decrease in cost incurred in this division of approximately $108,000 is scattered throughout various departments but some of the main reasons for this decrease are as follows:

- The IS department experienced a decrease of approximately $50,000 due to a change in the Company’s treatment of computer hardware maintenance contracts; in 2005 Hydro began treating these costs as part of its capital acquisition rather than as an operating expense.
- The Rates & Financial Planning department experienced a decrease of approximately $14,000 due to additional expenditures incurred in 2004 relative to the general rate hearing such as the printing of communications to customers outlining the new rates.
- The supply chain department achieved savings in 2005 of approximately $43,000. While no specific reason can be sited for the decrease in this department, it was noted that material costs include printing, courier, Hydro Place janitorial, snow clearing, and repairs, which tend to vary from year to year.

Professional services

Professional services costs for 2005 were $4,240,844, which increased from 2004 levels by approximately $593,000 or 16.2%. A breakdown of the cost categories within professional services for 2002 to 2005 is outlined below.

(000)'s	2005	2004	2003	2002	Var 05-04
Consultants	**$2,039**	$1,766	$2,236	$3,315	**$273**
PUB Related costs	**1,303**	1,018	1,237	806	**285**
Software Aquisitions & Maintenance	**899**	864	1,018	1,202	**35**
	$4,241	$3,648	$4,491	$5,323	**$593**

Consultants' fees (including audit and legal) which represent the largest portion of total professional fees were approximately $2 million in 2005. The increase of $273,000 or 15.5% over 2004 levels is largely made up of additional expenditures in the Executive Leadership & Associates Division. Further fluctuations were noted within the Finance and Regulated Divisions; however these variances largely offset each other. Details by division are noted below:

	2005	2004	Variance
Executive Leadership & Associates	**$377,776**	$136,531	$241,245
Humn Resrces & Organization Effectiveness	**241,122**	218,055	23,067
Finance	**518,735**	417,582	101,153
Engineering Services	**109,956**	100,891	9,065
Regulated	**791,483**	893,140	(101,657)
	$2,039,072	$1,766,199	$272,873

The increase in the Executive Leadership & Associates Division is related to the recruitment and hiring of three new executive vice-presidents as well as additional costs incurred for media planning and advertising related to publications in various media throughout the province on safety, the environment and other on-going events.

The variance in the Finance Division is primarily attributable to a new depreciation study conducted by Gannett Fleming Inc. in 2005 related to the electric generation, transmission and distribution systems of the Company as of December 31, 2004.

The decrease in the Regulated Division is largely due to additional professional fee projects that were conducted only in 2004. These projects included a health risk assessment, landfill analysis, chemical consultant fees and benchmarking efforts.

A summary of major professional fee projects for 2005 is as follows:

Alstom Power Canada Inc.	$ 122,456	Long Term Partnering Agreement related to maintenance for Holyrood Thermal Plant
General Electric Canada Inc,	$ 174,000	Long Term Partnering Agreement related to maintenance for Holyrood Thermal Plant
Cantox Environmental Inc.	$ 52,495	Air Emission Assessment - Holyrood Thermal Plant
Ray & Berndtson/Lovas Stanley	$ 118,704	Hiring & Placement Services
Pinchin LeBlanc Environmental	$ 110,787	Asbestos Management Plan Development
Gartner Canada	$ 340,198	Technology & Consulting Services
Air Testing Services Inc.	$ 103,828	Stack Emission Testing - Holyrood Thermal Plant
Bristol Communications	$ 139,355	Media planning, advertising, Annual Report and Environmental Performance Report
Software House International	$ 98,129	Two Year Anti-Viris Contract, Mircosoft Slect Software Agreement
SPSS Inc (Showcase)	$ 56,029	Showcase Maintenance Contract
Board of Commissioners of Public Utilities	$ 656,720	Assessment 05-06/millrate 1.3, Financial & Economic Consultants
HYDRO - Amort. of deferred rate hear costs	$ 720,000	
	$ 2,692,701	

For 2005 regulatory related expenses totaled approximately $1,303,000, an increase of 27.9% compared to 2004. This increase primarily relates to the amortization of external regulatory costs for the 2003 General Rate Hearing. In P.U. 14 (2004), the Board approved the deferral of $1,800,000 in rate hearing costs and its amortization over a 36 month period. Amortization of rate hearing costs began in September 2004 at a cost of $360,000 for that year, however for 2005, a full year of amortization was recorded which increased this amount to $720,000.

