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2. When searching within the Prefiled Testimony file, you should be aware that the following Schedules were imported as images and as a result cannot be searched electronically.

    i. K.C. McShane Schedules I and XX
    ii. D.G. Hall Schedules I to VI
    iii. D.W. Osmond Schedules II and III
    iv. J.A. Brickhill Schedule III

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PREFILED

TESTIMONY

An application to the
Board of Commissioners of Public Utilities

Proposed Power Rates
To be charged by
Newfoundland & Labrador Hydro
To
Newfoundland Power,
Island Industrial Customers and
Rural Customers

May 2001

HYDRO
THE POWER OF COMMITMENT

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

AND

IN THE MATTER OF an Application by Newfoundland and Labrador Hydro for approvals of: (1) Under Section 70 of the Act, changes in the rates to be charged for the supply of power and energy to its Retail Customer, Newfoundland Power, its Rural Customers and its Industrial Customers; (2) Under Section 71 of the Act, its Rules and Regulations applicable to the supply of electricity to its Rural Customers; (3) Under Section 71 of the Act, the contracts setting out the terms and conditions applicable to the supply of electricity to its Industrial Customers; and (4) Under Section 41 of the Act, its 2002 Capital Budget.

DIRECT EVIDENCE OF WITNESSES
TO BE CALLED BY
NEWFOUNDLAND AND LABRADOR HYDRO

TABLE OF CONTENTS

NEWFOUNDLAND AND LABRADOR HYDRO
May 2001

W.E. Wells

NEWFOUNDLAND AND LABRADOR HYDRO

EVIDENCE OF WILLIAM E. WELLS

Q. Would you please state your name and place of residence?

A. My name is William E. Wells and I live in the City of St. John's.

Q. Please outline your role with Newfoundland and Labrador Hydro.

A. I am President and Chief Executive Officer of Newfoundland and Labrador Hydro (Hydro) which is the parent company of the Hydro Group of Companies. The Hydro Group is made up of Hydro and the following subsidiary and affiliated companies:

1. Churchill Falls (Labrador) Corporation Limited (CF(L)Co);
2. Lower Churchill Development Corporation Limited (LCDC);
3. Gull Island Power Company Limited (GIPCo); and
4. Twin Falls Power Corporation Limited (TWINCo).

I am a Member of the Board of Directors of Hydro and all of the subsidiary and affiliated companies, with the exception of TWINCo.

Q. What, in your opinion, are the principal issues that most affect this Rate Application?

A. In my view there are five principal issues in this application. I will briefly expand on each issue under the following headings:

1. Cost of No. 6 Fuel;
2. Elimination of the Rural subsidy paid by Hydro's Industrial Customers;
3. Cost of Increased Capacity and the Associated Energy;

4. Rates and Regulatory Issues; and
5. Legislative Amendments.

Q. Would you please review the issues related to the cost of fuel?

A. The issue is the cost of No. 6 fuel which is required to supply our thermal generating plant at Holyrood. During the last Rate Referral, the Board of Commissioners of Public Utilities (the Board) recommended a price of $12.50/barrel as the price of fuel to be included in the base rate. Over the intervening years, the price of No. 6 fuel has been, at times, significantly higher than that figure and only during one brief period has it dipped below. The Rate Stabilization Plan (RSP) has shielded customers from these variations in their electricity bills, as it was designed to do. The RSP has also ensured that Hydro did not have to pass the immediate impact of fuel price increases on to its customers. Fortunately, we experienced higher than average inflows to our reservoirs which assisted in reducing the amounts charged to the RSP. The higher inflows resulted in a higher percentage of production from the hydraulic plants, thereby reducing thermal production and the consumption of No. 6 fuel.

On the basis of the recent dramatic escalation in fuel prices, which are not forecast to return to previous lower levels, Hydro is projecting that the balance in the RSP for Newfoundland Power's (NP) customers will later this year exceed the $50 million cap set by the Board. If these projections are correct, alternatives are limited. The Board will have to either, change the price of fuel in base rates to be more reflective of current and future costs, or change the amount that may be deferred by increasing the cap in the RSP with respect to NP, or a combination of the two. I should also note the fact that Hydro must pay for its purchases of No. 6 fuel in U.S. dollars. The exchange rate reflected in the lower Canadian dollar has a significant impact on Hydro's cost of fuel. The price of No. 6 fuel will by far have the largest impact on rate increases. In fact, the price of No. 6 fuel is the overriding issue of cost with respect to this Rate Application.

Q. Would you please review the issues with respect to the elimination of the rural subsidy paid by Hydro's Island Industrial Customers?

A. Another factor which is central to this Rate Application is the phase out of the subsidy paid by Hydro's Island Industrial Customers to support rural rates. This is one of the Legislative Amendments to which I will refer. The 1996 Amendment to the Electrical Power Control Act (EPCA) stated: "after December 31, 1999 industrial customers shall not be required to subsidize the cost of power provided to rural customers in the Province". Hydro's Island Industrial Customers have not been required to contribute to the deficit incurred in Hydro's operation of its Island rural interconnected and isolated systems, since December 31, 1999. Since then, Hydro has been absorbing this cost. In response to Hydro's application to the Board for a determination of the reallocation of costs with respect to this issue, the Board issued an Interim Order dated the 27th day of October 2000 which, in part, required that Hydro file a general rate application. That portion of the costs previously paid by Hydro's Island Industrial Customers for the rural subsidy, must be allocated to Hydro's other customers by Order of the Board. This issue is obviously a key component of this Rate Application.

Q. Since the last Referral, are there additional costs which Hydro must pay for increased capacity and energy?

A. Reflective of changing public policy over the past decade across North America and elsewhere, there was a move to expand the generation of electrical power beyond that of the traditional role of large public utilities. The Public Utilities Act was amended in 1992 exempting small hydro (up to 15 MW) from the application of the Act. Accordingly in 1992 upon request, Hydro waived its franchise right to the development of small hydropower up to 15 MW and issued a Request for Proposals for power and energy from small hydro developments to meet a forecast shortfall in capacity and energy capability on the Island Interconnected System. This resulted in agreements signed in 1995 with the Star Lake Hydro Partnership and Algonquin Power to develop 15 MW and 4 MW, respectively. The contracts to supply capacity and energy with these non-utility generators (NUGs) cost approximately $10 million/year, which cost must now be incorporated into Hydro's rates. These costs are offset to some extent by lower fuel costs at the Holyrood Thermal Plant.

Hydro has also entered into a contract with Abitibi-Consolidated Inc. in Stephenville which provides for 46 MW of interruptible power. This provides additional peaking capacity to Hydro of up to 46 MW during winter peak periods. The approximate cost of this contract per annum is $1.3 million.

Q. Would you please outline the issues with respect to rates and regulation?

A. Yes, this is the area that I have categorized generally as Rates and Regulatory Issues. There are a number of specific rates and regulatory issues that have been carried over since the date of the Referral in 1991. The Board's 1993 Report on Cost of Service Methodology and the Report on Rural Electrical Service in 1996 have substantially influenced Hydro's approach in the allocation of costs and rate design which are outlined in this application. There are significant rate issues for Rural Customers on which Hydro will make recommendations based on typical utility and regulatory practices, and outline the potential results. However, as we shall see during the course of this application, significant and sensitive issues will emerge with respect to, and within, rural rate classifications that must be addressed in either the short or longer-term. Hydro's approach to such issues is generally intended to cushion the rate impact on its customers, for example, by proposing the phase-in of rate increases, and the acceptance of less than a "normal" return on equity, in the shorter-term.

The initiatives that Hydro has proposed with respect to rates and rate structures permit the incorporation of principles of equity in establishing rate structures based on the cost of service. At the same time, the impact of these changes on individual classes of ratepayers is recognized and taken into account. It is important that we adhere to sound and proven regulatory principles and practices. It is necessary to achieve the ultimate objective through a period of adjustment. The fact that there must be a period of adjustment should not preclude doing the right thing over time and ensuring that we have equitable rate structures. There can be no equity amongst ratepayers or among rate classes if issues are to be decided in an ad hoc manner. Hydro therefore strongly endorses its proposals that we move now to more uniform rates based on the cost of service. We should also address the issue of preferential rates and lay the foundation to ensure that we have a period of adjustment for the ratepayers affected which would allow, within a reasonable time, achieving the objective of rate equity.

Q. What legislative amendments have been introduced since the last referral which have implications for the manner in which Hydro is regulated, other than the phase-out of the rural subsidy paid by Industrial Customers?

A. There are a number of significant amendments, which were made to the Public Utilities Act, the Electrical Power Control Act ,1994, and the Hydro Corporation Act, which became effective on the 19th day of January 1996. One of the most important, from a policy perspective, was the fact that

Hydro was to operate as a fully regulated utility under the jurisdiction of the Public Utilities Board. As well, Hydro was exempted from the Freedom of Information Act, the Provincial Preference Act, the Public Tender Act and the Public Service (Collective Bargaining) Act.

Q. What are the implications of these amendments for Hydro?

A. Amendments to the Hydro Corporation Act repealed the provisions that exempted Hydro from the Public Utilities Act and thus Hydro's rates, retail and industrial, became subject to the approval of the Board. Also, the capital budget of Hydro and borrowing by Hydro must be approved by the Board. As a fully regulated utility, Hydro is permitted a just and reasonable rate of return on its rate base. Previously, Hydro's income was based on interest coverage. This is the first Hearing in which the Board will set Hydro's rate base, which will be used in the calculation of rates to meet Hydro's revenue requirements. It is extremely important that the Board set the direction it will take over the longer-term in establishing the appropriate financial targets for Hydro.

The legislative amendments indicate that, as a matter of public policy, Hydro is intended to operate as a fully regulated utility, more similar to that of an investor-owned utility than had previously been the case.

Q. Would that, in your opinion, preclude Hydro from being an instrument of Government policy?

A. No, in my experience over the past five years, the Government as shareholder has indicated that Hydro has a role to play in support of Government policy or, as an instrument of public policy, that would not be inconsistent with the legislative fact that Hydro is to operate as a fully regulated utility.

Q. What are the specific rate issues that Hydro is addressing in this Rate Application?

A. Hydro's Rate Application is intended to address five specific rate issues;

1. Increase in the rates to be charged to NP;
2. Increase in the rates to be charged to Industrial Customers;
3. Adjustment and restructuring in rural rates;
4. The elimination of preferential rates over time; and
5. The implementation of full cost recovery for Government departments and agencies.

First, Hydro is proposing to increase the base rate which it charges for the supply of electricity to NP, by 6.7% commencing January 1, 2002, which corresponds to approximately a 3.7% increase at the end consumer level. The proposed new rate will be presented in the form of an "energy only" rate charge, consistent with Hydro's current practice.

Second, Hydro proposes to increase the rates which it charges its Industrial Customers commencing January 1, 2002. Hydro's Industrial Customers are supplied power and energy under individual contracts. By Legislative Amendment effective January 19, 1996, rates charged to Industrial Customers are to be approved by the Board. Hydro is proposing to increase the base rate which it charges for the supply of electricity to its Industrial Customers, which include the Abitibi-Consolidated Inc. paper mills at Grand Falls and Stephenville, Corner Brook Pulp and Paper Limited at Corner Brook and North Atlantic Refining Limited at Come-by-Chance, by 10.4%, commencing January 1, 2002. While it is Hydro's intent to have, to the degree possible, uniform terms in the contracts with its Industrial Customers, there are specific issues related to each entity which must be accommodated in the terms of the individual contracts. Details with respect to the proposed industrial contracts will be outlined in

Mr. Osmond's evidence. As a result of legislative amendment, the Board must also approve the contracts between Hydro and its Industrial Customers.

Third, Hydro proposes the following changes to rates it charges its Rural Customers. These customers fall into three categories:

a. **Island Interconnected and L'Anse au Loup Systems**: Hydro proposes that the Board confirm the established policy that the rates charged these customers be the same as the rates charged NP's customers. This will mean an approximate 3.7% increase in the rates paid by these customers. The implications for individual customers will depend, of course, on the manner in which NP flows through the increased costs to its customers which it must pay to Hydro, as a result of this Hearing.

b. **Labrador Interconnected System**: Hydro is proposing that all customers served from the Labrador Interconnected System be subject to a common rate classification system with uniform rates. It is proposed that there be an initial rate effective January 1, 2002. At its next rate hearing Hydro will provide the Board with a five-year rate plan that will complete the phasing-in of Labrador Interconnected rates for the new rate classes.

   With the introduction of the proposed new rate classification system, it is important to note that customers' rate changes may vary significantly based on individual consumption patterns. The impacts on customers' bills are outlined in Mr. Hamilton's evidence. There are some complexities and sensitivities which I should like to address later in outlining Hydro's position with respect to the rate changes proposed for Labrador Interconnected rates.

c. Isolated Systems: Hydro will also propose specific rates for customers on the Isolated Rural Systems, commencing January 1, 2002, based on reconfirmation of the policy that the first 700 kWh per month of energy should be identical in price to that paid by Island Interconnected Customers.

Rates for consumption over 700 kWh/month should, in the short-term, continue to be automatically changed by the average percentage change in NP rates charged to its customers.

Fourth, Hydro is proposing that the preferential rates on the Isolated Rural Systems that currently apply to fish plants, churches and community halls, be addressed in Hydro's next Rate Application. In making this proposal, Hydro is fully cognizant of the fact that it will delay the finalization of having uniform rates reflecting greater cost recovery and the principles of rate equity promoted in this application. Hydro makes this proposal in light of the impact of the rate increases requested.

Fifth, Hydro is proposing implementation of full cost recovery in isolated systems for Government departments and agencies. It is proposed that there be an initial rate effective January 1, 2002. At its next rate hearing, Hydro will provide the Board with a five-year rate plan that will complete the phase-in period.

Proposals relating to specific rates will be supported by an analysis of Hydro's forecast costs, and evidence as to the appropriate rate structures, given the inter-relationship between Hydro's rural and other customers.

It should be noted that, in addition to the specific rate proposals outlined above, there will be RSP adjustments for customers which are estimated to be in the range of 6% - 7% in 2002.

Q. What are the policy considerations that guided the development of the new rates proposed for NP and Hydro's Industrial Customers?

A. The rates proposed reflect three fundamental considerations.

1. The level of costs which Hydro anticipates for 2002 and in particular the cost of No. 6 fuel, used at the Holyrood Generating Station during the year, which we forecast will average $28/barrel. Given the significant impact on rates that would occur if fuel were to be rebased at $28/barrel, as noted in Mr. Osmond's evidence, we have concluded that it would be more appropriate to rebase the price of No. 6 fuel at $20/barrel. This reduces the impact of the rate increase and takes into consideration that prices are forecast to decline below $28/barrel beyond 2002.
2. Hydro has reviewed with its financial advisors, the appropriate financial targets which it should achieve. Again, given the impact on rates attributable to the rebasing of No. 6 fuel, Hydro is seeking confirmation from the Board of its longer-term financial targets and approval of a short-term Return on Equity (ROE).
3. Hydro has developed rates which reflect the immediate financial requirements of the corporation and as well recognize the equity required amongst rate classes to ensure the cost of service is reflected in the rates to be charged. Hydro's proposals are designed and intended to reduce the impact of rate increases to its customers. However, Hydro, the Board and all of Hydro's customers, must accept the reality of the costs associated in operating the system. Most especially, we must accept the higher fuel prices and adjust to the consequences.

Q. Would you please explain the policy considerations that affect rates charged to Rural Customers?

A. Hydro's Rural Customers fall into three categories:

1. Island Interconnected and L'Anse au Loup Systems;
2. Isolated Rural Systems; and
3. Labrador Interconnected System.

First, I should like to address the rates to be charged to Island Interconnected and L'Anse au Loup Rural Customers. The practice for many years has been to charge Hydro's Island Interconnected Rural Customers and since 1996, the L'Anse au Loup customers, exactly the same rates as customers of NP. Hydro recommends that this policy be continued. Hydro is therefore seeking approval of the Board to charge exactly the same rates to its Island Interconnected and L'Anse au Loup Rural Customers in future as will be charged by NP to its customers.

Hydro further recommends that the Board approve the policy of allowing Hydro to automatically adjust the rates which it charges to Isolated Rural Customers, applicable to the first 700 kWh/month of consumption and Street and Area Lighting to reflect any future changes in the rates charged by NP. Further, it is recommended that rates for consumption over 700 kWh for both domestic and general service customers should continue to be automatically changed by the average percentage change in NP rates charged to its customers.

There is the matter of the deficit in the operation of the Isolated Rural Systems. As a matter of policy, Hydro's objective is to minimize, to the extent possible, the rural deficit. One way to achieve this objective is to reduce the costs in operating and maintaining the rural systems. There have been a number of initiatives to reduce costs over the years, outlined elsewhere in my evidence and detailed in the evidence of other witnesses on behalf of Hydro. Another approach to minimize the rural deficit is to increase the level of cost recovery through redesigning the rates as outlined in Mr. Osmond's evidence.

Q. Could you expand on Hydro's position with respect to rates to be charged to Labrador Interconnected Rural Customers?

A. The Board, in its 1993 Report on Hydro's Cost of Service Methodology, recommended one cost of service study for the Labrador Interconnected System.

There are presently 24 rate classes in Labrador City, Wabush and Happy Valley/Goose Bay to service a total of approximately 8,700 customers. Given the significant disparity in rates being charged to customers who essentially receive the same service, Hydro is proposing that the transition to uniform rates be phased-in.

Q. How would that phase-in approach be applied?

A. As a first step, Hydro is proposing to implement the Island Interconnected rate structure (six classes) to replace the existing twenty-four rate classes. This approach would eliminate the multiplicity of rate classes for the customers served by the Labrador Interconnected System. Hydro's Labrador customers will be assigned to the appropriate class based on the customers' load characteristics. The implementation of the new rate structure will not result in any additional revenues to Hydro, however, individual customers will receive increases or decreases depending on the nature of the adjustment within the new rate classes. Hydro is proposing this cost based rate system be fully implemented over a phase-in period, starting in January 1, 2002. The implementation of the rates to be charged for each of the new rate classes is outlined in Mr. Hamilton's evidence. Again, the overall adjustment in rates is based on the cost of service, equitably divided amongst the customers in each rate class.

Q. In addition to the rate proposals you have outlined, what other items does Hydro wish to address in this application?

A. Hydro will propose a rate of return on rate base and return on equity which it believes is necessary for Hydro to achieve in the longer-term in order for the Corporation to comply with the requirements of the EPCA. Hydro's immediate financial objectives will be explained in the context of the longer-term financial targets which Hydro and its financial advisors believe are essential for Hydro to obtain.

Hydro is also requesting the approval of its capital budget for 2002.

Hydro will present the Board with information and evidence relating to a number of other issues, including information with respect to the need for new sources of base load generation and Hydro's capital market activity in 2002. Hydro will review various initiatives undertaken in the Corporation over the past years relevant to the conduct of its operations. As well, Hydro will review other factors that influence the operation of Hydro's systems in the current environment.

Q. Would you please outline Hydro's position with respect to the level of profit that it deems to be appropriate?

A. I would like to preface my remarks in this area by saying that in the assessment of Hydro's financial position and the determination of its revenue requirement, the corporation should not be viewed differently than any other utility, operated as a commercial entity, whether it be investor-owned or, as in the case of Hydro, Crown-owned. Having established the appropriate financial criteria for such an entity, Hydro's position must be assessed in light of current circumstances. A reasoned approach will permit conclusions to be drawn and decisions made which are appropriate to the current situation while accommodating the financial principles which would normally apply.

It is Hydro's view that the normal financial targets for a utility operating as a commercial entity would be, as our financial experts have advised, a debt/equity ratio of 60/40 and a ROE of 11% to 11.5%, the equivalent return on rate base being approximately 9.5%. There are, in Hydro's view, reasons why these targets should not be applied at this time. First and foremost is the quantum of the rate increase and its impact on Hydro's customers. The principal driver of the rate increase is the price of No. 6 fuel, relative to the price currently in Hydro's base rates. In the absence of that one factor, which is not a controllable cost, the issues in this application could be dealt with in an entirely different context. The government guarantee of Hydro's debt permits Hydro to operate with a differing capital structure without incurring a corresponding increase in costs in accessing the capital required for its operations. As a result, the target of an 80/20 debt/equity ratio, at least in the short-term and until there is a change in public policy, should suffice instead of the arguably normal requirement of a 60/40 debt/equity ratio.

Q. Does that also affect Hydro's assessment of the other financial indicators?

A. Yes, in the short-term. Implicit in anything less than an 11% to 11.5% ROE is the fact that the Government (shareholder) representing taxpayers is not getting an appropriate return on its investment in Hydro. Taxpayers implicitly are subsidizing ratepayers to some degree. However, in the current circumstances, Hydro is proposing a 3% ROE in the short-term to assist in offsetting the rate impacts resulting from increased fuel costs. If

Hydro were to request a normal 11% to 11.5% ROE, the result would be an estimated further 6% increase in base rates which Hydro does not consider to be appropriate at this time for the reasons stated. I wish to strongly emphasize that this proposal is one intended to apply for a limited duration only. To maintain a sound financial structure and to ensure that Hydro does not affect the provincial credit rating, Hydro must and should have a normal return on equity in due course. It is absolutely essential that, should the Board accept Hydro's short-term proposal, it send a clear signal to the financial markets of the world of its views as to what the normal ROE should be for Hydro in future.

Q. Are there other issues in addition to those to which you have previously referred, that have influenced Hydro in requesting an 11% to 11.5% ROE as an appropriate return in what you have characterized as a normal situation?

A. Yes. A number of factors have been taken into consideration in the establishment of Hydro's financial objectives. I should note that Hydro, by legislation, is to: "earn a just and reasonable return" as a matter of public policy. Commencing in 1995 Government, as shareholder, required Hydro to pay dividends. It would therefore seem logical to conclude that Hydro be operated as a utility having a sound financial structure, capable of supporting its debt, by securing a sufficient return to cover its debt obligations and provide a return on equity.

I should also point out that in 1992, the Board recommended that Hydro: "move slowly towards the attainment of an 80/20 debt/equity target". That recommendation is consistent with the principle of moving towards ensuring that Hydro's debt be more self-supporting. What is essential at this Hearing, is the determination that Hydro be able to achieve at least an 80/20 debt/equity ratio in its regulated activities. Our expert financial witnesses strongly advise that we move to even higher ratios of equity to debt. I concur that these objectives are desirable in the longer-term.

Following the requirement of Hydro to pay dividends in 1995, the Board of Directors of Hydro established a dividend policy of payment of 75% of the net operating income, provided it did not negatively impact the debt/equity ratio.

It is important, as our expert financial witnesses will indicate, that Hydro be regarded by the financial community as a self-supporting entity. While the Hydro debt is guaranteed by the Province, from a provincial perspective and as a matter of public policy, it is equally important that Hydro's financial position not negatively affect the Province's credit rating.

It is as a result of these considerations and in keeping with Hydro's legislated mandate to maintain a sound financial structure, supported by advice from our financial advisors, that it is proposed that Hydro's ROE enable it to target a debt/equity ratio of 80/20. Implicit in this approach is the acceptance of some degree of subsidy of ratepayers by taxpayers. Our financial advisors have addressed this issue of appropriate returns to any investor, including taxpayers, on their investment. At the present time, and until there is an overt change in public policy as suggested in Mr. Osmond's evidence, Hydro is not advocating a further lowering of the ratio of debt to equity.

Q. Given the rationale underlying Hydro's position of what the ROE should be for the longer-term, would you please outline the reasons as to why Hydro is proposing a 3% ROE in the short-term?

A. I think it is extremely important that everyone understand Hydro's position with respect to that issue. We want to ensure that Hydro's return on equity under the new rate base structure is reviewed and approved on the basis of what would be appropriate for “normal” conditions. Given the significant escalation in fuel prices, the effects on specific rate classes of the adjustments to reflect the results of the cost of service study, and the phase-out of the industrial contribution to the rural subsidy, Hydro is proposing in the short-term a 3% ROE. This proposal is intended to provide some relief in the current situation by not imposing an additional 6% increase to the rates which would occur if Hydro were to receive an appropriate ROE at this time. In the absence of these factors, Hydro would be proposing that the new rates would result in an immediate 11% to 11.5% ROE. It is important at this Hearing that the Board confirm the appropriate long-term financial targets for Hydro.

Q. Would you please expand on the other initiatives to which you have referred, that Hydro has undertaken?

A. There have been a number of initiatives undertaken since the last Rate Referral and before dealing with the specifics, I would like to put them in the context of the economic situation which prevailed throughout the 1990’s in the Province.

Generally, the 1990’s may be characterized as a time of restraint in expenditures for both public and private entities. While Canada slowly emerged from a recessionary period in the latter half of the decade, the economic recovery in Newfoundland was more muted. This is evidenced in the general restraint in wages which characterized the earlier part of the decade and the freeze in public service wages which Government applied to Hydro and which was not removed until 1996. As well, since the date of the last Hearing all commercial enterprises, both public and private, have had to make substantial adjustments to the way in which their business is conducted. Hydro’s collective bargaining position and compensation arrangements have been reflective of the general restraint in wages and compensation throughout the 1990's.

It should be noted that Hydro's controllable expenses are approximately 30% of the total annual costs, 80% of which include employee compensation and system equipment maintenance. Hydro has reduced the number in its permanent complement since 1992 by 159, or a factor of 16%. This has been achieved by attrition, layoffs and internal reorganization.

To the extent that Hydro can influence its costs, other initiatives were taken over the intervening years to assist in reducing costs and provide a more cost-effective service. These initiatives include measures to increase efficiencies in the production of power and energy, for example the runner replacements at the Bay d'Espoir plant. The Energy Management System has operated very effectively and we have maximized the use of the water available with due consideration for system reliability and security. The effective water management of the entire system throughout the Island portion of the province has reduced the amount of No. 6 fuel that would otherwise have been consumed to meet the energy requirements within the system.

We have also experienced a substantial change in the organizational structures within Hydro, especially in our Transmission and Rural Operations Division (TRO). The changes within the organizational structure of TRO are noted in more detail in Mr. Reeves' evidence. The elimination of positions, consolidation and the realignment of personnel in Hydro have been a constant throughout the 1990's, even at the highest levels within the corporation, where the number of executive positions have been reduced to five from nine. The initiatives taken have ensured that costs have not increased as they would have in the absence of any action being taken.

As the Board is aware, Hydro operates the Rural Isolated and Island Rural Interconnected Systems at a loss. The most pronounced losses occur in the operation of isolated diesel systems. Isolated diesel systems have been interconnected to either the Island or Labrador grid where it has been shown to be cost-effective, as outlined in Mr. Budgell's evidence. In 1996, Hydro completed the interconnection of the Great Northern Peninsula to the Island grid, incorporating the isolated system from St. Anthony to Roddickton.

In the mid-1990's Hydro found itself, as did many other companies, operating its business processes from various computer platforms and non-integrated system packages. In addition many of these systems were not Y2K compliant. Rather than refurbishing systems that were ten years old and since Y2K was a critical initiative, Hydro purchased the J.D. Edwards suite of products in early 1997. This integrated suite of products includes modules for financials, payroll, purchasing and inventory, maintenance and customer billing.

In recognition of the need for an increased level of customer services, Hydro consolidated the various customer services functions in a Customer Services Department including customer billing, accounts receivable, energy management, damage claim analysis and assessments of contributions in aid of construction. Hydro also centralized the coordination of meter reading, collection and customer communications functions at its head office. A Communications Centre was established with toll free services for emergencies, accounts and billings inquiries. Hydro has also initiated an annual residential customer survey as a means to identify those areas of greatest concern to our customers and to measure our progress in meeting those concerns. Recently Hydro introduced an enhanced energy management program through which we have provided our field and head office personnel with a better understanding of energy management issues that are important to our customers. In keeping with this initiative Hydro has, in partnership with the Conservation Corps of Newfoundland and Labrador, been able to promote energy efficiency and pass on to our customers helpful advice on these issues.

Q. Since the date of the last Rate Referral, are there other factors which have impacted the way in which Hydro conducts its business?

A. In carrying out its mandate, Hydro must adjust to change in public expectations. The reliability and stability of the electrical supply has become increasingly important, not only to Industrial Customers, but commercial and retail customers as well. The new technologies that affect everyday life in the workplace or the home are dependent on electrical power.

The fact is that Hydro operates the only non-interconnected grid in North America, on the Island of Newfoundland. The system must supply and transmit energy over long distances, through rugged terrain, to relatively sparsely populated areas. The larger individual units of generation in such a relatively small system, present unique problems in maintaining the reliability essential to consumers in today's society. This is especially so in the absence of an interconnection to other grids.

Over the past number of years environmental issues have become increasingly important to the public resulting in changing public expectations with respect to the activities of a corporation such as Hydro which, by the very nature of its operations, has the capability to impact the environment. In light of these changing public expectations, Hydro has adopted a proactive stance on environmental issues. In doing so, I think that Hydro has acted responsibly, however, such actions do not come without a cost. The changing public expectations have also been reflected in the environmental laws in both the federal and provincial jurisdictions to which Hydro is subject, and the regulatory regime applicable to those laws.

Q. Would you please outline some of the initiatives taken by Hydro with respect to this more proactive stance on environmental issues?

A. In taking a more proactive stance, Hydro has made a major policy shift to public acknowledgement of the issues that affect Hydro, and endeavoured to have an open and consultative process with concerned stakeholders. Since 1997, Hydro has participated in the Environmental Commitment and Responsibility (ECR) program, established with approximately 30 other electric utilities in Canada in the Canadian Electricity Association. Hydro introduced a new environmental policy in 1998 on which Hydro's Environmental Management System is founded.

Hydro adopted the ISO 14001 standard to fulfill the requirement of the ECR program. As a result, the Holyrood Generating Station was registered in January 1999 as ISO 14001 compliant, a first in Atlantic Canada for a facility of this size and type. In the spring of 2000, all Hydro's hydroelectric generating stations on the Island of Newfoundland and the plant at Churchill Falls were registered as ISO 14001 compliant. In 2002, Transmission and Rural Operations, Telecommunications and Hydro Place will be registered.

Hydro also reports to the Voluntary Challenge and Registry (VCR) most recently for 1999 and 2000. We have also carried out Environmental

Site Assessments (ESA) at decommissioned sites, followed by remediation of those sites. We have developed a ten-year program to do ESA's on 100 real estate holdings throughout the province. There will be ESA's on all high-risk properties and physical remediation using a risk based process.

Q. Do you have anything to report to the Board with respect to Hydro's plans to build or develop a new source of base load generation to serve the Island's growing needs?

A. Throughout the 1990's, there has been a relatively low increase in the level of load growth. Following the conclusion of the Power Purchase Agreements with the Star Lake Hydro Partnership and Algonquin Power in 1995, Hydro forecast deficits in capacity and energy that would have to be met by 2003. The actual forecast requirements and the action taken by Hydro are detailed in the evidence of Mr. Budgell. New sources of generation that are required on the Island system include the development of Granite Canal hydroelectric project by Hydro and the purchase of power and energy from Abitibi-Consolidated Inc. and Corner Brook Pulp & Paper Limited. These initiatives were undertaken pursuant to an Order-in-Council.

As well, at the direction of the Government of Newfoundland and Labrador in November of 2000, Hydro issued a Request for Proposals to assist in determining the feasibility of wind power as a source of future energy to meet the Island's energy requirements. The intent is to establish the capability and costs of wind power through a demonstration project that will include the transfer of technology and the assessment and performance of the technology within the Newfoundland environment.

Q. Will Hydro be borrowing in capital markets in 2002?

A. In 2002, Hydro's borrowing program is forecast to be approximately $300 million, of which $100 million is to retire the Series *Z* $100 million bond issue which will mature in October of 2002. The balance remaining, following the refinancing of its debt retirement will be used to finance a portion of Hydro's capital program, including the construction of Granite Canal. Hydro's proposed 2002 capital budget is $48 million, excluding the exempted capital expenditures of $71 million.

Q. Who will be presenting evidence on behalf of Hydro at this Rate Application?

A. I have outlined the specific proposals which Hydro wishes the Board to consider. The following witnesses will provide further information, explanations and expert opinion.

1. **Ms. Kathleen C. McShane**, Senior Consultant and Vice-President of Foster Associates Inc., will:
    a) Address the principles that should underpin the determination of the rate base, capital structure and return on rate base;
    b) Provide an expert opinion on the reasonableness of the proposals made by Hydro for the test year 2002; and
    c) Recommend appropriate targets for capital structure and return on equity.

2. **Mr. Douglas G. Hall**, Managing Director, Global Banking for RBC Dominion Securities Inc. will comment on:
    a) An appropriate level of debt and equity in the capital structure;
    b) The cost of debt;

c) The impact of the Provincial Guarantee on Hydro debt; and

d) The cost of equity and various related matters.

3. **Mr. David W. Reeves**, Vice-President Transmission and Rural Operations Hydro, will present evidence on:

    a) Hydro's transmission facilities on the Island of Newfoundland and in Labrador;

    b) Hydro's Interconnected and Isolated Rural Systems on the Island and in Labrador;

    c) The organizational structure in place to manage the transmission and rural facilities;

    d) Initiatives which have taken place to improve the organizational structure and reliability of the transmission and rural systems and to improve the cost effectiveness of the rural systems; and

    e) The Transmission and Rural Operations portion of Hydro's 2002 Capital Budget.

4. **Mr. Robert Henderson**, Manager System Operations Hydro, will present evidence on:

    a) Hydro's production facilities on the interconnected power system in Labrador and on the Island;

    b) Hydro's Energy Control Centre and the telecontrol facilities used in the operation of the power systems;

    c) The operating policy of Hydro's interconnected systems' production facilities;

    d) A comparison of the actual energy supply costs for 1992 with the costs provided to the Board in 1992;

e) A comparison of the actual energy supply costs for 2000 with the actual 1992 costs; and

f) A forecast of energy supply costs for 2001 and 2002.

5. **Mr. Hubert Budgell**, Director System Planning Hydro, will present evidence on:

   a) For each of the Island and Labrador Interconnected Systems and the Isolated Rural Systems;

      i. A comparison of the actual customer load with forecasts presented to the Board for 1992;

      ii. The latest forecasts of customer load;

      iii. Initiatives taken by Hydro to meet additional load since the last referral;

      iv. The requirement for additional means of supply and a description of any projects committed to meet near-term requirements; and

      v. Future supply options available.

   b) The assignment of Hydro's plant to customers for cost of service purposes; and

   c) The 2002 Capital Program for the Production Division.

6. **Mr. John Roberts**, Corporate Controller Hydro, will cover:

   a) Hydro's actual financial performance in 1992 compared to estimates presented to the Board during the last Rate Hearing;

   b) Hydro's actual results for 2000;

   c) Hydro's estimate of its financial performance for 2001;

   d) Hydro's projected revenue requirement for 2002;

   e) Hydro's rate base calculation for 2002;

   f) Hydro's cost of capital for 2002;

   g) The status of the Rate Stabilization Plan since the last hearing;

h) The treatment of the realized foreign exchange losses; and

i) Results of Hydro's recent depreciation study and the implications on this application.

7. **Mr. Derek Osmond**, Vice-President Finance Hydro, will:

a) Outline the proposed price of No. 6 fuel to be included in Hydro's rates;

b) Outline the proposed financial targets recommended by Hydro;

c) Explain Hydro's current rate policies and the timeframe over which proposed revisions to these rates would take place;

d) Explain Hydro's review of, and position relating to oil price hedging; and

e) Explain how Hydro's 2002 Capital Budget compares to prior year capital budgets and how the 2002 Capital Budget will be financed.

8. **Mr. John A. Brickhill**, President and CEO of Foster Associates, Inc., will present the following evidence:

a) Results from the "Study of Distribution System Cost Classification" (Distribution Study) completed by Foster Associates for Newfoundland and Labrador Hydro;

b) Outline of the Cost of Service (COS) methodology changes from the Generic Methodology outlined in the Board's 1993 Report on the Cost of Service Methodology Inquiry (1993 Board Report); and

c) The 2002 Test Year Cost of Service Study.

9. **Mr. Paul Hamilton**, Regulatory Specialist Hydro, will review:

a) Hydro's long-term rate design objectives and their relationship to sound rate design criteria;

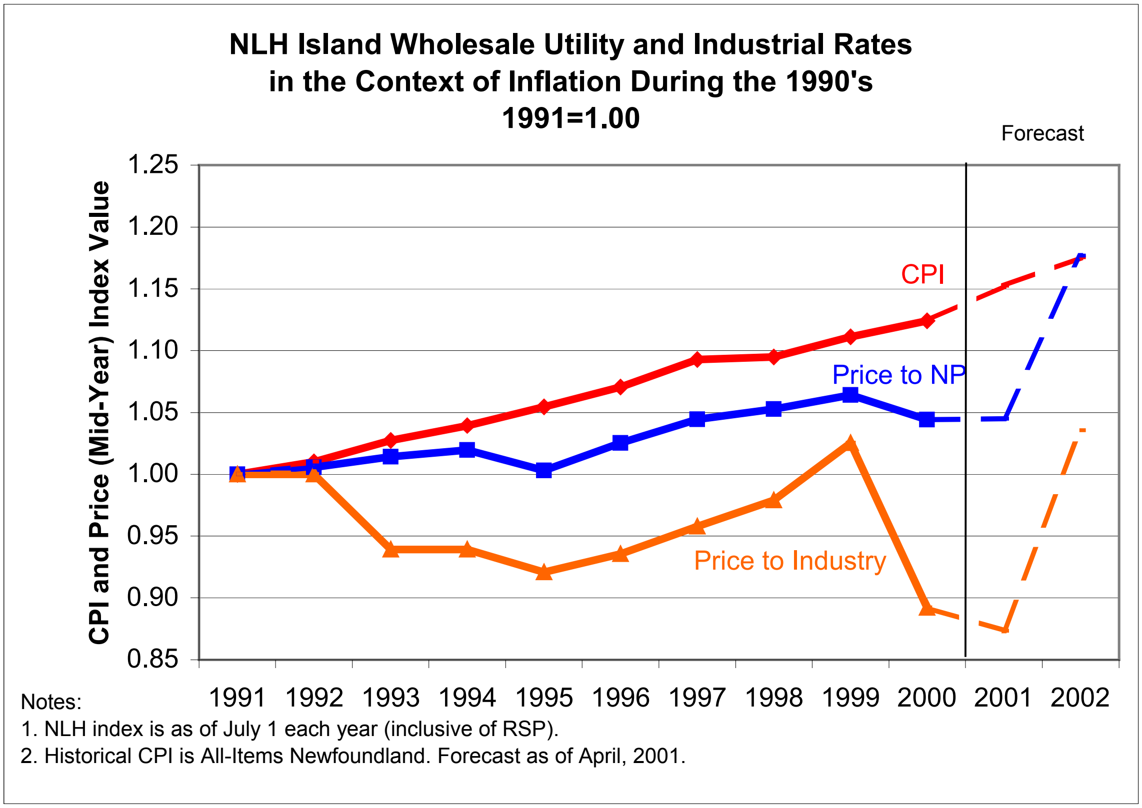
b) The role of Hydro's 2002 Cost of Service (COS) Study results in the rate design process;

c) Hydro's proposed rates and the impacts they will have on our various customer classes; and

d) Proposed changes to Hydro's Rules and Regulations.

Q. Do you have any final comments with respect to the rates that Hydro has proposed?

A. Hydro's rate proposals should be assessed against the time which has expired since the last increase was granted. Hydro's customers have had the benefit of a real decline in the price of electricity over the past ten years as the following chart indicates. The RSP has and continues to play a very important role in helping to stabilize monthly billings and has assisted in smoothing out the impact of fuel price adjustments. As we have seen in other energy services, the impact of higher fuel prices must now be absorbed in Hydro's electricity rates to our wholesale and Industrial Customers. This cannot in any way diminish the benefit that Hydro's customers have received over the past decade.



Q. How would you characterize the issues which you are bringing before the Board?

A. All of the issues are important. There are however critical financial policy issues with respect to Hydro's longer-term financial targets and its return on rate base. There are also critical rate policy issues both for Hydro and for its customers. In Hydro's view, these critical issues must be addressed and clarified during this Rate Application. Short-term results must be obtained within the context of a longer-term view. To do otherwise will result in a far more chaotic experience for Hydro's customers and those dependent on Hydro's services, whether directly or indirectly. The Board must confirm what is appropriate with respect to Hydro's financial guidelines for the future while making appropriate adjustments in the shorter-term to allow for a smooth implementation of rate adjustments and equity within rate classifications over the near and longer-term.

Q. Does this conclude your evidence at this time?

A. Yes, it does.

K.C. McShane

TABLE OF CONTENTS
Evidence of K.C. McShane

NEWFOUNDLAND & LABRADOR HYDRO
EVIDENCE OF KATHLEEN C. McSHANE

I. INTRODUCTION

Q. Please state your name, title and business address.

A. My name is Kathleen C. McShane. I am a Senior Consultant and Vice President of Foster Associates, Inc., an economic consulting firm located at 4550 Montgomery Avenue, Suite 350N, Bethesda, Maryland 20814, where I have been employed as a financial analyst and regulatory economist since 1981.

Q. What are your educational background and experience?

A. I hold a M.B.A. in Finance from the University of Florida (1980) and the designation of Chartered Financial Analyst (1989). My fields of expertise are finance and form of regulation. I have presented expert testimony on behalf of Canadian and U.S. utilities in more than 100 cases since 1987. A summary of my qualifications is included as Appendix A to this document.

Q. What is the purpose of your testimony?

A. I have been requested by Newfoundland and Labrador Hydro (Hydro) to:

1. Address the principles that should underpin the determination of the rate base, capital structure and return on rate base;
2. Provide an expert opinion on the reasonableness of the proposals made by Hydro in this regard for the test year 2002; and
3. Recommend appropriate targets for capital structure and return on equity.

II. BACKGROUND

Q. Please summarize the events which have given rise to Hydro's application for rates to be set using a rate base/rate of return model of regulation.

A. As a Crown corporation, Hydro's revenue requirement has been set historically using an "interest coverage" model. Under that model, the revenue requirement to be recovered from ratepayers was the sum of (1) operating and maintenance expenses; (2) depreciation expense; (3) interest expense related to debt which is financing regulated operations; and (4) margin. The amount of margin included in the revenue requirement was set essentially to provide protection that helped ensure that Hydro would recover in rates adequate funds to pay the interest expense for which it was obligated.

In the most recent Report of the Board of Commissioners of Public Utilities (the Board) for proposed retail rates to be charged by Hydro, dated April 1992, the Board recommended that Hydro be allowed the opportunity to earn an interest coverage of 1.08 times gross interest, excluding Rural Isolated Systems. With respect to capital structure, the Board stated, "The Board continues to believe that the appropriate debt/equity target is 80:20. As there is not presently a target date to achieve this ratio being dictated by the financial market or Hydro, the Board recommends Hydro move slowly toward the attainment of this target." Inasmuch as the Board recommended a slow movement toward the target, it did not explicitly set a margin designed to allow Hydro to attain those ratios.

In 1996, the Hydro Corporation Act was amended to subject Hydro to the provisions of the Public Utilities Act. Pursuant to the legislation, Hydro's rates are to be determined on the basis of a rate base/rate of return model, similar to that which governs the regulation of the preponderance of investor-owned utilities in North America, and specifically, similar to that used to set rates for Newfoundland Power. Hydro's filing for rates for the test year 2002 is its first filing using a rate base/rate of return model since the legislation was amended.

III. RATE BASE/RATE OF RETURN MODEL

Q. Would you please briefly explain the concept of the rate base/rate of return model of regulation?

A. The basic premise of the rate base/rate of return model is that a utility is entitled to the opportunity to earn a fair return on the investor-supplied capital that finances the assets that are devoted to the provision of utility service. The application of the model first entails specification of the value of the assets, tangible and intangible, that are required to supply utility service to customers.

The total value of the assets required to supply utility service, which is determined on the basis of "original cost",[1] is the rate base upon which a fair and reasonable return is allowed.

The setting of the allowed return on rate base requires the determination of the amounts of investor-supplied capital which are financing the rate base and a specification of the cost of each form of investor-supplied capital. The return on rate base is the cost of each form of financing weighted by the forecast amounts of each type of capital financing the rate base assets. The weighted average cost of the capital financing the rate base multiplied by the rate base equals the return on rate base, in dollars, to be included in the revenue requirement. The following table illustrates the model.

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[1] The "original cost" approach to rate base valuation is the historical cost, less accumulated depreciation and amortization, of the assets devoted to public service. It is the primary asset costing method utilized for regulatory purposes in North America.

TABLE 1
ILLUSTRATIVE RATE OF RETURN ON RATE BASE
(Rate Base: $1,500)

	Mid-Year Capitalization (1)	Proportions of Capital (2)	Cost Rates (3)	Weighted Components (4)	Rate Base Adjusted to Capital (5)	Return on Rate Base (6)
Debt	$1,250	71.4%	8.5%	6.07%	$1,071	$ 91.04
Equity	500	28.6%	10.0%	2.86%	429	42.90
TOTAL	$1,750	100.0%		8.93%	$1,500	$133.94

Q. Are there other Crown corporations or publicly-owned utilities in Canada which are regulated using a rate base/rate of return model?

A. Yes. They include BC Hydro, EPCOR Utilities, HydroOne (which was formed from the transmission/distribution operations of the former Ontario Hydro), Hydro-Québec, Northwest Territories Power Corporation and Yukon Energy.

IV. RATE BASE

Q. Does the legislation governing the regulation of Hydro provide any guidance for the determination of rate base?

A. Yes. The Hydro Act provides a relatively broad interpretation for the calculation of rate base. Section 17(2) states that "For all purposes of the Public Utilities Act, the rate base of the corporation shall include the property and assets of the corporation at their net book value but excludes investments in subsidiaries of the corporation." The Public Utilities Act (Sections 78(2) and (3)) is more specific in the delineation of the elements that may be included in, or excluded from, the rate base. Hydro has relied primarily upon the language of the Public Utilities Act, as well as North

American regulatory practice and precedent, to govern its determination of the rate base upon which a return should be allowed.