Loss on disposal

In 2005, loss on disposal of assets totaled $3.3 million, the highest level in the last four years. A breakdown of this increase of approximately $479,000 or 17% is provided below:

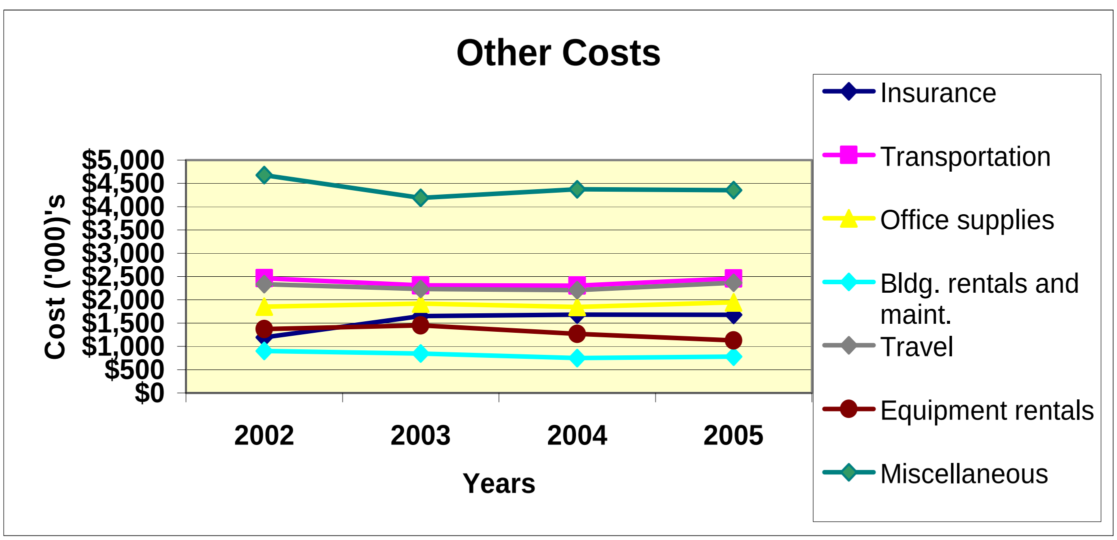
(000)'s	**2005**	2004	2003	2002	**Var 05-04**
Net book value of disposed assets	**$4,251**	$3,792	$3,880	$3,467	**$459**
Disposal proceeds	**(974)**	(999)	(756)	(709)	**25**
Auction fees and expenses	**14**	19	24	11	**(5)**
	$3,291	$2,812	$3,148	$2,769	**$479**

As is evident in the table above, the net book value of the disposed assets which encompasses much of the costs associated with the loss on the disposal of capital assets tends to vary from year to year. In 2005 the largest disposals were noted in the asset categories hydraulic generation and substations distribution whereas in 2004 the largest disposal was in the asset category diesel generation. Also included in the 2004 balance is the $1 million write-off of the remaining residual balance on the woodchip fired thermal generating station in Roddickton. This capital asset was originally written down in 1999 by $16.7 million after the Board issued P.U.5 (2000 - 2001) authorizing Hydro to abandon the woodchip plant.

Other Costs – remaining account groupings

Variances in the remaining account groupings of Other Costs are detailed in the table and graph below.

('000)'s	**2005**	2004	2003	2002	**Variance 05-04**	Variance 04-03	Variance 03-02
Insurance	**1,674**	1,682	1,655	1,198	**(8)**	27	457
Transportation	**2,459**	2,307	2,308	2,464	**151**	(1)	(156)
Office supplies	**1,948**	1,846	1,922	1,856	**102**	(76)	66
Bldg. rentals and maint.	**778**	752	850	900	**26**	(98)	(50)
Travel	**2,367**	2,206	2,233	2,337	**161**	(27)	(104)
Equipment rentals	**1,128**	1,269	1,453	1,372	**(141)**	(184)	81
Miscellaneous	**4,355**	4,370	4,191	4,674	**(15)**	179	(483)



Explanations of the larger variances in the remaining account groupings are as follows:

- The transportation expense category combines expenses relating to aircraft rentals, vehicle expenses, mobile equipment expenses and vehicle rentals. In 2005 transportation costs totaled $2.459 million compared to $2.308 million in 2004. This increase of approximately $151,000 is a result of the increasing price cost per litre of fuel.

  Information provided by Hydro on its vehicle fleet shows that the Company had 358 vehicles and 344 mobile equipment units at December 31, 2005 compared 359 vehicles and 358 mobile equipment units at December 31, 2004.

- Office supplies expense for 2005 was $102,000, or 5.5%, higher than in 2004. This increase is primarily attributable to a rise in advertising expense. In 2004, all advertising was placed on hold until a review of marketing and media placement was completed. While advertising costs increased by approximately $66,000 over 2004, spending in this expense category did not reach the levels incurred in 2003 and 2002. The remaining increase in office supplies in 2005 of $36,000 was due primarily to the rising cost of heat and light.

- In 2005 travel and conference expense increased from 2004 levels by approximately $161,000. The largest portion of this variance relates to travel costs which increased from $2,196,000 in 2004 to $2,344,000 in 2005. The increase in conference costs for 2005 was much smaller with an increase of approximately $13,000. Within the travel category various cost fluctuations were noted among the divisions, however the Regulated Operations Division accounts for the majority of the increase due to a higher maintenance program within the Central and Labrador regions of the province and additional maintenance requirements at the sites for the hydro and thermal generation units.

- In 2005 there was an $141,000 decrease in equipment rental expenses compared to 2004.

  The decrease in equipment rental costs for 2005 was due to configuration changes to the telecommunication leased services system and the implementation of the Citrix computing platform, which was completed in 2004. This platform resulted in decreased costs to area offices for leased services for the entire year in 2005.

Cost Recovery Charges

Cost recovery charges to CF(L)Co. for 2005 have decreased from 2004 by approximately $740,000 or 33.8%. The breakdown of cost recovery charges by division is as follows:

	2005	2004	2003	2002	**Var 05-04**
Executive Leadership & Associates	**$45,083**	$247,155	$299,486	$233,587	**($202,072)**
Human Resources & Organization Effectiveness	**6,179**	148,986	131,158	171,070	**(142,807)**
Finance	**1,307,541**	1,625,797	1,362,887	1,515,054	**(318,256)**
Engineering Services	**49,846**	64,529	53,724	53,213	**(14,683)**
Regulated	**43,182**	105,436	26,659	33,029	**(62,254)**
	$1,451,831	$2,191,903	$1,873,914	$2,005,953	**($740,072)**

This reduction in the Cost recovery account in 2005 is primarily due to the change in the manner in which salary costs charged to CF(L)Co are reflected in the accounts. In 2004 and prior years all salary charges to CF(L)Co were reflected as a recovery in the individual business units and were therefore reported in the cost recovery account. Beginning in 2005 salary costs identified on timesheets as related to CF(L)Co are transferred out of the individual business units into the non-regulated business unit. In effect regulated expenses now exclude any timesheeted salary amounts related to CF(L)Co as opposed to having these amounts included in the divisional salaries and then reflected separately as a recovery. Other salary amounts which are recovered on a percentage basis are still reflected in the cost recovery accounts. The amount of salaries transferred out to the non-regulated business unit in 2005 was $740,188 which is consistent with the reduction in cost recovery charges to CF(L)Co as noted above.

Hydro's methodology for determining cost recovery charges utilizes specific work orders in most situations to capture the actual costs of providing services to CF(L)Co. Cost 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.

Interest

Net interest and guarantee fees increased $3.0 million or 3.1% in 2005 compared to 2004. This increase is primarily attributable to a decrease in interest earned. Interest earned had been steadily increasing since 2001 which was largely attributed to interest earned on sinking fund investments and the RSP. However in 2004 Hydro sold a number of sinking fund investments which had been originally purchased at a premium, thus decreasing the amount of interest earned on these funds in 2005. In addition to this, the historical RSP plan balance decreased by $29 million from 2004 to 2005 and the new plan balance moved from a balance of $3.1 million due from customers to $11.8 million due to customers. The significant reduction in the balance of both of these plans contributed significantly to the decrease in interest earned for the year.