Q. What are the principal items that have been included in Hydro's forecast rate base?

A. The rate base includes net plant in service, working capital, and realized foreign exchange losses. As described in detail in the pre-filed testimony of Mr. Roberts, the net plant in service comprises all capital assets, expected to be used and useful in supplying utility service during the test year, net of accumulated depreciation. The amounts to be included in rate base are equal to the forecast mid-year 2002 balances, using the simple average of the opening and closing balances for the year. The use of a simple mid-year balance is consistent with the approach adopted by the Public Utilities Board for the determination of Newfoundland Power's rate base.

The working capital component of Hydro's rate base consists of the following items:

- Materials and Supplies
- Fuel Inventory
- Cash Working Capital

Each of these items represents an investment required to supply utility service which must be financed by investors.

Q. How were the materials and supplies and fuel inventory amounts included in rate base determined?

A. Both materials and supplies and fuel inventory were forecast using a 13-month average, i.e., the average of the test year opening balance and the month-end balances for each of the 12 months during the test year. The use of a 13-month average ensures that the amount to be included in rate base is not unduly impacted by seasonal variability.

Q. Please discuss Hydro's cash working capital calculation.

A. The cash working capital allowance reflects the average amount of capital provided by investors above and beyond investments in plant and other separately identified rate base items, including other components of working capital (e.g., materials and inventory), that bridges the gap between the time expenditures are made to provide service and the time payment is received for the service. Since the rate base in its entirety is intended to represent the amount of investor-supplied capital required to provide service, the cash working capital component should be compatible with the determination of the other elements of the rate base.

Hydro has calculated its cash working capital requirement by analyzing the leads and lags on cash flows related to revenues and operating and maintenance expenses. The lead/lag approach to determining cash working capital requirements has been the methodology most widely adopted by regulators. Hydro utilized this lead/lag approach to analyze its own cash flows related to revenues and to operations and maintenance expense.

The lead/lag study recognizes that the utility renders service prior to receipt of payment from ratepayers, but that there is generally also a delay in payment by the utility for goods and services it acquired. The lead/lag study analyzes transactions throughout the year to determine the net lag days between the date utility service is rendered and when payment is received (revenue lag), and the time between the time expenditures are recorded and payment is made for such expenditures (expense lag). The revenue lag is comprised of three components: (1) the service lag, (2) the billing lag, and (3) the collection lag. The service lag is measured from the midpoint of the service period to the meter reading date. The time from the meter reading to the billing date represents the billing lag, and the time lag from the billing date to the receipt of payments from customers corresponds to the collection lag. The total revenue lag therefore measures the time lag between the midpoint of the service period and the payment date. For Hydro, the estimated revenue lag for the 2002 test year, as described in Mr. Roberts' testimony, is 39.5 days.

The expense lag is determined by reference to when a service was provided to the utility, and when that service was settled by payment. The difference in these dates corresponds to the expense lag. Not all expense transactions can be analyzed due to the number of transactions completed during a given year. Some judgement must be applied in selecting the transactions that are analyzed. As detailed in Mr. Roberts' testimony, Hydro has specifically analyzed expense categories that account for 92% of total operating and maintenance expenses. The remainder of the expenses were assigned a 45 day lag, based on the premise that service is provided to Hydro at mid-month and payment is rendered 30 days after the service period has ended. The net expense lag is 20.1 days.

The cash working capital allowance is then calculated as:

$$\frac{\text{Revenue Lag} - \text{Expense Lag}}{\text{365 days}} \times \begin{array}{c}\text{Total O\&M Expenses}\\ \text{(Excluding Fuel)}^{1}\end{array}$$

This means then that Hydro requires investor-supplied capital equal to approximately nineteen days of operating expenses to account for the fact

[1] Fuel expense is excluded from the cash working capital calculation because fuel inventory is treated as a separate rate base item. Total O&M Expenses include power purchases.

that revenues are received, on a net basis, nineteen days later than payments for services received are rendered. As I stated earlier, the cash working capital allowance equals the amount of investor-supplied financing required to bridge the gap between receipt of revenues from ratepayers and payment for services rendered to Hydro.

Q. Newfoundland Power's cash working capital allowance is expressed as a percentage of its total operating and maintenance expenses. Does Newfoundland Power use a different methodology than that utilized by Hydro?

A. No. It is my understanding that Newfoundland Power periodically performs a lead/lag analysis, whose results can then be expressed as a percentage of total operating expenses, which is then applied to total expenses for a future test year. Lead/lag studies can be extremely time-consuming, and unless there is a material change in the revenue or expense lags, the results of a previously approved lead/lag analysis are often applied to future test year expenses. Since this is the first opportunity that Hydro has had to calculate its cash working capital requirement, a lead/lag analysis is necessary to establish the appropriate percentage for Hydro.

If Hydro's lead/lag analysis for the 2002 test year is approved by the Board, the cash working capital allowance for years beyond 2002 can be set in the same manner as Newfoundland Power.

The percentage is equal to 5.3%, and is calculated from the following:

$$\frac{\text{Revenue Lag} - \text{Expense Lag}}{\text{365 days}}$$

For future years the 5.3% should be applied to Hydro's forecast operating and maintenance expenses plus power purchases (excluding fuel expense) to arrive at the dollar amount of the cash working capital allowance which will be included in the forecast rate base[1].

Q. Please explain Hydro's inclusion of realized foreign exchange losses in the rate base.

A. The realized foreign exchange losses relate to issues of Swiss Franc and Japanese Yen denominated debt which were repaid in 1997. Because the Canadian dollar had depreciated significantly against the Swiss Franc and Japanese Yen over the terms of the issues, the repayment of the issues at maturity required a significantly greater outlay of funds than had been recovered in rates.

Prior to 1992, Hydro did not recognize any provision for potential foreign exchange losses in rates, since it continued to roll over (refinance) the loans, thus avoiding realized foreign exchange losses. In its April 1992 Report, the Board determined that a large foreign exchange loss related to the Swiss Franc loan would in fact be incurred and ordered Hydro to begin recording annually a provision for amortizing the expected loss at $1.0 million per annum.

When the foreign currency loans were repaid in 1997, Hydro realized a foreign exchange loss of $96.3 million. When the Hydro Act was amended in 1996, the legislation provided for recovery of the realized foreign exchange loss. Specifically, the Act states, "For all purposes of the Public Utilities Act, the expenses chargeable to operating account by the corporation shall include …. (b) an amount equal to the difference between the amount at which an indebtedness of the corporation which is

[1] As explained in Mr. Roberts' testimony, the cash working capital for Hydro is reduced by the cash working capital provided by the lag between the collection and remittance of HST.

denominated in a foreign currency is shown in the audited financial statements of the corporation for the year ending December 31, 1994, and the cost to the corporation, in Canadian dollars, of foreign currencies purchased from time to time by the corporation and used by the corporation to repay all or part of such indebtedness …”.

The inclusion of the realized foreign exchange loss in rate base recognizes that Hydro must continue to finance the outstanding realized foreign exchange loss until it is fully recovered through amortization. Thus, Hydro continues to require investor-supplied capital to support the net amount (for 2002, net of the $10 million provision for foreign exchange losses accumulated since the Board’s 1992 Report) of unrecovered realized foreign exchange losses.

Q. Why has Hydro not included the Rate Stabilization Plan (RSP) in rate base?

A. The component of the RSP which is recovered annually from (refunded to) customers is treated as a surcharge (or, if owed to customers, as a separately identified refund), not as part of base rates. As currently structured, the embedded cost of debt is applied to the unamortized balance of the RSP. However, going forward, I recommend that the unamortized balance of the RSP be treated the same as rate base items, i.e., the overall cost of capital, or return on rate base, should be applied to the RSP. The rationale for this recommendation reflects the fact that the RSP is not financed by debt alone, but by the same proportions of capital that finance all other regulated assets of the Corporation.

Q. Does the same recommendation apply to Construction Work in Progress (CWIP)?

A. Yes. CWIP, which is excluded from rate base until the assets are put into service, currently attracts the embedded cost of debt. However, the same overall cost of capital (return on rate base) should be applied to CWIP, as to assets which are included in the rate base. The financing of CWIP is no different than the financing of rate base assets: CWIP is supported by the overall outstanding utility capitalization. Regulatory precedents throughout North America support utilization of the weighted average cost of capital as the rate for calculating the return to be applied to CWIP (frequently referred to as Allowance for Funds Used During Construction (AFUDC)).

V. RETURN ON RATE BASE

Q. Please explain how the rate of return on rate base is determined once the rate base itself has been established.

A. The first step is to determine what the various forms of capital are that finance utility assets, and the forecast amounts which will be outstanding during the test year. The sum of the amounts of capital that will be financing utility assets is the utility capital.

Q. Will the total capital of the Corporation be equal to the utility rate base?

A. No, for several reasons. First, the total capital of a utility will include the financing of some assets that are not included in the rate base. These assets may include non-utility assets, utility assets which have been disallowed, construction work in progress, and, as in the case of Hydro, assets such as the RSP which are afforded separate regulatory treatment. Even without such assets, the rate base and capital are not likely to match exactly. To illustrate, the capital is equal to the simple mid-year average of the forecast amounts of the various forms of capital (based on beginning-of-year and end-of-year balances). However, the working capital component of the rate base represents a 13-month average of the outstanding amounts, rather than a simple mid-year amount. As a result, rate base and capital will not match exactly.

Therefore, the forecast capitalization amounts must be adjusted, based on the capitalization ratios, to equal the total rate base value, as shown in column 5 of the illustrative Table I. In column 5 the $1,750 of capitalization (column 1) is reduced to match the $1,500 rate base before calculating the return on rate base (column 6).

To ensure that a utility does not recover capital costs related to assets that are not in rate base, the utility capitalization ratios (and the corresponding cost rates of each form of capital) are applied to the approved rate base to arrive at the return on a rate base to be recovered in base rates.

Q. What forms of capital underpin the financing of utility assets?

A. Utility assets are typically financed with long-term and short-term debt, preferred stock, common equity and no-cost capital.

Q. What if there is specific capital that can be identified with non-utility assets?

A. That capital would be removed from the corporate capitalization to arrive at the utility-only capitalization. Hydro did this by removing the debt and equity (retained earnings) specifically attributable to Hydro's investment in Churchill Falls and removing from equity Hydro's earnings from recall energy.

Q. Please define no-cost capital.

A. No-cost capital refers to funds that are available to finance utility assets but is provided by ratepayers, rather than investors. These funds are included in the capitalization of the utility at zero cost or, alternatively, are deducted from the rate base, to ensure that ratepayers receive credit for funds which they have provided. Investors should not earn a return on capital they do not supply to the utility.

Q. What would be some examples of no-cost capital?

A. Some examples of no-cost capital include: contributions in aid of construction, reserve for injuries and damages, or provision for self-insurance, deferred taxes (for investor-owned utilities), and any other future liability that the ratepayer has funded in advance of the liability becoming payable.

Q. Hydro's financial forecasts indicate an average test year liability of $24.3 million related to "post-employment benefits other than pensions." Is this no-cost capital?

A. For purposes of determining the weighted average cost of capital to be applied to the rate base, yes. In March 1999 the Canadian Institute of Chartered Accountants (CICA) instituted a new standard (Section 3461) for the treatment of these benefits, effective January 1, 2000. Prior to the change, companies accounted for the benefits on a "pay as you go" or "cash" basis. The new standard calls for the benefits to be accounted for on an accrual basis. The switch from a "cash" to an "accrual" basis of accounting created transitional obligations for most corporations. For Hydro, the obligation attributable to regulated operations amounted to $21.2 million. Hydro elected to charge retained earnings for the entire amount of the transitional obligation, thus creating a liability for future employee benefits. By comparison, many Canadian utilities are amortizing the transitional obligation over the remaining employee service life, as permitted under the CICA guidelines, and seeking to recover the transitional obligation from ratepayers over the amortization period.

Hydro has included in its revenue requirement the annual provision for future employee benefits (based on the accrual method), as well as an amount for carrying costs on the past liability for future employee benefits, the average of which is $24.3 million for the test year. The discount rate of 7% used to calculate the carrying costs on the employee future benefits obligation is actuarially determined, based on long-term high quality corporate bond yields. Carrying costs on the future liability must be assessed since the future liability is expressed in present value terms. The future liability must earn a return so as to provide for sufficient funds when the liability becomes due and payable. To avoid double counting the carrying costs of the future liability, the forecast liability has been included in the capital structure at zero cost.

VI. CAPITAL STRUCTURE

Q. Please discuss Hydro's forecast utility capital structure for the 2002 test year.

A. Hydro's forecast utility capital structure is summarized in the following table:

TABLE 2 2002 FORECAST UTILITY CAPITAL STRUCTURE		
COMPONENT	**MID-YEAR BALANCE ($thousands)**	**PROPORTION**
Short Term Debt	173,580	11.1%
Long Term Debt (Gross)	1,229,663	
Sinking Funds	(87,363)	
Unamortized Debt Discount and Financing Expense	(12,868)	
Long Term Debt (Net)	1,129,432	72.1%
Liability for Employee Future Benefits	24,339	1.5%
Common Equity	239,099	15.3%
	1,566,450	100.0%

The basis for the forecast amounts is discussed in the pre-filed testimony of Mr. Roberts.

Q. Please explain why the sinking fund balances are deducted from the gross amount of long-term debt in calculating the capital structure proportions.

A. The provisions of certain of the long-term debt issues of Hydro require that Hydro create a sinking fund, which funds are set aside for the repayment of the issues at their maturity. To a large extent, the sinking funds are invested in Hydro's own bonds, which it purchases on the open market. The maintenance of sinking funds to retire the outstanding bonds at maturity means that, although the bonds are still outstanding – and interest must be paid on those bonds – they are no longer financing rate base assets. As a result, the sinking funds should be deducted from the gross amount of debt outstanding to determine the net amount of debt available to finance utility assets. As discussed below (Section VII, Cost of Debt), the related interest earned on the sinking fund assets is netted against the gross amount of interest payable on the gross amount of utility debt outstanding to determine the cost of debt to be recovered from ratepayers.

Q. Please discuss the reasonableness of Hydro's forecast capital structure.

A. I analyzed Hydro's forecast capital structure from two perspectives:

1. Is the forecast capital structure compatible with the premise that Hydro should maintain financial parameters that are commercially sound and consistent with achieving an investment grade debt rating on a stand-alone basis?
2. In light of the fact that the Province of Newfoundland unconditionally guarantees the debt of Hydro and charges Hydro a guarantee fee as compensation, is the forecast capital structure adequate?

Q. Please describe the principles that should underpin the financing of Hydro's utility operations as a commercial entity.

A. I start with the proposition that a utility, Crown corporation or investor-owned, should be financed in a manner which is compatible with commercial viability on a stand-alone basis, without subsidies as among stakeholders (ratepayers vs. investors or among classes of ratepayers).

The capital structure should be consistent with the business risks of the utility and should permit the utility, on a stand-alone basis, to achieve an investment grade debt rating. An investment grade debt rating is one which is BBB or better. For Hydro, a capital structure consistent with a BBB rating, equal to that of the Province, which guarantees its debt, is a reasonable objective.

Q. What capital structure, in your opinion, would permit Hydro given its business risk profile, to achieve a debt rating of BBB on a stand-alone basis?

A. Based on (1) an overview of the relative business risk of Hydro; (2) the guidelines set forth by the Canadian Bond Rating Service (CBRS) for capital structures of investor-owned utilities; (3) guidelines set forth by Standard & Poor's (S&P), one of the principal U.S. debt rating agencies; and (4) the actual capital structures maintained by both Canadian and U.S. electric utilities, I conclude that a 60/40 debt/equity ratio would be required to permit Hydro to achieve a stand-alone BBB rating.

Q. Please enumerate the key business risk elements that would determine a reasonable capital structure for Hydro on a stand-alone basis.

A. They are:

<u>Strengths</u>

- RSP offers protection from variations in forecast load, generation mix and fuel prices
- Expected strong economic growth in Province
- Geographic location limits competitive threats
- Electric utility industry restructuring not an immediate issue.

<u>Challenges</u>

- Low population density/relatively high cost structure
- RSP defers recovery of actual costs
- Fuel cost risk (e.g., thermal efficiency)
- Small number of large Industrial Customers

Q. Please explain the CBRS rating guidelines.

A. CBRS publishes several quantitative guidelines for different categories of Canadian utilities for different debt rating categories. Among these is a debt ratio guideline. The guidelines for the various debt rating categories are as follows for electric and gas utilities:

RATING CATEGORY	AA	A	BBB
Debt Ratio	45-55%	50-65%	Over 60%

Q. What are the Standard & Poor's guidelines?

A. Standard & Poor's ranks the business risk profile of utilities on a scale of "1 to 10", with "1" being the least risky and "10" being the most risky. There are at present no U.S. utilities which are ranked "1". The average business risk ranking for all U.S. electric utilities with debt rated BBB or better is 5. In my opinion, if Hydro were rated by S&P as a stand-alone entity, its business risk ranking would be in the 2-3 range based on the strengths and challenges enumerated above.

The S&P guidelines for debt/capital ratios for BBB rated utilities are as follows:

BUSINESS RISK RANKING	DEBT/CAPITAL
2	56.5-63.5%
3	53.0-61.0%

Q. What are the debt ratios maintained by Canadian investor-owned electric utilities?

A. The average 1999 year-end debt ratio of the major investor-owned electric utilities whose debt is rated by either CBRS or the Dominion Bond Rating Service (DBRS) was 54.8% (total equity ratio of 45.2%) (Schedule II). The average CBRS and DBRS ratings of these utilities were A (See Schedule III).

Q. What have been the debt ratios of U.S. electric utilities?

A. The average for all investor owned electrics with an S&P debt rating of BBB or better was 49.7% (total equity ratio of 50.3%). For electric utilities in the BBB rating category only, the average debt ratio was 52.1% (total equity ratio of 47.9%) (see Schedule IV).

Q. On balance, what conclusion do you draw from the preceding data and analysis?

A. I conclude that Hydro would require a 60/40 debt/common equity ratio, as a relatively low risk utility, to achieve a debt rating of BBB on a stand-alone basis.

Q. If Hydro were actually rated on a stand-alone basis (i.e., no Provincial debt guarantee), would the debt rating agencies consider the impact of its investment in Churchill Falls, which has, in the past, provided considerable financial support to Hydro's capital structure ratios?

A. Yes. However, the capital structure for which utility customers should be asked to pay should reflect the risks of the regulated utility operations only. Therefore, even if the non-consolidated capital structure of Hydro including its investment in Churchill Falls were to reflect a debt ratio of, say, 40%, to recognize the higher business risks associated with Churchill Falls relative to the utility, the utility ratepayers of Hydro should not be required to incur the additional cost of the thicker equity. To do so would be tantamount to asking Hydro ratepayers to subsidize Hydro's investment in Churchill Falls.

Q. Doesn't the implementation of capital structure targets for a Crown corporation which are similar to those of investor-owned utilities negate the very purpose of the Crown corporation structure?

A. Absolutely not. Crown corporations were established for the provision of electric utility service to ensure universal availability of service at a standard price. The key cost benefits to customers are the exemption from income taxes and, with the backing of the Provincial shareholder, a relatively low cost of debt. The Crown corporation structure, however, should not be construed as a means to shift to taxpayers (the ultimate equity shareholder in the Corporation) the actual economic costs of providing electric utility service. Although there is clearly an overlap between taxpayers and utility ratepayers, they are not identical. By ensuring that the true economic costs of providing utility service are borne by the ratepayers, appropriate market signals are being sent. If the taxpayer is subsidizing the ratepayer by virtue of setting rates which do not reflect the economic costs of the service provided, ratepayers are encouraged to over-consume scarce resources.[1]

As equity shareholder, a Provincial government should provide a framework for the Crown corporations which is compatible with operating a business, including the establishment of financial parameters that are reflective of the risks to which the business is exposed. In principle, Hydro should be financed in a manner that does not require that its debt be guaranteed by the Province.

Q. How does the fact that the Province guarantees the debt of Hydro and is compensated for the guarantee by way of a fee impact the capital structure targets?

A. The existence of a guarantee allows Hydro access to the capital markets at a lower cost than it could achieve on its own, under virtually all market

[1] In this regard, the Ontario Energy Board stated (H.R. 16, 1987), "(Ontario) Hydro should make a distinction between an Ontario resident's interest as a taxpayer and his or her interest as a consumer of electricity from Hydro. The Ontario resident would then no longer have to consume more, simply to receive his or her share of the "profit" or benefit from the Corporation."

conditions, and with less stringent provisions.[1] The existence of a guarantee allows Hydro to operate with a higher debt ratio at a cost of debt that is significantly lower than it would be able to achieve without the guarantee.

As long as the guarantee is being provided by the Province, and Hydro compensates the Province (as investor) for bearing the risk related to the guarantee, the Corporation can (and should be) financed with a higher debt ratio than would be reasonable absent the guarantee fee.

Q. What, in your opinion, is an appropriate medium-term target for Hydro in light of the guarantee and the guarantee fee?

A. In my opinion, in the medium-term, the Company should seek to move its capital structure ratios to approximately 70-75% debt and 25-30% equity. These ratios would be in line with the typical capital structure ratios maintained by other Crown corporations (see Schedule I).

Q. Hydro's test year debt ratio is considerably above the medium-term debt ratio target you recommended. Will the high leverage negatively impact on the Province's credit rating?

A. There is no evidence that an 83% debt to capital structure will negatively impact on the Province's credit rating. My conclusion is based primarily on a review of debt rating agency reports covering the major Canadian Crown corporations engaged in electric utility operations and whose debt is either guaranteed by, or is a direct obligation of, the Province.

[1] Investor-owned utilities are often subject to debt trust indentures which specify to maximum debt ratios and minimum interest coverage ratios.

In only one recent case, New Brunswick Power, has the Crown corporation's high level of debt impacted negatively on the Province's credit rating. In December 1999, the Canadian Bond Rating Service (CBRS) changed the Province of New Brunswick's outlook from "stable" to "negative" citing, among other factors, a large write-down of asset value taken by NB Power which reduced its common equity ratio to 1%. In that case, the total debt attributable to NB Power accounted for over 30% of the total outstanding liabilities of the Province, compared to approximately 12% in the case of Hydro.

However, the Dominion Bond Rating Service (DBRS) has, in numerous cases, noted the weakness of the capital structure ratios maintained by various Crown corporations, as compared to both the average for publicly-owned utilities (70% debt) and investor-owned utilities (55% debt) (Schedule I).

To illustrate, in its October 2000 report, "The Canadian Electric Utility Industry," DBRS concluded regarding the capital structure ratios of B.C. Hydro, "Key debt ratios are strongly influenced by excessive debt levels, with debt-to-capital for F1999 at 83.5%. This compares to 50-60% for private utilities. Given the high level of earnings returned to the Provincial Government (80%-90% over the last 5 years), the balance sheet is expected to remain among the weakest of all utilities in Canada." In respect of the Manitoba Hydro-Electric Board, DBRS concluded, "Current debt-to-capital at 88% is very weak, even compared to other government utilities, which typically average about 70% debt-to-equity. Excessive debt levels are the Utility's primary challenge and account for consistently weak financial ratios." In contrast, with regard to HydroOne, the debt rating agency found, "The capital structure is realistic, with an initial debt-to-equity ratio (preferred shares treated as common equivalents) set at 56%, that is comparable to private sector utilities, and allows for favourable coverage ratios."

Q. What comments did DBRS make with respect to Hydro in that report?

A. The report for Newfoundland and Labrador Hydro stated, "During 1999, the Utility was able to reduce outstanding debt by $121 million, which lowered the debt-to-capital ratio to 63% from 65% the previous year and improved interest coverage ratios accordingly. The debt-to-capital ratio compares favorably to the 70% government utility average, but remains well above the 48% typical of the private sector, while interest coverage ratios are in line with government utility group averages. With capital expenditures dropping somewhat to about $55 million, further improvement is expected in key debt ratios in 2000."

Q. Please reconcile the comments in the report regarding Hydro's 1999 capital structure and the forecast capital structure for test year 2002.

A. There are two reasons for the difference. First, the capital structure cited in the DBRS report includes the debt and equity related to Hydro's investment in Churchill Falls. Hydro's forecast non-consolidated debt ratio for 2002 of 71%, inclusive of the financing of the investment in Churchill Falls, is directly comparable to the 63% debt ratio in 1999 cited in the DBRS report. The capital structure which Hydro is proposing for the test year is a forecast utility-only capital structure, from which the debt and equity related to its investment in Churchill Falls have been removed.

The second principal difference between the 1999 non-consolidated capital structure and the forecast test year utility capital structure is the payment of dividends to the equity shareholder, the Province of Newfoundland. The dividend of $105 million ($70 million of which is attributable to regulated earnings) to be paid in 2002 is a key factor accounting for a forecast test year utility common equity ratio of 15.3%.

Q. Since the Province guarantees the debt of Hydro, and you anticipate that the forecast capital structure will not negatively impact on the credit rating of the Province, why do you not conclude that a 15% common equity ratio is an appropriate target for Hydro?

A. In my opinion, Hydro should have as an objective the elimination of dependence on the Province for financial support, and hence, the elimination of potential subsidization. As such, the capital structure ratio targets for Hydro's utility operations should be predicated on sound economic and financial principles.

Q. How do you recommend that Hydro achieve the target utility capital structures that you propose?

A. In my view, the target should be achieved gradually, so as to avoid undue rate shock, with the support of a reasonable allowed return on equity (see Section VIII below) and supportive dividend policy.

Q. What do you mean by a supportive dividend policy?

A. A supportive dividend policy is one which is predictable to both shareholders and management, and thus permits reasonable planning on the part of both shareholders and management. It is also compatible with both the level of the utility's capital budget and the objective of maintaining a reasonable and stable capital structure.

The predictability of the dividend policy is also in the best interests of ratepayers, who are then provided with assurance that the costs of capital they incur in rates will be equal to those incurred by Hydro. If dividends are declared which result in less equity than has been allowed for ratemaking purposes, ratepayers will effectively be asked to pay for a return on equity which does not exist. Ratepayers should not be expected to compensate a utility and its shareholders for non-existent equity.

Q. Is Hydro's dividend payout ratio target of 75% of net operating income, which is subject to the caveat that the dividend payout not increase the debt levels of Hydro to unacceptable levels, reasonable?

A. The reasonableness of the target should be evaluated in light of industry standards and the needs of the specific utility. The target should reflect the utility's forecast capital expenditures and the objective of achieving and/or maintaining a balanced capital structure. The 75% payout target is in line with the typical dividend payout ratios of major investor-owned electric and gas utilities with publicly-traded common stock. It is also equivalent to the payout ratio targets set for the Crown corporations, BC Hydro and HydroOne.

The 75% target payout ratio set by Hydro's Board, <u>including their caveat</u>, is reasonable in that context. However, given Hydro's high debt ratio relative to a reasonable target, the dividend payouts should be structured so as to provide Hydro the opportunity to achieve a commercially viable capital structure.[1]

[1] In contrast to investor-owned utilities, which can raise additional equity to achieve a balanced capital structure, either through direct sales of equity in the capital markets or by an equity infusion from the parent, Hydro's sole source of equity funds is through retained earnings.

VII. COST OF DEBT

Q. Please briefly describe how Hydro should calculate its embedded cost of debt for the test year, with rate base/rate of return regulation.

A. The embedded cost of debt should be calculated as follows:

$$\frac{\text{Net interest expense}}{\text{Net debt in capital structure}}$$

The net interest expense is equal to:

Gross Interest Payable on Outstanding Utility Debt
+ Annual Amortization of Debt Discount and Expense
+ Guarantee Fee
- Interest on Sinking Fund Assets

The net debt is equal to:

Gross Utility Debt Outstanding
- Unamortized Debt Discount and Expense
- Sinking Fund Assets

Q. Is the guarantee fee a legitimate component of the cost of debt?

A. Yes. The test for whether the guarantee fee is a legitimate component of the cost of debt is whether the cost inclusive of the guarantee fee is less than or equal to the cost at which the utility could raise debt on the strength of its own financial parameters. At the forecast utility capital structure, the cost of debt to Hydro, absent the Provincial guarantee, would be more than 100 basis points higher than the debt cost calculated with the guarantee fee.

Q. What is Hydro's embedded cost of debt using the above formula?

A. The embedded cost of debt is 8.35%, developed fully in the testimony of Mr. Roberts.

VIII. RETURN ON EQUITY

Q. What is the legislative basis for setting the return on equity for Hydro?

A. The Public Utilities Act, to which Hydro is subject, states, "A public utility is entitled to earn annually a just and reasonable return as determined by the board on the rate base as fixed and determined by the board for each type or kind of service supplied by the public utility".

The determination of a just and reasonable return on rate base requires a determination of the appropriate return on each component of the capital that is financing the rate base, including the return on the common equity portion financing rate base.

Q. What standards should underpin the determination of a just and reasonable return on equity for Hydro?

A. The standards are the same as those which are applicable to investor-owned utilities. There are three standards governing the determination of a fair return which have been articulated in landmark court decisions,[1] as well as numerous utility regulatory decisions. These standards set the parameters for the return requirement necessary to induce investment in public utility assets; they call for a utility to be provided the opportunity to:

[1] Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia (262 U.S. 679, 1923); Federal Power Commission v. Hope Natural Gas Company (320 U.S. 391, 1944); and Northwestern Utilities Ltd. v. Edmonton (1929 SCR 186).

- earn a return on the value of its property commensurate with that of comparable risk enterprises;
- maintain its financial integrity; and,
- attract capital on reasonable terms.

The concept of a fair and reasonable return does not reduce to a simple mathematical construct. It would be unjust and unreasonable to view it as such. A fair and reasonable return falls within a range, bounded by the cost of attracting capital and the returns achievable by firms of similar risk to utilities (comparable earnings standard).

Q. Since Hydro is a Crown corporation, and its shareholder is the Province (and, thus, ultimately the taxpayers of Newfoundland), why are these standards relevant?

A. The equity funds reinvested in Hydro by the Province have an opportunity cost. The determination of a reasonable return on equity should be independent of the happenstance of the identity of the shareholder. The Province (and taxpayers as shareholders) should expect to earn a return on the equity funds reinvested in Hydro equivalent to the return they could have earned on an alternative investment of comparable risk.

Q. Are there any publicly-owned utilities which are afforded the opportunity to earn a return commensurate with those of investor-owned utilities?

A. Yes. B.C. Hydro, SaskEnergy, SaskPower, EPCOR Utilities, HydroOne and the municipally-owned electric distributors in Ontario, Northwest Territories Power Corporation and Yukon Energy.

Q. On what premise have you estimated the fair return for Hydro as regards its financial risk?

A. For purposes of this evidence, I have estimated the return that would be applicable to Hydro at a reasonable stand-alone capital structure (no debt guarantee).[1]

Q. Since Hydro does not have publicly traded shares, how have you estimated a fair return on equity for the Corporation?

A. I have estimated a fair return by reference to proxies which do have publicly traded stock and whose total (business plus financial) risk would approximate that of Hydro.

Q. What tests have you employed to estimate a fair return on equity for Hydro?

A. I have employed the three tests which are typically utilized in the regulatory arena to determine a just and reasonable return:

1. Equity Risk Premium Test
2. Discounted Cash Flow Test
3. Comparable Earnings Test

<u>EQUITY RISK PREMIUM TEST</u>

Q. Please summarize the underlying premises of the equity risk premium test.

A. The equity risk premium test is derived from the basic concept of finance that there is a direct relationship between the level of risk assumed and the return required. Since an investor in common equity takes greater risk than an investor in bonds, the former requires a premium above bond

[1] The same return would be applicable to Hydro assuming the more leveraged capital structure compatible with a debt guarantee and reasonable compensation (guarantee fee) provided to the investors who bear the financial risk.

yields in compensation for the greater risk. The equity risk premium test is a measure of the market-related cost of attracting capital, i.e., a return on the market value of the common stock, not the book value.

The estimation of the required equity risk premium for either the market as a whole, or a utility specific, is not an exact science. Hence, it is necessary to evaluate a broad spectrum of data and alternative risk premium estimation approaches to arrive at a reasonable determination of the required equity risk premium.

There are two broad approaches to estimating the equity risk premium for a utility. The first begins with an estimate of the expected equity risk premium for the entire equity market (i.e., the equity market portfolio), subsequently adjusted to reflect the risk of a utility relative to the market as a whole. The second approach develops the risk premium directly for a particular stock or industry (e.g., utilities). In both approaches, the estimated equity risk premiums are obtained by subtracting the estimated risk-free rate from the estimated expected return on the market portfolio or the individual industry/stock. The expected equity risk premium can be developed (1) from an analysis of historic market risk premiums and (2) from prospective market risk premiums based on discounted cash flow (DCF) estimates of the expected market return. DCF-based estimates of the cost of equity comprise the dividend yield plus investor expectations of longer-term growth.

It is critical to recognize that the equity risk premium test is a forward-looking concept that reflects investor expectations. The magnitude of the differential between the expected return on equities and the yield on bonds is a function of investors' views of such key factors as inflation, productivity, profitability and investors' willingness to take risks.

It is precisely because the risk premium is a forward-looking concept that:

1. Historic risk premium data need to be evaluated in light of prevailing economic/capital market conditions; and,
2. Direct estimates of the forward-looking risk premium need to supplement measurement of the risk premium by reference to historic data.

Risk-Free Rate

Q. What is the point of departure for applying the equity risk premium test?

A. The point of departure for applying the equity risk premium test is a forecast of the risk-free rate to which the equity risk premium is applied. Reliance on a long-term government bond yield as the risk–free rate recognizes (1) the administered nature of short-term rates; and (2) the long-term nature of the assets to which the equity return is applicable.

The forecast 30-year yield is based on the consensus forecast of 10-year Canada bonds plus the normal spread between 10- and 30-year Canadas. *Consensus Forecasts*, Consensus Economics (April 2001) anticipates that the 10-year yield 12 months hence will be 5.5%. The recent spread between 10- and 30-year Canadas is 35 basis points, which results in a 30-year Canada yield of 5.8%. Rounded to the nearest quarter point, a 5.75% yield is a reasonable forecast for the 2002 test year and will be used as the risk-free rate to which the equity risk premium will be added.

Risk-Adjusted Market Risk Premium

Q. Please explain the derivation of the risk-adjusted equity market risk premium.

A. The risk-adjusted equity market risk premium approach to estimating the required utility equity risk premium entails estimating the equity risk premium for the equity market as a whole, and subsequently adjusting it to recognize the risk of a utility relative to the equity market portfolio.

The estimate of the expected equity market risk premium is by reference to both historic (experienced) market risk premiums and estimates of the forward-looking risk premium. In my opinion, both approaches are required to ensure that the resulting estimate is compatible with current market expectations. Moreover, analysis of historic risk premiums should not be limited to the Canadian experience.

First, Canadian investment opportunities are not limited to domestic investments. The risk premium analysis needs to recognize the increasing globalization of capital markets and the increasing proportion of Canadians' investments in foreign equity securities (particularly U.S. securities).

Second, there are factors specific to the historic Canadian risk premium which cast doubt on the very premise of reliance on historic data, i.e., that they are a proxy for investor expectations. Most important with respect to the achieved equity returns is the historical resource-orientation of the Canadian equity market. The average achieved returns on the TSE 300 are significantly impacted by the relatively poor performance of commodity-linked securities.[1]

As the Canadian equity market diversifies away from its traditional commodity focus, the past returns achieved on the TSE 300 become less indicative of investor expectations. In contrast, the historic U.S. equity

[1] The relative performance of the TSE 300 has also been negatively impacted by the performance of relatively small and illiquid stocks and the inclusion in the index of firms with less than solid financial credentials.

returns reflect a more diversified and liquid market. The diversified nature of the U.S. equity market, as well as the close relationship between the Canadian and U.S. capital markets and economies, make the U.S. equity market a relevant benchmark for estimating the equity risk premium from the perspective of Canadian investors.

With respect to the historic long Canada bond returns, the achieved averages reflect yields that exceeded those on U.S. Treasuries by close to 1%. That differential no longer exists. The structural changes that have occurred in the Canadian bond market warrant looking beyond the Canadian historic risk premiums. The recent similarity between Canadian and U.S. government bond yields lends further support to reflecting the U.S. equity risk premium experience in the estimate of the equity market risk premium.

The experienced Canadian equity risk premiums since World War II (1947-2000) have been in the range of 5.8% (compound average) to 6.5% (arithmetic average). The corresponding U.S. equity risk premiums have been in the range of 7.9-8.6%. A conservative means of combining the two is to weight the Canadian and U.S. experience by the maximum proportion of an RRSP that can be directly invested in foreign securities. Under the 2000 Federal Budget, the cap has been raised to 30% (from 20% in 1999). Giving 70% weight to the Canadian historic risk premiums and 30% weight to the U.S. risk premiums, the indicated expected equity market risk premium is in the approximate range of 6.5-7.0%, based on compound and arithmetic historic averages respectively (see Schedule VI).

Forward-looking equity risk premiums can be estimated using a discounted cash flow approach to estimating the expected return on the equity market. The dividend yield on the TSE 300 plus the consensus of investment analysts' forecasts[1] of normalized long-term (five-year) earnings growth for the TSE 300 equals the expected equity market return. The expected equity market return less the corresponding long Canada bond yield results in a measure of the forward-looking equity market risk premium. The forward-looking risk premium analysis indicates that the expected equity market return has averaged approximately 14.0% over the period 1991-2000 (Schedule VII). At a forecast long Canada yield of 5.75%, the expected market risk premium is 8.25% (14.0% - 5.75%).

A similar study for the U.S. market (S&P 500 versus long Treasury bonds) indicates an expected equity market return of approximately 15.5% (Schedule VIII), which would result in an equity market risk premium of 9.75% at a long government bond yield of 5.75%.

Applying the same weight to the Canadian and U.S. forward-looking equity market risk premiums as to those based on historic average differentials, the forward-looking equity risk premium for the market would be approximately 8.75%.

Q. Various studies of investment analysts' forecasts have concluded that the analysts' forecasts have been optimistic in comparison to actual earnings and therefore overstate the market return. How do you respond?

A. While it is acknowledged that forecasts have been optimistic and that they are not sustainable over the longer-term,[2] they provide an important independent perspective on investor expectations. First, they are the most direct measure available of what growth expectations underlie equity market prices (and thus the dividend yield) at a given point in time.

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[1] Compiled by I/B/E/S International.

[2] However, it must be recognized that as expected growth declines and the companies mature, the dividend yield component will correspondingly rise.

Second, the forward-looking estimates indicate there has not been a material change in the expected market return since the mid-1990's. The decline in the dividend yield on the TSE 300 since the early 1990's has been virtually offset by an increase in expected growth.[1] In that context, they support the proposition that expected equity returns do not move in tandem with interest rates.

Third, while experts may disagree on the extent of investor optimism, the higher forward-looking risk premiums relative to the historic values are consistent with the basic economic fundamentals that will support higher long-term sustainable growth relative to the past, primarily rising productivity and low inflation.

Q. What conclusions have you drawn with respect to the expected equity market risk premium?

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[1] Investor polls have confirmed that expectations of returns from the stock market have been in line with the return indicated by the sum of the dividend yield plus forecasts of earnings growth. To illustrate, according to a September 1998 poll, reported by the *Wall Street Journal* (12/14/98), the average annual return investors expect from stocks over the next 10 years was 16%. A late 1999 study (Ivo Welch, "Views of Financial Economists on the Equity Premium and on Professional Controversies," Anderson Graduate School of Management at UCLA, December 15, 1999), stated the following,

> "Small investor surveys tend to find equity premium expectations between 10 percent and 15 percent per year. On 10/10/97, the New York Times reports that a Montgomery Asset Management telephone survey found an expected 1-year stock market return of 22 percent. On 7/28/1999, the New York Times reports that a similar Paine-Webber survey found expected stock market returns in excess of 20 percent for both the 1-year and 10-year horizons. On 11/15/1999 the Financial Times reports a Gallup/Paine-Webber poll which found 'only' a 16 percent expected stock market return over both 1 and 10 year horizons."

The most recent monthly Gallup Poll of investor expectations (August 2000) indicated that individual investors in the U.S. expect a stock market return of 14.1% over the next ten years, compared to an average 10-year return expectation of 15.6% during 1999 and 16.3% during the first seven months of 2000.

The Globe and Mail (April 30, 2001), reporting a more recent survey, stated, "Despite the market's swoon, the average American investor still expects double-digit future annual gains, according to the study, done by Stephen Johnson, president of Northwest Survey & Data Services in Eugene, Ore. About one American in five, in fact, expects stock investments to gain more than 20 per cent in a normal year."

A. The estimated equity market risk premium is in the range of 6.5-7.5%, based on an analysis of historic Canadian/U.S. risk premiums, supplemented by direct measures of the forward-looking risk premium. The forward-looking risk premiums confirm that historic averages are likely to understate current investor expectations.

A. Please explain the adjustment to the market risk premium required for relative risk.

A. The 6.5-7.5% market risk premium needs to be adjusted for the risk of a utility relative to that of the market as a whole. The Capital Asset Pricing Model (CAPM), a variant of the equity risk premium test premised on restrictive assumptions, holds that the investor need only be compensated for systematic, or non-diversifiable, risk. In the context of the CAPM, investor risk can be captured in a single variable, the stock "beta". The stock "beta" measures risk as the volatility of an individual stock or a portfolio of stocks relative to the volatility of that of the market. The equity risk premium applicable to a particular stock or portfolio of stocks is equal to its stock "beta" multiplied by the equity market risk premium. Betas are typically measured by reference to historic relative volatility using simple regression analysis.[1]

The following table summarizes recent calculated betas for individual major Canadian electric/gas distributors as well as the TSE Gas/Electric Index.

[1] A company's calculated beta is the ratio of (1) the covariance of a stock's return with the return on the market to (2) the variance of the market return estimated using regression analysis.

TABLE 3
Canadian Utility Betas
(60 months ending in indicated year)

	1997	1998	1999	2000
Five Gas/Electric Utilities				
Average	.45	.54	.38	.24
Median	.47	.54	.36	.25
TSE 300 Gas/Electric Utility Index	.46	.55	.38	.21

Source: Schedule IX.

The observed recent decline in the measured utility betas through 1999 can be traced to the negative impact of rising interest rates on utility stock prices. Utility stock prices began to decline in February 1999. However, because the TSE 300 market portfolio continued to rise despite increasing interest rates propelled by Nortel Networks and BCE which together accounted for 28.7% of the TSE 300 by the end of 1999, the disparate movements in utility equities compared to the market portfolio produced lowered measured utility betas.[1]

The "disconnect" between utility shares and the rest of the market should not be interpreted as a change in the relative riskiness of utility shares, but rather as an indication of several weaknesses of beta as a measure of the relative return requirement. The absolute volatility of utility stocks rose significantly; over similar periods, the five year standard deviation of monthly market returns for the TSE Gas and Electric Utility Index increased by over 22% from the 1994-1998 period to the 1996-2000

[1] The 2000 utility betas estimate excluding Nortel Networks from the TSE 300 were materially higher.

CANADIAN UTILITY BETAS (Ending 2000, Excluding Nortel from TSE 300)	
Five Gas/Electric Utilities	
Average	.41
Median	.41
TSE 300 Gas/Electric Utility Index	.40

period, compared to the 15% increase in the TSE 300's standard deviation.

While the beta can often provide some insight into the trend in risk for portfolios of stocks, it is an inadequate measure for determining the required risk premium for a utility.[1]

Since utilities are interest-sensitive stocks, one would expect their price movements to be correlated not only with the stock market, but also with movements in the bond market. The interest rate sensitivity of utility shares was tested by first regressing the monthly returns of the TSE Gas/Electric Index against those of the TSE 300 over the period 1970-2000. That analysis shows the following:

Monthly TSE Gas/				(Monthly TSE
Electric Return	=	0.0058 +	0.52	300 Return)
t-statistics	=	3.23	14.34	
R^2	=	35.7%		

When the analysis is expanded to include bond returns, the following regression is produced:

			(Monthly TSE	(Monthly long Canadian
Monthly TSE Gas/			300 Return)	bond return)
Electric Return	=	0.0021 +	0.43	+ .53
t-statistics	=	1.27	12.4	9.0
R^2	=	47.4%		

[1] First, among several criticisms of the CAPM, a number of empirical studies have concluded that the theoretical intercept (the risk free rate) is too low and the slope of the security market line is too steep. These findings suggest that the CAPM would produce returns that are below the true required return for low beta utility stocks. A more recent study concluded that the relationship between beta and return has been essentially flat. Moreover, in practice betas are measured using an imperfect proxy for "the market" which fails to incorporate the whole gamut of market instruments, which includes bonds, short-term debt instruments, real estate and international securities. A particular problem in Canada is that its market is marked by a small number of utilities, several of which are relatively illiquid or thinly traded.

The R^2 in the second equation is considerably higher than in the previous equation, which means the addition of bond returns explains considerably more of the utility stock returns than the stock market returns alone. The fact that the constant is significantly closer to zero (0.0021 vs. 0.0058) and no longer statistically different from zero in the second equation confirms that the addition of bond returns (i.e., interest sensitivity) to the analysis explains a larger proportion of the total actual equity returns achieved by utilities historically. This analysis suggests that the stock market beta alone does not capture the interest sensitivity, or interest rate risk for a utility, as indicated by the fact that the volatility in the bond market adds significant explanatory power to utility returns.

The regression analysis including both stock and bond returns, assuming a market risk premium of 7.0% and a bond yield (return) of 5.75% (i.e., an annual market return of 12.75%) indicates a utility return of about 11.1%. The 11.1% utility return, in turn, implies a utility risk premium of 5.35%, which is approximately 75% of the market risk premium of 7.0%.

It is also appropriate to give some recognition to total market risk (including both diversifiable and non-diversifiable risk) as measured by the standard deviation of market returns. To estimate the relative total risk of Canadian utilities, the monthly standard deviations of total market returns for the TSE 300 and for each of the 14 major Group Indices of the TSE 300 were calculated, as well as for the Gas/Electrical Utilities sub-index of the Utilities Group Index over recent five-year periods. The standard deviations of market returns of the Gas/Electrical Utilities sub-index were then compared to those of the TSE 300, the simple average and market value-weighted average standard deviations of the 14 Group Indices. Table 4 below shows the ratios of the standard deviations of the Gas/Electrical Utilities to those of the TSE 300 and the 14 TSE 300 Group Indices.

TABLE 4 Standard Deviation of TSE Gas/Electric Utilities Sub-Index as a Percent of:			
Period	**Standard Deviation of TSE 300**	**(Simple Average) Standard Deviation of 14 TSE 300 Group Indices**	**Standard Deviation of 14 TSE 300 Group Indices (Market Value-Weighted Average)**
1993-1997	78.7%	53.8%	56.8%
1994-1998	77.6%	59.0%	59.6%
1995-1999	83.4%	61.5%	60.7%
1996-2000	81.5%	62.9%	57.7%

Source: Schedule X.

These relationships indicate an increase in the relative volatility of Canadian utility shares and provide further evidence that sole reliance on simple calculated betas would understate the required return for a regulated utility.

Based on the preceding analysis, reliance on adjusted betas – widely used in the financial community – provides a more accurate perspective of the utility risk/return relationship than the simple calculated beta. Use of such an adjustment is more consistent with relative standard deviations of market returns – which measure total market risk (both diversifiable and non-diversifiable) – and the explicit consideration of utility common equity shares' interest rate sensitivity.

On balance, the adjusted betas indicate a relative risk adjustment for an average risk, or benchmark, Canadian electric/gas utility of approximately 0.60-0.65.

Based on an adjustment of 0.60-0.65 to the required equity market risk premium of 7.0%, the required equity risk premium for a benchmark Canadian electric/gas utility at a long Canada yield of 5.75% is approximately 4.25%.

Q. What analysis have you undertaken to estimate the risk premium for utilities directly?

A. The following sections summarize that analysis.

<u>Direct Estimate of Utility Risk Premiums</u>

Direct analysis of <u>achieved</u> utility risk premiums shows that the long-term equity risk premium has been 4.75-5.25% for Canadian electric and gas utilities over the period 1956-2000, based on both arithmetic average and long-term compound returns. For U.S. electric utilities, the risk premiums were approximately 5.0-6.0% over the entire post-World War II period (1947-2000) (Schedule XI). The results for both Canadian and U.S. utilities support an equity risk premium estimate for a benchmark Canadian utility of 5.0-5.5%.

An equity risk premium test was also performed using the discounted cash flow model (DCF) to estimate expected utility returns over time. A sample of U.S. gas distributors (LDCs) was used as a proxy for a benchmark Canadian utility. U.S. utilities were used primarily due to the dearth of direct estimates of investor growth expectations for Canadian utilities; the U.S. LDCs are of similar risk to the typical low risk Canadian utility (see Schedules XIII and XVII). LDCs were used in place of electric utilities because they have undergone a lesser degree of restructuring over the past decade, which permits a more accurate portrayal of the relationship between interest rates and utility costs of equity. DCF estimates were constructed for the period 1993-2000 using monthly consensus forecasts of long-term normalized earnings growth plus the corresponding dividend yield to measure the expected utility return (Schedule XII). The average risk premium over the period was 4.3%; the corresponding average long-term government bond yield was 6.4%. A correlation between interest rates and the corresponding implied equity risk premiums (DCF cost minus bond yield) indicates that the utility equity risk premium has risen/fallen 66 basis points for every percentage point change in interest rates. At a long Canada yield of 5.75%, the required equity risk premium for a benchmark utility is approximately 4.7%.

Bare-Bones Cost of Equity

Q. What does your equity risk premium analysis indicate is the required return on equity for the typical Canadian utility?

A. On balance, the various risk premium analyses indicate that the required equity risk premium for a typical, or benchmark, Canadian utility is in the range of 4.25-4.50%. Adding a 4.25-4.50% equity risk premium to the forecast long Canada bond yield of 5.75% results in a cost of equity in the range of 10.0-10.25%. The 10.0-10.25% return on equity range is a “bare-bones” cost, which needs to be adjusted for financing flexibility.

Financing Flexibility

Q. Please explain the adjustment for financing flexibility.

A. An adjustment to the equity risk premium test result for financing flexibility is required because the measurement of the return requirement based on market data results in a "bare-bones" cost, in the sense that if this return is applied to the book equity of the rate base -- and assuming the expected return corresponds to the approved return -- the market value of the utility would be kept close to book value.

The financing flexibility allowance is an integral part of the cost of capital as well as a required component of the concept of a fair return. That allowance is intended to cover three distinct aspects: (1) flotation costs, comprising financing and market pressure costs arising at the time of the sale of new equity; (2) a margin, or cushion, for unanticipated capital market conditions; and (3) a recognition of the "fairness" principle, in the sense that regulation should not seek to keep the market value of a utility stock close to book value, when industrials of comparable investment risk have been able to consistently maintain the real value of their assets considerably above book value.

The financing flexibility adjustment recognizes that return regulation remains, fundamentally, a surrogate for competition. Competitive industrials of reasonably similar risk to utilities have consistently been able to maintain the real value of their assets significantly in excess of book value, consistent with the proposition that, under competition market value will tend to equal the replacement cost, not the book value, of assets. Utility return regulation should not seek to target the market/book ratios achieved by such industrials, but it also should not preclude utilities from achieving a level of financial integrity that gives some recognition to the longer run tendency for the market value of industrials to equate to the replacement cost of their productive capacity. This is warranted not only on grounds of fairness, but also on economic grounds, to avoid misallocation of resources. To ignore these principles in determining an appropriate financing flexibility adjustment is to ignore the basic premise of regulation.

As a Crown corporation, Hydro does not raise capital in the public equity markets; therefore it would not incur out-of-pocket equity financing and market pressure costs. However, both the cushion, or safety margin, for unanticipated capital market conditions and the fairness element are integral components of the economic cost of equity. Both should be recognized in the allowed return on equity for a regulated utility, irrespective of ownership. A recognition of these factors warrants a financing flexibility adjustment to the "bare bones" equity cost of no less than 50 basis points.

Adding a financing flexibility adjustment of 50 basis points to the 10.0-10.25% "bare-bones" cost of equity range results in a return on equity in the range of 10.5-10.75% for Hydro.

<u>DISCOUNTED CASH FLOW TEST</u>

Q. Please describe the discounted cash flow test.

A. The discounted cash flow (DCF) approach proceeds from the proposition that the price of a common stock is the present value of the future expected cash flows to the investor, discounted at a rate which reflects the riskiness of those cash flows. If the price of the security is known (can be observed), and if the expected stream of cash flows can be estimated, it is possible to approximate the investor's required return (or capitalization rate) as the rate which equates the price of the stock to the discounted value of future cash flows.

Theoretically, the cash flows extend to infinity. However, as the expected cash flows extend further into the future, their discounted value adds less and less to the price of the stock. Moreover, investors in common stocks are unlikely to forecast (or be able to forecast with any accuracy) cash flows beyond five years.

The constant growth DCF model rests on the assumption that investors expect cash flows to grow at a constant rate throughout the life of the stock. The assumption that investors expect a stock to grow at a constant rate over the longer term is most applicable to stocks in mature industries. Growth rates in these industries will vary from year to year and over the business cycle, but will tend to deviate around a long-term expected value. As a pragmatic matter, the application of a constant growth model is compatible with the likelihood that investors do not (and cannot) forecast reliably beyond five years. Hence, the current market price and dividend yield do not explicitly anticipate any changes in the outlook for growth.

The constant growth model is expressed as follows:

$$\text{Cost of Equity (k)} = \frac{D_0 (1 + g)}{P_0} + g$$

In words, the formula states that the DCF cost of equity is equal to the dividend yield plus the expected constant growth rate. The dividend yield component $D_0(1 + g)/P_0$, is equivalent to the next expected dividend divided by the recent price.

Estimation of Growth Expectations

Q. How do you estimate investor growth expectations?

A. Investor expectations of growth cannot be directly measured, they must be inferred. It is important to recognize that it is the investor's expectations that must be inferred; it is the investors who have set the market price. Even if the underlying expectations may appear unreasonable or unsustainable, i.e., seem to represent a “castle in the air view”, if these expectations are embedded in the dividend yield, these expectations must be accepted if the dividend yield and growth rate components are to be internally consistent.

Various studies have concluded that analysts’ forecasts are a better predictor of growth than naive forecasts equivalent to historic growth; moreover analysts’ forecasts have been shown to be more closely related to investors’ expectations.

Forecasts are widely available to both individual and institutional investors. Each month I/B/E/S International, Inc. releases its compilation of a consensus of analysts’ forecasts for longer-term (5-year) normalized earnings growth rates for individual companies. The I/B/E/S estimates are a standard input to DCF models for estimating the cost of equity. In principle, growth in dividends, earnings, book value and stock price, in the longer-term, should be the same. Since earnings are the fundamental driving force behind potential growth in dividends, forecasts of normalized earnings growth are a reasonable approximation for investor expectations of future dividend growth.

<u>Sample Selection</u>

Q. To what companies did you apply the DCF test?

A. The discounted cash flow test was applied to a sample of six electric utilities that serve as a proxy for an average risk Canadian electric utility. This sample includes all electrics:

(1) classified by Value Line as an electric utility;
(2) with no merger activity ongoing;
(3) with a S&P debt rating of A- or higher;

(4) with no less than 80% of assets devoted to electric utility operations;

(5) whose activities are not limited to generation; and,

(6) for which at least three analysts' growth rate forecasts are available from the I/B/E/S database.[1]

The six electric utilities are listed on Schedule XIV. The sample is of relatively similar risk to an average risk Canadian electric/gas utility (see Schedule XVII) and is thus a proxy for a benchmark Canadian electric utility.

Application of the DCF Model to U.S. Electrics

Q. Please describe your application of the DCF model.

A. The average and median I/B/E/S expectations of long-term earnings growth (December 2000) for the six selected electric utilities were 5.0% and 4.5% respectively. The dividend yields, calculated using the average of the closing prices for the three months ending December 2000 in relation to the corresponding annualized dividend paid during the quarter, were 5.4% and 5.5%, based on the sample average and the median respectively (Schedule XV).

The current dividend yield needs to be adjusted for growth expectations in order to be compatible with the constant growth model. The dividend yield component of the constant growth DCF model contains the next expected dividend as measured by the current dividend (D_0) adjusted for the longer-term growth expectation. Hence, the current dividend yield should be adjusted for expected growth to arrive at an adjusted yield. The dividend yield is adjusted by one-half of the expected growth rate to recognize that

[1] Multiple forecasts ensure that the results capture the market view, and not simply the view of a single analyst.

the individual companies raise dividends throughout the year, and, on average, at mid-year. When the adjusted dividend yield is added to the expected growth rate, the estimated required return on the current value of common equity is 10.5% and 10.8%, based on the sample average and median DCF costs respectively. The resulting cost is a “bare-bones” cost, reflecting the return investors expect to achieve on the market value of their investment. That return needs to be adjusted, at a minimum, for financing flexibility sufficient to permit a utility (notionally) to raise additional equity without impairment of the utility’s financial integrity.

Adding 50 basis points to the 10.5-10.75% bare-bones cost for financing flexibility yields a cost of equity for Hydro of 11.0-11.25%.

COMPARABLE EARNINGS TEST

Q. Please explain the conceptual basis of the comparable earnings test.

A. The comparable earnings test provides a measure of the fair return based on the concept of opportunity cost. Specifically, the test arises from the notion that capital should not be committed to a venture unless it can earn a return commensurate with that available prospectively in alternative ventures of comparable risk. Since regulation is a surrogate for competition, the opportunity cost principle entails permitting utilities the opportunity to earn a return commensurate with the levels achievable by competitive firms facing similar risk. The comparable earnings test, which measures returns in relation to book value, is consistent with the original cost rate base form of regulation.

The comparable earnings test is an implementation of the comparable earnings standard, as distinguished from the cost of attracting capital standard. The comparable earnings standard recognizes that utility costs are measured in vintaged dollars and that rates are based on accounting costs, not economic costs. In contrast, the cost of attracting capital standard relies on costs expressed in dollars of current purchasing power, i.e., a market-related cost of capital. In the absence of experienced inflation, the two concepts would be quite similar, but the impact of inflation has rendered them dissimilar and distinct.

The concept that regulation is a surrogate for competition may be interpreted to mean that the combination of an original cost rate base and a fair return should result in a value to investors commensurate with that of competitive ventures of similar risk. The fact that an original cost rate base provides a starting point for the application of a fair return does not mean that the original cost of the assets is a measure of their fair value. The comparable earnings standard, as well as the principle of fairness, suggest that, if competitive industrial firms facing similar risk to utilities are able to maintain the value of their assets considerably above book value, the return allowed to utilities should not seek to maintain the value of utility assets at book value. It is critical that the regulator recognize the comparable earnings standard in setting a just and reasonable return.

<u>Application of the Comparable Earnings Test</u>

Q. Please summarize your application of the comparable earnings test.

A. Application of the comparable earnings test first requires the selection of a group of Canadian industrials of generally similar risk to utilities. The selection should conform to investor perceptions of the risk characteristics of utilities, which are generally characterized by relative stability of earnings, dividends and market prices. These were the principal criteria for the selection of the Canadian industrial companies (from consumer-oriented industries), resulting in a sample of 17 companies.

Since industrials' returns on equity tend to be cyclical, the appropriate period for measuring industrial returns should encompass an entire business cycle, covering years of expansion and decline. That cycle should be representative of a future normal cycle, e.g., similar in terms of inflation and real economic growth. Over the past point-to-point business cycle (1991-1999), the experienced returns on equity of this sample of 17 industrials averaged approximately 12.5-12.75% (Schedule XVI).[1]

The average economic growth during this cycle was 2.5%, compared to the consensus' expected rate of growth of approximately 3.1% for the next decade (2001-2010). Prospective longer-term Canadian inflation is forecast to average 2.0% (CPI) compared to the 1991-1999 business cycle average of 1.9%. The higher expected real growth, but similar inflation relative to the past indicates that the experienced returns on book equity, absent extraordinary events, provide a conservative proxy for the future.

The conservative nature of this conclusion is supported by the increase in the level of returns achieved during the cycle, from 11.25-11.75% in 1991-1994 to 13.25-14.0% in 1995-1999. The 1991-1994 average of approximately 11.5% reflects in part the effect of the prolonged recession and restructuring. The recent average (1995-1999) returns are similar to those achieved by low risk Canadian industrials during the prior (1983-1991) business cycle.

With respect to the relative investment risk of the Canadian industrials compared to high grade utilities, the business risk of the industrials exceeds that of utilities; however, this difference is largely offset by the industrials' significantly lower financial risk resulting from higher equity ratios. The statistical data indicate that Canadian utilities have

[1] Preliminary results for 2000 raise the cycle average to a range of approximately 12.5-13.25% (see Schedule XVI).

experienced greater stability of book returns and market prices than the industrials, but the stock and bond ratings indicate that the selected sample of industrials falls in approximately the same risk class as the average (benchmark) non-diversified utility. Since the adjusted betas of the industrials and non-diversified utilities have been similar (approximately 0.62 and 0.58 respectively),[1] the industrials serve as a reasonable proxy for a fair return for a benchmark utility.

The returns of U.S. industrials offer a further perspective on the opportunity cost foregone by Canadian investors. These returns are pertinent not only because there is a relatively small number of low risk industrials in Canada but also because of the increasing globalization of markets and, specifically, the close connection between the U.S. and Canadian economies and capital markets.

The returns of a sample of 36 low risk U.S. industrials averaged approximately 17.3% over the business cycle 1991-1999. When adjusted for risk differences with the benchmark Canadian utilities, and for differential U.S./Canadian tax rates, the comparable return on equity is approximately 12.5-13.0%.

The estimate of a normal cycle average level of returns for low risk Canadian industrials is within a range of 12.5-12.75%. The risk- and tax-adjusted return for U.S. industrials is approximately 12.5-13.0%. With primary weight given to the Canadian results, the fair return applicable to a benchmark Canadian utility based on the comparable earnings test is in the range of 12.5-12.75%.

[1] Raw betas shown on Schedule XVII; Adjusted betas = (.67 x "raw beta") + (.33 x market mean beta of 1.0).

IX. FAIR RETURN ON EQUITY FOR HYDRO

Q. Please summarize the results of the three tests and provide your recommendations.

A. The results of the three tests used to estimate a reasonable return on equity for Hydro are summarized below:

Equity Risk Premium	10.5-10.75%
Discounted Cash Flow	11.0-11.25%
Comparable Earnings	12.5-12.75%

In arriving at my recommendation, I have given primary weight to the cost of attracting capital, as measured by both the equity risk premium and DCF tests, but conclude that the comparable earnings test is entitled significant weight in setting a return that balances both ratepayer and shareholder interests. Based on these results, a fair return for Hydro would be 11.0-11.5%.

Q. How does your recommendation compare to the recent allowed returns for Hydro's peers?

A. As shown on Schedule XIX, the average allowed returns on equity for investor-owned Canadian utilities in 2000 and 2001 were approximately 9.8% and 9.6% respectively. However, the recent levels of allowed returns on equity for Canadian utilities are considered by the investment community to be lower than those available on alternative investments of similar risk. By comparison, the average allowed return on equity for U.S. electric utilities, with which Canadian utilities compete for capital in global markets, was 11.4% in 2000 rising to over 12% in the fourth quarter

("Major Rate Case Decisions, January 1990-December 2000, Regulatory Research Associates, Inc., *Regulatory Focus*, January 2001).

Q. If Hydro should, in principle, be permitted the opportunity to earn a return on equity commensurate with those achievable by firms of similar risk, why is the Corporation applying for a return that is significantly lower than the true opportunity cost?

A. Hydro is concerned with minimizing the requested rate increase for 2002, and is therefore willing to earn a less than compensatory return in the short-term in order to help minimize the rate increase.

Q. Since Hydro is moving to rate base/rate of return regulation, is interest coverage still an important financial indicator in setting the allowed return?

A. Yes. The standards of a reasonable return include providing a utility the opportunity to maintain its financial integrity and to attract capital on reasonable terms. These standards entail maintaining adequate financial parameters, which include interest coverage.

Q. Please provide some perspective on the level of the forecast test year interest coverage for Hydro compared to its peers'.

A. The recent average interest coverage ratio reported by DBRS, which serves as a benchmark, for publicly-owned utilities is 1.6 times (see Schedule XX). That interest coverage ratio compares to a pre-tax interest coverage ratio of approximately 2.5-3.0 times for Canadian investor-owned electrics (see Schedule XXI). The higher interest coverage ratios achieved by investor-owned utilities are, in part, a function of the fact that investor-owned utilities pay corporate income taxes (at a typical statutory rate of close to 45%).

Q. What approximate level of utility interest coverage ratio is indicated at your recommended stand-alone target capital structure and an allowed return on equity for Hydro commensurate with that recently allowed other Canadian utilities?

A. Approximately 1.8 times, at Hydro's embedded debt cost of 8.35% (including the guarantee fee). The interest coverage ratio can be approximated as follows:

	PROPORTION	COST	WEIGHTED COST
Debt	60%	8.35%	5.0%
Equity	40%	9.75%	3.9%
Return on Rate Base			8.9%

Interest Coverage = Return on Rate Base ÷ Weighted Cost of Debt

8.9% ÷ 5.0% = 1.8 times.

An interest coverage ratio for Hydro of 1.8 times would be comparable to a pre-tax interest coverage ratio of 2.3 times for an investor-owned utility paying corporate income tax at a 45% statutory tax rate.

X. RETURN ON RATE BASE

Q. What is the Corporation's requested return on rate base?

A. The requested return on rate base is 7.40%,[1] which is equal to its weighted average cost of capital[2] based on the following:

[1] The effective return on rate base requested is 7.35%, because Hydro is not seeking to earn an equity return on the Rural portion of rate base, which accounts for approximately 10% of forecast total rate base.

[2] In principle, the weighted average cost of capital should reflect the Corporation's true cost of equity. Since Hydro is only requesting a return on equity of 3%, the 3% equity return is substituted for the cost of equity in the calculation.

TABLE 5 WEIGHTED AVERAGE COST OF CAPITAL			
	PROPORTION	**COST RATE**	**WEIGHTED COST**
Debt	83.18%	8.35%	6.94%
Liability for Employee Future Benefits	1.55%	0.00%	0.00%
Equity	15.27%	3.00%	0.46%
			7.40%

Q. The Board has traditionally expressed the allowed return on rate base in terms of a range. Is such a range appropriate for Hydro?

A. No, not under present circumstances. The function of the return on rate base range is to determine whether a utility has over- or under-earned a reasonable return on rate base. If the utility exceeds the upper end of the range, it is deemed to have over-earned, and is obligated to refund the excess to customers. If the utility's return falls short of the lower end of the range, it has the ability to seek rate relief from the Board. For Newfoundland Power, the range in the return on rate base adopted by the Board in Order No. P.U. 36 (1998-1999) was 36 basis points.

The usefulness of such a range as a guide to over- or under-earnings is premised on the setting of an allowed return on rate base which reflects the utility's true cost of capital. Since Hydro is only seeking to earn a return on equity of 3%, the requested return on rate base understates its true cost of capital.

Based on my conclusion that a fair rate of return on equity for Hydro would be approximately 11.25%, the corresponding weighted average cost of capital and return on rate base using the forecast capital structure and debt cost would be approximately 8.6%. Since Hydro is requesting a return on rate base of only 7.40%, it would not be reasonable to conclude that Hydro's actual return on rate base would be required to fall short of an already inadequate return before it could again bring an application for a rate increase to the Board. By the same token, since Hydro is requesting, in the short-term, a return on rate base which does not fully reflect its weighted average cost of capital, it would be unreasonable to conclude that an achieved return on rate base of, illustratively, 25 basis points above its requested return on rate base would constitute excess earnings.

For Hydro's 2002 test year, a range for the rate of return on rate base would only be relevant if the Board decided to make a determination of an appropriate capital structure, return on equity and return on rate base (independent of the corresponding values actually approved to set test year rates). Nevertheless, that range would be essentially irrelevant since the probability that Hydro's 2002 return would approach the bottom end of a reasonable range is minimal.

Q. Does this conclude your evidence?

A. Yes.

APPENDIX A

QUALIFICATIONS OF KATHLEEN C. McSHANE

Kathleen McShane is a Senior Vice President and senior consultant with Foster Associates, Inc., where she has been employed since 1981. She holds an M.B.A. degree in Finance from the University of Florida, and M.A. and B.A. degrees from the University of Rhode Island. She is also a Chartered Financial Analyst.

Ms. McShane worked for the University of Florida and its Public Utility Research Center, functioning as a research and teaching assistant, before joining Foster Associates. She taught both undergraduate and graduate classes in financial management and assisted in the preparation of a financial management textbook.

At Foster Associates, Ms. McShane has worked in the areas of financial analysis, energy economics and cost allocation. Ms. McShane has presented testimony in more than 100 proceedings on rate of return and capital structure before federal, state, provincial and territorial regulatory boards, on behalf of U.S. and Canadian telephone companies, gas pipelines and distributors, and electric utilities. These studies include the assessment of the impact of competition, rate design, contractual arrangements, and capital structure on return requirements. Ms. McShane has also provided consulting services for numerous U.S. and Canadian companies on financial and regulatory issues, including financing, dividend policy, corporate structure, cost of capital, automatic adjustments for return on equity, and form of regulation (including performance-based regulation).

Ms. McShane was principal author of a study on the applicability of alternative incentive regulation proposals to Canadian gas pipelines. She was instrumental in the design and preparation of a study of the profitability of 25 major U.S. gas pipelines, in which she developed estimates of rate base, capital structure, profit margins, unit costs of providing services, and various measures of return on investment. In a study prepared for the Canadian Ministry of Energy, Ms. McShane analyzed Federal regulation of U.S. pipelines, including trends in rate design and rate structures. Ms. McShane has also co-managed market demand studies, focusing on demand for Canadian gas in U.S. markets. Other studies performed by

Ms. McShane include a comparison of municipal and privately owned gas utilities, an analysis of the appropriate capitalization and financing for a new gas pipeline, risk/return analyses of proposed water and gas distribution companies and an independent power project, pros and cons of performance-based regulation, and a study on pricing of a competitive product for the U.S. Postal Service. She has also conducted seminars on cost of capital for regulated utilities, with focus on the Canadian regulatory arena.

Publications and Papers

- "Marketing Canadian Natural Gas in the U.S.", (co-authored with Dr. William G. Foster), published by the IAEE in Proceedings: Fifth Annual North American Meeting, 1983.

- "Canadian Gas Exports: Impact of Competitive Pricing on Demand", (co-authored with Dr. William G. Foster), presented to A.G.A.'s Gas Price Elasticity Seminar, February 1986.

- "Market-Oriented Sales Rates and Transportation Services of U.S. Natural Gas Distribution Companies", (co-authored with Dr. William G. Foster), published by the IAEE in Papers and Proceedings of the Eighth Annual North American Conference, May 1987.

- "Incentive Regulation: An Alternative to Assessing LDC Performance", (co-authored with Dr. William G. Foster), presented at the Natural Gas Conference, Chicago, Illinois, sponsored by The Center for Regulatory Studies, May 1993.

- "Atlanta Gas Light's Unbundling Proposal: More Unbundling Required?" presented at the 24th Annual Rate Symposium, Kansas City, Missouri, sponsored by several Commissions and Universities, April 1998.

- "The Effects of Unbundling on a Utility's Risk Profile and Rate of Return", (co-authored with Owen Edmondson, Vice President of ATCO Electric), presented at the Unbundling Rates Conference, New Orleans, Louisiana sponsored by Infocast, January 2000.

Expert Testimony/Opinions

on

Rate of Return & Capital Structure

Alberta Natural Gas	1994
Alberta Power/ATCO Electric	1989, 1991, 1993, 1995, 1998, 1999, 2000
AltaGas Utilities	2000
Ameren (Central Illinois Power & Union Electric)	2000 (3 cases)
ATCO Gas	2000
ATCO Pipelines	2000
BC Gas	1992, 1994
Bell Canada	1987, 1993
Benchmark Utility Cost of Equity (British Columbia)	1999
Canadian Western Natural Gas	1989, 1998, 1999
Centra Gas B.C.	1992, 1995, 1996
Centra Gas Ontario	1990, 1991, 1993, 1994, 1996
Consumers Gas	1988, 1989, 1991, 1992, 1993, 1994, 1995, 1996, 1997
Dow Pool A Joint Venture	1992
Edmonton Water/EPCOR Water Services	1994, 2000
Enbridge Gas New Brunswick	2000
Foothills Pipe Lines	1993
Gas Company of Hawaii	2000
Gaz Metropolitain	1988
Gazifère	1993, 1994, 1995, 1996, 1997, 1998
HydroOne/Ontario Hydro Services Corp.	1999, 2000
Laclede Gas Company	1998, 1999
Maritimes NRG (Nova Scotia) and (New Brunswick)	1999
Multi-Pipeline Cost of Capital Hearing (National Energy Board)	1994

Natural Resource Gas	1994, 1997
Northwestel, Inc.	2000
Newfoundland Power	1998
Newfoundland Telephone	1992
Northwestern Utilities	1987, 1990
Northwest Territories Power Corp.	1990, 1992, 1993, 1995
Ozark Gas Transmission	2000
Pacific Northern Gas	1990, 1991, 1994, 1997, 1999
St. Lawrence Gas	1997
Southern Union Gas	1990, 1991, 1993
Stentor	1997
Tecumseh Gas Storage	1989, 1990
TransCanada PipeLines	1988, 1989, 1991 (2 cases), 1992, 1993
TransGas and SaskEnergy LDC	1995
Trans Québec & Maritimes Pipeline	1987
Union Gas	1988, 1989, 1990, 1992, 1994, 1996, 1998
Westcoast Energy	1989, 1990, 1992 (2 cases), 1993
West Kootenay Power	1995, 1999
Yukon Electrical Co. Ltd./Yukon Energy	1991, 1993

Expert Testimony/Opinions

On

Other Issues

Client	Issue	Date
Gaz Metro/ Province of Quebec	Cost Allocation/ Incremental vs. Rolled-In Tolling	1984
Canadian Western Natural Gas	Cash Working Capital/ Compounding Effect	1989
Maritime Electric	Form of Regulation	1995
Enbridge Consumers Gas	Principles of Cost Allocation	1997
Enbridge Consumers Gas	Unbundling/Regulatory Compact	1998
Gazifère Inc.	Cash Working Capital	2000
Maritime Electric	Subsidies	2000

LIST OF SCHEDULES

List of Schedules (cont'd)

Section B – Financial Ratios

Table 9 (a) % Debt (1) in the Capital Structure

Government Owned	1999	1998	1997	1996	1995	1994	1993	1992
B.C. Hydro	83.5%	85.2%	85.3%	86.1%	87.0%	87.5%	87.1%	85.8%
EPCOR Power	55.6%	57.3%	61.6%	63.8%	67.5%	71.5%	74.6%	72.4%
Saskatchewan Power	56.4%	58.9%	61.0%	64.3%	67.2%	67.8%	68.9%	68.6%
Manitoba Hydro	88.1%	89.5%	90.8%	92.4%	93.8%	95.0%	96.1%	96.9%
Ontario Hydro	-	111.3%	117.1%	92.6%	87.9%	89.9%	91.4%	83.7%
Ontario Power Generation	38.7%	-	-	-	-	-	-	-
Hydro One	54.6%	-	-	-	-	-	-	-
Hydro-Quebec	73.8%	75.0%	74.8%	75.6%	76.6%	76.5%	76.1%	76.3%
N.B. Power	99.4%	99.9%	88.6%	88.3%	88.0%	88.0%	88.4%	88.3%
Nfld. & Lab. Hydro	63.1%	65.2%	68.1%	69.4%	70.1%	70.3%	69.6%	71.2%
Churchill Falls	49.4%	53.8%	55.2%	56.4%	58.1%	55.5%	57.1%	58.7%
Group Average	*70.3%*	*86.0%*	*87.2%*	*82.3%*	*81.8%*	*82.7%*	*83.5%*	*80.8%*
Investor Owned								
West Kootenay	59.1%	61.3%	59.1%	58.9%	56.8%	58.2%	51.3%	48.8%
ATCO Electric	53.2%	55.2%	58.7%	60.8%	63.8%	66.8%	62.7%	62.5%
TransAlta Utilities	51.7%	48.1%	49.6%	47.9%	52.9%	50.0%	50.3%	44.7%
Northern Ontario Power	34.6%	34.6%	32.8%	32.4%	61.5%	61.6%	62.5%	41.1%
Nova Scotia Power	65.8%	67.2%	68.8%	69.0%	68.7%	69.2%	69.5%	68.2%
Group Average	*55.4%*	*55.2%*	*56.9%*	*56.5%*	*60.9%*	*60.5%*	*59.4%*	*55.6%*
Cdn Industry Average	69.1%	83.8%	84.9%	80.5%	80.4%	81.2%	81.7%	79.1%

(1) Includes all debt equivalents, net of sinking fund assets.

Most utilities are slowly improving debt proportions, as there are generally no large expansion projects, and excess cash flow pays down debt. Several government-owned utilities have debt levels above 80%, which results in weak coverage and finance ratios. Private utilities are in the 50%-65% range, which explains their better financial ratios. We expect this trend to continue in the future, with limited new projects and good cash flow helping to allow a debt pay-down, provided that they limit future dividends.

CAPITAL STRUCTURE RATIOS
OF MAJOR INVESTOR-OWNED CANADIAN ELECTRIC UTILITIES
(1999)

Company	Long-term Debt a/	Short-Term Debt	Preferred Stock Classified as Debt b/	Preferred Stock b/	Common Stock Equity c/
CU Inc.	50.0	1.0	1.6	7.5	40.0
Maritime Electric	53.9	4.3	0.0	0.0	41.8
Newfoundland Power	51.0	3.5	0.0	1.8	43.7
Nova Scotia Power	40.0	12.9	0.0	9.3	37.8
TransAlta Utilities	49.7	1.9	0.0	9.1	39.3
West Kootenay Power	59.1	0.0	0.0	0.0	40.9
Averages	**50.6**	**3.9**	**0.3**	**4.6**	**40.6**

a/ Includes current portion of long-term debt.
b/ Includes minority interest in preferred shares of subsidiary companies.
c/ Includes minority interest in common shares of subsidiary companies.

Source: Annual Reports to Stockholders.

CAPSTR1

DEBT AND COMMON STOCK QUALITY RATINGS
OF MAJOR INVESTOR-OWNED CANADIAN ELECTRIC UTILITIES

Company	Debt Rated	DBRS Bond Rating	CBRS Bond Rating	CBS Stock Ranking
CU Inc.	Debentures	A(high)	AA-	Very conservative
Maritime Electric	First Mortgage Bonds	NR	BBB+	NR
Newfoundland Power	First Mtge. S.F. Bonds	A	A-	Conservative
Nova Scotia Power	Debentures	A(low)	A	Conservative
TransAlta Utilities	Secured S.F. Debentures	A(high)	A+	Conservative
West Kootenay Power	Secured Debentures	BBB(high)	NR	NR

Note: Debt ratings are for utility; Stock rankings are for parent.

Source: DBRS Bond RatingS, Canadian Bond Rating Service, The Blue Book of CBS Stock Reports.

RATE

DEBT RATINGS, BUSINESS RISK RANK, AND DEBT RATIO
FOR U.S. INVESTOR-OWNED ELECTRIC UTILITIES

	S & P Rating	Business Risk Rank	99 Debt Ratio
Florida Power & Light Co.	AA-	4	31.4
Indianapolis Power & Light	AA-	4	44.6
Madison Gas & Electric Co.	AA	5	48.6
Otter Tail Power Co.	AA-	5	39.5
San Diego Gas & Electric Co.	AA-	5	40.3
Wisconsin Electric Power Co.	AA-	4	50.8
Wisconsin Power & Light Co.	AA-	4	47.5
Wisconsin Public Service Corp.	AA+	4	42.4
Average (AA Rated)		**4**	**43.1**
Allegheny Generating Co.	A+	5	54.8
Baltimore Gas & Electric Co.	A+	4	48.3
Central Illinois Public Service Co.	A+	3	51.8
Consolidated Edison Co. of N.Y.	A+	4	51.9
Idaho Power Co.	A+	3	52.7
IES Utilities Inc.	A+	5	54.5
Interstate Power Co.	A+	5	44.6
Massachusetts Electric Co.	A+	3	44.5
Monongahala Power Co.	A+	4	44.6
Narragansett Electric Co.	A+	3	38.5
New England Power Co.	A+	4	55.1
Northwestern Corp.	A+	6	52.5
Oklahoma Gas & Electric Co.	A+	4	57.8
Orange & Rockland Utilities Inc.	A+	4	54.7
Potomac Edison Co.	A+	3	42.0
Union Electric Co.	A+	4	40.8
West Penn Power Co.	A+	3	69.8
Alabama Power Co.	A	4	48.1
Black Hills Corp.	A	6	54.5
Delmarva Power & Light Co.	A	5	55.7
Georgia Power Co.	A	4	42.3
Gulf Power Co.	A	4	45.2
Jersey Central Power & Light Co.	A	3	43.6
Metropolitan Edison Co.	A	3	47.6
Mid American Energy Co.	A	4	46.4
Mississippi Power Co.	A	4	47.2
Northern States Power Wisconsin	A	4	46.7
Pennsylvania Electric Co.	A	3	47.7
Portland General Electric Co.	A	4	48.3
Potomac Electric Power Co.	A	5	60.2
Savannah Electric & Power Co.	A	4	45.9
South Carolina Electric & Gas Co.	A	4	45.9
Southern Indiana Gas & Electric Co.	A	5	42.1
Tampa Electric Co.	A	4	50.1
Virginia Electric & Power	A	4	49.5
Appalachian Power Co.	A-	4	60.1
Atlantic City Electric Co.	A-	6	56.9
Boston Edison Co.	A-	3	49.0
Cambridge Electric Light Co.	A-	3	21.1
Central Power & Light Co.	A-	4	54.3
Cincinnati Gas & Electric Co.	A-	4	47.2
Columbus Southern Power Co.	A-	4	52.3
Commonwealth Edison Co.	A-	4	45.9
Commonwealth Electric Co.	A-	3	29.9
Empire District Electric Co.	A-	5	59.6
Indiana Michigan Power Co.	A-	4	60.2

DEBT RATINGS, BUSINESS RISK RANK, AND DEBT RATIO
FOR U.S. INVESTOR-OWNED ELECTRIC UTILITIES

	S & P Rating	Business Risk Rank	99 Debt Ratio
Kansas City Power & Light Co.	A-	6	50.0
Kentucky Power Co.	A-	4	59.5
Ohio Power Co.	A-	4	49.7
PECO Energy Co.	A-	4	52.4
PP&L Electric Utilities Corp.	A-	5	44.5
PSI Energy Inc.	A-	4	56.8
Public Service Co. of Colorado	A-	5	53.1
Public Service Co. of Oklahoma	A-	4	45.3
Public Service Electric & Gas Co.	A-	7	54.0
Rochester Gas & Electric Corp.	A-	5	46.7
Southwestern Electric Power Co.	A-	4	46.6
Southwestern Public Service Co.	A-	4	47.6
St. Joseph Light & Power Co.	A-	6	48.9
West Texas Utilities Co.	A-	4	55.8
Average (A rated)		**4**	**49.6**
Arizona Public Service Co.	BBB+	6	52.0
Avista Corp.	BBB	6	60.7
Carolina Power & Light Co.	BBB+	5	49.4
Cleco Corp.	BBB+	6	60.8
Dayton Power & Light Co.	BBB+	4	37.3
Detroit Edison	BBB+	6	52.6
Duquesne Light Co.	BBB+	6	65.6
Entergy Arkansas Inc.	BBB	6	63.6
Entergy Louisiana Inc.	BBB	7	49.3
Entergy Mississippi Inc.	BBB	7	49.4
Entergy New Orleans Inc.	BBB	7	53.3
Florida Power Corp.	BBB+	4	47.1
Hawaiian Electric Co.	BBB+	6	44.5
Illinois Power Co.	BBB+	6	57.0
Kentucky Utilities Co.	BBB+	4	44.7
Louisville Gas & Electric Co.	BBB+	4	49.0
Minnesota Power Inc.	BBB+	7	47.0
Montana Power Co.	BBB+	6	37.5
Northern Indiana Public Service Co.	BBB	5	50.7
Puget Sound Energy Inc.	BBB+	4	60.3
Reliant Energy	BBB+	6	67.0
Sierra Pacific Power Co.	BBB+	5	52.0
Texas Utilities Electric Co.	BBB+	5	41.9
United Illuminating Co.	BBB+	5	53.2
UtiliCorp United Inc.	BBB	6	56.1
Average (BBB rated)		**6**	**52.1**
Average (all U.S. Electrics)		**5**	**49.7**

Source: Standard & Poor's Global Sector Review, various issues.

GSRELROE

TREND IN INTEREST RATES AND OUTSTANDING BOND YIELDS
(Percent Per Annum)

	Prime Rate		Government Securities: 3-Month Bills		Government Securities: 10-Year Bonds		Government Securities: 30-Year Bonds		Government Securities: Canadian Long-term	Canadian Inflation	Exchange Rates (Canadian dollars
Year	**Canadian**	**U.S.**	**Canadian**	**U.S. a/**	**Canadian**	**U.S.**	**Canadian**	**U.S. b/**	**Bonds c/**	**Indexed Bonds**	**in U.S. funds)**
1976	10.08	6.84	8.87	5.00		7.61		7.86	9.18		1.01
1977	8.50	6.83	7.33	5.26		7.42		7.67	8.70		0.94
1978	9.69	9.06	8.68	7.22		8.41		8.49	9.28		0.88
1979	12.92	12.67	11.68	10.04		9.44		9.29	10.21		0.85
1980	14.27	15.27	12.80	11.51		11.46		11.30	12.48		0.86
1981	19.29	18.87	17.72	14.08		13.91		13.44	15.22		0.83
1982	15.79	14.86	13.62	10.69		13.00		12.76	14.26		0.81
1983	11.16	10.79	9.32	8.63		11.10		11.18	11.79		0.81
1984	12.10	12.04	11.06	9.58		12.44		12.39	12.75		0.77
1985	10.58	9.93	9.43	7.49		10.62		10.79	11.04		0.73
1986	10.56	8.33	8.97	5.97		7.68		7.80	9.52		0.72
1987	9.55	8.22	8.15	5.82		8.39		8.59	9.95		0.75
1988	10.83	9.32	9.48	6.69		8.85		8.96	10.24		0.81
1989	13.33	10.87	12.04	8.12		8.49		8.45	9.92		0.84
1990	14.06	10.01	12.80	7.51	10.76	8.55	10.69	8.61	10.85		0.86
1991	9.94	8.46	8.73	5.42	9.42	7.86	9.72	8.14	9.76		0.87
1992	7.48	6.25	6.59	3.45	8.05	7.01	8.68	7.67	8.77	4.62	0.83
1993	5.94	6.00	4.84	3.02	7.22	5.87	7.86	6.59	7.85	4.28	0.77
1994	6.88	7.23	5.54	4.34	8.43	7.08	8.69	7.37	8.63	4.41	0.73
1995	8.65	8.81	6.89	5.44	8.08	6.58	8.41	6.88	8.28	4.68	0.73
1996	6.06	8.27	4.21	5.04	7.20	6.44	7.75	6.73	7.50	4.61	0.73
1997	4.96	5.44	3.26	5.11	6.11	6.32	6.66	6.58	6.42	4.14	0.72
1998	6.60	8.31	4.73	4.79	5.30	5.26	5.59	5.54	5.47	4.02	0.67
1999	6.44	8.02	4.69	4.70	5.55	5.69	5.72	5.91	5.69	4.07	0.67
2000	7.27	9.27	5.45	5.85	5.89	5.98	5.71	5.91	5.89	3.69	0.67
2000 Jan	6.50	8.50	5.05	5.39	6.44	6.68	6.27	6.57	6.36	4.02	0.69
Feb	6.75	8.75	4.96	5.67	6.19	6.38	5.83	6.13	5.98	3.92	0.69
Mar	7.00	9.00	5.27	5.70	6.03	6.13	5.84	5.94	5.96	3.80	0.69
Apr	7.00	9.00	5.43	5.62	6.10	6.15	5.92	5.95	6.03	3.64	0.68
May	7.50	9.50	5.67	5.73	6.00	6.42	5.63	6.14	5.94	3.81	0.67
Jun	7.50	9.50	5.53	5.68	5.93	6.08	5.61	5.94	5.90	3.77	0.68
July	7.50	9.50	5.61	6.01	5.86	6.04	5.53	5.80	5.83	3.65	0.68
Aug	7.50	9.50	5.58	6.11	5.77	5.75	5.55	5.69	5.79	3.67	0.67
Sep	7.50	9.50	5.56	6.03	5.75	5.82	5.67	5.89	5.84	3.60	0.66
Oct	7.50	9.50	5.61	6.18	5.72	5.74	5.61	5.80	5.79	3.52	0.65
Nov	7.50	9.50	5.62	6.21	5.54	5.48	5.51	5.60	5.63	3.51	0.65
Dec	7.50	9.50	5.49	5.89	5.35	5.12	5.56	5.46	5.59	3.42	0.65
2001 Jan	7.25	9.00	5.24	4.99	5.46	5.19	5.73	5.54	5.71	3.37	0.67
Feb	7.25	8.50	5.03	4.73	5.48	4.90	5.75	5.33	5.63	3.40	0.65
Mar	6.75	8.00	4.62	4.20	5.39	4.97	5.80	5.46	5.74	3.47	0.64
Apr	6.50	7.50	4.44	3.89	5.78	5.34	6.02	5.78	5.94	3.61	0.65

a/ Rates on new issues.
b/ 20-year constant maturities for 1974-1978; 30-year maturities after 1978. Series represents yields on the more actively traded issues adjusted to constant maturities by the U.S. Treasury based on daily closing bids.
c/ l0 years or more.
Note: Monthly data reflect rate in effect at end of month.
Source: Bank of Canada Review; CBRS; Globe and Mail; Annual Statistical Digest (Federal Reserve System); Federal Reserve Bulletin (various issues).