The following is a summary of interest expense for 2002 to 2005:

(millions)	**2005**	2004	**Var 05-04**	2003	2002
Gross interest	**$106.9**	$107.2	**($0.3)**	$106.1	$97.4
Debt guarantee fee	**14.4**	14.6	**(0.2)**	13.9	12.2
Amortization of debt discount and financing costs	**1.0**	1.0	**0.0**	0.9	1.2
Foreign exchange losses	**2.3**	2.2	**0.1**	2.2	2.2
	124.6	125.0	**(0.4)**	123.1	113.0
Less:					
Interest earned	**(18.5)**	(22.6)	**4.1**	(21.5)	(14.5)
Interest attributable to CF(L)Co share purchase	**(2.3)**	(2.3)	**0.0**	(2.2)	(2.3)
Interest capitalized during construction	**(4.3)**	(3.6)	**(0.7)**	(7.3)	(7.7)
	$99.5	$96.5	**$3.0**	$92.1	$88.5

Non-Regulated Activity

Scope: ***Review Hydro's non-regulated activity and assess the reasonableness of adjustments in the calculation of regulated earnings.***

In P.U.7 (2002-2003), the Board ordered Hydro to file separate financial statements for regulated and non-regulated activities, including a reconciliation to annual consolidated financial statements. Included below are the details of the Company's Non-Regulated Statement of Earnings and Retained Earnings for the years ended December 31, 2003 to 2005.

	2005	2004	2003
Revenue			
Energy Sales	$ 54,322	$ 48,135	$ 37,256
Operations and Administration			
Net Operating	3,407	3,027	2,903
Fuels	35	-	-
Loss on Disposal of Assets	-	27	-
Power Purchased	3,704	4,808	4,145
Depreciation	13	2	
	7,159	7,864	7,048
Net Operating Income	47,163	40,271	30,208
Other Revenue			
Equity in CF(L) Co.	14,591	14,984	11,312
Preferred Dividends	9,138	6,889	7,211
Interest Share Purchase Debt	(2,253)	(2,295)	(2,165)
	21,476	19,578	16,358
Net Income before unusual items	$ 68,639	$ 59,849	$ 46,566
Unusual items			
Write-down of construction in progress	-	-	(9,606)
Write-down of investment in LCDC	-	-	(12,725)
	-	-	(22,331)
Net Income	$ 68,639	$ 59,849	$ 24,235
Retained earnings, beginning of year	$ 239,616	$ 229,122	$ 239,699
Net Income	68,639	59,849	24,235
Dividends			
Hydro	(45,516)	(40,435)	(28,561)
CF(L)Co.	(8,437)	(8,920)	(6,251)
	(53,953)	(49,355)	(34,812)
Retained earnings, end of year	$ 254,302	$ 239,616	$ 229,122

Our review of non-regulated operations included the following procedures:

- assessed the Company's compliance with P.U. 7 (2002-2003);
- compared non-regulated expenses and operations for 2005 to prior years and investigated any unusual fluctuations; and
- reviewed detailed listings of expenses for 2005 and investigated any unusual items.

The Company has complied with P.U. 7 (2002-2003) and has filed separate financial statements for both regulatory and non-regulatory operations for 2005. Based on our review, we conclude that Hydro has appropriately identified and defined its various non-regulated operations and has established appropriate procedures for recording and reporting on these activities. Separate business units for the various non-regulated operations within its financial reporting system were used throughout the year.

Based upon our review and analysis, the amounts reported as non-regulated expenses appear reasonable and are in compliance with Board Orders, including P.U. 7 (2002-2003) and P.U. 14 (2004).