TREND IN INTEREST RATES AND OUTSTANDING BOND YIELDS
(Percent Per Annum)

		CBRS Utilities [a/]		CBRS Provincials [b/]	
Year		**A**	**BBB**	**A**	**BBB**
1976		10.61	10.78	N/A	N/A
1977		9.95	10.16	N/A	N/A
1978		10.16	10.35	N/A	N/A
1979		11.08	11.14	N/A	N/A
1980		13.46	13.43	N/A	N/A
1981		16.26	16.41	N/A	N/A
1982		15.84	16.13	N/A	N/A
1983		12.85	12.79	N/A	N/A
1984		13.56	13.55	N/A	N/A
1985		11.71	11.84	N/A	N/A
1986		10.42	10.72	N/A	N/A
1987		11.00	11.26	N/A	N/A
1988		11.20	11.46	N/A	N/A
1989		11.05	11.32	N/A	N/A
1990		12.13	12.37	N/A	N/A
1991		11.00	11.10	N/A	N/A
1992		10.01	10.08	N/A	N/A
1993		9.08	9.38	N/A	N/A
1994		9.81	10.39	N/A	N/A
1995		9.29	10.13	8.77	9.03
1996		8.10	8.26	7.89	8.05
1997		6.94	7.15	6.81	6.84
1998		6.16	6.30	5.86	5.96
1999		6.64	6.72	6.18	6.31
1999	Jan	6.04	6.11	5.60	5.76
	Feb	6.29	6.38	5.90	6.05
	Mar	6.13	6.23	5.71	5.85
	Apr	6.20	6.34	5.75	5.90
	May	6.31	6.48	5.93	6.06
	Jun	6.51	6.66	6.06	6.20
	Jul	6.78	6.86	6.33	6.48
	Aug	6.85	6.89	6.41	6.55
	Sep	6.89	6.92	6.36	6.50
	Oct	7.15	7.18	6.60	6.74
	Nov	7.24	7.26	6.69	6.80
	Dec	7.29	7.31	6.78	6.88
2000	Jan	7.44	7.46	6.89	6.99
	Feb	6.93	6.95	6.47	6.57
	Mar	6.58	6.69	6.39	6.49
	Apr	7.10	N/A	6.60	6.70
	May	7.09	N/A	6.47	6.55
	Jun	6.95	N/A	6.29	6.38
	Jul	6.93	N/A	6.29	6.38
	Aug	6.85	N/A	6.16	6.25
	Sep	7.02	N/A	6.30	6.39

a/ Reflect the long-term index through 1995 and the average of yields of 10-, 20-, and 30-year indices beginning in 1996.
b/ Reflect the average of yields of 10-, 20-, and 30-year indices.
Note: Monthly data reflect rate in effect at end of month.
CBRS discontinued publishing utility and provincial bond yields in September 2000.
Source: CBRS

SCHEDULE VI
K. C. McShane

CANADIAN AND U.S. POST-WWII HISTORIC EQUITY
RISK PREMIUMS

Holding Period	Stock Return	Bond Return	Risk Premium
Canada (1947-2000)			
1-year	13.1	6.6	6.5
5-years	11.5	6.6	4.9
10-years	10.9	6.5	4.4
Compound	11.9	6.1	5.8
U.S. (1947-2000)			
1-year	14.3	5.7	8.6
5-years	13.2	5.8	7.4
10-years	12.3	5.8	6.5
Compound	13.1	5.2	7.9
Canada/U.S. Average[1/] (1947-2000)			
1-year	13.7	6.8	6.9
5-years	12.4	6.6	5.8
10-years	11.6	6.5	5.1
Compound	12.7	6.3	6.4

1/ Candian stock and bond returns were given 70% weight;
U.S. stock and bond returns, adjusted for the impact of
annual exchange rate changes, were given 30% weight.

HISTRP

TSE 300
DCF-BASED MARKET RISK PREMIUM STUDY
(Quarterly Averages of Monthly Data)

	TSE Growth	TSE Dividend Yield 1/	DCF Cost of Equity	Long Canada Yield	Equity Risk Premium
1991 1Q	11.3 %	3.8 %	15.1 %	10.0 %	5.2 %
2Q	11.0	3.6	14.6	10.1	4.6
3Q	11.0	3.5	14.5	9.9	4.6
4Q	11.0	3.4	14.4	9.1	5.3
1992 1Q	11.0	3.3	14.3	9.1	5.3
2Q	10.0	3.4	13.4	9.2	4.2
3Q	10.0	3.3	13.3	8.3	4.9
4Q	9.7	3.2	12.9	8.5	4.4
1993 1Q	10.0	3.1	13.1	8.4	4.7
2Q	10.3	2.7	13.0	8.1	4.9
3Q	10.3	2.6	12.9	7.6	5.3
4Q	10.7	2.4	13.1	7.3	5.8
1994 1Q	12.0	2.3	14.3	7.5	6.8
2Q	12.0	2.5	14.5	8.7	5.8
3Q	12.0	2.4	14.4	9.1	5.3
4Q	12.0	2.5	14.5	9.2	5.3
1995 1Q	12.0	2.6	14.6	9.0	5.6
2Q	11.0	2.5	13.5	8.2	5.3
3Q	11.0	2.4	13.4	8.3	5.1
4Q	11.0	2.4	13.4	7.7	5.8
1996 1Q	11.0	2.3	13.3	7.7	5.6
2Q	11.0	2.2	13.2	8.0	5.2
3Q	11.7	2.2	13.9	7.6	6.2
4Q	11.7	1.9	13.6	6.7	6.9
1997 1Q	11.7	1.9	13.5	6.9	6.6
2Q	12.0	1.8	13.8	6.8	7.0
3Q	11.7	1.7	13.3	6.2	7.2
4Q	12.0	1.7	13.7	5.8	7.9
1998 1Q	12.7	1.6	14.3	5.6	8.7
2Q	13.0	1.5	14.5	5.5	9.0
3Q	13.0	1.9	14.9	5.5	9.5
4Q	13.0	1.8	14.8	5.3	9.5
1999 1Q	13.0	1.7	14.7	5.2	9.5
2Q	13.0	1.6	14.6	5.5	9.1
3Q	13.0	1.6	14.6	5.8	8.8
4Q	12.7	1.5	14.2	6.3	7.9
2000 1Q	13.0	1.3	14.3	6.1	8.2
2Q	13.0	1.2	14.2	6.0	8.3
3Q	13.7	1.1	14.8	5.8	8.9
4Q	14.0	1.2	15.2	5.6	9.6
Averages					
1991-2000	**11.7**	**2.3**	**14.0**	**7.4**	**6.6**
1996-2000	**12.5**	**1.7**	**14.2**	**6.2**	**8.0**
1998-2000	**13.1**	**1.5**	**14.6**	**5.7**	**8.9**

1/ Dividend Yield is adjusted for half of growth.

Source: I/B/E/S Rewind, Standard & Poor's Research Insight, Bank of Canada Review.

TSEMRP

S&P 500
DCF-BASED MARKET RISK PREMIUM STUDY
(Quarterly Averages of Monthly Data)

	S&P 500 Growth	Dividend Yield 1/	DCF Cost	Long Treasury Bond Yield	Risk Premium
1991 1Q	11.8 %	3.2 %	15.0 %	8.2 %	6.8 %
2Q	11.9	3.7	15.5	8.3	7.2
3Q	11.9	3.3	15.2	8.2	7.0
4Q	11.9	3.2	15.2	7.9	7.3
1992 1Q	12.1	3.0	15.2	7.8	7.4
2Q	12.0	3.4	15.4	7.9	7.5
3Q	12.0	3.2	15.2	7.4	7.7
4Q	12.0	2.9	15.0	7.5	7.4
1993 1Q	11.8	3.0	14.8	7.0	7.8
2Q	11.5	3.1	14.6	6.9	7.7
3Q	11.3	3.0	14.3	6.3	8.0
4Q	11.3	2.7	14.0	6.2	7.8
1994 1Q	11.4	2.8	14.2	6.7	7.4
2Q	11.5	3.2	14.7	7.3	7.4
3Q	11.6	3.0	14.6	7.6	7.0
4Q	11.6	3.0	14.6	7.9	6.6
1995 1Q	11.5	2.8	14.3	7.6	6.7
2Q	11.6	2.9	14.5	6.9	7.6
3Q	11.9	2.6	14.5	6.7	7.8
4Q	12.0	2.5	14.5	6.2	8.3
1996 1Q	11.9	2.3	14.2	6.4	7.9
2Q	12.3	2.3	14.7	7.0	7.7
3Q	12.5	2.5	15.1	7.0	8.1
4Q	12.8	2.1	15.0	6.6	8.4
1997 1Q	13.0	1.9	14.9	6.9	8.0
2Q	13.3	1.9	15.2	6.9	8.3
3Q	13.7	1.7	15.4	6.5	9.0
4Q	13.6	1.7	15.3	6.1	9.2
1998 1Q	13.7	1.5	15.3	5.9	9.3
2Q	14.0	1.5	15.5	5.9	9.7
3Q	14.4	1.7	16.1	5.3	10.8
4Q	14.6	1.4	16.0	5.2	10.9
1999 1Q	15.7	1.4	17.0	5.5	11.6
2Q	15.7	1.3	17.0	5.8	11.2
3Q	16.0	1.4	17.4	6.1	11.3
4Q	16.9	1.2	18.1	6.4	11.7
2000 1Q	17.7	1.2	18.9	6.2	12.7
2Q	17.9	1.3	19.2	6.0	13.2
3Q	18.6	1.2	19.8	5.8	14.0
4Q	17.9	1.2	19.1	5.7	13.4
Averages					
1991 - 2000	**13.3**	**2.3**	**15.6**	**6.7**	**8.9**
1996 - 2000	**14.8**	**1.6**	**16.5**	**6.1**	**10.3**
1998 - 2000	**16.1**	**1.4**	**17.5**	**5.8**	**11.6**

1/ Dividend Yield is adjusted for half of IBES growth.

Source: I/B/E/S Rewind, Standard & Poor's Research Insight

SPMRP

SCHEDULE IX
K. C. McShane

BETAS FOR CANADIAN GAS AND ELECTRIC UTILITIES

RAW BETAS
FIVE YEAR PERIOD ENDING

COMPANY	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Electric and Gas Distributors													
BC Gas	0.52	0.54	0.52	0.49	0.41	0.41	0.53	0.59	0.54	0.47	0.48	0.36	0.25
Canadian Utilities	0.39	0.42	0.41	0.38	0.45	0.45	0.54	0.48	0.55	0.63	0.62	0.54	0.38
Emera	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.52 [2/]	0.40	0.55	0.41	0.27
Fortis	0.36	0.32	0.26	0.29	0.41	0.36	0.44	0.51	0.37	0.30	0.49	0.33	0.23
TransAlta Utilities	0.20	0.22	0.27	0.26	0.36	0.44	0.55	0.59	0.57	0.47	0.54	0.28	0.05
Electric and Gas Distributors													
Mean	**0.30**	**0.30**	**0.29**	**0.28**	**0.33**	**0.33**	**0.41**	**0.43**	**0.41**	**0.45**	**0.54**	**0.38**	**0.24**
Median	**0.36**	**0.32**	**0.27**	**0.29**	**0.41**	**0.41**	**0.53**	**0.51**	**0.54**	**0.47**	**0.54**	**0.36**	**0.25**
TSE Gas/Electric Index	0.32	0.35	0.35	0.35	0.35	0.42	0.48	0.52	0.52	0.46	0.55	0.38	0.21

ADJUSTED BETAS 1/
FIVE YEAR PERIOD ENDING

COMPANY	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Electric and Gas Distributors													
BC Gas	0.68	0.69	0.68	0.66	0.60	0.60	0.69	0.73	0.69	0.64	0.65	0.57	0.50
Canadian Utilities	0.59	0.61	0.60	0.58	0.63	0.63	0.69	0.65	0.70	0.75	0.75	0.69	0.58
Emera	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.33	0.60	0.70	0.60	0.51
Fortis	0.57	0.54	0.50	0.52	0.60	0.57	0.62	0.67	0.58	0.53	0.66	0.55	0.48
TransAlta Utilities	0.46	0.48	0.51	0.51	0.57	0.62	0.70	0.73	0.71	0.64	0.69	0.52	0.36
Electric and Gas Distributors													
Mean	**0.46**	**0.46**	**0.46**	**0.45**	**0.48**	**0.49**	**0.54**	**0.55**	**0.60**	**0.63**	**0.69**	**0.59**	**0.49**
Median	**0.57**	**0.54**	**0.51**	**0.52**	**0.60**	**0.60**	**0.69**	**0.67**	**0.69**	**0.64**	**0.69**	**0.57**	**0.50**
TSE Gas/Electric Index	0.54	0.56	0.56	0.56	0.56	0.61	0.65	0.68	0.68	0.64	0.70	0.58	0.47

1/ Adjusted beta = "raw" beta * 67% + market beta of 1.0 * 33%.
2/ Beta is based on 51 months

Source: TSE Review.

CUBETA

**STANDARD DEVIATIONS OF MARKET RETURNS
FOR 14 GROUP INDICES OF TSE 300 AND
TSE GAS/ELECTRIC UTILITIES SUB-INDEX**

Index	1993-97		1994-98		1995-99		1996-00	
Gas/Electric Utilities	**2.8**	**%**	**3.6**	**%**	**4.0**	**%**	**4.4**	**%**
TSE 300	**3.5**		**4.7**		**4.8**		**5.4**	
14 Group Indices								
Metals/Minerals	5.3		6.6		7.6		7.9	
Gold & Precious Minerals	9.4		11.6		12.1		12.0	
Oil and Gas	5.6		6.2		7.3		8.0	
Paper/Forest Products	5.8		6.5		7.1		7.4	
Consumer Products	4.1		4.9		5.2		6.5	
Industrial Products	4.8		6.1		6.9		9.1	
Real Estate	6.7		6.3		5.9		5.9	
Trans./Enviro. Services	5.4		5.8		5.7		5.9	
Pipelines	3.7		4.2		4.5		5.7	
Utilities	3.3		5.2		6.6		7.0	
Communications & Media	3.8		4.5		4.8		5.8	
Merchandising	3.6		4.7		4.6		4.8	
Financial Services	4.4		6.1		6.2		6.6	
Conglomerates	6.7		7.3		7.2		5.3	
Simple Average	**5.2**		**6.1**		**6.5**		**7.0**	
Market Value Weighted Average	**4.9**		**6.1**		**6.6**		**7.6**	

Source: TSE Review

stdev

CANADIAN AND U.S. UTILITY HISTORIC EQUITY RISK PREMIUMS

TSE GAS/ELECTRIC INDEX
(1956-2000)

Holding Period	Stock Return	Bond Return	Risk Premium
1-year	12.8	7.5	5.3
5-years	11.4	7.8	3.6
10-years	11.1	7.7	3.4
Compound	11.8	7.0	4.8

S&P ELECTRIC INDEX
(1947-2000)

Holding Period	Stock Return	Bond Return	Risk Premium
1-year	11.6	5.7	5.9
5-years	10.7	5.8	4.9
10-years	10.5	5.8	4.7
Compound	10.3	5.2	5.1

Sources: TSE Review, Bank of Canada Review, Standard & Poor's Analysts' Handbook, Ibbotson Associates Stocks, Bonds, Bills and Infation.

ELECRP

SELECTED U.S. LOCAL NATURAL GAS DISTRIBUTION COMPANIES
DCF-BASED RISK PREMIUM STUDY
(Quarterly Averages of Monthly Data)

	Dividend Yields 1/	IBES EPS Growth Forecast	DCF Cost	U.S. Long Treasury Yield	Risk Premium	Dividend Yield/ Treasury Yield
1993 1Q	5.4	6.5	11.9	7.0	4.9	76.9
2Q	5.2	6.4	11.6	6.9	4.7	75.9
3Q	4.9	6.5	11.4	6.3	5.1	78.2
4Q	5.3	6.0	11.2	6.2	5.0	84.8
1994 1Q	5.4	5.4	10.8	6.7	4.1	80.1
2Q	5.8	5.6	11.4	7.3	4.0	78.9
3Q	6.0	5.6	11.6	7.6	4.0	79.8
4Q	6.3	5.2	11.5	7.9	3.6	79.2
1995 1Q	6.1	4.9	11.0	7.6	3.4	79.7
2Q	5.9	5.1	11.0	6.9	4.1	85.6
3Q	5.8	5.0	10.8	6.7	4.1	87.1
4Q	5.4	5.1	10.5	6.2	4.3	87.5
1996 1Q	5.3	5.2	10.5	6.4	4.1	83.3
2Q	5.3	5.2	10.5	7.0	3.6	76.2
3Q	5.2	5.3	10.5	7.0	3.5	74.1
4Q	4.9	5.4	10.3	6.6	3.7	74.2
1997 1Q	5.1	5.2	10.3	6.9	3.4	73.7
2Q	5.0	5.2	10.2	6.9	3.3	72.7
3Q	4.8	5.3	10.1	6.5	3.6	73.9
4Q	4.5	5.5	10.0	6.1	4.0	74.1
1998 1Q	4.5	5.9	10.3	5.9	4.4	75.3
2Q	4.5	5.9	10.4	5.8	4.6	77.4
3Q	4.8	6.0	10.8	5.3	5.5	89.9
4Q	4.4	5.8	10.2	5.2	5.0	84.7
1999 1Q	5.0	5.8	10.8	5.5	5.3	91.3
2Q	4.9	5.6	10.6	5.8	4.8	85.3
3Q	4.9	5.6	10.5	6.1	4.4	79.6
4Q	5.1	5.5	10.6	6.4	4.2	78.9
2000 1Q	5.8	5.4	11.3	6.3	5.0	92.5
2Q	5.7	5.3	11.0	6.0	5.0	94.6
3Q	5.3	5.7	11.1	5.8	5.3	92.2
4Q	4.8	5.7	10.5	5.6	4.9	85.7
Averages						
1993-2000	**5.2**	**5.6**	**10.8**	**6.4**	**4.3**	**81.4**
1998-2000	**5.0**	**5.7**	**10.7**	**5.8**	**4.9**	**85.6**

1/ Dividend Yield is adjusted for half of IBES growth

Note: Values reflect quarterly averages of monthly data used in the analysis.

Source: Standard & Poor's Research Insight, IBES International, Inc.,
U.S. Federal Reserve Statistical Release

VLGDDYBY

SCHEDULE XIII
K. C. McShane

INDIVIDUAL COMPANY RISK DATA FOR EIGHT U.S. LDCs

	Value Line				S & P		
Company	Safety Rank	Earnings Predictability	Financial Strength	Sept. 2000 Beta	Business Risk Rank	Debt Rating	Common Equity Ratio
AGL RESOURCES INC	2	65	B++	0.60	3	A-	42.9
ATMOS ENERGY CORP	3	45	B+	0.55	3	A-	38.4
NEW JERSEY RESOURCES	2	100	B++	0.55	2 1/	A 1/	49.4
NICOR INC	1	85	A+	0.60	3 2/	AA 1/	43.5
NORTHWEST NATURAL GAS CO	2	55	B++	0.60	3	A	46.9
PEOPLES ENERGY CORP	1	55	A	0.70	4	A+	44.0
PIEDMONT NATURAL GAS CO	2	85	B++	0.60	3	A	47.5
WGL HOLDINGS INC	1	60	A	0.60	3	AA-	48.7
Median	**2**	**60**	**B++**	**0.60**	**3**	**A**	**46.9**

Source: Standard & Poor's Research Insight; Value Line, December 2000;
Standard & Poor's Utilities and Perspectives (March 2001).

1/ For subsidiary, New Jersey Natural Gas
2/ For subsidiary, Nicor Gas Co.

LDCR

SCHEDULE XIV
K. C. McShane

INDIVIDUAL COMPANY RISK DATA FOR SIX U.S. ELECTRIC UTILITIES

	Value Line				S & P		
Company	Safety Rank	Earnings Predictability	Financial Strength	Beta	Business Risk Rank	Debt Rating	Common Equity Ratio
AMEREN CORP	1	85	A+	0.55	5	A+	49.8
IDACORP INC	2	80	B++	0.50	4	A+	42.1 1/
KANSAS CITY POWER & LIGHT	2	55	B++	0.60	6	A	40.0
NSTAR	1	85	A	0.55	4	A-	39.1 1/
POTOMAC ELECTRIC POWER	2	75	B++	0.50	5	A	35.6 1/
VECTREN CORP	2	NMF	A	NMF	4	A	33.3
Median	**2**	**80**	**A / B++**	**0.55**	**4.5**	**A**	**39.6**

Source: Standard & Poor's Research Insight; Value Line;
Standard & Poor's Utilities and Perspectives (March 2001).

1/ 1999 Common Equity Ratio

ELECR

DCF COST OF EQUITY, HISTORIC PAYOUT RATIOS, AND VALUE LINE RETURN ON EQUITY AND PAYOUT FORECASTS FOR SELECTED ELECTRIC UTILITY COMPANIES
(Percentages)

Company	October-December 2000 Dividend Yield	IBES Long-Term EPS Growth Forecast (December 2000)	DCF Cost 1/	Value Line ROE Forecast (2003-2005)	Historic Dividend Payout Ratios (1993-2000)	Value Line Dividend Payout Forecast (2003-2005)
AMEREN CORP	5.8	3.0	8.9	13.5	86.9	73.9
IDACORP INC	3.8	4.0	7.9	12.0	83.5	56.4
KANSAS CITY POWER & LIGHT	6.4	4.0	10.6	13.5	88.1	78.2
NSTAR	5.1	5.7	10.9	13.0	75.0	54.6
POTOMAC ELECTRIC POWER	7.1	5.0	12.3	12.5	92.6	35.7
VECTREN CORP	4.3	8.0	12.5	15.5	78.0 2/	46.9
Average	**5.4**	**5.0**	**10.5**	**13.3**	**84.0**	**57.6**
Median	**5.5**	**4.5**	**10.8**	**13.3**	**86.9**	**55.5**

1/ Adjusted dividend yield plus growth;
[DY*(1+(.5*Growth))] + Growth

2/ 1999-2000

Source: IBES International, Inc., Standard & Poor's Research Insight, Value Line.

EDCF

SCHEDULE XVI
K.C. McShane

RETURNS ON AVERAGE COMMON STOCK EQUITY FOR 17 LOW RISK CANADIAN INDUSTRIALS

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	Average 1991-1999	Average 1991-2000	Average 1995-2000
BOMBARDIER INC	13.8	14.4	15.1	16.2	9.3	21.0	17.1	18.6	21.6	26.9	16.3	17.4	19.1
CANADA BREAD LTD	21.1	13.9	15.6	14.5	12.6	12.8	14.2	1.3	2.7	7.4	12.1	11.6	8.5
CANADIAN TIRE CORP	11.9	6.4	6.9	0.5	10.2	10.4	11.4	13.0	11.2	10.6	9.1	9.2	11.1
CCL INDUSTRIES	0.1	16.0	2.0	8.6	9.5	10.3	9.6	8.7	9.4	4.8	8.2	7.9	8.7
CORBY (H.) DISTILLERY	10.9	21.6	23.6	30.8	28.0	22.3	20.9	29.3	46.5	37.0	26.0	27.1	30.7
DOVER INDUSTRIES LTD	13.3	11.2	12.0	12.1	10.5	7.0	3.8	8.0	5.5	3.0	9.3	8.6	6.3
DUPONT CANADA	9.2	12.6	9.4	19.9	20.4	19.7	20.6	27.3	19.5	18.2	17.6	17.7	20.9
IMPERIAL OIL LTD	2.3	2.9	4.2	5.7	8.6	15.0	18.9	12.9	13.5	32.4	9.3	11.7	16.9
LEONS FURNITURE LTD	14.6	11.4	16.4	15.3	14.0	13.4	15.1	16.7	21.1	19.3	15.4	15.7	16.6
LOBLAW COS LTD	13.2	8.7	9.6	12.4	13.3	14.2	15.3	12.8	13.7	15.7	12.6	12.9	14.2
MOLSON INC	14.6	15.7	10.1	6.5	-26.8	3.7	11.8	16.3	-4.1	14.5	5.3	6.2	2.6
QUEBECOR INC	4.9	16.5	10.8	11.3	20.6	14.2	12.4	13.0	30.5	48.0	14.9	18.2	23.1
REITMANS (CANADA)	9.4	15.4	11.1	9.0	6.2	0.8	8.9	9.4	30.1	10.2	11.2	11.1	10.9
SHELL CANADA LTD	-4.0	2.7	0.6	10.7	16.0	16.3	14.8	13.1	17.7	22.1	9.8	11.0	16.7
THOMSON CORP	9.9	6.0	10.0	14.6	22.4	14.2	12.9	34.7	8.0	17.9	14.7	15.0	18.3
UNICAN SECURITY SYS	2.7	11.2	15.0	19.2	17.0	16.3	10.3	11.4	10.3	11.7	12.6	12.5	12.8
WINPAK LTD	10.7	12.4	13.7	13.0	11.4	12.7	10.9	13.0	15.1	15.2	12.5	12.8	13.0
Median	**10.7**	**12.4**	**10.8**	**12.4**	**12.6**	**14.2**	**12.9**	**13.0**	**13.7**	**15.7**	**12.5**	**12.5**	**14.2**
Average											**12.8**	**13.3**	**14.7**
Average of Medians											**12.5**	**12.8**	**13.7**

Source: Standard & Poor's Research Insight

17ROECDA

SCHEDULE XVII
K. C. McShane

**SELECTED RISK STATISTICS
FOR SIX CANADIAN ELECTRIC & GAS UTILITIES
AND 17 LOW RISK CANADIAN INDUSTRIALS**

	1990-1999 Coefficients of Variation		Raw	Standard Deviation	CBS	DBRS	CBRS	1999 Common
	Book Returns	EBIT	Beta a/	of Market Returns	Stock Rating	Bond Rating	Bond Rating	Equity Ratio b/
Gas and Electric Utilities								
BC GAS INC	38.0	24.8	0.36	5.1	Very Conservative	A	A	32.5
CANADIAN UTILITIES	6.0	16.8	0.54	5.0	Very Conservative	A(HIGH)	AA-	40.0
EMERA	90.9	14.8	0.41	5.0	Conservative	A(LOW)	A	37.8
FORTIS	15.5	16.7	0.33	3.8	Conservative	A	A-	43.7
TRANSALTA CORPORATION	8.3	17.9	0.28	6.0	Very Conservative	A(HIGH)	A+	39.3
Median	**15.5**	**16.8**	**0.36**	**5.0**	**Very Conservative**	**A**	**A**	**39.3**
Average	**31.7**	**18.2**	**0.38**	**5.0**	**Conservative**	**A**	**A**	**38.7**
Industrials								
BOMBARDIER INC	23.5	54.4	0.76	7.3	Very Conservative	A(high)	A+	31.8
CANADA BREAD LTD	51.8	32.4	0.41	8.3	Average	NR	NR	93.4
CANADIAN TIRE CORP	43.1	19.5	0.81	7.4	Very Conservative	A(high)	A+	47.5
CCL INDUSTRIES	56.8	47.2	0.34	5.3	Average	NR	NR	51.0
CORBY (H.) DISTILLERY	37.3	10.1	0.19	5.8	NR	NR	NR	56.2
DOVER INDUSTRIES LTD	35.6	16.7	0.07	4.4	NR	NR	NR	86.2
DUPONT CANADA	34.0	38.4	0.67	5.6	Conservative	A+(high)	AA+	100.0
IMPERIAL OIL LTD	63.9	30.2	0.31	6.7	Conservative	A+	AA	78.2
LEONS FURNITURE LTD	17.5	38.0	0.28	7.4	Average	NR	NR	100.0
LOBLAW COS LTD	17.0	53.9	0.35	7.2	Very Conservative	A(high)	A+	51.6
MOLSON INC	258.2	36.8	0.53	5.8	Very Conservative	A(low)	A	46.0
QUEBECOR INC	48.6	59.6	0.56	6.1	Very Conservative	NR	NR	21.4
REITMANS (CANADA)	72.7	124.9	0.28	5.7	Average	NR	NR	100.0
SHELL CANADA LTD	81.5	60.6	0.51	6.5	Conservative	A+(low)	AA-	89.6
THOMSON CORP	60.1	25.4	0.72	6.4	Very Conservative	A(high)	A+	70.0
UNICAN SECURITY SYS	39.0	63.7	0.42	6.9	Average	NR	NR	64.8
WINPAK LTD	11.2	43.7	0.43	6.7	Higher Risk	NR	NR	66.2
Median	**43.1**	**38.4**	**0.42**	**6.5**	**Conservative**	**A**	**A+**	**66.2**
Average	**56.0**	**44.4**	**0.45**	**6.4**	**Conservative**	**A**	**A+**	**67.9**

a/ 60-month period ending December 1999.
b/ Equity ratio calculated on the basis of total permanent capital plus short-term debt, excluding deferred taxes.
Note: Utility bond ratings and common equity ratios are for subsidiaries, all other data are for parents.

Source: Standard & Poor's Research Insight; TSE Review; The Blue Book of CBS Stock Reports; Dominion Bond Rating Service; and Canadian Bond Rating Service.

RISKST

RETURNS ON EQUITY AND BETAS
FOR 36 LOW RISK U.S. INDUSTRIALS

	Returns on Equity											
	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	Average 1991-1999	Value Line Beta
PLUM CREEK TIMBER CO INC	7.9	7.2	27.2	39.5	46.2	38.6	54.0	16.6	9.5	20.5	28.8	0.55
CURTISS-WRIGHT CORP	3.5	16.1	14.7	-2.0	12.9	11.0	9.1	14.4	13.4	16.0	11.7	0.60
HANNAFORD BROTHERS CO	17.8	15.6	15.2	14.6	14.6	14.4	13.8	10.2	15.0	14.1	14.2	0.65
UNIVERSAL FOODS CORP	22.1	21.6	14.0	18.6	16.1	19.2	12.4	17.7	18.5	19.1	17.5	0.65
MCCORMICK & CO	19.5	21.5	23.0	22.0	12.8	19.3	10.3	23.3	26.6	26.8	20.6	0.65
SMUCKER (JM) CO	17.8	17.0	17.3	13.4	14.7	11.0	10.9	12.2	12.1	8.3	13.0	0.70
BALDOR ELECTRIC	11.9	9.3	10.9	12.7	15.3	16.3	17.1	18.2	17.6	16.5	14.9	0.70
UNIVERSAL CORP/VA	9.5	6.1	20.5	22.3	9.7	6.7	17.7	22.7	27.8	23.4	17.4	0.70
ALBERTSONS INC	23.2	22.5	21.3	24.5	27.1	25.5	23.5	22.2	21.7	10.0	22.0	0.70
GENERAL DYNAMICS CORP	-31.8	28.9	42.3	58.0	19.1	22.3	16.5	17.4	17.6	32.7	28.3	0.70
EASTMAN KODAK CO	10.5	0.3	15.7	13.5	22.3	27.4	26.1	0.1	38.9	35.2	19.9	0.75
FEDERAL SIGNAL CORP	22.0	20.0	20.0	21.0	22.3	22.0	23.8	20.6	19.1	17.0	20.7	0.75
BANDAG INC	35.1	29.9	26.3	21.1	22.2	23.3	20.1	27.9	12.7	11.4	21.6	0.75
COMMERCIAL METALS	13.2	5.9	6.0	9.7	10.9	14.0	14.4	11.2	11.6	11.8	10.6	0.80
CONAGRA INC	20.0	17.2	17.1	19.3	20.0	7.6	26.0	23.9	12.6	14.1	17.5	0.80
EATON CORP	15.7	6.5	13.3	17.5	23.9	21.8	16.9	21.9	16.9	26.4	18.3	0.80
ECOLAB INC	12.3	-69.6	20.0	21.2	20.2	21.6	23.2	25.0	31.0	24.2	13.0	0.85
ENRON CORP	11.2	13.1	15.1	13.0	16.8	17.5	17.2	1.9	11.1	12.5	13.1	0.85
WENDY'S INTERNATIONAL INC	8.8	11.2	12.9	14.0	15.2	14.7	16.6	11.6	11.0	15.6	13.6	0.85
SUPERVALU INC	16.8	20.7	15.2	15.4	3.5	13.9	13.9	18.5	15.3	15.6	14.7	0.85
TELEFLEX INC	16.4	14.9	14.2	13.2	14.2	14.7	15.0	16.1	16.5	16.7	15.1	0.85
ALBERTO-CULVER CO	17.9	12.5	14.4	14.1	14.1	15.1	15.8	18.5	16.1	15.6	15.1	0.85
SONOCO PRODUCTS CO	9.8	17.6	14.5	20.0	19.1	22.3	21.2	-0.1	23.0	21.8	17.7	0.85
BRIGGS & STRATTON	13.3	13.1	17.3	20.9	26.8	24.9	19.7	14.5	21.2	31.1	21.0	0.85
DONNELLEY (R R) & SONS CO	14.9	12.3	13.1	9.7	14.1	14.4	-8.3	8.1	20.4	25.3	12.1	0.90
JOHNSON CONTROLS INC	8.4	8.3	10.3	11.5	13.9	14.9	16.1	17.7	18.4	19.6	14.5	0.90
AVERY DENNISON CORP	0.9	7.5	9.8	10.9	15.1	18.6	21.4	24.5	26.7	26.2	17.9	0.90
KNIGHT-RIDDER INC	16.5	12.9	12.5	12.2	13.9	14.3	23.9	30.8	22.8	18.9	18.0	0.90
CLOROX CO/DE	19.2	6.6	14.7	19.7	23.7	21.7	23.7	25.3	28.1	18.5	20.2	0.90
SUPERIOR INDUSTRIES INTL	15.1	19.2	23.8	28.8	29.9	24.7	19.5	20.6	17.5	21.3	22.8	0.90
PEPSICO INC	24.5	20.7	23.9	27.2	27.0	22.7	16.5	31.6	29.9	30.9	25.6	0.90
DEXTER CORP	12.6	-2.2	12.1	10.8	11.5	11.4	13.1	15.1	8.3	25.3	11.7	0.95
BECTON DICKINSON & CO	15.7	14.5	13.5	13.8	15.4	17.4	20.8	22.2	15.8	16.4	16.6	0.95
SHERWIN-WILLIAMS CO	17.1	15.7	16.3	17.0	17.9	17.7	17.5	17.4	16.5	17.8	17.1	0.95
WINN-DIXIE STORES INC	19.1	20.4	23.9	24.4	21.2	20.2	19.8	15.3	14.7	13.1	19.2	0.95
BARD (C.R.) INC	11.9	16.2	19.8	16.0	18.2	17.3	15.9	12.3	44.2	20.7	20.1	0.95
MEDIAN	**15.4**	**14.7**	**15.2**	**16.5**	**16.5**	**17.6**	**17.1**	**17.7**	**17.5**	**18.7**	**17.5**	**0.85**
AVERAGE											**17.7**	**0.81**
AVERAGE OF MEDIANS											**16.8**	

Source: Standard & Poor's Research Insight

EQUITY RETURN AWARDS AND CAPITAL STRUCTURES ADOPTED BY REGULATORY BOARDS FOR INVESTOR-OWNED CANADIAN UTILITIES
(Percentages)

	Decision Date	Order/ File Number	Debt	Preferred Stock	Deferred Taxes	Common Stock Equity	Equity Return	Forecast 30-Year Bond Yield
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Electrics								
ATCO Electric a/ b/	10/97	U97065	48.10	16.20		35.70	11.25	7.75
Newfoundland Power	11/00	PU 30(2000-2001)	53.55	1.93		44.52	9.59 f/	5.75
Nova Scotia Power	3/96	NSUARB-P-868	55.0-59.0	8.0-10.0		33.0-35.0	10.50-11.00	7.70 e/
TransAlta Utilities (Integrated)	11/99	U99099	49.50	9.50		41.00	9.25	5.75
Generation	11/99	U99099	50.50	9.50		40.00	9.25	5.75
Transmission	11/99	U99099	55.50	9.50		35.00	9.25	5.75
Distribution	11/99	U99099	36.00	9.50		54.50	9.25	5.75
West Kootenay Power	12/99; 12/00	L-61-00	58.90 d/	0.00	1.10	40.00	9.75	5.73
Gas Distributors								
B.C. Gas	12/00	L-61-00	57.64 c/	9.36		33.00	9.25	5.73
Canadian Western Natural Gas a/	3/00	2000-9	47.15	15.67		37.18	9.375	5.60
Enbridge Consumers Gas	12/99	RP-1999	61.46	3.54		35.00	9.73	6.02
Gaz Metropolitain	4/01	D-2001-109	54.00	7.50		38.50	9.60	5.78
Northwestern Utilities a/	1/94	E-94001	38.74	26.74		34.52	11.875	8.00
Pacific Northern Gas	4/00; 12/00	L-61-00	60.58 c/	3.41		36.00	10.00	5.73
Union Gas	1/99	EBRO 499	61.09 c/	3.91		35.00	9.61	5.66
Gas Pipelines								
Alberta Natural Gas	12/00	RH-2-94	70.00	0.00		30.00	9.61	5.73
Foothills Pipe Lines (Yukon) Ltd.	12/00	RH-2-94	70.00	0.00		30.00	9.61	5.73
Nova Gas Transmission Ltd.	12/00; 3/97	U96119	68.00 c/	0.00		32.00	9.61	5.73
TransCanada PipeLines	12/00	RH-3-94	60.88	9.12		30.00	9.61	5.73
Trans Quebec & Maritimes Pipeline	12/00	RH-2-94	70.00	0.00		30.00	9.61	5.73
Westcoast Energy	12/00	RH-2-94	63.39	1.61		35.00	9.61	5.73

a/ Excludes no-cost capital and CIAC.
b/ Superseded by 5/99 approval of settlement for 1999 & 2000, ROE not specified.
c/ Includes short-term debt of 13.55% for B.C. Gas, 13.1% for Centra Gas Manitoba, 5.38% for Nova Gas Transmission, 3.53% for Pacific Northern Gas, 0.56% for Union Gas.
d/ Includes short-term debt.
e/ Average of witness forecasts.
f/ ROE unchanged from 2000 because forecast 30-year Canada yield changed by less than 50 basis points (from 6.18% to 5.75%).

Source: Board Decisions.

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RATES OF RETURN ON COMMON EQUITY ADOPTED BY REGULATORY BOARDS FOR INVESTOR-OWNED CANADIAN UTILITIES

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Electrics												
ATCO Electric	13.50	13.50	13.25	11.88	NA	NA	11.25	b/	b/	b/	b/	b/
Newfoundland Power	13.95	13.25	NA	NA	NA	NA	11.00	NA	9.25	9.25	9.59	9.59
Nova Scotia Power	--	--	--	11.75	NA	NA	10.75	NA	NA	NA	NA	NA
TransAlta Utilities	13.50	13.50	13.25	11.88	NA	12.25	11.25	b/	c/	9.25	9.25	NA
West Kootenay Power	13.50	NA	11.75	11.50	11.00	12.25	11.25	10.50	10.25	9.50	10.00	9.75
Average of Electrics	**13.61**	**13.42**	**12.75**	**11.75**	**11.00**	**12.25**	**11.10**	**10.50**	**9.75**	**9.33**	**9.61**	**9.67**
LDCs												
BC Gas Utility	NA	NA	12.25	NA	10.65	12.00	11.00	10.25	10.00	9.25	9.50	9.25
Canadian Western	13.25	13.25	12.25	12.25	NA	NA	NA	NA	10.50	9.38	NA	NA
Centra Gas Ontario	13.50	13.75	13.50	12.50	11.85	12.13	NA	11.25	10.69	a/	a/	a/
Enbridge Consumers Gas	13.25	13.13	13.13	12.30	11.60	11.65	11.88	11.50	10.30	9.51	9.73	NA
Gaz Metro	14.25	14.25	14.00	12.50	12.00	12.00	12.00	11.50	10.75	9.64	9.72	9.60
Northwestern Utilities	NA	13.75	13.75	11.88	11.88	NA	NA	NA	NA	NA	NA	NA
Pacific Northern Gas	15.00	14.00	13.25	NA	11.50	12.75	11.75	11.00	10.75	10.00	10.25	10.00
Union Gas	13.75	13.50	13.50	13.00	12.50	11.75	11.75	11.00	10.44	9.61	9.95	NA
Average of LDCs	**13.83**	**13.66**	**13.20**	**12.40**	**11.71**	**12.05**	**11.68**	**11.08**	**10.49**	**9.56**	**9.83**	**9.62**
Gas Pipelines												
Foothills	14.25	14.25	14.25	12.50	11.50	12.25	11.25	10.67	10.21	9.58	9.90	9.61
TransCanada	13.25	13.50	13.25	12.25	11.25	12.25	11.25	10.67	10.21	9.58	9.90	9.61
Westcoast Energy	13.25	13.75	12.50	12.25	11.50	12.25	11.25	10.67	10.21	9.58	9.90	9.61
Average of Gas Pipelines	**13.58**	**13.83**	**13.33**	**12.33**	**11.42**	**12.25**	**11.25**	**10.67**	**10.21**	**9.58**	**9.90**	**9.61**
Average of All Companies	**13.71**	**13.64**	**13.13**	**12.19**	**11.57**	**12.14**	**11.36**	**10.90**	**10.30**	**9.51**	**9.79**	**9.63**

Note: A rate freeze was in effect for BC Gas in 1990 and 1991, BCUC regulation resumed in late 1991.
Nova Scotia Power was privatized in 1992.

a/ Merged with Union Gas.
b/ Negotiated settlement, details not available.
c/ Negotiated settlement, implicit ROE made public is 10.5%.

Source: Regulatory Decisions

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Table 10 (a) EBIT Interest Coverage (1) (times)

Government Owned	1999	1998	1997	1996	1995	1994	1993	1992
B.C. Hydro	1.91	1.64	1.65	1.47	1.18	1.21	1.19	1.35
EPCOR Power	2.03	1.95	1.76	1.81	1.74	1.38	0.80	1.10
Saskatchewan Power	1.86	1.79	1.68	1.69	1.37	1.41	1.36	1.43
Manitoba Hydro	1.31	1.19	1.22	1.21	1.15	1.13	1.12	0.92
Ontario Hydro	-	1.39	1.13	1.23	1.22	1.25	0.91	0.78
Ontario Power Generation	4.94	-	-	-	-	-	-	-
Hydro One	2.45	-	-	-	-	-	-	-
Hydro-Quebec	1.22	1.17	1.19	1.09	1.04	1.06	1.04	1.06
N.B. Power	1.12	1.13	0.92	0.79	0.74	0.81	0.91	0.82
Nfld. & Lab. Hydro	1.51	1.45	1.24	1.17	1.19	1.11	1.14	1.14
Churchill Falls	1.75	1.68	1.53	1.46	1.50	1.44	1.56	1.60
Group Average	*1.58*	*1.32*	*1.22*	*1.20*	*1.14*	*1.15*	*1.01*	*0.97*
Investor Owned								
West Kootenay	2.20	2.22	2.70	2.72	2.48	2.05	2.68	3.00
ATCO Electric	3.01	3.19	3.01	2.89	2.90	2.96	2.95	2.69
TransAlta Utilities	2.78	3.59	3.19	4.02	3.75	3.71	3.81	3.56
Northern Ontario Power	2.81	1.44	2.06	2.20	2.19	1.94	2.61	4.31
Nova Scotia Power	2.48	2.22	2.17	1.85	1.62	1.49	1.37	1.10
Group Average	*2.72*	*2.89*	*2.74*	*2.84*	*2.62*	*2.53*	*2.47*	*2.24*
Industry Average	1.66	1.40	1.30	1.28	1.22	1.23	1.08	1.04

(1) Before capitalized interest, AFUDC, debt amortizations and preferred dividends.

EBIT coverage is showing the same improving trend as the fixed-charges coverage ratio. It differs from fixed-charges coverage in that it excludes preferred dividends in the denominator. The sharp improvement in 1999 was largely due to the recapitalization and restructuring of the former Ontario Hydro.

PRE-TAX INTEREST COVERAGE RATIOS FOR MAJOR CANADIAN INVESTOR-OWNED ELECTRIC UTILITIES

Company	1995	1996	1997	1998	1999
Electric Utilities					
CU Inc.	3.1	3.3	3.4	3.4	3.2
Maritime Electric	3.6	3.1	2.7	2.1	2.3
Newfoundland Power	2.9	2.7	2.7	2.4	2.4
Nova Scotia Power	1.6	1.7	1.8	1.8	1.9
TransAlta Utilities	3.8	4.1	3.3	3.6	2.7
West Kootenay Power	2.5	2.8	2.8	2.3	2.3
Average	**2.9**	**3.0**	**2.8**	**2.6**	**2.5**

Source: CBRS, Inc., Annual Reports to Shareholders.

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D.G. Hall

NEWFOUNDLAND AND LABRADOR HYDRO
EVIDENCE OF DOUGLAS G. HALL

Q. Would you please state your name, address and occupation?

A. My name is Douglas G. Hall. My business address is 1969 Upper Water Street, Suite 1101, Halifax, NS B3J 3R7. I am a Managing Director, Global Banking for RBC Dominion Securities Inc., part of the Royal Bank Financial Group.

Q. Please comment on your relevant work experience and academic credentials.

A. I have worked in the Investment Banking sector with RBC Dominion Securities since November 1979. During all that time, I have covered regulated utility companies across Canada, including the issuance of debt, preferred shares and common equity, mergers and acquisitions advice and privatization work.

On the regulatory front, I have previously testified for Maritime Telegraph and Telephone before the Canadian Radio-television and Telecommunications Commission, for BC Gas before the British Columbia Utilities Commission, for Alberta Power and Canadian Western Natural Gas before the Alberta Public Utilities Board and for Manitoba Hydro before the Manitoba Public Utilities Board. In all these appearances, I have focused on capital structure, appropriate returns and general market issues.

I have a Bachelor of Arts and Science from Queen's University, a Masters in Business Administration from Ivey School of Business at the University of Western Ontario and I hold a Chartered Financial Analyst designation from the Association for Investment Management and Research.

Q. What is the relationship between RBC Dominion Securities and Newfoundland and Labrador Hydro?

A. RBC Dominion Securities has acted as underwriter and financial advisor to Hydro and the Province of Newfoundland and Labrador (the Province) for over 50 years.

Q. What is your understanding of the purpose of this hearing?

A. Hydro's last rate referral occurred in 1992. Recently, Hydro has assessed its financial position in light of the considerable increase in fuel costs during 2000 and projected for 2001 and 2002, combined with amendment of the Electrical Power Control Act (EPCA) in 1996 which provided for the phase out of the rural deficit previously paid by Industrial Customers. Hydro has been directed by the Board to file a Rate Application by May 31, 2001. This hearing will also address changes to the determination of Hydro's retail rates due to amendments to the Hydro Corporation Act in 1996. As a result of these amendments, rates will in future be determined on the basis of a rate base/rate of return model.

Q. What business entity are you reviewing?

A. I am reviewing the regulated portion of Hydro's business including the supply of power to retail, industrial and Rural Customers (the Utility).

Q. What areas will your evidence cover?

A. Consistent with the focus on rate base in this hearing, I will be commenting on:

1. An appropriate level of debt and equity in the capital structure;
2. The cost of debt;

3. The impact of the Provincial guarantee on that debt; and
4. The cost of equity and various related matters.

Q. What information have you reviewed in preparation for this hearing?

A. I have reviewed various items, including:

1. financial forecasts prepared by Hydro for this hearing;
2. the financial objectives set forth in the EPCA;
3. the economic environment in the Province, and its outlook;
4. the debt ratings of Hydro and the Province by Dominion Bond Rating Service, as shown in Schedule I; and
5. the trend in net debt and interest coverage ratios of the Utility and comparable electric utilities.

Q. What is the current situation in Canada with respect to net debt in capital structure (debt to capital) for electric utilities?

A. All businesses attempt to determine an appropriate balance between business and financial risks. A corporation faced with high business risks logically tries to avoid high financial risks – the reason why many companies in volatile industries are completely funded with equity. On the other hand, a corporation with low business risks can operate comfortably with more financial leverage.

As shown in Schedule II, most investor-owned electric utilities in 1999 had debt to capital in the range of 50% to 65%, reflecting a level of financial risk that is considered appropriate given the business risk associated with the operation of an electric utility.

Within the Crown-owned utilities group, SaskPower and, more recently, Ontario Power Generation (OPG) and Hydro One, have debt to capital similar to investor-owned companies. It is important to note that these utilities do not have the benefit of a provincial guarantee on their debt. The Province of Ontario during 2000 reorganized Ontario Hydro by creating new electric utility companies to operate in the industry. In establishing the initial balance sheets for these companies, the government carefully considered their respective business risks in a rigorous process, which makes these ratios particularly useful.

In the case of an investor-owned utility, or a Crown-owned utility operated on commercial terms with no provincial guarantee, a reasonable target capital structure today would be composed of 55% to 60% debt and 45% to 40% equity.

Q. How do the above comments on debt to capital relate to the Utility?

A. To respond to this question, I must begin by stating that, in my view, there can be meaningful and tangible benefits to operating the Utility on commercial terms. It is reasonable to argue that a utility operated and financed on commercial terms results in fair and equitable treatment of all stakeholders (ratepayers, investors and others).

As part of this concept of emulating commercial norms, the Utility should, in my view, target a debt level of 55% to 60%, similar to the level maintained by the commercially operated Crown-owned utilities and the investor-owned utilities. In addition to satisfying the goal of fair and equitable treatment of all stakeholders, the Utility would in all likelihood earn an investment grade credit rating. With such a rating, there would be flexibility as to the need for a Provincial guarantee. This result would be desirable, since it would relieve the taxpayers of Newfoundland and Labrador from the associated credit risks.

The Utility's projected ratio of debt in its capital structure for this hearing is 83.2%. Given that 80% debt to capital ratios are seen as " weak" in terms of capital structure by rating agencies, this level of debt is too high. Any increase in this measure would cause concern for the providers of capital to the Utility - indeed for the Province as well. I would suggest a 75% debt to capital as a reasonable shorter-term goal for the Utility.

Q. Are there advantages associated with the Provincial guarantee?

A. The guarantee of the Province of Newfoundland and Labrador on the outstanding debt of the Utility provides a number of benefits.

First, it allows Hydro to access the debt markets at virtually any time, since the Province's ability to support its obligations by taxation is particularly valued in difficult capital market conditions. Thus, the Utility can be assured that it can raise funds for necessary capital spending and refinancings when needed, which would not be true for a utility operating at excessive debt to capital levels on a stand-alone basis.

Second, Hydro is not required to prepare full prospectuses for financings and maintain continuous disclosure records, which are a costly administrative burden.

Third, the cost of financing remains attractive. As shown in Schedule III, the yield on a Province of Newfoundland and Labrador long-term bond is roughly equivalent to the yield on Hydro's long-term bonds, that is 6.8%. After adding the cost of the guarantee fee, the cost of debt for the Utility would be about 7.8%, which is reasonable for a BBB rated generation based electric utility.

Finally, it can enable the Utility to operate at a higher level of debt to capital than a utility not having the benefit of a provincial guarantee, without endangering its “self-supporting” status.

In the utility sector in today’s markets, a yield of 7.8% for long-term obligations of an electric generating company would equate to a credit rating level of BBB. To obtain a BBB rating from the major credit rating agencies the Utility, without a provincial guarantee, would require a debt to capital of roughly 60%, with favourable trends and strong fundamentals. Thus, the Utility is able to finance considerably more of its obligations with debt – and without added interest costs.

Without the Provincial guarantee, Hydro could not attain these levels of debt at the cost it pays. Thus, the guarantee fee paid to the Province is an expense to the Utility for value received, and is quite clearly an appropriate component of the cost of debt to the Utility.

Q. In view of these advantages, is it your opinion that the Utility should strive to eliminate the guarantee fee?

A. As discussed previously, the principle of equitable treatment of all stakeholders would suggest that the Utility operate with a financially sound capital structure. One consequence of this approach is that the Utility should be able to demonstrate a strong credit rating, thereby obviating the need for a Provincial guarantee. In the transition period, however, there are significant advantages to the Utility in the guarantee, and hence, as long as the Province makes it available at reasonable cost, electricity consumers are better served by the Utility using it.

Q. What is the cost of equity?

A. As Hydro is a Crown corporation, the task of determining an appropriate return on equity for the Utility first requires consideration of the guidelines to be employed.

For example, it is possible to assert that the Province, as sole shareholder of the Utility, should only earn an equity return equal to its cost of debt. This position implicitly assumes that the Province borrows the funds necessary to invest in the business, and thus considers the investment as a debt instrument. In this model, the distinction between debt and equity in the utility is lost, and indeed there are Crown-owned utilities in Canada – Manitoba Hydro and New Brunswick Power, for example - that operate in this fashion.

This approach, of course, totally ignores the true cost of the equity provided by the Province – in most cases represented by earnings left in the Utility. Outside investors in electric utilities require a certain level of return to compensate them for the business risks to which they are exposed, and it seems illogical that the Province, as manager of the taxpayers' funds, should require any less. If the utility gets into financial difficulties of any kind, the taxpayers are exposed to any liabilities. By not charging a proper rate on the equity in the business, the Province is merely ignoring its real equity costs.

My view is that Hydro operates a commercially viable energy business that happens to be owned by the Province. The Province, as shareholder, is no different from any other investor, and should require a return on its equity commensurate with the business risks it faces. In this light, an appropriate return on equity would be the return required by any other investor who might invest in Hydro.

Q. What is an appropriate ROE level for the Utility?

A. Section 3 of the EPCA states that the rates to be charged by the Utility "should provide sufficient revenue to the producer or retailer of the power to enable it to earn a just and reasonable return as construed under the Public Utilities Act so that it is able to achieve and maintain a sound credit rating in the financial markets of the world". The Public Utilities Act in turn states that "A public utility is entitled to earn annually a just and reasonable return as determined by the board on the rate base as fixed and determined by the board for each type or kind of service supplied by the public utility". It would appear that the Province contemplates that the operation of the utility should be profitable and financially sound.

As a starting point for determining a just and reasonable return for the Province's investment in the Utility, I reviewed the latest decision of this Board for Newfoundland Power. This utility operates in the same province and is faced with similar economic and political influences. Thus, there should logically be some relationship between their allowed returns, subject to adjustments that might be made for their differing business risks.

The Board in their 1998-99 decision with respect to Newfoundland Power found that the utility could earn a return of 9.25% on the 45% common equity portion of approved rate base for the year 1998, and described a range of rates as a target. In addition, this Board implemented a formula mechanism to adjust that return to reflect changes in interest rates over time.

One logical basis for discussion of allowed equity returns for the Utility would be to adapt the principles in that decision to the present circumstances. The most obvious adaptation is in the area of business risks. In general, generating companies in the electricity industry are seen to be exposed to greater business risks than distribution utilities, since they are subject to operational challenges, commodity price fluctuations, market demand variability, service requirements under all conditions, and in many regions an increasing inability to recover these costs from their customer base due to competitive pressures. Thus, the bias would be to increase the allowed returns for the Utility, although continued regulatory control over the Utility's entire operations and the use of the RSP could offset these higher risks.

My firm has considerable experience in reviewing the financial performance of electric utilities (see RBC Dominion Securities Research report in Schedule IV). This report contains a 2001 forecasted ROE for Newfoundland Power at 9.59% and the other Canadian electric utilities at more than 10%. I have also reviewed actual ROEs of Canadian utilities in Canada (Schedule V), where investor-owned utilities reported ROE results for 1999 near 10% and government-owned utilities reported ROE results for the same period at considerably higher levels.

In view of these considerations, and given the higher operating risks that the Utility must deal with, it seems reasonable to suggest that an appropriate level of return on equity should be in the range of 10% to 12%.

Q. What is your view on the 3% ROE requested by the Utility?

A. In submitting a request for 3% return on equity in respect to the 2002 test year, the Utility is characterizing this ROE as a temporary measure only. A 3% return on equity is, in my opinion, totally inadequate. This return on the Province's investment in the Utility could be construed as a use of taxpayers' funds to reduce the cost of capital. Lowering the measurement criteria results in the taxpayers of the Province subsidizing the consumers of the region, because they are accepting a lower than reasonable rate of return on their equity investment.

I am aware of the argument for different treatment of Hydro because it is owned by the Crown, but, speaking from a commercial perspective, it is inappropriate to rule that the identity of a shareholder should have any bearing on what is a just and reasonable return on an investment.

Q. What impact will the requested 3% ROE on 15.3% equity component of rate base have on Hydro's standing in the capital markets?

A. Capital market providers in general, and the credit rating agencies in particular, focus on a utility's business outlook and trends in ratios more than they rely on particular measures for any one period. If the Board signals to the credit markets that these results are derived from on-going principles to be used to regulate Hydro, I would expect considerable pressure on the current credit ratings of Hydro, and by extension the Province. If, on the other hand, the Board provides a degree of assurance to Hydro that its decision is caused by unusual circumstances that are expected to disappear shortly, and that the Utility's financial ratios will be allowed to return to more acceptable levels within, say, five years, I would expect no immediate adverse reaction from credit suppliers.

Q. Do you have any comments with regards to interest coverage?

A. Although the focus of regulation for the Utility has shifted from interest coverage to rate base return, the level of interest coverage remains an important factor to consider. Crown-owned utilities today operate on average at roughly 1.6 times coverage, comparable to about 2.5 to 3.0 times for companies which pay income taxes. Of course there are many factors which can influence performance under this measure, such as debt to capital positioning and return on equity, but, at the requested rates, the Utility will produce a coverage ratio of 1.08 times - which is clearly substandard.

Q. What is your opinion with regard to the Utility's current dividend policy for Hydro's regulated activity?

A. The Board of Hydro has established a dividend payout target of 75% of net operating earnings, provided that the payment of the dividend would not increase the leverage of the Utility to unacceptable levels. This policy is reasonable when compared to various peer group companies, as can be seen by the actual payouts in Schedule VI.

It is common for companies with higher than desired leverage ratios to contain the payout of dividends in order to build up retained earnings in the business. For example, TransAlta Utilities maintained the same per share cash dividend for many years, while earnings results were low.

Provided that the Utility's earnings remain healthy, however, and the leverage remains in line, this level of payout of earnings as dividends would seem prudent to maintain.

Q. What is the financial impact of these decisions on the Province?

A. The principal determinant of the credit rating accorded Hydro is the credit rating accorded the Province. However, the financial soundness of the Utility can and does impact on the credit rating of the Province. Hydro accounts for approximately 12% of the total outstanding liabilities of the Province, and thus any marked deterioration in Hydro's creditworthiness must impact ultimately on that of the Province.

The key to Hydro's potential impact on the credit rating of the Province is its ability to operate on a financially self-sufficient basis. There are two parameters that are seen as integral to the assessment by rating agencies of its financial self-sufficiency. The first is a history of consistent and healthy financial ratios. The second is an adequate equity base, supported by an appropriate return on equity and a reasonable dividend payout ratio. Both factors are necessary to provide a level of protection against unforeseen events.

In assessing the creditworthiness of the Province, every credit rating agency reviews the operations of Crown-owned businesses, to determine whether there is any reasonable likelihood that any guarantees on debt will be triggered. If the agencies consider that the Utility is a self-sustaining business, *i.e*. capable under reasonable circumstances of paying its own way, then the Provincially guaranteed utility obligations could be viewed as "self-supported" debt. In that case, the utility debt is not consolidated into the Province's books for rating purposes, and the Province's own credit rating is not adversely impacted by the activities of Hydro.

Q. What are your concluding remarks?

A. From its filed testimony, the Utility anticipates reporting an ROE of 3%, leverage of 83.2% debt and interest coverage ratio in 2002 of 1.08. In our view, these levels are well below the prudent levels at which this business should function. Continued operation at these levels violates the principles required for self-sufficiency; *i.e.* consistent and healthy financial ratios, and an adequate equity base. In addition, they rely on taxpayer acceptance of sub-standard returns on their investment in the Utility - in effect, subsidization of the ratepayer by the taxpayer.

Given the presence of the guarantee, however, this financial position does not necessarily preclude Hydro from being assessed as financially viable and thus achieve neutral credit rating agency impact on the Province's debt, as long as it can be viewed as short-term in nature. As described earlier, the credit rating agencies are generally concerned more with the trends evidenced by operations than the absolute level of any single measure.

If there is evidence of continually declining performance measures with no positive regulatory or corporate moves to address the problems, there will be mounting concern about the “self-supporting” characterization of Hydro’s debt. If, on the other hand, the results are caused by unusual circumstances, and if the Board has evidenced concern with the situation and provided guidelines to the Utility for improvements, and if the Utility has programs in place to return to more prudent levels in the medium term, it is likely that Hydro can retain the categorization of its debt as ‘”self-supported”, even in the face of poor results in the short-term.

Q. Does this conclude your evidence?

A. Yes.

Provincial Ratings - Long Term Debt

Province of Newfoundland & Labrador

Current Report: July 13, 2000
Previous Report: July 22, 1999

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RATING

Rating	*Trend*	*Rating Action*	*Debt Rated*
BBB	Stable	Confirmed	Long-Term Debt issued/guaranteed by Province*

* Includes Newfoundland & Labrador Hydro and Newfoundland Municipal Financing Corporation

RATING HISTORY	*Current*	*1999*	*1998*	*1997*	*1996*	*1995*	*1994*	*1993*
Long-Term Debt	BBB	BBB	BBB	BBB (low)	BBB (low)	BBB (low)	BBB (low)	BBB (low)

RATING UPDATE

The Province of Newfoundland and Labrador's ("Province") long-term rating is confirmed at BBB, with a Stable trend. The Province's credit rating is supported by the following factors: (1) a demonstrated commitment to program expenditure control; (2) a declining debt burden, as measured by the debt-to-GDP ratio; (3) continued improvements in the Province's economic fundamentals, including significant diversification in the economic base and a strong oil and gas sector; and (4) a declining tax burden.

It is projected that the Province will record a DBRS-adjusted deficit of $122 million on a modified cash basis in 2000-01. DBRS does not have sufficient information to provide projected fiscal results on a modified accrual basis, the accounting basis used by all of the other Provinces. However, based on historical adjustments to convert to the modified accrual basis, DBRS expects that the Province's deficit (DBRS-adjusted) will likely be closer to $270 million.

While the Province's economy has performed very well in recent years and the outlook remains quite favourable given the economic diversification and projected continued oil and gas developments over the next five years, the Province has made limited progress in achieving a balanced budget on a modified accrual basis due to the substantial interest on the unfunded pension liabilities. As a result, the Province's level of tax-supported debt (including unfunded pension liabilities) has continued to rise. However, the ability of the provincial economy to support this increased debt has improved. The status of the Province's pension plans has improved and the unfunded positions on the pension plans are expected to decline over the long-term due to the changes made to the public service pension plans, including employee contribution increases, special provincial government contributions and benefit concessions. DBRS expects the Province's financial condition to continue to improve, although the pace of improvement is expected to remain limited by a number of fundamental challenges. These challenges include: (1) the highest provincial debt-to-GDP ratio of all provinces at 74.6% at the end of 1999-2000; (2) a continued high dependence on federal transfers at 44% of total revenues, although this should begin to decline as the energy sector begins to make a significant contribution to the Province's revenues; (3) a high tax burden, despite the tax cuts introduced since November 1999; and (4) continued weaker than average economic fundamentals.

RATING CONSIDERATIONS

Strengths:

- Proven commitment to program expenditure control
- Declining debt burden
- Improved economic fundamentals and positive outlook
- Declining tax burden

Challenges:

- Surpluses not yet achieved on a modified accrual basis
- High debt burden
- High reliance on federal transfers
- High provincial tax burden
- Weaker than average economic fundamentals

FINANCIAL INFORMATION

Fiscal Year ending March 31

	2000-01B	1999-2000P	1998-99	1997-98	1996-97	1995-96	1994-95
Debt* ($ millions)	9,097	9,032	8,874	8,466	8,448	8,653	8,533
Debt*/ GDP	67.1%	74.6%	78.5%	79.6%	81.0%	81.3%	83.2%
Surplus (Deficit)* ($ millions)	(122)	22	(169)	(222)	(140)	(155)	(380)
Surplus (Deficit)*/ GDP	(0.9%)	0.2%	(1.5%)	(2.0%)	(1.3%)	(1.5%)	(3.7%)
Interest Costs/Total Revenue*	14.6%	13.6%	13.5%	14.2%	13.8%	14.0%	13.8%
Federal Transfers/Total Revenue*	44.0%	43.8%	47.2%	45.5%	42.0%	43.9%	46.9%
Nominal GDP ($ millions)	13,552	12,111	11,308	10,642	10,429	10,649	10,257
Real GDP growth	4.7%	5.3%	6.2%	1.5%	(3.3%)	2.2%	4.7%
Unemployment rate	15.9%	16.9%	18.0%	18.6%	19.3%	18.1%	20.2%

* DBRS-adjusted basis. Historical surplus (deficit) numbers have been revised to be comparable with other provinces. Projected and budgeted numbers, and historical ratios are still on a modified cash basis.

Source: Province of Newfoundland and Labrador, Statistics Canada and DBRS estimates.

PROVINCE

Newfoundland & Labrador is located on the Atlantic seaboard, and has the second smallest population of the Canadian provinces.

Commercial Paper and Short Term Debt Ratings

Newfoundland and Labrador Hydro

(*The rating is a flow-through of the rating of the Province of Newfoundland and Labrador, which guarantees the Utility's debt. This report analyzes the Utility.)

Current Report: September 20, 2000
Previous Report: November 1, 1999

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RATING*

Rating	*Trend*	*Rating Action*	*Debt Rated*
R-2 (high)	Stable	Confirmed	Commercial Paper/T-Bills

RATING HISTORY* (as at Dec. 31)

	Current	*1999*	*1998*	*1997*	*1996*	*1995*	*1994*
Commercial Paper/T-Bill	R-2 (high)	R-2 (high)	R-2 (high)	R-2 (middle)	R-2 (middle)	R-2 (middle)	R-2 (middle)

COMMENTARY

The rating is a flow-through of the rating of the Province of Newfoundland and Labrador, which guarantees the Utility's debt obligations. Operating cash flows have historically been more than sufficient to finance maintenance capital expenditures, and, with the contribution from the 3-year recall agreement, have allowed for material debt reduction over the last two years. Capital expenditures are expected to fall slightly during 2000 to about $55 million but will increase substantially over the following two years and peak at about $130 million in 2002 to finance a new 40 MW hydro plant to meet growing demand, as well as expenditures on an ongoing transmission and system reliability program. Key debt ratios should continue to improve during 2000, with the recall agreement contributing $11 million to operating cash flows. External financing may be required thereafter to meet the growing level of capital expenditures, and key debt ratios could come under short-term pressure depending on whether the recall agreement, which ends in March 2001, is renewed on similar terms. The agreement has allowed for the sale of 130 MW of power at current market rates, rather than the 0.27¢ per kWh that prevails under the existing contract between Hydro-Québec and Churchill Falls. The Utility's debt-to-capital fell to 63% in December 1999 from 65% the previous year, and presently compares favourably to the government utility debt-to-capital average of 70%. Interest coverage ratios have improved accordingly, and are in line with government utility averages.

CONSIDERATIONS

Strengths:

- Debt is unconditionally guaranteed by the Province
- Surplus cash flows available for debt reduction
- Two-thirds interest in Churchill Falls; excellent potential for capacity additions in Labrador
- Geographic isolation, unavailability of gas minimize competitive pressures, impact of industry deregulation
- Rate stabilization plan contributes to earnings stability

Challenges:

- Earnings sensitive to water levels and oil prices
- Rate stabilization plan incorporates unrealistically low oil price assumptions
- Low population density/high cost of service
- Realized foreign exchange losses: $96 million
- Proposed capacity expansion would likely pressure key debt ratios once construction commences

FINANCIAL INFORMATION

For years ended December 31

	1999	1998	1997	1996	1995	1994	1993
EBIT Interest Coverage (times)	1.51	1.45	1.24	1.17	1.19	1.11	1.14
Net Debt in Capital Structure	63.1%	65.1%	68.1%	69.4%	70.1%	70.3%	69.6%
Cash Flow/Total Debt (times)	0.11	0.09	0.06	0.04	0.04	0.05	0.05
Cash Flow/Capital Expenditures (times)	1.97	3.11	2.30	1.61	1.34	2.38	2.21
Operating Income ($ millions)	131	139	127	122	125	119	125
Net Income (bef extras.) ($ millions)	68	70	43	29	33	21	25
Operating Cash Flow ($ millions)	111	86	58	39	41	50	40
Electricity Sales (millions of kWhs)	7,988	7,598	6,781	6,589	6,506	6,364	6,457
Electricity Revenues (cents per kWh sold)	3.96	3.98	4.30	4.35	4.38	4.39	4.42
Variable Costs (cents per net gen kWh sold)	2.17	2.04	2.02	2.10	2.08	2.14	2.12
Fixed Costs (cents per net gen kWh sold)	2.33	2.46	2.32	2.46	2.45	2.58	2.53
Purchased Power (cents per gross kWh purchased)	0.74	0.56	0.61	0.60	0.60	0.62	0.59
Pre-tax Margin* (cents per kWh sold)	0.59	0.65	0.44	0.29	0.33	0.18	0.20

* Excludes ancillary revenues.

THE COMPANY Newfoundland and Labrador Hydro generates and transmits electricity for the province. The Utility sells about 65% of its output to a private sector distributor and distributes the remainder to rural customers and a small group of industrial companies.

ORDER-IN-COUNCIL LIMIT $300 million.

Newfoundland and Labrador Hydro

(*The rating is a flow-through of the rating of the Province of Newfoundland and Labrador, which guarantees the Utility's debt. This report analyzes the Utility.)

Current Report: September 20, 2000
Previous Report: November 1, 1999

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RATING*

Rating	Trend	Rating Action	Debt Rated
BBB	Stable	Confirmed	Long-Term Debt

RATING HISTORY* (as at Dec. 31)

	Current	1999	1998	1997	1996	1995	1994
Long-Term Debt	BBB	BBB	BBB	BBB (low)	BBB (low)	BBB (low)	BBB (low)

COMMENTARY

The rating is a flow-through of the rating of the Province of Newfoundland and Labrador, which guarantees the Utility's debt obligations. The Utility's net earnings and cash flows have increased substantially since 1997 as a result of the recall agreement with Hydro-Québec. The 3-year agreement, which ends in March 2001 should contribute roughly $11 million to earnings and cash flows in 2000 and allow for ongoing debt reduction. During 1999, the Utility was able to reduce outstanding debt by $121 million, which lowered the debt-to-capital ratio to 63% from 65% the previous year and improved interest coverage ratios accordingly. The debt-to-capital ratio compares favourably to the 70% government utility average, but remains well above the 48% typical of the private sector, while interest coverage ratios are in line with government utility group averages. With capital expenditures dropping somewhat to about $55 million, further improvement is expected in key debt ratios in 2000. Capital expenditures will increase substantially thereafter to about $100 million in 2001 and will peak at $130 million in 2002 to finance a new 40 MW hydro facility to meet growing demand and ongoing expenditures on a 5-year transmission and system reliability program. External financing requirements will likely be required to meet the growing level of capital expenditures and key debt ratios could come under some short-term pressure until the new hydro facility begins contributing to earnings in 2003. The degree of pressure on financial ratios during 2002-3 will be strongly influenced by whether the recall agreement is renewed on similar terms and conditions beyond March 2001.

CONSIDERATIONS

Strengths:

- Debt is unconditionally guaranteed by the Province
- Surplus cash flows available for debt reduction
- Two-thirds interest in Churchill Falls: excellent potential for capacity additions in Labrador
- Geographic isolation, unavailability of gas minimize competitive pressures, impact of industry deregulation
- Rate stabilization plan contributes to earnings stability

Challenges:

- Earnings sensitive to water levels and oil prices
- Rate stabilization plan incorporates unrealistically low oil price assumptions
- Low population density/high cost of service
- Realized foreign exchange losses: $96 million
- Large Labrador projects could pressure key debt ratios once construction commences

FINANCIAL INFORMATION

For years ended December 31

	1999	1998	1997	1996	1995	1994
EBIT Interest Coverage (times)	1.51	1.45	1.24	1.17	1.19	1.11
Net Debt in Capital Structure	63.1%	65.1%	68.1%	69.4%	70.1%	70.3%
Cash Flow/Total Debt (times)	0.11	0.09	0.06	0.04	0.04	0.05
Cash Flow/Capital Expenditures (times)	1.97	3.11	2.30	1.61	1.34	2.38
Operating Income ($ millions)	131	139	127	122	125	119
Net Income (bef extras.) ($ millions)	68	70	43	29	33	21
Operating Cash Flow ($ millions)	111	86	58	39	41	50
Electricity Sales (millions of kWhs)	7,988	7,598	6,781	6,589	6,506	6,364
Electricity Revenues (cents per kWh sold)	3.96	3.98	4.30	4.35	4.38	4.39
Variable Costs (cents per net gen kWh sold)	2.17	2.04	2.02	2.10	2.08	2.14
Fixed Costs (cents per net gen kWh sold)	2.33	2.46	2.32	2.46	2.45	2.58
Purchased Power (cents per gross kWh purchased)	0.74	0.56	0.61	0.60	0.60	0.62
Pre-tax Margin* (cents per kWh sold)	0.59	0.65	0.44	0.29	0.33	0.18

* Excludes ancillary revenues.

THE COMPANY Newfoundland and Labrador Hydro generates and transmits electricity in the province. The Utility sells about 65% of its output to a private sector distributor, Newfoundland Power Inc., and distributes the remainder to rural customers and a small group of industrial companies.

Section B – Financial Ratios

Table 9 (a) % Debt (1) in the Capital Structure

Government Owned	1999	1998	1997	1996	1995	1994	1993	1992
B.C. Hydro	83.5%	85.2%	85.3%	86.1%	87.0%	87.5%	87.1%	85.8%
EPCOR Power	55.6%	57.3%	61.6%	63.8%	67.5%	71.5%	74.6%	72.4%
Saskatchewan Power	56.4%	58.9%	61.0%	64.3%	67.2%	67.8%	68.9%	68.6%
Manitoba Hydro	88.1%	89.5%	90.8%	92.4%	93.8%	95.0%	96.1%	96.9%
Ontario Hydro	-	111.3%	117.1%	92.6%	87.9%	89.9%	91.4%	83.7%
Ontario Power Generation	38.7%	-	-	-	-	-	-	-
Hydro One	54.6%	-	-	-	-	-	-	-
Hydro-Quebec	73.8%	75.0%	74.8%	75.6%	76.6%	76.5%	76.1%	76.3%
N.B. Power	99.4%	99.9%	88.6%	88.3%	88.0%	88.0%	88.4%	88.3%
Nfld. & Lab. Hydro	63.1%	65.2%	68.1%	69.4%	70.1%	70.3%	69.6%	71.2%
Churchill Falls	49.4%	53.8%	55.2%	56.4%	58.1%	55.5%	57.1%	58.7%
Group Average	*70.3%*	*86.0%*	*87.2%*	*82.3%*	*81.8%*	*82.7%*	*83.5%*	*80.8%*
Investor Owned								
West Kootenay	59.1%	61.3%	59.1%	58.9%	56.8%	58.2%	51.3%	48.8%
ATCO Electric	53.2%	55.2%	58.7%	60.8%	63.8%	66.8%	62.7%	62.5%
TransAlta Utilities	51.7%	48.1%	49.6%	47.9%	52.9%	50.0%	50.3%	44.7%
Northern Ontario Power	34.6%	34.6%	32.8%	32.4%	61.5%	61.6%	62.5%	41.1%
Nova Scotia Power	65.8%	67.2%	68.8%	69.0%	68.7%	69.2%	69.5%	68.2%
Group Average	*55.4%*	*55.2%*	*56.9%*	*56.5%*	*60.9%*	*60.5%*	*59.4%*	*55.6%*
Cdn Industry Average	69.1%	83.8%	84.9%	80.5%	80.4%	81.2%	81.7%	79.1%

(1) Includes all debt equivalents, net of sinking fund assets.

Most utilities are slowly improving debt proportions, as there are generally no large expansion projects, and excess cash flow pays down debt. Several government-owned utilities have debt levels above 80%, which results in weak coverage and finance ratios. Private utilities are in the 50%-65% range, which explains their better financial ratios. We expect this trend to continue in the future, with limited new projects and good cash flow helping to allow a debt pay-down, provided that they limit future dividends.

Schedule III
D.G. Hall

RBC Dominion Securities Inc.

Representative Bond Yields

Issuer	Details	Bid Price	Bid Yield	Modified Duration	Spread to Canadas
Canada	5.5 1SEP02	101.017	4.697	1.3	
Canada	8.75 1DEC05	113.254	5.44	3.7	
Canada	7.25 1JUN07	108.474	5.586	4.8	
Canada	6 1JUN08	101.879	5.673	5.6	
Canada	5.5 1JUN09	98.472	5.738	6.3	
Canada	5.5 1JUN10	98.12	5.768	6.9	
Canada	10.25 15MAR14	138.343	5.943	7.9	
Canada	8 1JUN23	123.251	6.073	11.1	
Canada	5.75 1JUN29	96.25	6.028	13.3	
Newfoundland & Labrador	5.9 12DEC07	99.535	5.985	5.3	39.9
Newfoundland & Labrador	5.7 7OCT08	97.18	6.178	5.9	50.5
Newfoundland & Labrador	6.7 3NOV09	102.733	6.28	6.4	54.2
Newfoundland & Labrador	9.375 25FEB10	120.389	6.32	6.2	55.2
Newfoundland & Labrador	10.125 22NOV14	131.805	6.548	7.9	60.5
Newfoundland & Labrador	9.15 7JUL25 BBS	127.418	6.818	10.9	74.5
Newfoundland & Labrador	8.45 5FEB26 BBS	119.297	6.823	11.2	75.0
Newfoundland & Labrador	6.15 17APR28 BBS	91.804	6.818	12.5	79.0
Newfoundland & Labrador	6.5 17OCT29 BBS	96.264	6.798	12.6	77.0
Newfoundland & Labrador	6.55 17OCT30 BBS	96.978	6.788	12.7	76.0
Newfoundland & Labrador Hydro	5.5 30APR08	96.168	6.183	5.7	51.0
Newfoundland & Labrador Hydro	10.5 15JUN14	134.417	6.548	7.7	60.5
Newfoundland & Labrador Hydro	10.25 14JUL17	135.989	6.598	8.8	65.5
Newfoundland & Labrador Hydro	8.4 27FEB26 BBS	118.722	6.823	11.3	75.0
Ontario Hydro	8.5 26MAY25 BBS	123.19	6.568	11.1	49.5
Ontario	7.5 19JAN06 GLOBAL	107.636	5.63	3.9	19.0
Ontario	5.7 1DEC08	98.17	6.003	5.9	33.0
Ontario	6.5 8MAR29 BBS	99.884	6.508	12.7	48.0

April 27, 2001

RBC
DOMINION
SECURITIES

October 31, 2000

ROE OUTLOOK FOR 2001

PIPELINES AND GAS & ELECTRIC UTILITIES

OVERVIEW

Fall is the time of year when most regulated pipeline and gas & electric utilities have their return on equity (ROE) set in accordance with various formulas established by the companies' respective regulators. Notwithstanding a move towards deregulation and performance-based regulation, the allowed ROE continues to be used to determine the net income that a number of the companies can earn. **We believe that allowed ROEs in 2001 will generally be 25-30 basis points lower than the levels allowed for 2000.** In light of the low levels of allowed ROEs calculated by the various formulas, and the changing nature of the risk associated with the operations of these companies, a number of utility and pipeline companies are pursuing modifications to their ROE formulas and/or incentive regulation. Both endeavours are motivated by the objective of allowing the companies to earn higher ROEs that more appropriately compensate for the risk associated with their operations.

HIGHLIGHTS

- A number of pipeline and gas utilities will have their ROEs set in November in accordance with either the National Energy Board's multi-pipeline ROE formula or similar formulas applied by the relevant regulator.
- While the forecast of the 2001 10-year Government of Canada bond yield, as determined by the various formulas, has changed only slightly from that applied to establish the allowed ROEs for 2000, an inverted yield curve has resulted in a forecast of the 30-year Government of Canada bond yield that is approximately 40 basis points lower than that applied last year. The impact is a decline in the forecast of allowed ROEs of 25 to 30 basis points compared to those allowed in 2000.
- Companies with the greatest earnings sensitivity to changes in the 2001 allowed ROEs are **TransCanada PipeLines** (TRP $14.30 – 3 (NEUTRAL)), **BC Gas*** (BCG $29.25 – 2 (OUTPERFORM)), **Canadian Utilities** (CU $41.40 – 1 (STRONG BUY)) and **Fortis** (FTS $34.50 – 3 (NEUTRAL)).

* Maureen Howe is an associate of an insider of BC Gas. The information contained in this report has been obtained from sources other than such insider.

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(Priced as of October 27, 2000)

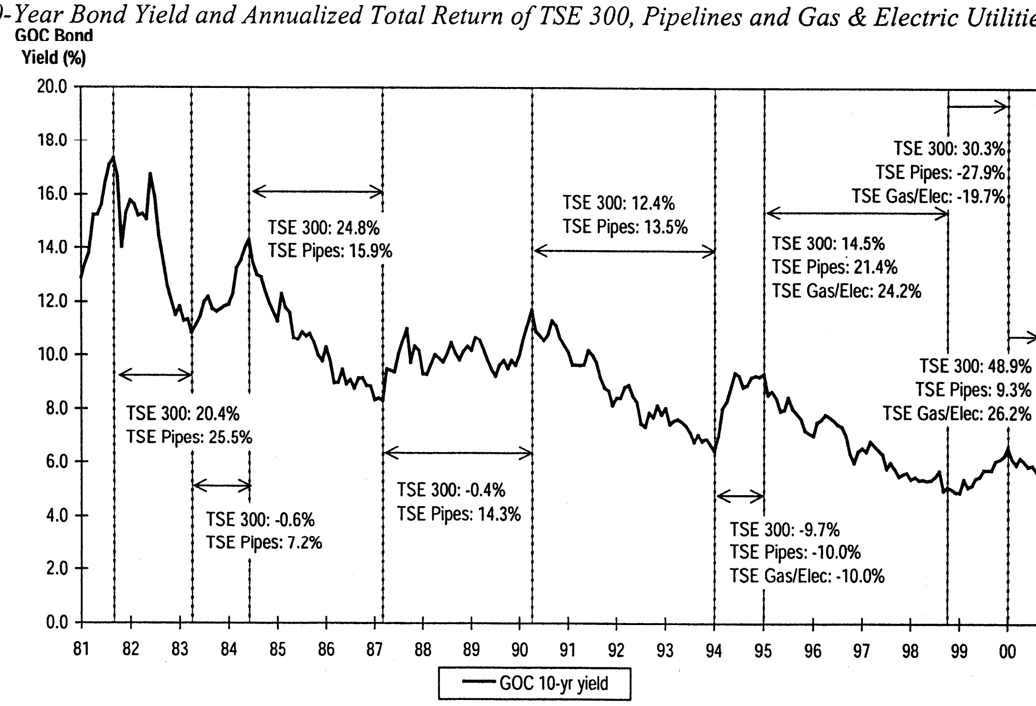
BACKGROUND

During the two decades preceding the autumn of 1998, interest rates in Canada experienced a secular decline. The yield on the 10-year Government of Canada (GOC) benchmark bond reached a high of more than 17.3% in September 1981. In January 1999, the yield on the 10-year GOC benchmark bond reached a low of approximately 4.9%. Allowed ROEs for 1999, which were generally determined in the fall of 1998, reached lows ranging from 9.25% to 10.00%. **There was a modest increase in ROEs for the 2000 regulatory period from the 1999 lows. However, the forecast for allowed returns for 2001 indicates a return to ROEs near to the 1999 lows.**

Notwithstanding the relationship between many companies' allowed ROEs (i.e. earnings levels) and the level of interest rates, the share prices of pipeline and gas & electric utilities negatively correlate with the level of interest rates. Higher interest rates lead to lower share prices as the stream of future dividends is discounted at higher rates.

The following chart illustrates the relative total return performance of the pipelines and gas & electric utilities sub-indices versus the TSE 300 Composite Index since 1981 during periods of increasing and decreasing interest rates. For the pipeline index, the average annualized total return during periods of declining interest rates was 17.1%, compared to an average annualized return of –4.1% during periods of rising interest rates. Although there are fewer observations for the gas & electric index, the effect is the same with an average annualized total return during periods of declining interest rates of 25.2% compared to –14.9% during periods of rising interest rates.

GOC 10-Year Bond Yield and Annualized Total Return of TSE 300, Pipelines and Gas & Electric Utilities



ROE FORMULAS

THE IMPORTANCE OF THE CONSENSUS FORECAST

Most regulators in Canada, including the National Energy Board (NEB), the British Columbia Utilities Commission (BCUC), the Ontario Energy Board (OEB), Quebec's Régie de l'énergie (the Régie), the Alberta Energy and Utilities Board (AEUB) for the previously regulated power generation, and the Board of Commissioners of Public Utilities of Newfoundland, have devised formulas to set the annual ROE. With the exception of the formulas implemented by Newfoundland's Board of Commissioners of Public Utilities and the AEUB, each formula utilizes a forecast of the 10-year Government of Canada bond yield published in the *Consensus Forecast* by Consensus Economics, London.[1]

In simplified terms, these formulas add a basis point spread to the average 10-year forecast yield published in the *Consensus Forecast* to establish an estimate of the 30-year Government of Canada bond yield. The formulas calculate the applied spread between the 10-year and the 30-year Government of Canada bond yields using actual averages over relatively short time periods around the time when the ROE is set.[2] The annual ROE is then adjusted by the year-over-year change in the forecast of the long-term Government of Canada bond multiplied by an adjustment factor.

RISK PREMIUMS

Typically, the formulas utilized by the Canadian regulators result in equity risk premiums that are inversely related to the level of interest rates. As interest rates decline, the equity risk premiums implied by the formula increase. This is due to the fact that as the forecast of the long GOC bond yield changes, the allowed ROE changes by an adjustment factor of less than one. The smaller the adjustment factor, the larger the implied equity risk premium as interest rates fall. In the case of the NEB multi-pipeline ROE formula, as the long bond yield drops, the ROE only declines by 0.75 times the change. In the case of BCUC and the Board of Commissioners of Newfoundland, as the long bond yield declines, the ROE changes by a factor of 0.80 times. However, both the BCUC and the Board of Commissioners of Newfoundland have interest rate ranges within which there is no change to the ROE. Further, for estimates of the yield on the 30-year GOC below 6.00%, the BCUC utilizes an adjustment factor of 1.0 times.

The following example illustrates that while the NEB multi-pipeline ROE declined from 12.25% in 1995 to its forecast 2001 level of 9.66%, the implied equity risk premium increased from 300 basis points to 386 basis points.

[1] Most formulas rely on the November issue of the *Consensus Forecast*. The Ontario Energy Board generally utilizes the August issue of the *Consensus Forecast* to set the ROE for Consumers Gas due to its September 30 year-end. For the 2000/01 regulatory year, the ROE for Consumers Gas, applying the historical formula, would be 9.52%. The Régie also utilizes the August issue of the *Consensus Forecast* in its formula.

[2] Each formula calculates the spread differently. We do not view any bias one way or the other across the various methods and have not specifically reported on the details of these calculations.

Change in the NEB Multi-Pipeline Risk Premium

Multi-pipeline 1995 allowed ROE	12.25%
1995 forecast 30-year GOC yield	9.25%
1995 implied equity risk premium	**3.00%**
2001 forecast 30-year GOC yield	5.80%
Change between 1995 and 2001 forecast bond yield	-3.45%
Multiply difference by .75X	-2.59%
Add change to 1995 allowed ROE of 12.25% to arrive at 2001 allowed ROE	9.66%
2001 implied equity risk premium	**3.86%**
Increase in the implied equity risk premium from 1995 to 2001	**0.86%**

IMPACT OF THE INVERTED YIELD CURVE

The Canadian yield curve has been inverted for a number of months and while the extent of the inversion has decreased recently, the spread between the 10- and the 30-year Government of Canada bond yields remains approximately –10 to –15 basis points.

The inverted yield curve results in a forecast of the 30-year Government of Canada bond yield that is below the forecast of the 10-year Government of Canada bond yield. While this is the current situation in Canada, the management of Consumers Gas has taken the position that a forecast of the 30-year GOC yield that is lower than the 10-year is an indication that the formula is "mis-specified". Consumers Gas has filed an alternative calculation with the regulator using historical spreads, which results in a forecast of the 30-year GOC yield of 6.39%. The impact of the proposed change to the formula is the calculation of an ROE that is 10.01% compared to an ROE of 9.52% under the previous methodology.

The OEB will hold a hearing later this year to examine Consumers Gas' proposed changes to the ROE formula and to determine the rates to be charged to customers during the 2000/2001 gas year.

CANADIAN ENERGY PIPELINES ASSOCIATION'S INITIATIVE

The Canadian Energy Pipelines Association (CEPA) has launched an initiative to convince its shippers and the NEB that the allowed return on equity granted to the Canadian pipeline companies is too low to provide the shareholders of pipeline companies with a fair return on equity invested. Although discussions have taken place between CEPA, representatives from the pipeline companies and the shippers on the various systems, no agreement has been filed with the NEB for ratification. In the absence of either an agreement being reached, or an application being filed with the NEB, we anticipate that the allowed multi-pipeline ROE will be set in accordance with the 1995 multi-pipeline ROE formula. Given a forecast of the 30-year GOC yield of 5.8% based on the October issue of *Consensus Economics Survey,* we estimate the 2001 multi-pipeline ROE will be 9.66%.

INCENTIVE AGREEMENTS

One of the methods employed by pipeline and gas & electric companies to mitigate the impact of an ROE formula that is viewed as being punitive is to pursue an incentive-based regulatory agreement that is not specifically tied to an ROE reset mechanism. For example, Enbridge's Canadian oil mainline established a base revenue requirement in 1995 when the multi-pipeline ROE was at 12.25%. Although new capital additions are rolled into the revenue requirement utilizing a deemed capital structure and the allowed multi-pipeline ROE during the year of completion, the majority of the earnings derived from the system have been "de-coupled" from the annual multi-pipeline allowed ROE.

TransCanada is currently undertaking negotiations with its shippers regarding a new tolling agreement for both its natural gas mainline and the Alberta System. While TransCanada is participating in the CEPA initiative to pursue a new ROE process or formula that results in higher allowed returns, it is simultaneously negotiating with its shippers to establish a new incentive tolling methodology. Depending on the form that the methodology ultimately takes, revisions to the ROE formula may not be relevant to TransCanada. For example, should TransCanada enter a type of price-cap regime, where tolls are fixed at a specified level, the annual reset of an ROE will have little if any impact on the company's earnings.

2001 FORECAST ALLOWED ROES

The majority of formula-based ROEs are set in November. Applying the formulas to the October *Consensus Forecast* of the 10-year GOC yield results in a good indication of the level of 2001 allowed ROEs for regulated companies.

Based on the results of the October survey, the 2001 NEB multi-pipeline ROE is calculated at 9.66% in accordance with the following steps:

NEB 2001 ROE Calculation

Consensus economic forecast 10-yr bond yield (3 months out)	6.00%
Consensus economic forecast 10-yr bond yield (12 months out)	5.90%
Average	5.95%
Add: average basis point spread between 10-year and 30-year GOC bond for October	-0.15%
2001 forecast of the 30-year Government of Canada Bond Yield	5.80%
1995 forecast of the 30-year Government of Canada Bond Yield	9.25%
Difference between 2001 and 1995 forecast	-3.45%
Multiply by .75	-2.59%
1995 ROE of 12.25%.	12.25%
Add to 1995 ROE to arrive at new 2001 forecast ROE	**9.66%**

The BCUC generic ROE for BC Gas is calculated in accordance with the following steps:

BCUC 2001 ROE Calculation

Consensus economic forecast 10-yr bond yield (3 months out)	6.00%
Consensus economic forecast 10-yr bond yield (12 months out)	5.90%
Average	5.95%
Add: Forecast basis point spread between 10-year and 30-year GOC bond for end of November 2000	-0.15%
2001 forecast of the 30 year Government of Canada Bond Yield	5.80%
Base 30-year Government of Canada Bond Yield	6.00%
Difference between 2001 and 6% forecast	-0.20%
No adjustment factor applied to GOC 30-year yield estimate below 6%	-0.20%
Base ROE	9.50%
Add to Base ROE	9.30%
Round to the nearest 25 basis points to arrive at 2001 forecast ROE	**9.25%**

The NEB multi-pipeline ROE is used in the determination of tolls for all NEB-regulated pipelines, with the exception of companies that have incentive agreements incorporating some type of price cap, revenue cap or alternative incentive rate-making methodology. However, even with price- and revenue-cap incentive agreements, the multi-pipeline ROE is still relevant for new capacity expenditures in some circumstances. In the case of NOVA Gas transmission, the multi-pipeline ROE was applied to new capacity expansions undertaken, even though NOVA was regulated by the Alberta Energy Board, not the NEB. **We expect with the expiry of the NOVA incentive agreement at the end of 2000, in the absence of a new tolling agreement being reached for the NOVA system and the TransCanada mainline, the multi-pipeline ROE will be used to set tolls for both gas transmission systems.**

In the following table, we summarize the major aspects of various formulas applied in Canada to the subsidiaries of the publicly traded pipeline and gas & electric utilities covered by RBC Dominion Securities.