A summary of the significant non-regulated activity in 2005 is as follows:

- Hydro purchases recall energy from CF(L) Co. and any excess beyond what is required to serve regulated customers in Labrador is available for export sales. These export sales totaled $49.3 million in 2005, with related purchased power costs of $3.7 million. Although revenue increased 11.8%, power purchased actually decreased by 3.4% compared to 2004 due to a drop in gross export sales of 34 GWh. The net profit relating to this activity in 2005 was approximately $45.6 million (2004 - $40.3 million). A new contract covering the period between April 1, 2004 and March 31, 2009 introduced a new sale price to Hydro-Quebec of $36.00 per MWh for the first 12 month period compared to $23.90 per MWh in the previous contract. The new contract also provides for an increase of 2% each subsequent 12 month period thereafter, resulting in a new price of $36.72 as of April 1, 2005.

- The supply of power to the Iron Ore Company of Canada (IOCC) in 2005 resulted in an increase in non-regulated revenue from this customer of 24.8% (increasing from $3.99 million to $4.99 million). These sales are directly driven by customer requirements; however the three month strike at IOCC in 2004 and a 2% rate increase in 2005 were the main contributing factors to the increase in non-regulated revenue in 2005. The rate increase to IOCC is based on a negotiated contract and does not require approval of the Board. The net profit from this activity increased from $1.2 million in 2004 to $1.9 million in 2005.

- The Company operates the electrical facilities in Natuashish on behalf of the Federal Government, and in turn receives reimbursement of the operating costs for this activity. The net recoveries in the non-regulated expense category were $132,900 in 2005, increasing from $37,200 in 2004. The increase is primarily a result of timing differences between when the expense is incurred and when Hydro receives reimbursement from the government.

- Other non-regulated costs totaled $393,500 for 2005 (2004 - $1,280,400). The majority of the decrease is attributable to the discontinuation of the interruptible 'B' contract with Abitibi. Payments under this contract amounted to $972,900 in 2004. Aside from this difference, salaries and fringe benefits and system equipment maintenance costs increased due to Hydro staff's involvement in the supply and installation of a fuel storage and transfer system for Battle Harbour in support of the Battle Harbour Historic Society. Office supplies and advertising increased because of an environmental site clean-up at Big Brook and professional fees increased due to Hydro's mandate expansion.

Rate Stabilization Plan

Scope: ***Conduct an examination of the changes to the Rate Stabilization Plan to assess compliance with Board orders.***

Our examination of the RSP for 2005 included reviewing compliance with Board Orders and assessing the charges and credits including financing charges in both the historical and current plans for reasonableness.

Historical RSP

As of December 31, 2005, the historical RSP plan which consists of the accumulated RSP balance as of December 31, 2003 had a balance of $104.9 million compared to $133.9 million at December 31, 2004. In 2005, RSP rate changes to industrial and utility customers effective January 1, 2005 and July 1, 2005 respectively enabled the plan to recover approximately $37.8 million from ratepayers. A large portion of this recovery resulted from a rate increase to utility customers from 0.593 cents per kWh to 0.636 cents per kWh. Per P.U. 40 (2003) there are two years remaining to recover the accumulated balance at December 31, 2005 from ratepayers.

The following table provides a breakdown of balances owing at December 31, 2005 and December 31, 2004 relating to the historical plan:

	2005			2004		
	Utility	Industrial	Total	Utility	Industrial	Total
Balance, beginning of year	$ 101,660	$ 32,274	$ 133,934	$ 114,790	$ 40,915	$ 155,705
Recovery	(28,545)	(9,289)	(37,834)	(20,961)	(11,269)	(32,230)
Financing charges	6,666	2,101	8,767	7,831	2,628	10,459
Balance, end of year	$ 79,781	$ 25,086	$ 104,867	$ 101,660	$ 32,274	$ 133,934

Current RSP

The current RSP had an accumulated credit balance of approximately $11.8 million at December 31, 2005. The largest component of this balance is the cumulative credit of $10.625 million in the hydraulic variation account. A credit balance of $1.296 million due to the industrial customers and a debit balance of $0.120 million due from the utility customer make up the balance of the plan as at December 31, 2005. A comparative breakdown of the balances in the current RSP at December 31, 2005 and 2004 is as follows:

	2005		2004	
Utility Customer	$ 119,850	due from customer	$ 4,910,867	due from customer
Industrial Customer	(1,295,593)	due to customer	3,712,142	due from customer
Sub-total	(1,175,743)		8,623,009	
Hydraulic Balance	(10,625,444)		(5,521,528)	
Total Plan Balance	$ (11,801,187)		$ 3,101,481	

For the second consecutive year favourable hydraulic conditions contributed to higher hydraulic production relative to the COS production resulting in fuel savings of $8.6 million for 2005. Other highlights of the current RSP for 2005 include:

- No. 6 fuel prices average approximately $8 higher than the COS price resulting in a fuel variation of $16.2 million due from customers.