2001 ROE Forecast and Component Parts of ROE Formulas

Regulator	Companies Impacted	Month that ROE is set	Base ROE	Base Forecast of Long GOC Yield	Adjustment Factor		2000 Allowed ROE	2001 Forecast ROE	
NEB	TransCanada Mainline	November	12.25%	9.25%	0.75		9.90%	**9.66%**	
	Westcoast Energy	November	12.25%	9.25%	0.75		9.90%	**9.66%**	
	Enbridge Oil Pipeline	November	12.25%	9.25%	0.75		9.90%	**9.66%**	
	Foothills	November	12.25%	9.25%	0.75		9.90%	**9.66%**	
	Alberta Natural Gas	November	12.25%	9.25%	0.75		9.90%	**9.66%**	
	NOVA System 1.	November	12.25%	9.25%	0.75		9.90%	**9.66%**	
	Norman Wells	November	12.25%	9.25%	0.75		9.90%	**9.66%**	
	TransQuebec & Maritimes	November	12.25%	9.25%	0.75		9.90%	**9.66%**	
Ontario Energy Board	Consumers Gas	August	10.30%	6.79%	0.75		9.73%	**9.52%**	2.
	Union Gas	November	9.86%	6.00%	0.75		na	**9.71%**	3.
BCUC 4.	BC Gas	November	9.50%	6.00%	0.80	5.	9.50%	**9.25%**	
Board of Commissioners of Newfoundland	Newfoundland Power	November	9.25%	5.75%	0.80		9.59%	**9.59%**	6.
AEUB 7.	TransAlta	Sept.,Oct., Nov.	na	na	1.00		na	**10.25%**	
	Canadian Utilities	Sept.,Oct., Nov.	na	na	1.00		na	**10.25%**	
Régie de l'énergie	Gaz Metropolitain	August	9.64%	5.76%	0.75		9.72%	**9.60%**	

1. The Alberta System is regulated by the Alberta Energy and Utilities Board. However, the return on capacity expansion capital is calculated at the NEB's multi-pipeline ROE.
2. The company has filed an application with the Ontario Energy Utilities Board to have the formula altered. Consumers Gas' contention is that in light of the inverted yield curve, the formula is no longer applicable. Consumers Gas has applied to the OEB for an ROE of 10.01%.
3. Union Gas applied an ROE formula in their 1999 revenue agreement. For 2000 rates, the company has filed a proposal for performance-based regulation. The OEB's decision is still pending.
4. The BCUC changed the base returns in its August 26, 1999 decision and the base yield on a long GOC bond was changed from 9.25% to 6.0%.
5. In the BCUC's August 26, 1999 decision, the adjustment factor was altered to apply only to changes in the yield on the long GOC bond when long yields are greater than 6.0%.
6. The Board of Commissioners of Public Utilities of Newfoundland does not use a forecast of the long Government of Canada bond yield in the ROE adjustment formula. The Board establishes the ROE using the actual yield on the long bond as published in the Globe and Mail for the last five trading days in October and the first five trading days in November. The ROE only changes if the weighted average cost of capital moves outside of a range of approximately plus or minus 25 basis points. Based on current GOC yields, the weighted average cost of capital is very close to the trigger. Should the weighted average cost of capital move outside of the range, which would occur at a long bond yield of approximately 5.65%, the allowed ROE would decline from 9.59% to approximately 9.25%.
7. In establishing the ROE to be used for the generation covered by the PPAs, the long bond yield estimate is the average redemption yield on all conventional Canadian government bonds with a maturity of 10 years or more, as published by the Bank of Canada. The average is calculated over the months September, October and November of the year prior to the test year. The risk premium is fixed at 450 basis points.

RISKS TO OUR FORECAST

Over the past year, the one-year forecast of the 10-year Government of Canada bond yield, as surveyed by *Consensus Forecast*, has declined from its 12-month high of 6.35% in May 2000 to 5.95% in October. Somewhat offsetting the impact of the declining forecast of the 10-year yield in the determination of the forecast of the 30-year Government of Canada bond yield is a reduction in the level of inversion in the Canada yield curve during this period. In May, the basis point spread between the 10-year and the 30-year GOC yield was approximately –40 basis points. Currently, the spread is in the range of –10 to –15 basis points. Based on the October *Consensus Forecast* and a –15 basis point spread between the 10-year and the 30-year Government of Canada bond yield, the forecast for the 30-year GOC bond yield is 5.8%.

Our forecast for the 2001 allowed ROEs for the Canadian pipeline and gas & electric sectors uses October data to arrive at the forecast of the 30-year GOC bond yield of 5.8%. However, as the forecast is generally determined in November, we believe there could be some downside risk to our estimate. Our view is based on the impact of high energy costs and the Federal Reserve's monetary policy on the North American economy over the past 12 months. Combined with recent profit warnings from technology companies, a significant driver in the North American economy, we believe that the risk of a more serious downturn rather than the "soft landing" targeted by the Fed will materially reduce the probability of additional Fed tightening over the next 12 months. However, in terms of calculating the allowed ROE, we believe that over the next month, the risk of a lower forecast 10-year GOC yield should be offset by a return to a positive slope for the Canadian yield curve, leading us to our forecast of 5.8% for the 30-year GOC yield.

ASSESSING THE FORMULAS

With respect to setting ROEs, we believe using a formula is preferable to the regulator subjectively decreeing the ROE, and we prefer some formulas to others.

In general, the smaller the adjustment factor (recall that the annual change in the ROE reflects the annual change in the forecast GOC bond yield times an adjustment factor), the more attractive the formula. Adjustment factors reflect the theory that the equity risk premium is inversely related to the level of interest rates. We believe this theory to be true.

We also prefer formulas that incorporate a forecast of the long-term GOC yield as opposed to basing the allowed ROE on an average of actual yields observed in the market. For example, in the case of the formula applied by the Board of Commissioners of Public Utilities of Newfoundland, using the spot rate resulted in one of the lowest allowed ROEs among Canadian pipelines and gas & electric utilities during 1999. We believe this will continue to be the case in an environment of declining interest rates since most forecasts tend to be closer to the long-term average of interest rates and, therefore, are higher than current observed yields.

Finally, in the case of the formula applied by the BCUC, a rounding calculation to the nearest 25 basis points is applied. We do not appreciate the necessity of this step and believe it adds a degree of randomness to the calculation. In addition, the BCUC is the only regulator in Canada to apply an asymmetric treatment to the annual adjustment of ROE. The BCUC reduces the allowed ROE on a one-to-one basis for estimates of the long-term GOC yield below 6% and only increases the allowed ROE by an adjustment factor of 0.80 for changes in the long GOC yield above 6%. The impact of this treatment is to decrease the allowed ROE for BC Gas at a faster rate than in other jurisdictions when rates are falling, but does not increase the ROE at the same level when rates rise above 6%. In our view, this approach is particularly punitive and lacks theoretical foundation.

The table below summarizes the ROEs generated through the application of the various formulas across different interest rate scenarios. Clearly, the formula utilized by the BCUC to set BC Gas' ROE and the formula utilized by the Board of Commissioners of Public Utilities of Newfoundland to set Fortis' ROE are the least attractive. The ROEs implied by the application of these formulas are consistently the lowest across various interest rate levels. The formula that consistently results in the highest ROE is that used by the AEUB to determine the returns for the generating units covered by the Power Purchase Arrangements.

Allowed ROEs

Forecast Yield on Long Government of Canada Bond	**5.50%**	**6.00%**	**6.50%**	**7.00%**	**7.50%**	**8.00%**	**8.50%**	**9.00%**	**9.50%**
Regulator:									
National Energy Board	9.44%	9.81%	10.19%	10.56%	10.94%	11.31%	11.69%	12.06%	12.44%
British Columbia Utilities Commission - BC Gas	9.00%	9.50%	10.000%	10.25%	10.75%	11.00%	11.50%	12.00%	12.25%
Ontario Energy Board - Union Gas	9.49%	9.86%	10.24%	10.61%	10.99%	11.36%	11.74%	12.11%	12.49%
Ontario Energy Board - Enbridge Consumers Gas	9.33%	9.71%	10.08%	10.46%	10.83%	11.21%	11.58%	11.96%	12.33%
Board of Commissioners of Newfoundland (1)	9.25%	9.25%	9.85%	10.25%	10.65%	11.05%	11.45%	11.85%	12.25%
Albert Energy and Utilities Board - Power Purchase Arrangements (2)	10.00%	10.50%	11.00%	11.50%	12.00%	12.50%	13.00%	13.50%	14.00%
Risk Premiums:									
National Energy Board	3.94%	3.81%	3.69%	3.56%	3.44%	3.31%	3.19%	3.06%	2.94%
British Columbia Utilities Commission - BC Gas	3.50%	3.50%	3.50%	3.25%	3.25%	3.00%	3.00%	3.00%	2.75%
Ontario Energy Board - Union Gas	3.99%	3.86%	3.74%	3.61%	3.49%	3.36%	3.24%	3.11%	2.99%
Ontario Energy Board - Enbridge Consumers Gas	3.83%	3.71%	3.58%	3.46%	3.33%	3.21%	3.08%	2.96%	2.83%
Board of Commissioners of Newfoundland	3.75%	3.25%	3.35%	3.25%	3.15%	3.05%	2.95%	2.85%	2.75%
Albert Energy and Utilities Board - Power Purchase Arrangements	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%

(1) The ROEs utilized by the Board of Commissioners of Newfoundland are actual ROEs as opposed to forecast ROEs. We believe that the application of actual ROEs increases the variability of year-to-year ROEs as forecast ROEs tend to revert towards the historical mean.

(2) The Alberta Energy and Utilities Board utilizes an average of the actual yields on all conventional Canadian government bonds of 10 years or more for the months of September, October and November of the preceding test year in determining the allowed ROEs for the generation units covered by the PPAs.

2001 EPS SENSITIVITY TO ROE CHANGES

With the yield on 30-year GOC bonds around 5.8%, we expect to see allowable ROEs in the range of 9.25% to 10.30% and have reflected such returns in our models and earnings estimates for the Canadian pipelines and gas & electric companies that we cover. However, there remains some uncertainty in the capital markets and the forecast long GOC yield that is ultimately applied to establish the ROEs could change considerably from the October forecast of 5.8%. In addition, certain companies are pursuing changes to the formulas applied by their regulators. As such, there remains uncertainty regarding the range of allowable ROEs for 2001.

In light of the above, we have undertaken a sensitivity analysis that looks at the earnings per share exposure in 2001 of those companies that are regulated under a cost-of-service methodology and have not yet had their ROE finalized for 2001.

The four companies with the largest exposure to allowed returns are TransCanada, BC Gas, Fortis and Canadian Utilities. TransCanada has a $0.03 EPS sensitivity to a 25-basis-point change in the multi-pipeline ROE, which represents 2.3% of our forecast EPS for 2001. BC Gas' EPS sensitivity to a 25-basis-point change is $0.05 per share, representing 2.1% of our 2001 forecast EPS for the company. Fortis has a $0.04 EPS sensitivity to a 25-basis-point change in the allowed ROE, representing 1.6% of our forecast EPS. Canadian Utilities has a $0.06 per share earnings sensitivity to a 25-basis-point change in the allowed ROE of its regulated operations, representing 1.7% of our forecast EPS for the company.

The following table sets out the affected ratebase, the equity component of ratebase and the earnings-per-share impact of a 25-basis-point change in allowed ROE.

2001 Estimated Earnings Sensitivities to a Change in Allowed ROE

Company	Estimated Ratebase Impacted by Change ($ millions)	Deemed Equity %	Deemed Equity ($ millions)	Earnings Impact 25 bp Change ($ millions)	EPS Impact	As a percentage of 2001 EPS
TransCanada						
Mainline	$9,256.5	30.00%	$2,777.0	$6.94	$0.01514	
Alberta System	5,200.0 (1)	32.00%	1664.0	4.16	0.00907	
ANG	198.7	30.00%	59.6	0.15	0.00032	
TQM	471.6	30.00%	141.5	0.35	0.00077	
Foothills Sask	303.2	30.00%	91.0	0.23	0.00050	
Foothills B.C.	120.1	30.00%	36.0	0.09	0.00020	
Foothills Alta	358.0	30.00%	107.4	0.27	0.00059	
Total	$15,908.1	30.65%	$4,876.4	$12.19	**$0.03**	**2.29%**
Enbridge						
Mainline	$713.3 (2)	41.00%	$292.5	0.73	0.0046	
Norman Wells	155.0	55.00%	85.3	0.21	0.0014	
Consumers Gas	3,029.4	35.00%	1060.3	2.65	0.0168	
Total	$3,897.7	36.89%	$1,438.0	$3.60	**$0.02**	**0.94%**
Westcoast						
B.C. Mainline	$173.1	30.00%	$51.9	$0.13	$0.0011	
Foothills	286.9	30.00%	86.1	0.22	0.0019	
Union Gas (3)	3,811.8	35.00%	1334.1	3.34	0.0293	
Centra B.C.	462.2	35.00%	161.8	0.40	0.0035	
Pacific Northern Gas	195.5	35.00%	68.4	0.17	0.0015	
Total	$4,929.5	34.53%	$1,702.3	$4.26	**$0.04**	**1.46%**
TransAlta						
PPAs	$1,957.7	45.00%	$881.0	$2.20	$0.0131	
Transmission	$656.8	40.45%	$265.7	0.66	0.0039	
	$2,614.5	43.86%	$1,146.6	$2.87	**$0.02**	**1.55%**
Canadian Utilities						
PPAs	$791.0	45.00%	$356.0	$0.89	$0.0271	
Electric Transmission (4)	na	na	na	na	na	
Electric Distribution	648.0	38.00%	246.2	0.62	0.0187	
Northwestern Utilities (5)	na	na	na	na	na	
Canadian Western	$558.4	39.00%	217.8	0.54	0.0166	
	$1,997.4	41.05%	$820.0	$2.05	**$0.06**	**1.73%**
ATCO						
ROE exposure through 51.9% interest in Canadian Utilities (see above)					**$0.04**	**0.99%**
BC Gas						
BC Gas Utility	$2,126.2	33.00%	$701.7	$1.75	**$0.05**	**2.09%**
Fortis						
Newfoundland Power	$546.3	45.00%	$245.8	$0.61	**$0.04**	**1.62%**

Notes:

(1) Under the Alberta System's incentive agreement, the multi-pipeline ROE applies only to new capacity additions. However, this agreement expires at the end of the year 2000. If a new incentive agreement is not negotiated, we believe that tolls on the system will be determined by applying the multi-pipeline ROE to the entire ratebase of the Alberta System.

(2) Changes in the allowed ROE apply only to non-routine adjustments that are added to ratebase.

(3) Union Gas has filed a performance-based rate application for 2000 with the Ontario Energy Board. A decision from the OEB is pending.

(4) Canadian Utilities has filed a negotiated settlement for its Electric Transmission system with the AEUB.

(5) Northwestern Utilities has a negotiated settlement with its customers and does not have ROE exposure.

CONCLUSION AND RECOMMENDATIONS

We reiterate our view that the net effect of lower interest rates on pipelines and gas & electric utilities is positive. The negative impact that higher rates have on earnings due to lower allowed rates of return is more than offset by the positive effect that lower interest rates have on the valuations of these stocks.

With respect to the earnings impact of a 25-basis-point decline in the 2001 allowed ROE, **TransCanada** has the largest potential percentage earnings reduction with an EPS sensitivity of $0.03, or 2.3% of forecast earnings per share for each 25-basis-point increase in its allowed ROE. **Enbridge** and **ATCO** have the lowest sensitivity to changes in allowed ROEs as the majority of their earnings come from companies with either negotiated agreements in place for the year 2001 or from non-regulated businesses.

With respect to the attractiveness of the various formulas, we view the formula implemented by the AEUB for the Alberta generation units covered by the power purchase arrangements as the most attractive of those used. The NEB's formula appears fair and unbiased in its approach to establishing the annual multi-pipeline ROE. In our assessment, the formula utilized by the BCUC to set BC Gas' ROE and the formula utilized by the Board of Commissioners of Public Utilities in Newfoundland to set Fortis' ROE are the least attractive and penalize these companies relative to their Canadian peer group.

Rankings and Recommendations

		PRICE	Earnings per Share[1]				P/E Ratio		Current	Current	Dividend Payout (%)		1-Year	1-Year	
	Tick	27-Oct-00	99	00(E)	01(E)	02(E)	2000E	2001E	Dividend	Div.Yield	2000E	2001E	Target	Exp. Return	Recommendation
PIPELINES (Industry Rank = 3)															
Enbridge*	ENB	$38.95	$1.92	$2.21	$2.41	$2.55	17.6	16.2	$1.29	3.3%	58.4%	53.5%	$39.00	3.4%	2 (OUTPERFORM)
TransCanada PipeLines	TRP	$14.30	$1.04	$1.15	$1.16	$1.24	12.4	12.3	$0.80	5.6%	69.6%	69.0%	$14.50	7.0%	3 (NEUTRAL)
Westcoast Energy	W	$31.10	$1.87	$2.45	$2.55	$2.65	12.7	12.2	$1.28	4.1%	52.2%	50.2%	$33.00	10.2%	2 (OUTPERFORM)
Average:							**14.3**	**13.6**		**4.3%**	**60.1%**	**57.6%**			
GAS/ELEC UTILITIES (Industry Rank = 3)															
ATCO Ltd.[2]	ACO.X	$36.60	$3.28	$3.40	$3.64	$3.84	10.8	10.1	$0.92	2.5%	27.1%	25.3%	$42.00	17.3%	1 (STRONG BUY)
BC Gas	BCG	$29.25	$1.94	$2.07	$2.20	$2.34	14.1	13.3	$1.24	4.2%	59.8%	56.5%	$32.50	15.4%	2 (OUTPERFORM)
Canadian Utilities[2]	CU	$41.40	$3.15	$3.52	$3.60	$3.70	11.8	11.5	$1.80	4.3%	51.1%	50.0%	$47.00	17.9%	1 (STRONG BUY)
Emera	EMA	$15.25	$1.20	$1.24	$1.30	$1.37	12.3	11.7	$0.84	5.5%	67.7%	64.6%	$17.00	17.0%	2 (OUTPERFORM)
Fortis	FTS	$34.50	$2.23	$2.51	$2.53	$2.63	13.7	13.6	$1.84	5.3%	73.3%	72.7%	$33.75	3.2%	3 (NEUTRAL)
TransAlta Corp.	TA	$19.70	$0.79	$0.93	$1.10	$1.10	21.2	17.9	$1.00	5.1%	107.5%	90.9%	$17.00	-8.6%	4 (UNDERPERFORM)
Average:							**14.0**	**13.0**		**4.5%**	**64.4%**	**60.0%**			

[1] Normalized fully diluted earnings per share.

[2] Not Voting shares

* Within the past 12 months, RBC Dominion Securities has undertaken an underwriting liability or has provided advice for a fee with respect to the securities of this company.

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Table 22 Return on Average Common Equity (before extras.)

Government Owned	1999	1998	1997	1996	1995	1994	1993	1992
B.C. Hydro	40.4%	31.9%	36.0%	30.6%	13.4%	16.5%	16.2%	27.9%
EPCOR Power	15.1%	16.0%	14.9%	17.8%	24.3%	22.8%	7.0%	13.2%
Saskatchewan Power	12.3%	12.6%	12.6%	14.4%	8.3%	9.1%	8.6%	12.0%
Manitoba Hydro	20.5%	16.3%	21.6%	25.0%	22.0%	21.8%	35.9%	-14.1%
Ontario Hydro	-	-24.5%	-25.6%	16.1%	14.9%	23.6%	0.2%	4.6%
Ontario Power Generation	17.9%	-	-	-	-	-	-	-
Hydro One	13.8%	-	-	-	-	-	-	-
Hydro-Quebec	6.6%	5.1%	6.2%	4.3%	3.3%	5.9%	7.2%	7.4%
N.B. Power	228.6%	8.4%	-9.9%	-18.2%	-23.6%	-13.1%	12.0%	-0.6%
Nfld. & Lab. Hydro	11.2%	12.3%	8.2%	5.7%	6.7%	4.5%	5.4%	5.7%
Churchill Falls	8.6%	8.8%	6.6%	5.9%	6.7%	6.4%	8.0%	8.5%
Group Average	*12.6%*	*17.7%*	*11.3%*	*9.1%*	*7.2%*	*10.7%*	*6.3%*	*7.6%*
Investor Owned								
West Kootenay	10.5%	10.3%	12.5%	12.7%	11.9%	10.1%	9.6%	10.3%
ATCO Electric	11.7%	12.2%	11.7%	10.8%	12.5%	12.9%	13.2%	13.9%
TransAlta Utilities	7.3%	11.7%	11.1%	14.1%	12.9%	12.4%	12.3%	13.3%
Northern Ontario Power	3.5%	0.7%	2.1%	5.4%	14.4%	11.8%	15.2%	15.3%
Nova Scotia Power	13.6%	11.3%	12.0%	10.0%	8.8%	8.8%	14.9%	15.1%
Group Average	*9.5%*	*10.2%*	*10.3%*	*11.5%*	*11.8%*	*11.4%*	*13.2%*	*13.7%*
Industry Average	14.8%	16.2%	10.9%	9.1%	7.5%	10.4%	7.2%	8.2%

The thin equity base of government owned utilities distorts this ratio and unduly raises the return. The investor-owned utilities have generated returns near 10%, which is respectable and more representative of industry performance than government-owned utilities. Unlike the government-owned utilities, investor-owned utilities are subject to earnings restrictions in the form of approved ROEs although they usually earn more than the approved ROE.

Table 13 Common Dividend Payout Ratio (1)

Government Owned	1999	1998	1997	1996	1995	1994	1993	1992
B.C. Hydro	62.9%	80.1%	63.4%	32.1%	76.7%	107.0%	128.9%	79.1%
EPCOR Power	61.5%	52.2%	60.8%	56.7%	31.4%	37.5%	130.8%	67.9%
Saskatchewan Power	44.1%	55.0%	54.5%	53.5%	69.2%	56.8%	71.2%	53.2%
Manitoba Hydro	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Ontario Hydro	-	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Ontario Power Generation	34.8%	-	-	-	-	-	-	-
Hydro One	0.0%	-	-	-	-	-	-	-
Hydro-Quebec	50.0%	41.1%	45.4%	0.0%	0.0%	0.0%	0.0%	0.0%
N.B. Power	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Nfld. & Lab. Hydro	24.9%	24.1%	48.2%	44.6%	59.3%	0.0%	0.0%	0.0%
Churchill Falls	71.7%	86.3%	99.6%	76.6%	77.3%	67.6%	81.3%	86.9%
Group Average	39.3%	31.1%	43.4%	15.1%	16.8%	14.8%	29.0%	23.4%
Investor Owned								
West Kootenay	56.6%	62.6%	54.2%	56.5%	60.6%	63.2%	69.7%	56.0%
ATCO Electric	79.1%	63.2%	56.4%	68.3%	60.0%	79.6%	76.0%	77.7%
TransAlta Utilities	194.7%	110.1%	210.8%	100.0%	123.4%	91.4%	99.9%	103.7%
Northern Ontario Power	115.0%	29.8%	181.3%	128.1%	96.3%	67.3%	115.6%	90.3%
Nova Scotia Power	57.2%	69.6%	66.3%	80.9%	92.4%	93.8%	56.4%	26.0%
Group Average	102.2%	84.0%	125.2%	89.4%	99.8%	87.4%	82.7%	81.9%
Industry Average	34.1%	43.7%	57.7%	35.4%	34.2%	26.0%	43.2%	34.4%

(1) Based on dividends declared, earnings before extraordinary items.

With balanced budgets, most provincial governments have less need to drain capital from their utilities. Accordingly, we expect the common dividend payout to improve in the future, enabling balance sheets of government-owned utilities to strengthen.

D.W. Reeves

NEWFOUNDLAND AND LABRADOR HYDRO

EVIDENCE OF DAVID W. REEVES

Q. Would you please give your name, address and occupation?

A. My name is David Reeves and I live in St. John's. I am a professional engineer and the Vice-President of Transmission and Rural Operations with Newfoundland and Labrador Hydro. I have been employed with Hydro for 29 years and have been in my current position for six years.

Q. What evidence will you be presenting to the Board?

A. I will be presenting evidence on the following topics:

1. Hydro's transmission facilities on the Island and in Labrador;
2. Hydro's Interconnected and Isolated Rural Systems on the Island and in Labrador;
3. The organizational structure in place to manage the transmission and rural facilities;
4. Initiatives which have taken place to improve the organizational structure and reliability of the transmission and rural systems and to improve the cost effectiveness of the rural systems; and
5. The Transmission and Rural Operations portion of Hydro's 2002 Capital Budget.

Q. Please describe Hydro's interconnected transmission systems on the Island and in Labrador.

A. Hydro owns and operates two interconnected transmission systems, one on the Island and the other in Labrador. These transmission systems connect Hydro's generating stations to its customers throughout the Province.

On the Island Interconnected System, Hydro owns and maintains 3,380 km of high voltage lines, and 53 high voltage terminal stations operating at 230, 138 and 69 kV.

On the Labrador Interconnected System, Hydro owns a 269 km 138 kV transmission line and the associated terminal stations interconnecting Happy Valley/Goose Bay to Churchill Falls. Hydro also owns 44 km of 46 kV sub-transmission lines in Labrador West, 13 km of which is from Wabush to the Newfoundland/Quebec border providing an emergency interconnection between Labrador West and Fermont, Quebec. To service its customers in Labrador West, Hydro has an arrangement with TWINCo, the owner of the transmission facilities, for wheeling electrical energy from Churchill Falls.

Schedule I shows the major components of Hydro's Interconnected Systems on the Island and in Labrador.

Q. Please describe Hydro's rural systems.

A. On the Island Interconnected System, Hydro owns and maintains 2,458 km of low voltage distribution lines, up to 25 kV, and 25 low voltage substations which service approximately 21,800 Rural Customers. These Rural Customers are serviced from distribution systems located in some 181 communities on the south coast, northeast coast and along the Great Northern Peninsula.

On the Labrador Interconnected System, Hydro owns and maintains 326 km of low voltage distribution lines and 9 substations in Wabush, Labrador City, Happy Valley/Goose Bay, North West River, Sheshatshiu, and Mud Lake and limited distribution facilities in Churchill Falls. Hydro services approximately 8,700 Rural Customers on the Labrador Interconnected System.

Hydro owns and operates 25 isolated diesel generating and distribution systems serving approximately 4,400 customers in 45 communities throughout Newfoundland and Labrador. Sixteen of these systems are located along coastal Labrador and nine are on the Island of Newfoundland.

Schedule II shows the location of these isolated diesel-generating plants and Schedule III gives a breakdown of the installed capacity of these plants. The total installed capacity of all 25 plants is approximately 29 MW.

All of these Isolated Rural Systems are serviced primarily by Hydro owned generation with two exceptions. At Mary's Harbour, in addition to diesel generation, Hydro purchases energy from a private company which owns and operates a small hydro plant. On the L'Anse au Loup System, Hydro purchases secondary energy, when available, from the Hydro-Quebec Lac Robertson hydro plant. These two purchases are covered by separate agreements which are based on a share-the-savings principle when compared to more expensive diesel generation.

Q. Please compare Hydro's energy production and supply cost forecasts for the Isolated Rural Systems provided to the Board for 1992 with the actual results for 1992.

A. Hydro's 1992 diesel production for the Labrador Isolated Rural Systems was 32,808 MWh, 1,026 MWh lower than the forecast. The energy purchased was 246 MWh, 154 MWh lower than the forecast.

For the Island Isolated Rural Systems, diesel production was 36,428 MWh, 1,743 MWh lower than forecast. The woodchip thermal production was 23,997 MWh, 3,597 MWh lower than forecast and hydroelectric production was 988 MWh, 62 MWh lower than forecast.

The actual and forecast production for 1992 are presented in Schedule IV.

The actual energy supply cost for Hydro's Isolated Rural Systems for 1992 was $7.3 million compared to the forecast of $7.7 million.

Q. Please compare actual production levels and supply cost for Hydro's Isolated Rural Systems for 2000 with that experienced in 1992.

A. In 2000, diesel production for the Labrador Isolated Rural Systems was 32,335 MWh, 473 MWh lower than 1992 due to more energy being purchased. The energy purchased was 12,412 MWh, 12,166 MWh higher than 1992 due to the purchase of secondary energy on the L'Anse au Loup System from the Hydro-Quebec Lac Robertson plant.

For the Island Isolated Rural Systems, diesel generation was 10,881 MWh, 25,547 MWh lower than 1992. The woodchip thermal production was zero, a decrease of 23,997 MWh. These decreases were a result of the interconnection of five Isolated Rural Systems to the Island Interconnected System. The hydroelectric production which was part of the St. Anthony/Roddickton Isolated Rural System in 1992 is now part of the Island Interconnected System. A comparison of the actuals for the years are shown in Schedule IV.

The actual energy supply cost for 2000 was $6.6 million, a decrease of $0.7 million when compared to the actual for 1992.

Q. Please provide the energy supply forecasts for Hydro's Isolated Rural Systems for 2001 and 2002.

A. The 2001 and 2002 diesel production for the Labrador Isolated Rural System is forecast to be 34,512 MWh and 34,461 MWh respectively and energy purchases are forecast to be 13,047 MWh and 13,150 MWh respectively.

For the Island Isolated Rural Systems, the 2001 and 2002 production is forecast to be 10,908 MWh and 10,768 MWh respectively.

A comparison of these forecasts is shown in Schedule IV.

The 2001 and 2002 forecast energy supply costs are $7.3 million and $6.9 million respectively.

Q. Please describe to the Board the structure which is in place to manage the Island and Labrador transmission and rural systems.

A. The responsibility for the maintenance of Hydro's Island and Labrador transmission systems and the operation and maintenance of the rural systems is assigned to Transmission and Rural Operations. These systems are managed by three regions: Central, Northern and Labrador.

Each region has a headquarters office, warehousing and centralized maintenance facilities. Due to the geographic size of the regions, additional depots are also located within each region to facilitate shorter travel time to work sites.

Q. Please outline the approach to maintenance and operation of the transmission and rural systems.

A. The responsibility for the maintenance of the transmission systems, and the maintenance and operation of the rural systems is assigned to each of the regions as described above. Each region is responsible for managing the assets through the identification of maintenance requirements, justification of operational and capital requirements and execution of the work.

These work activities are performed by work crews located throughout each region, and managed from the regional headquarters. Employees such as line workers are strategically located throughout the Island and Labrador for the routine maintenance and major repairs to transmission and distribution facilities.

The Energy Control Center (ECC) operates the interconnected transmission systems, as will be explained by Mr. Henderson. The distribution systems throughout the province are operated by their respective regions with the ECC having some distribution feeder control where remote control facilities exist.

The Isolated Rural Systems are operated on a "semi-attended" basis. Historically, many of the isolated diesel plants required full-time operating staff, however, with changes in technology, these plants now require only "semi-attended" staffing. This requires an operator to be present at the plant for scheduled intervals of time throughout the day to perform plant checks and running maintenance activities. During other periods of the day the operators are available in the community as required.

Q. What changes have been made to improve the organizational structure in Transmission and Rural Operations?

A. There are two changes which have taken place in Transmission and Rural Operations:

- Completion of a regional reorganization; and
- Rationalization of line maintenance staffing.

Q. Please describe the regional reorganization.

A. During 1996, Transmission and Rural Operations restructured its operational regions. Prior to this, there were six regions to maintain the transmission systems and operate and maintain rural systems of the Province.

These were as follows:

Region	**Location of Headquarters**
Eastern	Whitbourne
Central	Bishops Falls
Western	Stephenville
North Western	Port Saunders
Northern	St. Anthony
Labrador	Happy Valley/Goose Bay

These six regions were amalgamated into the following three regions:

Region	**Location of Headquarters**
Central	Bishops Falls
Northern	Port Saunders
Labrador	Happy Valley/Goose Bay

This amalgamation also resulted in several processes being centralized within the regional headquarters. These included management of the assets, maintenance planning and scheduling and field technical support.

Q. Please give an overview of changes to Hydro's line maintenance staffing.

A. Transmission and Rural Operations recently implemented changes to how Hydro maintains the transmission and distribution lines. The location of many lineworker crews was established in communities over 20 years ago when the situation with respect to the lines, communication and road access were quite different. After considering the number and location of staff and the location of depots, decreases were made in the staffing levels in early 2001.

Q. What significant initiatives have been undertaken to improve reliability of service since the last referral?

A. There have been a number of initiatives to improve reliability of service since the last referral as follows:

- Improvements to transmission line ice loading capability;
- Replacement of defective insulators; and
- Improvements to lightning protection for the Avalon Peninsula.

Q. Please describe the initiatives which have been completed to improve transmission line reliability with respect to ice loading capability.

A. Over the past thirty years, Hydro has experienced significant outages on the 230 kV transmission lines on the Avalon Peninsula, in Western Newfoundland and on the 69 kV transmission line feeding the Connaigre Peninsula. These outages were caused by ice loadings which exceeded the original design resulting in significant outages to customers in these areas.

During the period 1997 to 2000, Hydro completed upgrades on two transmission lines on the Avalon Peninsula. In 2001, a third transmission line will be upgraded thus completing the upgrading of the steel 230 kV transmission lines from Sunnyside to Hydro's Thermal Generating Plant in Holyrood.

Hydro is including in the 2002 Capital Budget the upgrading of the lines between the Holyrood Generating Plant and St. John's. This will complete the upgrade of the steel transmission lines from Sunnyside to St. John's.

In addition, in 1998 an upgrade was completed on the transmission line TL220 from Bay d'Espoir to the Connaigre Peninsula and in 1999 an upgrade was completed on the transmission line TL228 from Buchans to Corner Brook.

Q. Please give an overview of initiatives undertaken to address defective transmission line insulators.

A. In the 1980's, Hydro, through its preventative maintenance inspections detected an insulator problem similar to that being experienced by other utilities. It was determined that some Canadian Ohio Brass (COB) suspension insulators were prematurely failing due to a cement problem. The design of the insulation system for transmission lines consists of multiple suspension insulators in a string which allows for adverse environmental conditions. Therefore, having an individual insulator fail does not cause an immediate reliability problem. One of the purposes of Hydro's ongoing preventative maintenance program is to detect and replace individual insulators as they fail before reliability is affected.

The failure rate on the suspect COB insulators and timing of these failures were dependent on a number of factors which included the number of freeze-thaw cycles and other environmental conditions. A normal life expectancy for an insulator is approximately 40 years, however for these COB insulators the life has been between 10-30 years.

To address this insulator problem, an intensive testing program on transmission lines was implemented by Hydro. Due to the high number of defective insulators found in the central and eastern areas of the Island, a proactive approach was taken in these areas for the bulk replacement of COB insulators which began in 1992 and was completed in 1997. On the transmission lines in the western area of the Island, the testing did not reveal a high percentage of defective insulators. Thus, it was decided to continue to change out individual defective insulators as they were discovered during regular inspections and delay the bulk replacement until testing found a higher number of defective insulators.

Most recently in 1999, the COB insulator problem was detected on the 138 kV line L1301 from Churchill Falls to Goose Bay in Labrador. As a result, it was determined that all insulators had to be replaced. Half of the insulators on this line were replaced in 2000 and the remainder will be completed in 2001.

Q. Please explain what Hydro has done to improve lightning protection on the transmission lines providing electrical power to the Avalon Peninsula.

A. Over the years, Hydro experienced simultaneous outages on transmission lines TL202 and 206 as a result of lightning. These outages resulted in interruptions to all electrical customers on the Avalon Peninsula as TL202 and 206 are the primary 230 kV transmission lines which carry electrical power from the Bay d'Espoir plant to the Avalon Peninsula. In 2000, Hydro commenced the installation of lightning arrestors on TL206.

Prior to commencing this work, a review of the outages showed that on average, a simultaneous outage due to lightning was occurring once every two and one-half years. This was an unacceptable outage rate for such a large number of customers. A technical review was conducted which indicated that the best option was to proceed with the installation of lightning arrestors on each insulator string on one of the transmission lines. This technology has been used by other utilities with good success. With the installation of these lightning arrestors, it is estimated that the outage return rate of a simultaneous outage as a result of lightning will be significantly improved.

As stated previously, this work began in 2000 with the installation of lightning arrestors on one-half of line TL206. The remaining one-half was completed in March, 2001, prior to the lightning season.

Q. What initiatives have been undertaken to improve cost effectiveness of the Isolated Rural Systems?

A. There have been a number of initiatives as follows:

- Improvements in operation and maintenance strategy for the Isolated Rural Systems;
- Completion of new and upgraded diesel plants; and
- Interconnection of Isolated Rural Systems to the adjacent interconnected system.

Q. Please explain the changes which are being implemented to improve the operation and maintenance strategy for Hydro’s Isolated Rural Systems.

A. Historically, the operational strategy for the Isolated Rural Systems consisted of having operators located at each isolated system primarily responsible for operating the diesel plant. When maintenance was required on either the diesel plant or the distribution system, maintenance staff would travel to the communities from the regional headquarters. In 1998, a change was initiated to the operational strategy whereby a new classification called Diesel Systems Representative (DSR) was developed. The training necessary to enable staff to move to this new classification started in 1999 and full implementation of the DSR will be completed by year end, 2001.

This new position will not only be responsible for operating the diesel plant but also for some limited distribution line and plant maintenance work as well as some general maintenance duties, which should reduce the travel requirement for maintenance staff from regional offices. It will also give an improved reliability of service to the communities as the DSR will have the training to correct minor operational equipment problems. In addition to the maintenance functions, DSR's will also provide customer service in their community involving meter reading and interactions with the customers as required.

Q. Please give an overview of the diesel plants which have been upgraded and the isolated systems that have been interconnected.

A. Over the past ten years, Hydro has had a number of isolated diesel plants which required upgrading due to age and physical condition. Prior to commencing these upgrades, where options existed, an evaluation was completed to determine if it was cost effective to connect the communities serviced by these plants to one of the interconnected systems. As a result, six isolated diesel plants were removed from service after the associated communities were connected to the Interconnected System. The interconnection of the remaining systems was not cost effective and therefore the diesel plants were upgraded.

During this period, the following diesel plants were upgraded or are in the process of being upgraded:

- Hopedale in 1992;
- Grey River in 1992;
- Mary's Harbour in 1994;
- Port Hope Simpson in 1994;
- Ramea in 1998;
- Nain in progress; and
- McCallum in progress.

Over the same period, as a result of the cost effectiveness evaluations, the following diesel systems were connected to one of the interconnected systems:

- Petite Forte, 1993;
- Westport, 1996;
- Roddickton/St. Anthony, 1996;
- Southeast Bight, 1998;
- Mud Lake, 1998; and
- La Poile, 1999.

Q. Would you please give an overview of how Hydro's 2002 Capital Budget for Transmission and Rural Operations compares to those of the past five years.

A. As shown in Section A of Hydro's 2002 Capital Budget, the amount associated with the Transmission and Rural Operations is $24.7 million compared to the past five years average of approximately $26.1 million.

The following is a summary of these forecast expenditures:

Transmission and Rural Operations Division Capital Budget for 2002 ($thousands)	
Transmission	16,527
Rural Operations	8,129
Total Transmission and Rural Operations Division	24,656

Q. Please highlight the significant elements of the transmission portion of Hydro's 2002 Capital Budget.

A. The transmission portion of Hydro's 2002 Capital Budget of approximately $16.5 million addresses reliability issues primarily associated with improving the transmission system ice loading capabilities on the Avalon Peninsula and the replacement of defective insulators on a number of transmission lines.

As explained previously, the last phase of the ice loading upgrade on the Avalon Peninsula will be completed in 2002. Two transmission lines, one connecting the Holyrood and Hardwoods Terminal Stations and the other connecting the Hardwoods and Oxen Pond Terminal Stations, will be upgraded at a cost of approximately $13.6 million. Funds to complete engineering for this phase were approved by the Board for 2001.

As well, work will continue on the bulk replacement of insulators on five transmission lines located on the west coast of the Island. The total amount of this work is approximately $1.9 million.

Q. Please give a description of significant projects associated with the rural portion of Hydro's 2002 Capital Budget.

A. There are basically three categories as follows:

- Service extensions;
- Distribution upgrades; and
- Specific reliability improvements.

With respect to service extensions, a yearly allotment, based on past expenditures, is included for new service connections, including streetlights. The total budget for all regions for this category is approximately $1 million. For the period 1996 to 2000 the total average annual expenditures for all regions was $1.2 million.

Similar to the service extensions, there is also a yearly allotment for the upgrading of distribution lines and equipment. The total budget for all regions is approximately $1.3 million. This compares to the total average annual expenditures of $1.4 million for all regions for the period 1996 to 2000.

There are also a number of projects that relate to specific reliability improvements. Distribution line upgrades totaling approximately $1.3 million will be completed on: the South Brook, Kings Point, Burgeo, St. Anthony and Goose Cove systems. Replacement of diesel units will cost approximately $1.6 million. Replacement of defective distribution insulators in the Central Region of the Island will cost approximately $1 million. The last significant item in this category is the upgrading of two diesel plants, one at Harbour Deep and the other at St. Lewis. These upgrades are two-year projects with engineering in the first year and upgrading in the second. Harbour Deep will be completed in 2002 and St. Lewis in 2003. In 2002, $574,000 is the total forecast cost for both projects.

Q. Please give a description of significant items associated with Administration in the General Properties Section of Hydro's 2002 Capital Budget.

A. There is one item regarding the replacement of vehicles at a cost of $1.8 million which I will address. This is for the replacement of 35 vehicles including 6 cars, 17 pickups and 12 cab and chassis for line trucks. These replacements take into account their overall condition, distance driven and the history of maintenance costs.

Q. Section C of Hydro's 2002 Capital Budget lists projects which are subject to minimum filing requirements as established by the Board. Please give a description of these projects.

A. The projects in Section C are associated with new additions and capacity upgrades. These include the Avalon transmission line upgrades and the uprating of transmission line TL203 from Sunnyside to Western Avalon.

The upgrading of the lines from Holyrood to Oxen Pond for a higher ice loading was explained previously in my evidence. Inclusion of these projects in Section C results from the fact that in achieving the desired ice loading upgrades, larger conductors are required which also results in a higher energy transfer capability.

Uprating TL203 to increase the energy transfer capability involves the addition of mid span structures at critical locations. These new structures will give ground clearances necessary for the safe operation with the new loading capability. This increased transfer capability will be of most benefit during periods when the Holyrood Thermal Plant is off-line or when the east coast transmission system is experiencing a 230 kV line outage.

This upgrade will improve the reliability of service to customers on the Avalon Peninsula.

Q. What are the leases in Section D of Hydro's 2002 Capital Budget for which you are responsible?

A. There are a number of leases in Section D for which I am responsible. There is one lease for electrical test equipment and five property leases.

Q. Does this complete your evidence?

A. Yes.

Schedule I

D.W. Reeves

Provincial Transmission Grid

Schedule II
D.W. Reeves

Provincial Isolated Systems (Diesel)

NEWFOUNDLAND AND LABRADOR HYDRO
INSTALLED GENERATING CAPACITY
ISOLATED RURAL SYSTEMS

Plant Location	Installed Capacity (kW)
Labrador	
Black Tickle	850
Cartwright	1,670
Charlottetown	936
Davis Inlet	1,222
Hopedale	1,533
L'Anse au Loup	3,900
Makkovik	1,705
Mary's Harbour	1,550
Nain	2,600
Norman Bay	90
Paradise River	190
Port Hope Simpson	1,210
Postville	675
Rigolet	1,167
St. Lewis	1,236
Williams Harbour	362
SUBTOTAL	20,896
Island	
Francois	611
Grey River	522
Harbour Deep	613
Little Bay Islands	1,250
McCallum	522
Petites	155
Ramea	2,775
Rencontre East	675
St. Brendan's	735
SUBTOTAL	7,858
TOTAL INSTALLED CAPACITY (Dec. 31, 2000)	**28,754**

Schedule IV
D.W. Reeves

Newfoundland and Labrador Hydro
Forecast and Actual Net Production[1]
For 1992 Forecast and Actual, 2000 Actual, and 2001 - 2002 Forecast
Isolated Rural Systems

	1992			2000		2001		2002	
	Filed PUB 1991	Actual	Variance	Actual	Variance	Forecast	Variance	Forecast	Variance
	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh
Labrador									
Diesel	33,834	32,808	(1,026)	32,636	(172)	34,512	1,876	34,461	(51)
Purchased[2]	400	246	(154)	12,412	12,166	13,047	635	13,150	103
Subtotal	34,234	33,054	(1,180)	45,048	11,994	47,559	2,511	47,611	52
Island									
Diesel	38,171	36,428	(1,743)	10,881	(25,547)	10,908	27	10,768	(140)
Mini Hydro[3]	1,050	988	(62)	0	(988)	0	0	0	0
Woodchip[4]	27,594	23,997	(3,597)	0	(23,997)	0	0	0	0
Subtotal	66,815	61,413	(5,402)	10,881	(50,532)	10,908	27	10,768	(140)
Total Isolated Systems	101,049	94,467	(6,582)	55,929	(38,538)	58,467	2,538	58,379	(88)

1. Net production excludes station service.
2. Purchases from Mary's Harbour Hydro and starting in 1996 includes purchases from Hydro Quebec for L'Anse-au-Loup.
3. Hydro production from Roddickton mini hydro until interconnection in 1996.
4. Roddicktion woodchip plant ceased operations following interconnection.

R.J. Henderson

NEWFOUNDLAND AND LABRADOR HYDRO

EVIDENCE OF ROBERT J. HENDERSON

Q. Would you please state your name, address and occupation?

A. My name is Robert Henderson. I live in St. John's and I am the Manager of System Operations with Newfoundland and Labrador Hydro.

Q. Please outline your qualifications and experience.

A. I am a professional engineer working with Hydro since 1982. I have held various positions with Hydro in the Engineering, Planning and Operations areas. In 1995 I was promoted to my current position of Manager of System Operations.

Q. Please outline the responsibilities of your current position.

A. The responsibilities of my position include managing:

- The operation of Hydro's transmission and generation equipment on the interconnected power systems controlled by the Energy Control Centre (ECC);
- Planned and unplanned outages to system equipment;
- The economic operation of system equipment;
- Fuel budgets for all interconnected system plants;
- The operation of system reservoirs;
- The power purchase agreements; and
- The day-to-day activity with respect to administering the power sales agreements with Newfoundland Power and the Industrial Customers.

Q. What evidence will you be presenting?

A. I will be presenting evidence on the following:

1. Hydro's production facilities on the interconnected power system in Labrador and on the Island;
2. Hydro's Energy Control Centre and the Telecontrol facilities used in the operation of the power systems;
3. The operating policy for Hydro's interconnected systems' production facilities;
4. A comparison of the actual energy supply costs for 1992 with the costs provided to the Board in 1992;
5. A comparison of the actual energy supply costs for 2000 with the actual 1992 costs; and
6. A forecast of energy supply costs for 2001 and 2002.

Q. Please give a general description of Hydro's production facilities on the Island Interconnected System.

A. On the Island Interconnected System, Hydro owns and operates eight hydroelectric generating stations varying in size from 400 kW to 592,000 kW. It also owns and operates one oil-fired steam electric generating station at Holyrood, three oil-fired gas turbine plants, two diesel plants and two mobile diesel units. These plants and their capacities are listed in Schedule I attached to my evidence. The locations of the plants are shown on the map on Schedule II.

The gas turbine plants and diesel units are used only for emergency and limited peaking purposes due to their high cost of operation. The Holyrood generating plant and the hydroelectric plants are used for supplying base and peak load. Hydro's hydroelectric plants represent about 59 % of Hydro's total average energy producing capability.

Q. Have there been any changes to the capabilities of these facilities since 1992?

A. Yes, there have been changes to the Bay d'Espoir net capacity and a number of changes to the average energy capability of the hydroelectric plants.

The Bay d'Espoir plant net capacity has increased from 580 MW to 592 MW as a result of the new runners installed on units 1 to 6 over the period 1993 to 1996. Testing on these units has shown they have an additional capacity of 2 MW per unit.

The average annual energy capability of all hydroelectric units on the Island Interconnected System has changed from 4,211.9 GWh to 4,271.5 GWh, an increase of 59.6 GWh. This increase is due to Hydro's experience with water to energy conversion factors since the implementation of the Energy Management System in 1989, the addition of 10 years of hydrological data to our long-term average and the inclusion of the Roddickton mini-hydro plant as a result of the interconnection of the plant in 1996.

There has been an addition to total capacity of 10.2 MW due to the interconnection of the St. Anthony diesel plant, the Roddickton mini-hydro, and the mobile diesel units in Roddickton.

Q. What significant changes have been made to the Island Interconnected System production facilities since 1992 to improve reliability, efficiency and environmental performance?

A. There have been a number of significant changes to improve reliability, efficiency and environmental performance. These are:

- Runner replacements on Bay d'Espoir units 1 to 6;
- Exciter replacements on Bay d'Espoir units 1 to 6;

- Exciter replacements on Holyrood units 1 and 2;
- Electro-Hydraulic Control (EHC) replacement on Holyrood unit 2;
- Installation of on-line performance monitoring at Holyrood;
- Boiler Control and Station Service Control replacement on Holyrood unit 3;
- New water treatment plant at Holyrood; and
- Upgrade of the wastewater facility and other environmental improvements at Holyrood.

The runner replacements at Bay d'Espoir were completed between 1993 and 1996. This project provided three major benefits. The first, as previously mentioned, was an increase in capacity of 2 MW per unit. This was achieved through a redesign of the runners using modern design techniques. The second was a 2.8% increase in unit efficiency. The improvement in efficiency is an increase over the old runners, which had deteriorated due to weaknesses in the original material used in the runners. The new runners are made of stainless steel and are much less susceptible to deterioration. The third benefit was significant maintenance reductions. The old runners frequently had to be removed from the unit and repaired due to the deterioration.

The exciters at both Bay d'Espoir and Holyrood were of similar design and had become obsolete due to parts becoming difficult to obtain and the manufacturers no longer supporting these units. New exciters were installed between 1993 and 2000. The replacement exciters are of modern electronic design and will provide more reliable service.

The EHC systems on units 1 and 2 at Holyrood were identified to have also reached the end of their useful life. The EHC system on unit 2 was replaced in 2000. The EHC for unit 1 will be kept in service using parts from the old unit 2 EHC until 2003 when it is anticipated to be replaced.

The on-line efficiency monitoring system at Holyrood was placed in operation in 1995. It is a controllable losses computer program that monitors critical steam-electric generator system measurements and gives information to the operator where control changes can be made to improve the unit's efficiency.

The boiler control and station service control systems were replaced on unit 3 at Holyrood in 1997. The original controls were outdated and spare parts were no longer available to maintain the required reliability of the unit.

In 1998 the water treatment plant at Holyrood was replaced with a new plant as the existing plant had deteriorated beyond repair. The replacement plant resulted in greater water treatment efficiency and higher water quality.

In 1998 the wastewater treatment plant at Holyrood was upgraded in conjunction with the construction of a controlled waste landfill. These environmental projects were undertaken to improve wastewater releases from the plant and enable Hydro to discontinue disposal of furnace ash as well as other waste products at the Robin Hood Bay Municipal Landfill.

Q. What other sources of energy supply does Hydro utilize on the Island Interconnected System?

A. In addition to its own generation, Hydro utilizes purchased power and energy to meet its supply requirements. Hydro has long standing arrangements to buy energy from Corner Brook Pulp and Paper Limited and Abitibi Consolidated Inc. (ACI) (Grand Falls Division) when they have energy available that is surplus to their needs and it is cost effective for Hydro to purchase. As well, starting in the fall of 1998 Hydro began purchasing energy from two Non-Utility Generators (NUGs), the Star Lake Hydro Partnership from their Star Lake Hydroelectric Generating Station and Algonquin Power from their Rattle Brook Hydroelectric Generating Station.

Hydro also buys power for peaking purposes from ACI (Stephenville Division) through an interruptible load contract. In this arrangement ACI interrupts up to 46 MW of load when requested by Hydro. As well, Hydro can request Newfoundland Power to operate their stand-by gas turbines and diesel units to meet peak loads.

Q. What arrangement does Hydro have for purchasing energy from Non-Utility Generators?

A. In 1995 Hydro entered into agreements with Algonquin Power and the Star Lake Hydro Partnership for supply of “non-dispatchable” power and energy from two small hydraulic developments. These agreements are for 25 years starting on the in-service dates of the projects, October 1998. The rate Hydro pays for the energy purchased from these facilities is in four parts. There are winter rates applicable to the period November to March and non-winter rates applicable to the remainder of the year. Each set of rates has two components, a fixed part to reflect the capital cost of the project and a variable part, to reflect the variable operating costs, the latter of which changes with the annual change in the Consumer Price Index (CPI).

The Algonquin Power development is on Rattle Brook in White Bay. It is a 4 MW “run of river” development with an expected annual average energy production of 17.9 GWh.

The Star Lake Hydro Partnership development is on Star Lake near Red Indian Lake in central Newfoundland. It is a 15 MW development with minimal storage capability. It has an expected annual average energy production of 128 GWh.

The locations of these plants are shown on Schedule II of my evidence.

Q. What is Hydro's operating policy with respect to the use of all sources available to it on the Island Interconnected System for meeting customer energy requirements?

A. Hydro operates its large hydroelectric and Holyrood facilities to ensure sufficient water is maintained in the hydroelectric plant reservoirs to meet customer firm energy requirements should a repeat of the lowest historic inflow sequence experienced in our 50 years of records be realized. In addition to this, the hydroelectric plants are operated as efficiently as practical while minimizing water spillage. The Holyrood plant is scheduled to operate to supplement the hydroelectric units in a manner to produce energy as efficiently as possible. In this way the fuel related costs of operating Holyrood are minimized.

The NUGs and Hydro's small hydroelectric plants have little or no water storage capability and as a result their operation cannot be scheduled and must follow the pattern of water inflows to their watershed areas.

Hydro's and Newfoundland Power's gas turbine plants and diesel plants and the Interruptible contract with ACI in Stephenville are rarely used due to the relatively high cost of use. They are used only for peaking, that is, when other available sources are near their limit, or for an emergency, such as when there is limited transmission capability to the area where the plant is located.

Q. How is this operating policy implemented?

A. Hydro uses a computer simulation and optimization program to model all of its reservoirs and generating facilities. The program uses current water storage levels and load forecast data, and models the operation of the island generation system using the 50 historical hydrological sequences. The program determines an optimum schedule of production, which provides the lowest thermal production cost and ensures all firm loads are met in all historic hydrological sequences. It is used weekly by the System Operations group to schedule generating plant production for the upcoming week.

The program is also used to determine the minimum reservoir energy storage levels that should be maintained to ensure all firm loads can be met in the forecast period. These minimum storage levels are used as a reference for thermal production forecasting.

Schedule III provides the 2001 minimum energy storage targets and the 2001 energy in storage to date.

Q. Please give a brief description of Hydro's Energy Control Centre.

A. Hydro's Energy Control Centre (ECC) located in St. John's is responsible for the safe, secure and efficient flow of power through all of Hydro's interconnected generation, transmission and terminal equipment to the delivery points of Hydro's major customers and to the rural distribution systems. The ECC remotely monitors and controls 41 sites, which include Hydro's hydroelectric, gas turbine and steam-electric generating stations, terminal stations and water control structures.

The ECC is staffed 24 hours per day year round and, in addition to system control and monitoring, manages after-hours rural system customer trouble calls and initiates dispatching of field workers to address customer supply problems.

The central control system used by the ECC is the Energy Management System (EMS). The EMS provides the basic Supervisory Control and Data Acquisition (SCADA) system for all remote sites. In addition, it has an Automatic Generation Control (AGC) system that controls the output of the generating units at the Bay d'Espoir, Hinds Lake, Upper Salmon and Cat Arm generating plants. The AGC system uses an economic dispatch function to distribute the load carried by the units so that the load is met in the most efficient manner. The EMS also has a number of computer programs available to the ECC staff for assessing the security of the system for various system conditions such as generator or transmission equipment outages. Through these programs the ECC staff can take action to minimize the impact to the customer of system problems.

Q. Please describe the telecontrol facilities used to support the operation of the power system.

A. The telecontrol facilities form an integral part of Hydro's interconnected power systems. They consist of Remote Terminal Units (RTU) at the various remote sites and communications systems.

Each remote site that the ECC controls has an RTU. The RTU receives control signals from the EMS and sends them on to the local equipment to be controlled. The RTUs also send critical information back to the EMS. These facilities make it possible for the ECC operators to respond quickly to changes or emergencies on the interconnected power systems.

The communications system provides three basic functions to support power system operation. They are SCADA, teleprotection and operational voice. The SCADA communications are the communications between the EMS computer and the RTUs. Teleprotection communications operate between two or more terminals of a transmission line and are required to transmit line protection signals and to be extremely fast and reliable in order to protect the line from damage. Voice communications are required between all stations and the ECC and between the ECC and the field service personnel in remote locations such as along transmission line routes.

The communications systems consist of various media. For the SCADA function microwave, fibre optic, commercial services and power line carrier are the primary media. Microwave, power line carrier and fibre optic communications are the primary media for teleprotection. The operational voice system uses an island-wide VHF mobile radio system, power line carrier and microwave systems. Two independent facilities are usually provided so that the failure of one will not prevent voice communication. The commercial services consist of satellite services and common carrier services.

Schedule IV attached to my evidence provides a map showing Hydro's communications facilities in support of the SCADA and teleprotection functions.

Q. Please describe the basis for determining Hydro's Island Interconnected System energy supply forecast.

A. Hydro's energy supply forecast is based on the Operating Load Forecast and applying against this the long-term average hydraulic energy production from Hydro's generating plants, average energy from the NUGs and small amounts of energy anticipated from standby plants. Any additional energy requirement is met from the Holyrood Generating Station.

This method is consistent with the way these forecasts were completed in the past with the exception of the addition of the NUGs.

Q. Please provide a comparison of Hydro's energy production forecast for the Island Interconnected System provided to the Board for 1992 and the actual results for 1992.

A. Hydro's 1992 hydroelectric generation was 4,222 GWh, 10 GWh higher than the 1992 forecast due to 1992 inflows being slightly higher than the long-term averages. The thermal production was 1,705 GWh, 139 GWh lower than forecast due to lower system load and higher hydraulic generation and energy purchases. The energy purchases of 5 GWh were up primarily due to unforecasted surplus energy sales by ACI and Corner Brook Pulp and Paper. The actual and forecast energy production for 1992 are presented in Schedule V.

The energy supply costs for 1992 were $39.0 million which is an increase of $1.1 million over the 1992 forecast due to fuel prices being higher than the forecast offset by lower thermal production. The forecast and actual prices for 1992 are presented in Schedule VI.

Q. Please provide a comparison of the actual production levels and costs for the Island Interconnected System for 2000 with that experienced in 1992.

A. In 2000 the hydraulic generation was 5,017 GWh, 795 GWh higher than 1992 due to 2000 being one of the wettest years on record for our watershed areas. The energy purchases were 161 GWh, 156 GWh higher than 1992 due to the NUG energy purchases. The thermal generation in 2000 was 968 GWh, 736 GWh less than 1992 due to the hydraulic generation and energy purchase variances, offset by a slight increase in load. A comparison of the production for these two years is presented in Schedule V.

The energy supply costs for 2000 were $61.7 million, which is an increase of $22.2 million over the 1992 costs. The cost increase is due to higher fuel prices for No. 6 fuel at Holyrood of $10.2 million and higher power purchase costs of $12.2 million due primarily to the energy purchases from the NUGs. These were offset by the lower thermal production in 2000. The actual fuel prices for 2000 are presented in Schedule VII.

Q. Please provide the energy supply forecast for the Island Interconnected System for 2001 and 2002 and explain the changes from 2000.

A. The 2001 and 2002 forecast hydroelectric generation is 4,272 GWh, down 745 GWh from 2000 as hydraulic generation is forecast to be at the long-term average production. The energy purchases for 2001 and 2002 are forecast to be 146 GWh, down 15 GWh from 2000. The decrease in energy purchases is based on the NUGs returning to their expected long-term average production. The thermal production in 2001 and 2002 is forecast to be 1,975 GWh and 2,162 GWh respectively. The 2001 thermal production forecast is 1,007 GWh above 2000 due to the lower hydraulic generation and lower energy purchases and a 251 GWh increase in load. The 2002 thermal production forecast is 188 GWh higher than 2001 due to a forecast increase in load. A comparison of these production forecasts is provided in Schedule V.

The forecast energy supply costs for the Island Interconnected System for 2001 and 2002 are $115.6 million and $112.6 million respectively. These consist of the cost of No. 6 fuel for Holyrood at $103.8 million and $100.6 million for each year respectively. The power purchase costs are $11.2 million and $11.3 million respectively.

The increase in the No. 6 fuel expense in 2001 from 2000 of $54.5 million is due to higher forecast thermal production and higher forecast fuel prices. In 2002 the fuel expense is forecast to be lower due to lower forecast fuel prices. The power purchase cost for each year is up slightly due to NUG energy purchase price increases.

Q. Please provide the basis for determining the energy supply costs for 2001 and 2002, including the fuel prices used.

A. The fuel expenses are determined by applying forecast fuel prices to the fuel quantity requirement. The fuel quantity requirement for each plant is determined by applying a fuel conversion factor for each plant. In this forecast we are using fuel conversion factors of 610 kWh/bbl for Holyrood No. 6 fuel, 475 kWh/bbl for gas turbine fuel and 556 kWh/bbl for diesel plant fuel.

The conversion factor for Holyrood has increased from 605 kWh/bbl used in 1992 to 610 kWh/bbl. This increase reflects efficiency improvements, which have been experienced since 1995 when the new on-line monitoring system was placed in operation at Holyrood. The conversion factor for the gas turbine plants remains the same as was used in 1992. The diesel plant conversion factor has increased to 556 kWh/bbl from 531 kWh/bbl to reflect the inclusion of the more efficient St. Anthony plant, which is now part of the interconnected diesel plants.

The fuel oil price forecast used for 2001 and 2002 and a forecast to 2005 are provided in Schedule VIII. These prices are in Canadian dollars, and are for No. 6 fuel oil, 2.2% sulphur, at Holyrood based on forecast prices at New York Harbour. Hydro retains the services of the PIRA Energy Group of New York for its petroleum product market analysis and price forecasting. Their average underlying projection for crude oil prices through 2001 and 2002 is approximately $26(US) per barrel for West Texas Intermediate crude.

Their underlying projection for 2.2% sulfur No. 6 fuel oil is approximately $20(US) per barrel. To this Hydro applies the expected exchange rate to derive the Canadian dollar landed value. After taking into account variation in expected monthly fuel oil prices, the expected weighted purchase price for 2001 is $31.06(CDN) per barrel. The expected average price for 2002 is $28.38(CDN). These price projections reflect the outlook for oil market and exchange rate conditions as of the fall of 2000.

The power purchase expense for the NUGs was determined based on applying the long-term average production provided by the NUGs to the power contract rates. The rates for the NUGs, as I previously indicated, are in four parts, two of which escalate by the CPI. The rates for 2000, 2001 and 2002 are provided in Schedule IX.

Q. What arrangement does Hydro have for purchasing No. 6 fuel oil for Holyrood?

A. Hydro currently has a volume only contract for 10 million barrels of No. 6 fuel oil which began in 1997. At the end of 2000 there were 5.4 million barrels remaining under this contract.

The contract is awarded on the basis of competitive bids that meet Hydro's technical specifications for delivery at Hydro's Holyrood facility. The price Hydro pays for the fuel is in US dollars based on the average New York Harbour Price in the month a delivery is received.

Q. How does Hydro meet the power and energy supply requirements for the Labrador Interconnected System?

A. Hydro meets the power and energy requirements for the Labrador Interconnected System primarily through an agreement with CF(L)Co. Under that agreement Hydro purchases recall power and energy up to a maximum of 300 MW and 2,362 GWh annually.

Hydro has the right to use 67 MW of capacity in TWINCo's Wabush Terminal Station (T.S.) to enable the transfer of power and energy from Churchill Falls to Wabush and Labrador City. For that right, Hydro must pay a proportionate share of the Wabush T.S. operation and maintenance expenses.

Hydro also has standby generation in Happy Valley/Goose Bay to meet system emergencies. The standby generation consists of a 27 MW gas turbine remotely operated by the ECC, and an 11.7 MW diesel plant.

Q. Please provide a comparison of Hydro's forecast power and energy supply costs for the Labrador Interconnected System provided to the Board in 1992 to the actual results for 1992.

A. In 1992 Hydro increased the recall amount in order to supply the town of Labrador City and make additional sales to IOCC. At the beginning of the year the recall power and energy was for 136.5 MW with annual energy of 884.65 GWh. In November it was increased to 169.3 MW and 1,033.84 GWh of annual energy. The cost of this recall power and energy in 1992 was $2.7 million, which equaled the 1992 forecast. The actual energy purchased by Hydro in 1992 was 702.6 GWh as compared to the forecast of 721.6 GWh.

Hydro's share of the Wabush T.S. operating and maintenance expenses was $220,000, $154,000 above the forecast due to the transfer of Labrador City distribution system to Hydro. The fuel expenses for the standby diesel and gas turbine were less than $0.1 million.

Q. Please provide the actual power and energy supply costs for the Labrador Interconnected System for 2000 and explain the differences from the 1992 results.

A. In 2000 Hydro purchased 888.4 GWh from CF(L)Co for the supply to the Labrador Interconnected System at a cost of $2.6 million. This cost is down from 1992 by $0.1 million. The Wabush T.S. expenses in 2000 were $173,000, down $47,000 from 1992. The cost of fuel from the standby plants continued to be less than $0.1 million.

Q. Please compare the 2001 and 2002 forecast cost of power and energy for the Labrador Interconnected System with the actual 2000 costs.

A. In 2001 and 2002 Hydro is forecasting purchases from CF(L)Co for the Labrador Interconnected System of 1,026.2 and 1,042.3 GWh respectively. The cost of the recall power and energy for the Labrador Interconnected System is forecast to be $2.9 million and $2.8 million for 2001 and 2002 respectively. The decreases in costs are due to a CF(L)Co rate decrease effective September 1, 2001 which will remain in effect until September 2016. The Wabush T.S. expenses are $210,000 and $135,000 respectively. The higher cost in 2001 for the Wabush T.S. is due to some major work planned by TWINCo. The cost of fuel from the standby plants is forecast to continue to be less than $0.1 million.

Q. Does this conclude your evidence?

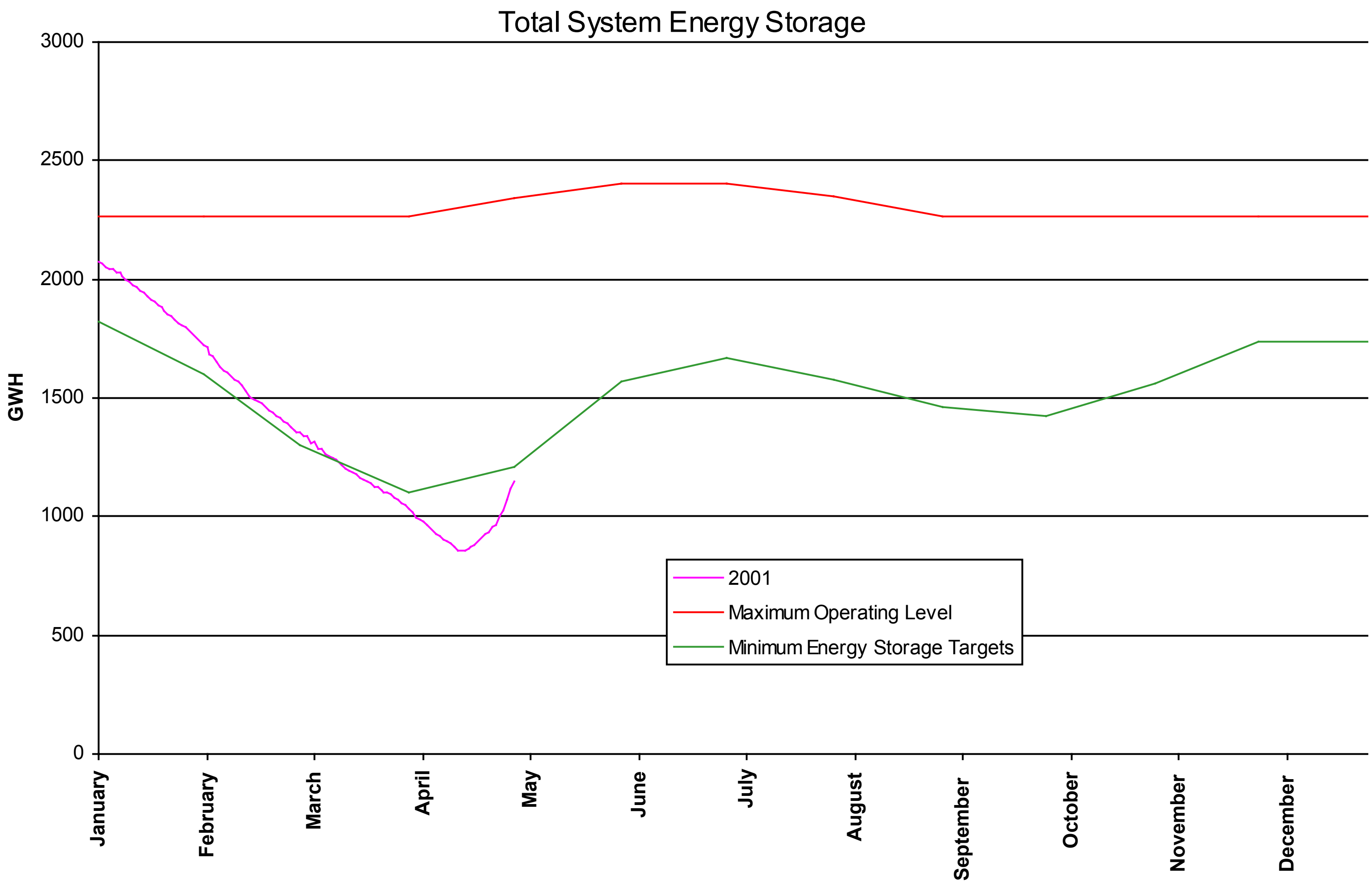
A. Yes.

NEWFOUNDLAND AND LABRADOR HYDRO
NET GENERATING CAPABILITY
ISLAND INTERCONNECTED SYSTEM

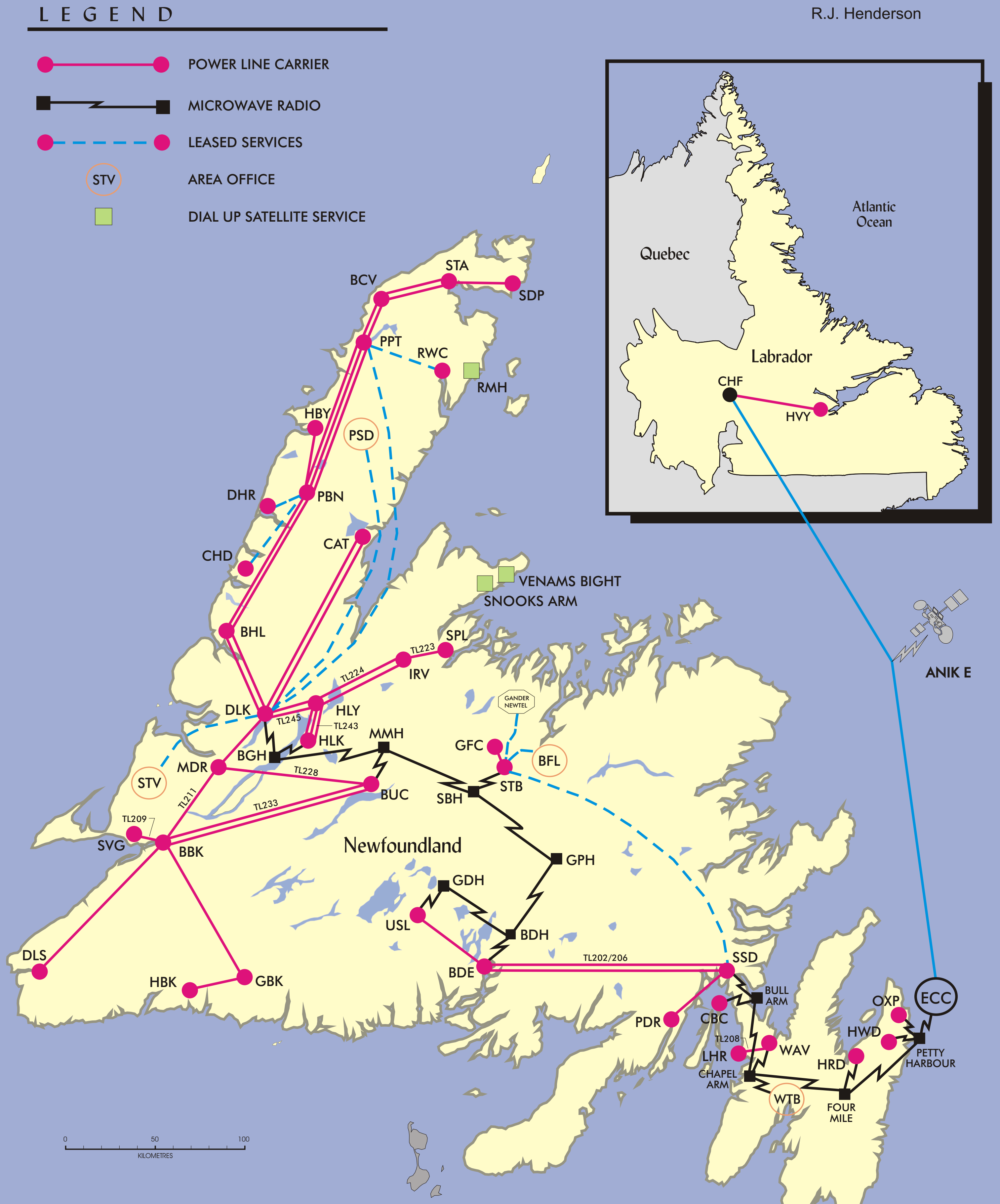
PLANT	**NET CAPACITY**	**AVERAGE ANNUAL ENERGY**
	(MW)	(GWh)
Hydroelectric		
Bay d'Espoir	592.0	2,598.0
Upper Salmon	84.0	552.0
Hinds Lake	75.0	340.0
Cat Arm	127.0	735.0
Paradise River	8.0	39.4
Snook's Arm, Venam's Bight and Roddickton	1.4	7.3
Total Hydroelectric	887.4	4,271.7
Thermal		
Holyrood – Oil fired Steam	465.5	2,996.0
Hardwoods Gas Turbine	54.0	-
Stephenville Gas Turbine	54.0	-
Holyrood Gas Turbine	10.0	-
Hawkes Bay Diesel	5.0	-
St. Anthony Diesel	8.0	-
Roddickton Mobile Diesels	1.7	-
Total Thermal	598.2	2,996.0
Total Capability	1,485.6	7,267.7


Schedule II
R.J. Henderson
LEGEND
HYDRO PLANT
THERMAL PLANT
OTHER GENERATION
GAS TURBINE
INTERCONNECTED DIESEL
Labrador
Quebec
Gulf of St. Lawrence
ST. ANTHONY
RODDICKTON
RODDICKTON MINI-HYDRO
HAWKES BAY
CAT ARM
RATTLE BROOK
VENAM'S BIGHT
SNOOK'S ARM
Atlantic Ocean
HINDS LAKE
STEPHENVILLE
STAR LAKE
Newfoundland
PROPOSED GRANITE CANAL HYDRO PLANT
UPPER SALMON
BAY D'ESPOIR
PARADISE RIVER
HARDWOODS
HOLYROOD
0
50
100
KILOMETRES
Quebec
Labrador
Atlantic Ocean
CHURCHILL FALLS
TWIN FALLS
GOOSE BAY
MUD LAKE
Newfoundland & Labrador Hydro
Interconnected Generation

Schedule III
R. J. Henderson



Schedule IV
R.J. Henderson



Telecommunication Facilities

As of end of 2001

**NEWFOUNDLAND AND LABRADOR HYDRO
COMPARISON OF ACTUAL AND FORECAST
ISLAND INTERCONNECTED SYSTEM
ENERGY SUPPLY (GWh)**

	Filed PUB 1991	1992 Actual	Variance from 1992 Forecast	2000 Actual	Variance from 1992 Actual	2001 Forecast	Variance from 2000 Actual	2002 Forecast	Variance from 2001 Forecast
Hydroelectric	4,211.91	4,221.58	9.67	5,016.71	795.13	4,271.67	(745.04)	4,271.67	0.00
Thermal Generation	1,844.19	1,704.79	(139.40)	968.30	(736.49)	1,974.93	1,006.63	2,162.43	187.50
Energy Purchased	0.00	4.71	4.71	161.18	156.47	145.90	(15.28)	145.90	0.00
Less Synchronous Condenser Use	0.00	2.24	2.24	4.75	2.51	0.00	(4.75)	0.00	0.00
Total Energy Supply	6,056.10	5,928.84	(127.26)	6,141.44	212.60	6,392.50	251.06	6,580.00	187.50

Schedule VI
R. J. Henderson

NEWFOUNDLAND AND LABRADOR HYDRO
COMPARISON OF FORECAST AND ACTUAL 1992 FUEL PURCHASE PRICES
INTERCONNECTED SYSTEMS
($/Barrel)

	No. 6 Fuel Oil Holyrood	No. 2 Fuel Oil				
		Forecast - $33.37/bbl				
	$12.50/bbl*	Holyrood	Hardwoods	Stephenville	Happy Valley	Hawkes Bay
January	12.17	35.80	No Purchases			
February	10.36					33.57
March	10.75				94.99	
April	12.65	33.73				33.57
May	15.09					
June						33.24
July					98.08	33.24
August						
September				36.44		34.67
October	19.98	35.00				34.67
November	19.34	35.00			74.48	36.26
December	15.39	33.79				

* price set in the 1992 hearing

Schedule VII
R. J. Henderson

NEWFOUNDLAND AND LABRADOR HYDRO
ACTUAL 2000 FUEL PURCHASE PRICES
INTERCONNECTED SYSTEMS
($/Barrel)

Actual for Months	No. 6 Fuel Oil Holyrood	No. 2 Fuel Oil					
		Holyrood	Hardwoods	Stephenville	Happy Valley	Hawkes Bay	St. Anthony
January	33.16	49.16	No Purchases				
February	30.16						
March		60.38					
April		52.44					
May	32.83	51.96					
June		55.63			64.92		
July					71.28		63.49
August		56.12			71.28		68.74
September		63.95					
October	40.04	71.49			86.09		
November	38.35	76.73				80.51	
December		78.15		47.09			

NEWFOUNDLAND AND LABRADOR HYDRO
FORECAST OF 2001 - 2005 FUEL PURCHASE PRICES
INTERCONNECTED SYSTEMS
($/Barrel)

	No. 6 Fuel Oil Holyrood	No. 2 Fuel Oil					
		Holyrood	Hardwoods	Stephenville	Happy Valley	Hawkes Bay	St. Anthony
2001							
January	37.38	68.42	68.42	69.69	71.67	71.67	68.84
February	34.76	64.60	64.60	65.80	67.67	67.67	65.00
March	31.63	57.76	57.76	58.83	60.51	60.51	58.12
April	29.43	52.19	52.19	53.16	54.67	54.67	52.51
May	29.29	51.71	51.71	52.67	54.17	54.17	52.03
June	27.99	49.80	49.80	50.73	52.17	52.17	50.11
July	27.10	49.48	49.48	50.40	51.84	51.84	49.79
August	25.95	49.96	49.96	50.89	52.34	52.34	50.27
September	25.95	49.64	49.64	50.57	52.01	52.01	49.95
October	27.96	53.14	53.14	54.13	55.67	55.67	53.47
November	28.88	55.53	55.53	56.56	58.17	58.17	55.87
December	28.74	56.64	56.64	57.70	59.34	59.34	56.99
Annual							
2002	28.38	53.14	53.14	54.13	55.67	55.67	53.47
2003	26.02	51.71	51.71	52.67	54.17	54.17	52.03
2004	23.13	50.12	50.12	51.05	52.51	52.51	50.43
2005	23.26	52.51	52.51	53.48	55.01	55.01	52.83

NEWFOUNDLAND AND LABRADOR HYDRO
NON-UTILITY GENERATION RATES
ISLAND INTERCONNECTED SYSTEM
(mills/kWh)

	January to March November, December	**April to October**
Algonquin Power		
Fixed	47.58	22.26
2000 Variable	39.56	39.56
2000 Combined	**87.14**	**61.82**
2001 Variable	40.60	40.60
2001 Combined	**88.18**	**62.86**
2002 Variable	41.35	41.35
2002 Combined	**88.93**	**63.61**
Star Lake Partnership		
Fixed	45.08	21.15
2000 Variable	35.58	35.58
2000 Combined	**80.66**	**56.73**
2001 Variable	36.51	36.51
2001 Combined	**81.59**	**57.66**
2002 Variable	37.19	37.19
2002 Combined	**82.27**	**58.34**

H.G. Budgell

NEWFOUNDLAND AND LABRADOR HYDRO

EVIDENCE OF HUBERT BUDGELL

Q. Would you please state your name, address and occupation?

A. My name is Hubert Budgell. I live in Mount Pearl and I am Director of System Planning with Hydro.

Q. Would you please give the Board an outline of your qualifications and experience?

A. I am a professional engineer and have been employed with Hydro since 1975. I have held various positions in the Operations and Planning areas and have been Director of System Planning since 1989.

Q. What are the main responsibilities of your current position?

A. As Director of System Planning, I am responsible for the development of load forecasts and the completion of planning studies which result in the recommendation of new generation, transmission and distribution facilities required to meet the load requirements of the Island and Labrador Interconnected Systems and the Isolated Rural Systems.

Q. What evidence will you be presenting to the Board?

A. I will present the following evidence to the Board:

1. For each of the Island and Labrador Interconnected Systems and the Isolated Rural Systems:
   a) a comparison of the actual customer load with the forecasts presented to the Board for 1992;

b) the latest forecasts of customer load;

c) initiatives undertaken by Hydro to meet additional load since the last referral;

d) the requirement for additional means of supply and a description of any projects committed to meet near-term requirements; and

e) future supply options available.

2. The assignment of Hydro's plant to customers for cost of service purposes; and

3. The 2002 Capital Program for the Production Division.

Q. What load forecasts does Hydro prepare and what purposes do they serve?

A. The following load forecasts are prepared by Hydro to address operating and future capital planning requirements:

1. Operating Load Forecast for the Island Interconnected System;
2. Operating Load Forecast for the Labrador Interconnected System;
3. Operating Load Forecast for Hydro's Rural Systems; and
4. Long-Term Planning Load Forecast for the Provincial Electrical Systems.

The Operating Load Forecasts for the Island and Labrador Interconnected Systems are five-year demand and energy load forecasts for industrial, Newfoundland Power and bulk rural systems requirements by month that are expected to be met by Hydro's sources. These forecasts are used for generation scheduling, budgeting and cost of service analysis.

The Operating Load Forecast for Hydro's Rural Systems is a five-year demand and energy forecast of load requirements for Hydro's approximately 35,000 domestic and general service customers served on the Interconnected and Rural Isolated Systems. These forecasts are used for generation, transmission and distribution planning, budgeting, cost of service analysis and as an input to the Operating Load Forecasts for the interconnected systems.

The Long-Term Planning Load Forecast for the Provincial Electrical Systems is a twenty-year forecast of annual peak and energy consumption on the Province's interconnected and isolated systems. The Island portion of this forecast includes load requirements to be met by Hydro's sources and our customers' generation facilities. The forecast is primarily used for long-term supply planning with particular focus on the Total Island Interconnected System.

Q. How does the actual load served by Hydro in 1992 on the Island Interconnected System compare to the forecast presented by Hydro to the Board for 1992?

A. Schedule I of my evidence presents a comparison of the forecast and actual load served by Hydro on the Island Interconnected System for 1992. Hydro's actual Island requirements in 1992 were 127 GWh less than forecast. Sales to Newfoundland Power and bulk deliveries to Hydro Rural were 41 GWh and 1 GWh less than forecast respectively, while sales to Industrial Customers were 93 GWh less than forecast.

Q. How does the actual load in 2000 for this system compare with the load in 1992?

A. For 2000, Hydro's requirements were 213 GWh higher than in 1992. Sales to Newfoundland Power and bulk deliveries to Hydro Rural were 20 GWh and 88 GWh higher, respectively. The latter was due primarily to the interconnection of the St. Anthony-Roddickton area to the Island Interconnected System. Industrial sales increased by 92 GWh. Hope Brook Gold Inc. and Albright and

Wilson Americas ceased to be Industrial Customers during 1997 and 1998, respectively.

Q. How does the actual load served by Hydro in 1992 on the Labrador Interconnected System compare to the forecast presented by Hydro to the Board for 1992?

A. Schedule II of my evidence presents a comparison of the forecast and actual load served by Hydro on the Labrador Interconnected System for 1992. Hydro's actual requirements in 1992 were 19 GWh less than forecast. Bulk deliveries to Hydro Rural increased by 108 GWh due to the addition of Labrador City to Hydro's service area in May of 1992. Lower sales to the Iron Ore Company of Canada (IOCC) and Canadian Forces Base (CFB) Goose Bay of 95 GWh and 56 GWh, respectively, offset this increase.

Q. How does the actual load in 2000 for this system compare with the load in 1992?

A. For 2000, Hydro's requirements were 187 GWh higher than in 1992. Hydro Rural bulk deliveries increased by 123 GWh. IOCC sales decreased by 3 GWh while CFB Goose Bay secondary sales increased by 16 GWh.

Q. How does the actual load served by Hydro in 1992 on the Isolated Rural Systems compare to the forecast presented by Hydro to the Board for 1992?

A. Schedule III of my evidence presents a comparison of the forecast and actual load served by Hydro on the Isolated Rural Systems in 1992. Hydro's actual requirements in 1992 were 6,582 MWh less than forecast. This resulted from a decrease in sales on the Labrador and Island Isolated Systems of 569 MWh and 4,805 MWh, respectively.

Q. How does the actual total load in 2000 for these systems compare with the load in 1992?

A. For 2000, Isolated Rural System requirements were 38,839 MWh lower than in 1992. Island Isolated System sales decreased by 45,591 MWh due primarily to the interconnection of St. Anthony-Roddickton to the main Island grid in 1996. Sales on the Labrador Isolated Systems increased by 11,052 MWh.

Q. How does the actual load experienced on the Total Island Interconnected System for 1991–2000 compare to the forecast presented by Hydro to the Board at the 1992 hearing?

A. Schedule IV of my evidence presents a comparison of the forecast and actual load for 1991–2000. During the 1990's, electricity demand on the Island Interconnected System was significantly lower than forecast. While Hydro's sales to its direct Industrial Customers were more or less in line with expectations, bulk deliveries to utility customers, and notably wholesale sales to Newfoundland Power, were significantly less than forecast.

The main factors limiting load growth during the 1990's can be primarily attributed to the general downturn of the provincial economy.

Q. What load forecasts are you presenting to the Board in relation to the current application?

A. I am presenting the following load forecasts:

1. Schedule V presents Hydro's Operating Load Forecast for the Island Interconnected System for the years 2001 and 2002;

2. Schedule VI presents Hydro's Operating Load Forecast for the Labrador Interconnected System for the years 2001 and 2002;
3. Schedule VII presents Hydro's Operating Load Forecast for the Isolated Rural Systems for the years 2001 and 2002; and
4. Schedule VIII presents the Long-Term Planning Load Forecast for the Total Island Interconnected System for the period 2001–2010.

Q. Would you please describe to the Board how Hydro prepares these forecasts?

A. The Operating Load Forecasts for the Island and Labrador Interconnected Systems (Schedules V and VI) are based on information supplied by Hydro's wholesale and Industrial Customers and Hydro's analysis for its own service regions. Starting in 2002, the forecast for bulk deliveries to Hydro Rural Interconnected in Schedule V reflects changes in bulk metering. This modification results from a change in assignment of plant as discussed later in my evidence.

The Operating Load Forecast for the Isolated Rural Systems as shown on Schedule VII represents the expected load requirements of customers served from each of the 25 Isolated Rural Systems. The principal rate classes for each individual system are reviewed and projected separately based on historic load patterns and expected trends. Larger general service customers are evaluated individually.

The Long-Term Planning Load Forecast for the Total Island Interconnected System shown in Schedule VIII presents Hydro's reference outlook for expected electricity consumption and peak demand for the next ten years. It is conditioned by numerous assumptions on provincial economic activity and relative energy prices. The key economic forecasts, which ultimately drive the load forecast, are prepared by the Provincial Government at Hydro's request. The combination of econometric modeling results, end-use considerations, customer input and judgment derives the final outlook for demand.

Q. When were these forecasts prepared?

A. The Operating Load Forecasts for the Island and Labrador Interconnected Systems were completed in November 2000 and March 2001, respectively. The Operating Load Forecast for Hydro Rural Systems was completed in December 2000 while the Long-Term Planning Load Forecast for the Provincial Electrical Systems was completed in January 2001.

Q. What initiatives has Hydro undertaken since the 1992 referral to meet the load requirements of the Island Interconnected System?

A. Since 1992, Hydro has:

1. Carried out a replacement program of turbine runners on Bay d'Espoir Units 1 to 6 over the 1993 to 1996 timeframe. The new stainless steel runners have improved overall unit efficiency by 2.8% and provided an additional 12 MW in capacity;
2. Entered into a contract with Abitibi Consolidated Inc.'s mill in Stephenville for 46 MW of interruptible power. This contract enables Hydro to interrupt up to 46 MW of demand during the winter peak period thereby providing additional peaking capacity to Hydro when its resources are nearing full capacity; and
3. Contracted for the purchase of energy from the 15 MW Star Lake and the 4 MW Rattle Brook hydroelectric developments. These projects were developed in response to a 1992 Request for Proposals for Non-Utility Generation from Small Hydro Projects and came into operation in 1998.

Q. What are Hydro's criteria for determining the timing of a new source of generation for the Island Interconnected System?

A. Hydro has established criteria related to the appropriate reliability, at the generation level, for the Island Interconnected System which sets the timing of generation source additions. These criteria set the minimum level for reserve capacity and energy installed in the system to insure an adequate supply for firm load. They are stated as follows:

Energy: The Island Interconnected System should have sufficient generating capability to supply all of its firm energy requirements with firm system capability.

Capacity: The Island Interconnected System should have sufficient generating capacity to satisfy a Loss of Load Hours (LOLH) expectation target of not more than 2.8 hours per year.