- Load variation for industrial customers, particularly in the last two months of the year after the shutdown of Abitibi-Stephenville, resulted in savings of $1.7 million for the industrial customers account.

- Fuel rider component of the RSP adjustment acted essentially as intended and provided for substantial recovery of the fuel price variation during the year.

The fuel price rider was established to adjust RSP rates for anticipated forecast fuel price changes. The fuel rider was introduced into rates for the utility customer July 1, 2005 and for the industrial customers the fuel rider came into effect on January 1, 2005. During 2005 the RSP adjustment, which includes the fuel price rider, resulted in recoveries of $12.895 million and $5.764 million for the utility and industrial customers respectively.

The tables below provide a breakdown of the activity in the RSP for 2005 as well as a continuity of the various component balances.

	2005 - Current Variation				
(000)'s	**Water Variation**	**Fuel Variation**	**Load Variation**	**Rural rate Alteration**	**Total**
Hydraulic balance	$ (8,647)				$ (8,647)
Industrial customers		3,207	(1,732)		1,475
Utility customers		12,969	301	(2,063)	11,207
Labrador Interconnected	29				29
Net change 2005	$ (8,618)	$ 16,176	$ (1,431)	$ (2,063)	$ 4,064

		2005					
(000)'s	**Balance Beginning of Year**	**Current Variation**	**Current Interest**	**Hydraulic Allocation**	**Recovery [2]**	**Net Change**	**Balance End of Year**
Hydraulic balance	$ (5,521)	$ (8,647)	$ (718)	$ 4,261		$ (5,104)	$ (10,625)
Industrial customers	3,713	1,475	120	(839)	(5,764)	(5,008)	(1,295)
Utility customers	4,909	11,207	291	(3,393)	(12,895)	(4,790)	119
Labrador Interconnected [1]	-	29		(29)			
Net change	$ 3,101	$ 4,064	$ (307)	$ -	$ (18,659)	$ (14,902)	$ (11,801)

1 The amount is written off to net income

2 Includes Fuel Price Rider

Based upon our review, we report that the RSP is operating in accordance with Board Orders and the charges and credits made to the Plan in 2005 are reasonable.

Deferred Charges

Scope: ***Conduct an examination of the changes to deferred charges and assess their reasonableness and prudence in relation to sales of power and energy.***

The following table shows the transactions in the deferred charges account for 2003 to 2005:

(000)'s	Balance Dec./02	Net Add.	Amort.	Balance Dec./03	Net Add.	Amort.	Balance Dec./04	Net Add.	Amort.	**Balance Dec./05**
CF(L) Co.	$350		(335)	$15		(5)	$10		(5)	**$5**
Realized foreign exchange losses	$84,121		(2,157)	$81,964		(2,157)	$79,807		(2,157)	**$77,650**
Rate hearing costs	$604	2,300	(603)	$2,301	(500)	(360)	$1,441		(720)	**$721**
Asbestos abatement								3,990	(133)	**$3,857**
Study costs								80		**$80**
Discounts/premiums & issue costs on long term debt	$3,697	1,581	(896)	$4,382		(997)	$3,385		(915)	**$2,470**
	$88,772	$3,881	($3,991)	$88,662	($500)	($3,519)	$84,643	$4,070	($3,930)	**$84,783**

During 2005, $3.99 million in costs associated with the Asbestos Abatement Plan at the Holyrood Thermal Plant were added to the deferred charges balance. These costs will be amortized over a five year period in accordance with P.U.2 (2005).

There was also $80,000 in additions during the year relating to an independent review of the treatment of Newfoundland Power's generation and a marginal cost study. As set out in P.U.14 (2004), the Board ordered both studies to be completed and the costs deferred and addressed in a future General Rate Application.

Key Performance Indicators

Scope: Review Hydro's Key Performance Indicators

In P.U. 14 (2004) Hydro was ordered to file annually with the Board a report outlining:

i. a strategic overview highlighting core strategies, corporate goals and achievements;
ii. appropriate historic, current and forecast comparisons of reliability, operating, financial and other key targeted outcomes/measures, including certain specified KPI's; and
iii. initiatives targeting productivity or efficiency improvements, including the status of ongoing projects and improved performance resulting from completed projects.

Hydro complied with this Order for 2005 with the filing of two reports in April 2006: "Strategic Goals and Objectives for Newfoundland and Labrador Hydro" and "Annual Report on Key Performance Indicators-Newfoundland and Labrador Hydro". These reports provide a good overview with respect to Hydro's strategies, goals and performance measures which should be of value to the Board in its regulatory oversight role.

The first report referenced above provides information on:

- Hydro's high-level goals identified through its strategic planning process in late 2005. These goals reflect the broadened mandate for Hydro and will guide its efforts over the next 3-5 years.
- Hydro's achievements relative to its 2005 strategics, goals and initiatives. This section provides details on activities and outcomes relative to a broad range of initiatives undertaken during the 2005 fiscal year.
- Initiatives targeting productivity or efficiency improvements. Some of these initiatives are more general in nature, or are described in general terms whereas others are very specific in nature. In order to better understand the context or significance of individual initiatives, it would be beneficial if Hydro were able to provide, where applicable, specific details on expected improvements in operating or financial performance.

The second report filed by Hydro is its annual report on Key Performance Indicators (KPI's). This report provides details on the KPI results for 2005 as well as information on Hydro's 2006 KPI targets. The KPI results for 2005 can be summarized as follows:

- Reliability KPIs - Hydro experienced an overall improvement in 2005 relative to 2004 with the majority of the KPIs showing positive results. Hydro added an additional KPI for 2005, Under Frequency Load Shedding (UFLS), because of its importance as an internal measure of reliability.

- Operating KPIs - Hydro experienced an improvement in its hydraulic conversion factor and a decrease in its thermal conversion factor in 2005 relative to 2004. Hydro attributes these results to higher reservoir conditions and higher production levels from hydroelectric assets combined with lower load conditions late in the year due to warm weather and the loss of load for Abitibi - Stephenville.
- Financial KPIs - Hydro's performance measures related to controllable unit costs increased in 2005 compared to 2004. This outcome was due to higher operating expenses, in particular system equipment maintenance, combined with a decrease in energy sales particularly to certain industrial customers.

We have reviewed the KPI results and the explanations provided by Hydro for the changes and variations experienced in 2005 and find them to be consistent with our observations and findings noted in conducting our annual financial review.

We believe the annual reporting by Hydro of its strategic goals and objectives and its KPI's is useful and of value to the Board in fulfilling its regulatory oversight role.

Contributions in Aid of Construction (CIAC's)

Scope: ***Review a sample of Contribution in Aid of Construction (CIAC) calculations for accuracy and compliance with approved policy.***

Our procedures in this area included the following:

- review the implementation of the undertakings of Hydro in respect of the revised CIAC policies as ordered in P.U. 4 (1997-98) and P.U. 19 (2005); and
- review a sample of CIAC calculations for accuracy and compliance with approved policy.

As part of our review we have held discussions with Hydro's Customer Communications and Support Supervisor (Acting) regarding the Company's CIAC policies and procedures and we have selected and reviewed documentation supporting a sample of five (5) CIAC calculations prepared during 2005.

Based on our review of five CIAC quotes in 2005, we noted that each of the files was very detailed, containing appropriate sketches of the area to calculate a correct quote, letters to interested parties outlining the details of the quote, the actual detailed calculation of the quote, and the necessary approval from supervisors. This was consistent with our findings in 2004.

Based on the results of our inquiry and review of documentation, we noted that the Board's requirements for the approval, review and calculation processes as specified in P.U.4 (1997-98) and P.U. 19 (2005), are being complied with.