Q. Has Hydro's generation planning criteria for the Island Interconnected System changed since the previous filing?

A. While the generation planning criteria for the Island Interconnected System has not changed since the previous filing, Hydro has changed the units of measure for the capacity criterion. It is now expressed as an LOLH target of 2.8 hours per year rather than the previous Loss of Load Expectation (LOLE) target of 0.2 days per year.

The conversion to LOLH coincided with the purchase of new generation planning software and the move to an hourly representation of system load for loss of load analysis, rather than the previous daily peak representation.

Q. Based on existing generation capacity, when is the next source of generation required on the Island Interconnected System?

A. Based on an examination of the Island's existing capability presented in Schedule IX, and the load forecast presented in Schedule VIII, using the planning criteria, the Island system has capacity and energy deficits starting in 2001 and 2002 respectively. Schedule X presents a summary of these capacity and energy deficits.

Q. Why did Hydro not plan to provide additional generation capability in response to the projected deficits in Schedule X starting in 2001 and 2002?

A. During the late 1990's, there was ongoing uncertainty with respect to both the load forecast as well as Hydro's long-term supply alternatives. This uncertainty led Hydro to believe it prudent to postpone a decision on the next source of generation for as long as possible in order to allow time to seek clarity on these issues. On the load forecast side, the potential development of the Voisey's Bay Nickel smelter/refinery on the Island could have had a significant effect on the choice of alternative(s) to meet a large increase in the Island load forecast. This was combined with long-term supply uncertainty surrounding the potential for a Labrador Infeed which could also significantly impact upon the near-term resource decision. While Hydro was anticipating deficits starting in 2001, the levels were not considered excessive and could be managed through short term operational planning. Thus, Hydro focused on the period of 2003 and beyond as the timing for additional supply.

Q. What initiatives are currently underway to meet these forecast capacity and energy deficits?

A. During 2000, Government, having been kept advised of anticipated capacity and energy deficits, authorized Hydro to proceed with the development of the Granite Canal Project and directed Hydro to initiate discussions on terms and conditions for purchased power arrangements with two Industrial Customers. These customers are Abitibi Consolidated Incorporated (ACI) and Corner Brook Pulp and Paper Limited (CBP&P) and the purchase arrangements consist of :

1. Incremental capacity and energy resulting from the addition of a new 26.9 MW hydroelectric unit at ACI's existing facility at Grand Falls and an upgrade of ACI's existing hydroelectric facility at Bishop's Falls. The additional capacity available from these projects is 32.3 MW; and
2. Capacity and energy produced from a 15 MW cogeneration unit at the Corner Brook mill. The new unit would utilize steam produced by CBP&P's existing No. 7 bark and oil fired boiler.

Having been informed of the terms and conditions for the purchase of power and energy from ACI and CBP&P, Government directed Hydro to conclude power purchase agreements.

Hydro has commenced construction of the 40 MW Granite Canal Hydro Project. The project is situated between Granite Lake and the Meelpaeg Reservoir within the existing Bay d'Espoir development and is planned to be completed by mid-2003.

The significant operating characteristics of each of these additions are summarized in Schedule XI.

Q. Are you aware of any other changes to Island system generation capability that are currently underway?

A. Yes, a planned upgrade of the 60 Hz generation at the Deer Lake Generation Plant will result in 3.5 MW of additional capacity and 36 GWh of additional average annual energy. This upgrade is expected to be completed by the fall of 2003.

Q. Based on the existing plus new committed generation capacity, when will the next new source of generation be required on the Island Interconnected System?

A. Based on the latest load forecast, beyond the 2003 additions, the Island system is expected to experience capacity and energy deficits starting in 2006 and 2007 respectively. Schedule XII presents a summary of these capacity and energy deficits. Hydro does not consider the deficit in 2006 significant and would normally plan to add capacity in 2007.

Q. What options are available to meet these future generation requirements?

A. In addition to those resources included in Hydro's own portfolio of near-term alternatives, any number of alternatives may be brought forward under a general request for generation proposals (RFP). Alternatives submitted under a general RFP can range from various forms of conventional technologies to alternative technologies such as wind power. The following are options which Hydro can develop:

1. The Island Pond Hydroelectric Project;
2. A Combined Cycle Plant at Holyrood;
3. Holyrood Unit IV Conventional Steam Unit; and
4. Gas Turbine Units.

Q. In November 2000 Hydro issued a Request for Proposals for a Wind Demonstration Project. What is Hydro's rationale for issuing this RFP?

A. During 2000, Government directed Hydro to issue a request for proposals to explore the potential for wind technology on the Island Interconnected System. Recent advances in wind generation technology may result in wind becoming a more competitive source of energy for the Island system. Additionally, the technology will result in a reduction of emissions at Hydro's facilities through fuel displacement. The assessment is being carried out in a two-stage process comprised of a stage one feasibility study and a potential demonstration project at stage two. Pending the outcome of the feasibility study stage, Hydro expects to contract for a wind demonstration project having a capacity of 5–25 MW. Hydro's primary objective for the wind demonstration project is to obtain information to assist in the assessment of wind generation as a future source of generation supply for the Island Interconnected System.

Q. What is Hydro's criterion for determining the timing and appropriate level of capacity of new sources of generation for the Isolated Rural systems?

A. Hydro's generation reliability criterion for the Isolated Rural Systems is stated as follows:

> Hydro shall maintain firm generation capacity to meet the system peak load. Firm generation capacity is defined as the total installed capacity on the system minus the largest single unit.

Q. Have there been any changes to system capacity on the Isolated Rural Systems since 1992 as a result of increased demand?

A. Yes, since 1992 the following Isolated Rural Systems have had generation capacity increased:

1. Port Hope Simpson in 1994;
2. Postville in 1995;
3. St. Lewis in 1996;
4. Davis Inlet in 1998;
5. Hopedale in 1999;
6. Davis Inlet and Makkovik in 2000; and
7. Charlottetown in 2001.

With the exception of Port Hope Simpson which involved the construction of a new diesel plant, these increases resulted from the addition or replacement of diesel units.

Q. What other significant supply initiatives has Hydro undertaken on the Isolated Rural Systems since the previous referral in 1992?

A. Since the 1992 referral, Hydro has carried out the following:

1. In 1993 Hydro interconnected the community of Petite Forte to the Island Interconnected System;
2. In 1996 Hydro:
   - Interconnected the Roddickton-St. Anthony System to the Island Interconnected System;
   - Interconnected the community of Westport to the Island Interconnected System;
   - Interconnected the L'Anse au Loup Diesel System to Hydro Quebec's North Shore System and entered into an agreement to purchase secondary energy made available from Hydro Quebec's Lac Robertson hydroelectric development;
3. In 1998 Hydro:
   - Interconnected the community of Mud Lake to the Labrador Interconnected System;

- Interconnected the community of South East Bight to the Island Interconnected System; and

4. In 1999 Hydro interconnected the community of LaPoile to the Island Interconnected System.

Q. Does Hydro have any plans to increase generation on the Isolated Rural Systems due to a requirement for additional firm generation?

A. There are no plans to increase firm generation capacities on Hydro's Isolated Rural Systems as a result of forecast load growth. However, as is outlined in Mr. Reeves' evidence, a number of diesel units are scheduled for replacement due to obsolescence.

With respect to the potential for additional interconnections, Hydro has not identified any further opportunities for cost effective interconnections of Isolated Rural Systems to the Island or Labrador Interconnected Systems.

Q. How does Hydro ensure that customer requirements are met on the Labrador Interconnected System?

A. Hydro ensures that the forecast requirements of the Labrador Interconnected System are met through purchases of recall power and energy from CF(L)Co, as previously outlined in the evidence of Mr. Henderson.

Q. Does Hydro have any plans to increase firm supply capability for the Labrador Interconnected System?

A. No. Based on the latest load forecast for the Labrador Interconnected System, the purchases from CF(L)Co will satisfy firm load requirements well into the future.

Q. Would you please summarize the 1993 recommendations of the Board related to the assignment of Hydro's plant?

A. The recommendations of the Board related to the assignment of plant were as proposed by Hydro in 1992 with the following changes:

1. "That the Howley - Cat Arm transmission line [*TL251, TL252 and TL253*][1] be treated as common";
2. "That transmission lines dedicated to the service of Hydro Rural rate classes be included in a sub-transmission function and the costs attributed thereto be allocated exclusively to such classes";
3. "That the methodology indicated in Recommendation 4 [*the previous clause*] be applied in the case of transmission serving NP [*Newfoundland Power*] and IC [*Industrial Customer*] but not the Rural classes, provided the costs total at least 2% of total transmission costs"; and
4. "That transmission lines and substations in the Island Interconnected System used solely or dominantly for the purpose of connecting remotely located generation to the main transmission system be classified in the same manner as the generating stations they serve".

Q. Have there been further recommendations with respect to assignment of Hydro's plant at subsequent hearings?

A Yes, in 1995, Hydro presented evidence at the Inquiry on Rural Electrical Service. At that time, the Board recommended "that both generation assets and the 138 kV transmission line on the Great Northern Peninsula be assigned, on a provisional basis, as being of common benefit to all Interconnected Customers and that sub-transmission costs (for lines whose voltage is below 138 kV) be specifically assigned. The Board further

[1] Text in [ ] added for clarity.

recommends re-examination of these cost assignment decisions, and rules for cost assignment, at a future hearing."

Q. Has Hydro accepted these recommendations by the Board related to the assignment of plant?

A. Yes, Hydro has reviewed the Board's recommendations related to the assignment of plant and accepts the recommendations. As well, Hydro has reviewed and revised its guidelines for the assignment of plant for the purposes of this application to be consistent with the Board's recommendations.

Q. Would you please outline Hydro's revised guidelines for the assignment of plant?

A. A cost of service methodology requires that the cost (capital and maintenance) of each component of plant be assigned to customers in a fair and equitable manner. For the purpose of plant assignment, customer includes Newfoundland Power, individual Industrial Customers and Hydro Rural. Plant is assigned as either "common" or "specifically assigned".

Common Plant is defined as plant that is of substantial benefit to two or more firm customers. Costs for common plant are assigned to all customers of the system.

The following facilities have been assigned as Common Plant:

a) All of Hydro's production facilities (hydraulic, thermal, gas turbine and diesel);
b) All of Hydro's transmission and terminal station plant, 66 kV and above, that is of substantial benefit to two or more customers;

c) All of Hydro's transmission and terminal station plant whose sole function is the interconnection of a generating facility with the system. Transmission and terminal plant in this category have their costs classified on the same basis as the generation that it interconnects; and

d) All of Hydro's transmission and terminal station plant that connects a single customer and remote generation or voltage support equipment, that is of substantial benefit to all customers on the grid. For the purposes of this guideline if, under any normal operating scenario, the output of remote generation can be delivered to the 230 kV grid (i.e. in excess of radial load), then the remote generation is considered to be of substantial benefit to all customers and as such the transmission and terminals plant connecting it to the grid would be assigned common.

Specifically Assigned Plant is defined as plant that is of benefit to only one customer. Costs for specifically assigned plant are assigned directly to the benefiting customer.

All of Hydro's generation and distribution facilities in the Isolated Rural Systems and distribution facilities in the interconnected systems have been assigned to Hydro Rural.

Hydro Rural Sub-transmission is defined as all transmission and terminal station plant serving only Hydro Rural rate classes.

NP-IC Sub-transmission is defined as transmission and terminal plant which serves both Newfoundland Power and an Industrial Customer but not Hydro Rural and has an original cost of at least 2% of the total transmission and terminal stations costs.

Q. Would you please outline significant system additions completed or planned for the Island Interconnected System since the 1992 Rate Hearing and indicate the proposed assignment for these additions?

A. Schedule XIII is a single line diagram of the Island Interconnected System for 2002 showing the proposed assignment for that year. Since 1992 there have been a number of significant changes and additions to the Island Interconnected System. These include:

In 1992

- Completion of 230 kV bus modifications at Bay d'Espoir - Assigned Common
- The addition of a 125 MVA, 230/66 kV transformer at Hardwoods Terminal Station – Assigned Common;

In 1993

- Completion of 230 kV bus modifications at Western Avalon Terminal Station – Assigned Common;

In 1995

- Completion of 230 kV bus modifications at Stony Brook Terminal Station – Assigned Common;

In 1996

- Interconnection of the St. Anthony-Roddickton System to the Island Interconnected System – Generation and associated transmission assigned Common, remainder of system assigned Hydro Rural Sub-transmission;

In 1998

- The replacement of a 66.7 MVA, 230/66 kV transformer with a new 125 MVA, 230/66 kV transformer at Massey Drive Terminal Station – Assigned Common
- The interconnection of the Star Lake Generating Station at Buchans Terminal Station – Assigned Common

- The interconnection of the Rattle Brook Generating Station – Assigned Common
- The removal and sale of two 83.3 MVA, 230/46 kV transformers from Long Harbour Terminal Station – Assignment Not Applicable;

In 1999

- Rerouting of a portion of the 69 kV transmission line TL220 from Bay d'Espoir to Barachoix – Assigned Hydro Rural Sub-transmission;

In 2000

- Upgrades of the existing capacitor banks at Hardwoods and Oxen Pond Terminal Stations and the addition of a second capacitor bank at each station – Assigned Common
- Upgrading of the 230 kV steel transmission line TL217 from Holyrood to Western Avalon – Assigned Common
- Rebuild of the 230 kV steel transmission line TL207 from Sunnyside to Come-By-Chance – Assigned Common
- The addition of lightning arrestors to one half of 230 kV transmission line TL206 between Bay d'Espoir and Sunnyside – Assigned Common
- Removal from service of the Roddickton Woodchip Plant and Roddickton Diesel Plant – Assignment Not Applicable;

In 2001

- Upgrading of the 230 kV steel transmission line TL237 from Come-By-Chance to Western Avalon – Assigned Common
- Rebuild of a portion of 66 kV transmission line TL225 from Deer Lake Power to Deer Lake Terminal Station – Assigned Common
- The addition of lightning arrestors to the remaining half of 230 kV transmission line TL206 between Bay d'Espoir and Sunnyside – Assigned Common; and

In 2002

- Upgrade of the 230 kV transmission lines TL218 and TL236 from Hardwoods to Oxen Pond Terminal Station – Assigned Common.

Q. Has the fact that remote generation on a number of radial systems can reach the 230 kV grid under normal operating conditions changed plant assignment?

A. Yes, changes in plant assignment are as follows:

On the Great Northern Peninsula system the assignment of the 138 kV and 66 kV transmission lines and associated terminal station equipment connecting the Hawkes Bay Diesel Plant, St. Anthony Diesel Plant and Roddickton generation to the main grid has been changed from Hydro Rural Sub-transmission to Common.

On the Doyles – Port-aux-Basques system the assignment of the 138 kV and 66 kV transmission lines and associated terminal station equipment connecting Newfoundland Power's Port-aux-Basques system to the Bottom Brook Terminal Station has been changed from Specifically Assigned to Common.

Q. Have there been any changes in assignment due to customer changes?

A. Yes, there have been two changes in assignment due to the discontinuation of service to former Industrial Customers Hope Brook Gold and Albright and Wilson Americas.

The interconnection of La Poile and closure of Hope Brook Gold has resulted in a change of assignment for the 138 kV transmission line from Grandy Brook to Hope Brook and the Hope Brook Terminal Station from Specifically

Assigned to Hope Brook Gold to Specifically Assigned to Hydro Rural and the 138kV transmission line from Bottom Brook to Grandy Brook from Common to Specifically Assigned to Hydro Rural.

The discontinuance of service to the former industrial customer Albright and Wilson Americas has resulted in the change of assignment for the 230 kV transmission line from Western Avalon to Long Harbour and the Long Harbour Terminal Station from Specifically Assigned to Albright and Wilson Americas to Common Plant as the remaining equipment, which includes a 24 MVAR capacitor bank, provides voltage support to the 230 kV system.

Q. Are there any other changes in assignment as a result of Hydro's review and revised guidelines?

Yes, the frequency converters at Corner Brook and Grand Falls, previously assigned Common Plant, have been Specifically Assigned to Corner Brook Pulp and Paper and Abitibi Consolidated Inc. – Grand Falls Division respectively. Following a review, it has been determined that these assets are of benefit to only the Grand Falls and Corner Brook Industrial Customers. As a result, the assignment has been changed from Common Plant to Specifically Assigned.

As well, the assignment of the 66kV plant feeding 400L at the Bottom Brook Terminal Station and Newfoundland Power at the Stephenville Terminal Station has been changed from Common Plant to Specifically Assigned, as these assets are of benefit to only Newfoundland Power.

Q. Are there any NP-IC Sub-transmission assets on the Hydro system?

A. No. At the present time there are no assets which meet the specific requirements of this assignment.

Q. Would you please explain how you have assigned Hydro's plant on the Labrador Interconnected System?

A. Schedule XIV is a single line diagram of the Labrador Interconnected System for 2002 showing the proposed assignment for that year. Hydro's plant on the Labrador Interconnected System has been assigned using the same definitions and guidelines as the Island Interconnected System. The transmission and terminals equipment connecting Churchill Falls and Happy Valley-Goose Bay has been assigned Common Plant. The gas turbine and North Side Diesel Plant at Happy Valley-Goose Bay have been assigned Common Plant. The distribution systems of Happy Valley-Goose Bay, Wabush and Labrador City have been assigned to applicable Hydro Rural rate classes.

Q. Would you please summarize Hydro's 2002 Capital Budget for the Production Division?

A. The following is a summary of forecast 2002 capital expenditures (exclusive of the Granite Canal Project) for the Production Division:

Production Division
Capital Budget for 2002
($thousands)

Generation	6,697
Information Systems & Telecommunications	13,685
Total Production Division	20,382

These expenditures are itemized on pages A-4, A-8 and A-9 of the 2002 Capital Budget attached to Hydro's application.

Q. Would you please outline the significant elements of Hydro's capital budget for Generation?

A. With respect to Generation, the more significant elements included in these estimates are:

- $1.6 million for the construction of a 25 kV distribution line to connect the Ebbegunbaeg Control Structure to existing facilities at the Upper Salmon Development. Analysis indicates that this option is more cost effective than operating and maintaining the existing diesel facilities;
- $0.9 million for the replacement of the obsolete excitation system on Unit 1 at Cat Arm. Funds to complete engineering for this project were approved by the Board for 2001;
- $0.8 million for the installation of continuous emissions monitoring system on each of the three generating units at the Holyrood Generating Station to improve emission control and unit efficiency; and
- $34 thousand in 2002 and $1.1 million in 2003 to replace the obsolete turbine electrohydraulic control system on Unit 1 at the Holyrood Generating Station.

Q. Would you please outline the significant elements of Hydro's capital budget for Information Systems and Telecontrol?

A. With respect to Information Systems and Telecontrol, the more significant elements of the capital budget are:

- $269 thousand in 2002 and $8.7 million in 2003 to complete an interconnection of Hydro's microwave facilities between the eastern and western regions of the Province. This project is phase three of Hydro's five-phase telecommunication plan previously filed with the Board in 1998;

- $651 thousand in 2002 and $1.4 million in 2003 to complete the replacement of Hydro's Power Line Carrier (PLC) system on the west coast. This project is phase four of Hydro's telecommunications plan submitted to the Board in 1998 and funds for this phase were approved by the Board for 2001;
- $8.4 million for the replacement of Hydro's VHF mobile radio system. The current system is no longer supported by the manufacturer and is technologically obsolete. This is phase five of Hydro's Telecommunications Plan; and
- $2.1 million for the replacement of two AS400 computers that currently support Hydro's integrated applications. The lease for the current equipment expires during 2002.

Q. Would you please outline those leases in Section D of Hydro's 2002 Capital Budget for the Production Division?

A. The Production Division is responsible for the following leases totaling $1.6 million:

- AS400 Computers;
- Increase to AS400 DASD System;
- Computer equipment to upgrade office technology;
- Mainframe Docuprint 65 Production Printing System; and
- Computerized Energy Management System.

The more significant of these is for the Energy Management System at $932 thousand and for the office computer equipment at $443 thousand.

Q. Does this conclude your evidence?

A. Yes.

Newfoundland and Labrador Hydro
Forecast and Actual System Sales and Load
For 1992 and 2000 Actual
Island Interconnected System

	1992						2000			
	Filed PUB 1991		Actual		Variance		Actual		Change Since 1992 Actual	
	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh
Newfoundland Power	1044.3	4284.1	1032.7	4243.0	(11.6)	(41.1)	957.2	4263.2	(75.5)	20.2
Hydro Rural Interconnected[1]	70.6	301.8	70.7	300.9	0.1	(0.9)	82.9	388.8	12.2	87.9
Corner Brook Pulp and Paper	40.0	313.1	43.0	296.7	3.0	(16.4)	49.0	357.8	6.0	61.1
Deer Lake Power[2]	2.0	15.8	40.7	18.1	38.7	2.3	24.4	18.5	(16.3)	0.4
Abitibi Consolidated – Grand Falls[3]	33.0	216.6	55.8	154.6	22.8	(62.0)	45.9	145.0	(9.9)	(9.6)
Abitibi Consolidated - Stephenville	66.2	489.4	71.1	489.4	4.9	0.0	70.4	537.7	(0.7)	48.3
North Atlantic Refining	28.4	223.8	28.0	180.4	(0.4)	(43.4)	30.3	219.7	2.3	39.3
Albright and Wilson Americas[4]	3.0	14.8	1.4	7.0	(1.6)	(7.8)	-	0	-	(7.0)
Hope Brook Gold Inc[5]	1.5	6.7	9.6	41.0	8.1	34.3	-	0	-	(41.0)
Hydro Auxiliaries[6]	-	4.6	-	2.5	-	(2.1)	-	0	-	(2.5)
Total Sales & Bulk Deliveries[1]	**-**	**5870.7**	**-**	**5733.5**	**-**	**(137.2)**	**-**	**5930.7**	**-**	**197.2**
Transmission Losses	-	185.5	-	195.3	-	9.8	-	210.8	-	15.5
Hydro Island Requirement	**-**	**6056.2**	**-**	**5928.8**	**-**	**(127.4)**	**-**	**6141.5**	**-**	**212.7**

[1] Hydro Rural data includes distribution and sub-transmission losses.
[2] 1992 Actual MW includes 38.7 MW Emergency. 2000 Actual MW includes 22.4 MW Emergency.
[3] 1992 Actual MW includes 24.8 MW Emergency. 2000 Actual MW includes 19.9 MW Emergency.
[4] Ceased service in 1998.
[5] Ceased service in 1997.
[6] Included in Station Services as of 1993.

Newfoundland and Labrador Hydro
Forecast and Actual System Sales and Load
For 1992 and 2000 Actual
Labrador Interconnected System

	1992						2000			
	Filed PUB 1991		Actual		Variance		Actual		Change Since 1992 Actual	
	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh
Hydro Rural Interconnected[1]										
Happy Valley Goose Bay	40.8	177.4	44.8	172.8	4.0	(4.6)	46.3	200.4	1.5	27.6
Wabush	10.9	49.7	11.3	52.4	0.4	2.7	13.2	57.7	1.9	5.3
Labrador City[2]	-	-	44.9	110.3	44.9	110.3	47.5	200.2	2.6	89.9
TOTAL	51.7	227.1	-	335.5	-	108.4	-	458.3	-	122.8
CFB Goose Bay (secondary sales)	23.8	126.0	21.6	70.2	(2.2)	(55.8)	22.0	86.4	0.4	16.2
Iron Ore Company of Canada	74.6	340.1	54.6	245.4	(20.0)	(94.7)	75.4	242.3	20.8	(3.1)
Total Sales & Bulk Deliveries[1]	**-**	**693.2**	**-**	**651.1**	**-**	**(42.1)**	**-**	**787.0**	**-**	**135.9**
Transmission Losses	-	28.4	-	51.9	-	23.5	-	103.0	-	51.1
Hydro Labrador Requirement[3]	**-**	**721.6**	**-**	**703.0**	**-**	**(18.6)**	**-**	**890.0**	**-**	**187.0**

[1] Hydro Rural data includes distribution losses.
[2] Hydro assumed responsibility for Labrador City distribution during 1992.
[3] Requirement as measured at Churchill Falls 230kV bus.

Schedule III
H.G. Budgell

Newfoundland and Labrador Hydro
Forecast and Actual System Sales and Load
For 1992 and 2000 Actual
Isolated Systems

	1992						2000			
	Filed PUB 1991		Actual		Variance		Actual		Change Since 1992 Actual	
Labrador	**kW**	**MWh**	**kW**	**MWh**	**kW**	**MWh**	**kW**	**MWh**	**kW**	**MWh**
Black Tickle	471	1100	372	1029	(99)	(71)	457	1209	85	180
Cartwright	702	2766	720	2877	18	111	834	3525	114	648
Charlottetown	372	943	416	1118	44	175	592	1936	176	818
Davis Inlet	317	1300	326	1295	9	(5)	644	2373	318	1078
Hopedale	584	2055	516	1845	(68)	(210)	640	2452	124	607
Makkovik	802	2465	512	1961	(290)	(504)	683	2611	171	650
Mary's Harbour	669	2370	668	2490	(1)	120	804	3585	136	1095
Mud Lake[1]	66	171	69	171	3	0	0	0	(69)	(171)
Nain	891	4267	1008	3906	117	(361)	1313	5098	407	1192
Norman Bay	36	74	21	72	(15)	(2)	54	123	33	51
Paradise River	75	207	62	180	(13)	(27)	56	187	(6)	7
Port Hope Simpson	459	1351	486	1563	27	212	600	2102	90	539
Postville	286	1001	288	1080	2	79	313	1127	25	47
Rigolet	342	1110	372	1200	30	90	456	1602	84	402
St. Lewis	321	1293	366	1288	45	(5)	480	1686	114	398
William's Harbour	99	319	53	262	(46)	(57)	97	317	44	55
L'Anse au Loup[2]	2517	8418	2304	8304	(213)	(114)	3074	11760	770	3456
Total Labrador Sales		**31210**		**30641**		**(569)**		**41693**		**11052**
Island										
Francois	269	699	268	695	(1)	(4)	256	681	(12)	(14)
Grey River	220	585	250	608	30	23	264	551	(20)	(57)
Harbour Deep	292	760	244	695	(48)	(65)	257	712	13	17
La Poile[3]	185	459	140	452	(45)	(7)	0	0	(140)	(452)
Little Bay Islands	578	1375	576	1367	(2)	(8)	565	1359	(11)	(8)
McCallum	192	575	184	576	(8)	1	238	556	19	(20)
Petite Forte[4]	131	365	136	352	5	(13)	0	0	(136)	(352)
Petites	122	296	113	290	(9)	(6)	58	131	(55)	(159)
Ramea	2406	7952	1940	7084	(466)	(868)	1337	4490	(652)	(2594)
Rencontre East	225	703	240	752	15	49	339	904	80	152
Roddickton/St. Anthony[5]	10947	44440	9980	40411	(967)	(4029)	0	0	(9980)	(40411)
South East Bight[6]	133	312	132	345	(1)	33	0	0	(132)	(345)
St. Brendans	332	992	345	1039	13	47	407	985	20	(54)
Westport[7]	437	1252	456	1294	19	42	0	0	(456)	(1294)
Total Island Sales		**60765**		**55960**		**(4805)**		**10369**		**(45591)**
Total Sales		**91975**		**86601**		**(5374)**		**52062**		**(34539)**
Distribution Losses		9074		7866		(1208)		3566		(4300)
Net Generation[8]		**101049**		**94467**		**(6582)**		**55628**		**(38839)**

[1] Mud Lake Interconnected 1998.
[2] L'Anse au Loup granted Interconnected Island rates 1996.
[3] La Poile Interconnected 1999.
[4] Petite Forte Interconnected 1993.
[5] Roddickton/St. Anthony Interconnected 1996.
[6] South East Bight Interconnected 1998.
[7] Westport Interconnected 1996.
[8] Excludes station service.

Newfoundland and Labrador Hydro
Demand and Energy Requirements
Forecast and Actual for 1991-2000
Total Island Interconnected System[1]

Year	Total Island Peak MW			Total Island Energy GWh		
	Filed 1991	Actual	Variance	Filed 1991	Actual	Variance
1991	1480	1488	8	7547	7464	(83)
1992	1536	1457	(79)	7812	7575	(237)
1993	1591	1452	(139)	8013	7730	(283)
1994	1627	1492	(135)	8162	7705	(457)
1995	1666	1429	(237)	8331	7724	(607)
1996	1688	1563	(125)	8427	7671	(756)
1997	1750	1418	(332)	8611	7983	(628)
1998	1785	1491	(294)	8731	7310	(1421)
1999	1828	1465	(363)	8907	7728	(1179)
2000	1868	1443	(425)	9065	8057	(1008)

[1] Includes load requirements met by Hydro’s sources and customers’ generation facilities.

Newfoundland and Labrador Hydro
Forecast System Sales and Load[1]
For 2001 and 2002
Island Interconnected System

	2000 Actual		2001 Forecast		2002 Forecast	
	MW	**GWh**	**MW[2]**	**GWh**	**MW[2]**	**GWh**
Newfoundland Power	957.2	4263.2	1014.4	4399.4	1026.8	4454.8
Hydro Rural Interconnected[3]	82.9	388.8	90.9	398.1	89.6	388.9
Corner Brook Pulp and Paper[4]	73.4	376.3	53.0	406.8	65.0	523.3
Abitibi Consolidated-Grand Falls	45.9	145.0	26.0	177.3	26.0	177.3
Abitibi Consolidated-Stephenville	70.4	537.7	70.0	560.0	71.0	568.6
North Atlantic Refining	30.3	219.7	30.0	233.6	30.0	233.6
Total Sales & Bulk Deliveries[3]	**-**	**5930.7**	**1266.1**	**6175.3**	**1291.0**	**6346.4**
Transmission Losses	-	210.8	50.6	217.2	53.2	233.7
Hydro Island Requirement	**-**	**6141.5**	**1316.7**	**6392.5**	**1344.2**	**6580.1**

[1] 2001 and 2002 Forecast are sourced to the November 2000 Operating Load Forecast.
[2] Peaks shown are January peaks.
[3] Hydro Rural data reflects changes in bulk metering for 2002.
[4] Includes Deer Lake Power.

Newfoundland and Labrador Hydro
Forecast System Sales and Load[1]
For 2001 and 2002
Labrador Interconnected System

	2000 Actual		2001 Forecast		2002 Forecast	
	MW	GWh	MW[2]	GWh	MW[2]	GWh
Hydro Rural Interconnected[3]						
Happy Valley Goose Bay	46.3	200.4	52.4	213.5	52.9	215.5
Wabush	13.2	57.7	14.3	59.4	14.5	59.7
Labrador City	47.5	200.2	49.3	207.6	49.5	208.2
TOTAL	-	458.3	116.0	480.5	116.9	483.4
CFB Goose Bay (secondary sales)	22.0	86.4	11.1	76.0	10.6	73.7
Iron Ore Company of Canada	75.4	242.3	83.0	353.4	85.0	366.8
Total Sales & Bulk Deliveries[3]	**-**	**787.0**	**166.4**	**909.9**	**167.2**	**923.9**
Transmission Losses		103.0	24.0	116.3	24.2	118.4
Hydro Labrador Requirement[4]		**890.0**	**190.4**	**1026.2**	**191.4**	**1042.3**

[1] 2001 and 2002 Forecast are sourced to the March 2001 Operating Load Forecast.
[2] Peaks shown are January peaks.
[3] Hydro Rural data includes distribution losses.
[4] Requirement as measured at Churchill Falls 230kV bus.

Newfoundland and Labrador Hydro
Forecast System Sales and Load[1]
For 2001 and 2002
Isolated Systems

	2000 Actual		2001 Forecast		2002 Forecast	
	kW	**MWh**	**kW[2]**	**MWh**	**kW**	**MWh**
Labrador						
Black Tickle	457	1209	534	1235	534	1237
Cartwright	834	3525	845	3534	841	3512
Charlottetown	592	1936	1318	3663	1330	3705
Davis Inlet	644	2373	731	2522	742	2562
Hopedale	640	2452	684	2535	691	2563
Makkovik	683	2611	740	2712	743	2729
Mary's Harbour	804	3585	915	3809	886	3686
Nain	1313	5098	1192	5072	1203	5117
Norman Bay	54	123	53	123	53	123
Paradise River	56	187	57	181	31	98
Port Hope Simpson	600	2102	615	2138	617	2148
Postville	313	1127	314	1135	315	1141
Rigolet	456	1602	442	1645	446	1658
St. Lewis	480	1686	490	1766	480	1729
William's Harbour	97	317	91	319	90	317
L'Anse au Loup	3074	11760	3066	11629	3097	11740
Total Labrador Sales	**-**	**41693**	**-**	**44018**	**-**	**44065**
Island						
Francois	256	681	254	686	252	681
Grey River	264	551	211	546	209	541
Harbour Deep	257	712	278	739	274	730
Little Bay Islands	565	1359	542	1295	537	1282
McCallum	238	556	222	554	220	549
Petites	58	131	52	123	50	117
Ramea	1337	4490	1331	4481	1310	4348
Rencontre East	339	904	307	921	304	913
St. Brendans	407	985	408	1004	403	993
Total Island Sales	**-**	**10369**	**-**	**10286**	**-**	**10154**
Total Sales		**52062**		**54304**		**54219**
Distribution Losses		3566		4163		4160
Net Generation[3]		**55628**		**58467**		**58379**

[1] 2001 and 2002 Forecast are sourced to December 2000 Operating Load Forecast Hydro Rural Systems.
[2] Demand month is system dependent.
[3] Excludes station service.

Newfoundland and Labrador Hydro
Demand and Energy Requirements
Forecast 2001 – 2010[1]
Total Island Interconnected System[2]

Year	MW	GWh
2000 Actual	1443	8057
2001	1576	8240
2002	1602	8316
2003	1611	8384
2004	1632	8479
2005	1652	8560
2006	1673	8639
2007	1596	8734
2008	1719	8831
2009	1735	8894
2010	1741	8929

[1] Source: Long-Term Planning Load Forecast 2001.
[2] Includes load requirements met by Hydro's sources and customers' generation facilities.

Newfoundland and Labrador Hydro
Island Interconnected System
System Capability

	Net Capacity (MW)	Annual Energy (GWh) Firm	Annual Energy (GWh) Average
Newfoundland and Labrador Hydro			
Bay d'Espoir	592.0	2234	2598
Upper Salmon	84.0	476	552
Hinds Lake	75.0	283	340
Cat Arm	127.0	605	735
Paradise River	8.0	27	39
Snook's, Venam's & Roddickton Mini Hydros	1.4	5	7
Total Hydro	**887.4**	**3630**	**4271**
Holyrood	465.5	2996	2996
Combustion Turbine	118.0	-	-
Hawke's Bay & St. Anthony Diesel	14.7	-	-
Total Thermal	**598.2**	**2996**	**2996**
Newfoundland Power Inc.			
Hydro	93.2	323	439
Combustion Turbine	47.2	-	-
Diesel	7.0	-	-
Total	**147.4**	**323**	**439**
Corner Brook Pulp and Paper Ltd.			
Hydro	**120.9**	**776**	**855**
Abitibi Consolidated Inc. (Grand Falls)			
Hydro	**58.5**	**443**	**470**
Non-Utility Generators			
Hydro	**19.0**	**107**	**146**
Total System Capability	**1831.4**	**8275**	**9177**

Newfoundland and Labrador Hydro
Island Interconnected System
Existing Generating Capability
Energy Balances and LOLH Indices

	Load Forecast		Existing System			
Year	Peak[1] MW	Firm Energy GWh	Net Capacity MW	Firm Capability GWh	LOLH[1] Hrs/yr	Energy Balance GWh
2001	1,576	8,240	1,831	8,275	2.86	35
2002	1,602	8,316	1,831	8,275	3.97	(41)
2003	1,611	8,384	1,831	8,275	4.70	(109)
2004	1,632	8,479	1,831	8,275	5.50	(204)
2005	1,652	8,560	1,831	8,275	8.48	(285)
2006	1,673	8,639	1,831	8,275	11.14	(364)
2007	1,696	8,734	1,831	8,275	15.04	(459)
2008	1,719	8,831	1,831	8,275	17.51	(556)
2009	1,735	8,894	1,831	8,275	24.36	(619)
2010	1,741	8,929	1,831	8,275	26.44	(654)

[1] The 46 MW Interruptible load is included in the peak load forecast and used in the determination of LOLH.

Newfoundland and Labrador Hydro
Island Interconnected System
Generation Additions

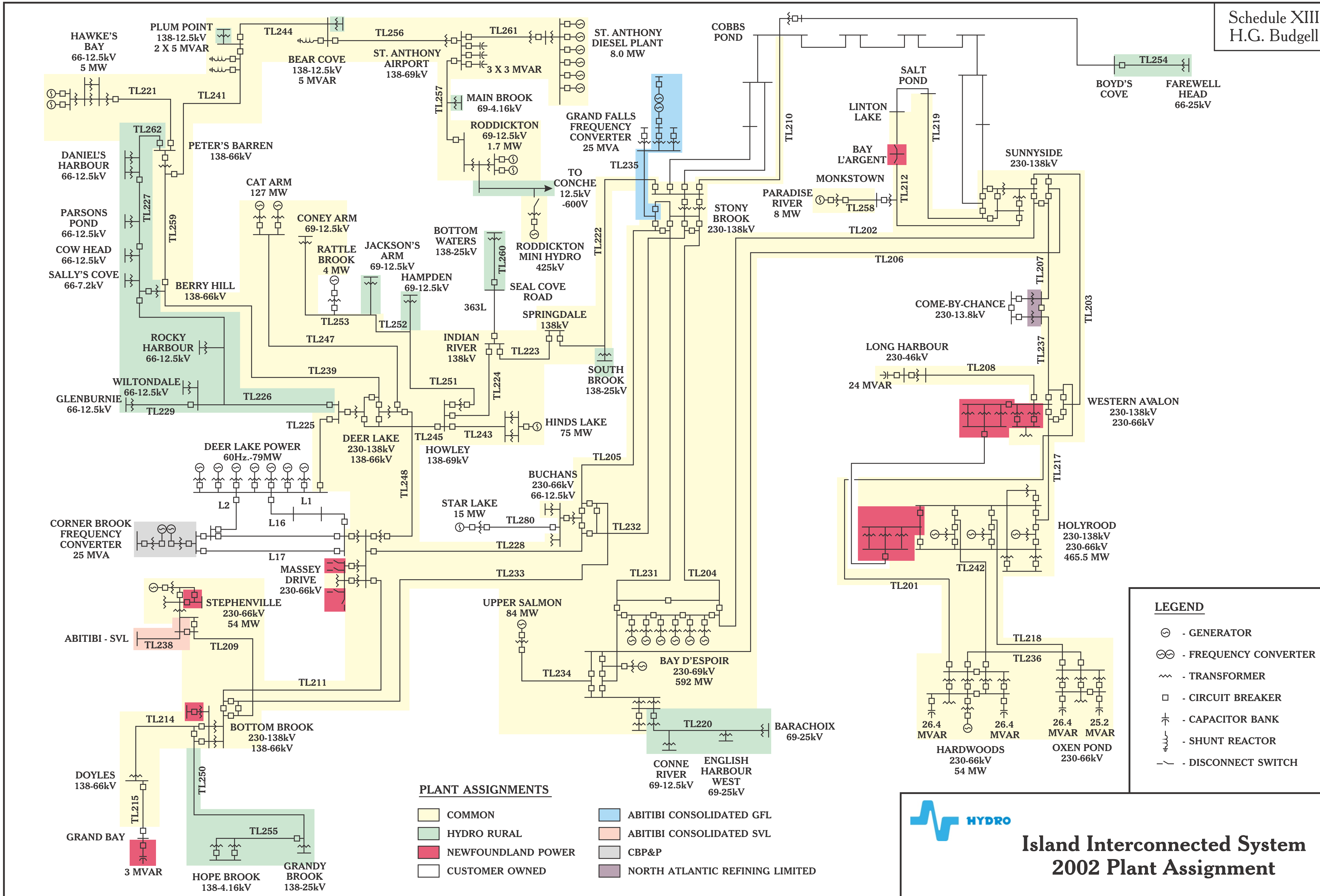
Project	Capacity MW	Annual Energy Capability (GWh) Firm	Average	In-service Date
Granite Canal	40.0	216	224	Mid-2003
ACI Beeton + Bishop's Falls Upgrade	32.3	110	137	Fall 2003
CBP&P Cogeneration	15.0	100	100	Mid-2003
TOTAL	**87.3**	**426**	**461**	

Newfoundland and Labrador Hydro
Island Interconnected System
Existing plus Committed Generation Capability
Energy Balances and LOLH Indices

	Load Forecast		Existing Plus Committed System			
Year	Peak[1] MW	Firm Energy GWh	Net Capacity MW	Firm Capability GWh	LOLH[1] Hrs/yr	Energy Balance GWh
2001	1,576	8,240	1,831	8,275	2.86	35
2002	1,602	8,316	1,831	8,280	3.97	(36)
2003	1,611	8,384	1,920	8,442	2.45	58
2004	1,632	8,479	1,920	8,715	1.45	236
2005	1,652	8,560	1,920	8,715	2.35	155
2006	1,673	8,639	1,920	8,715	3.23	76
2007	1,696	8,734	1,920	8,715	4.56	(19)
2008	1,719	8,831	1,920	8,715	5.54	(116)
2009	1,735	8,894	1,920	8,715	7.94	(179)
2010	1,741	8,929	1,920	8,715	8.71	(214)

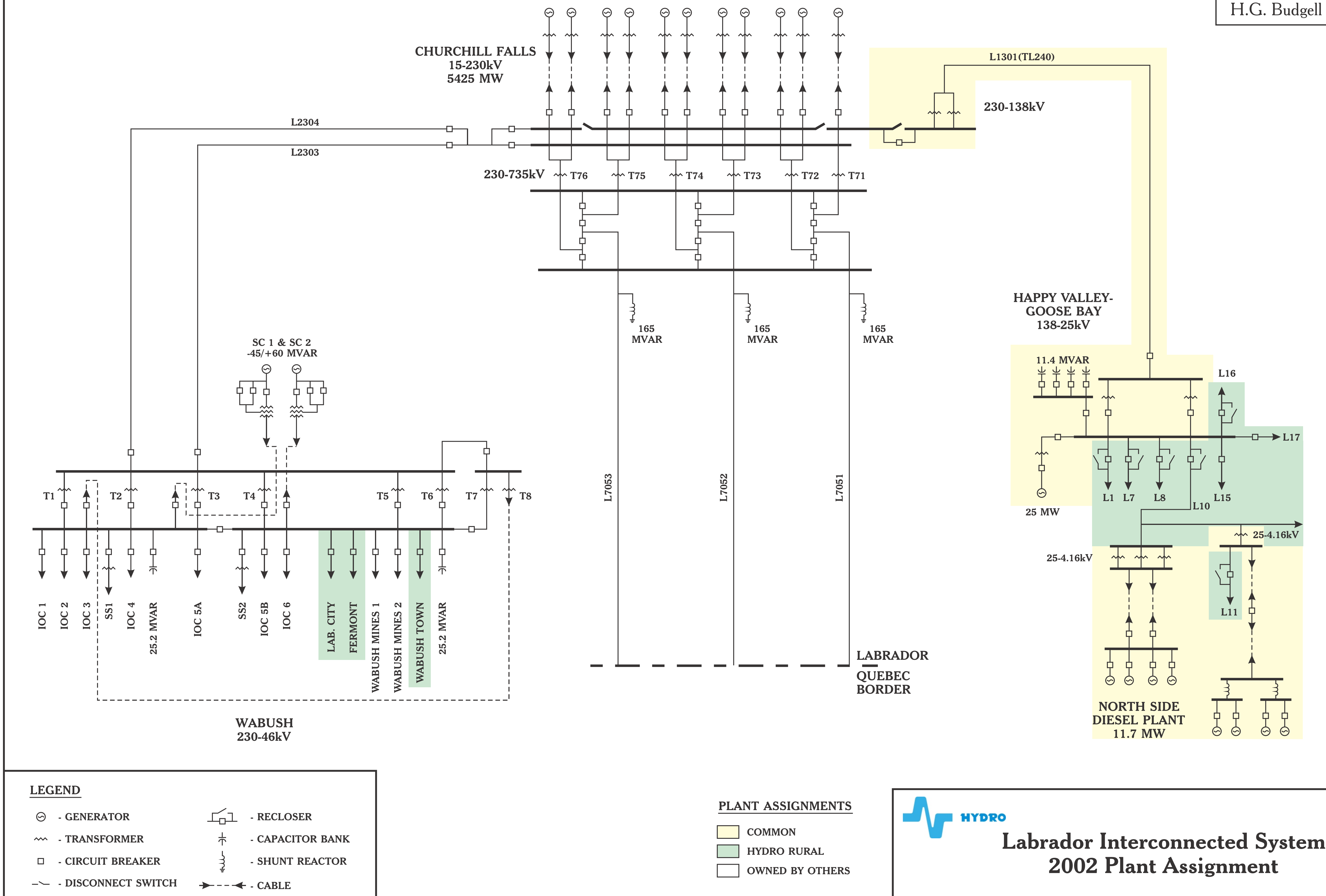
[1] The 46 MW Interruptible load is included in the peak load forecast and used in the determination of LOLH.

Schedule XIII
H.G. Budgell



Island Interconnected System
2002 Plant Assignment

Schedule XIV
H.G. Budgell



HYDRO

Labrador Interconnected System
2002 Plant Assignment

J.C. Roberts

NEWFOUNDLAND AND LABRADOR HYDRO

EVIDENCE OF JOHN C. ROBERTS

Q. Would you please give your name, address, qualifications and occupation?

A. My name is John Roberts and I live in St. John's, Newfoundland. I am a member of the Institute of Chartered Accountants of Newfoundland and I am the Corporate Controller of the Hydro Group. I have been employed by Hydro since 1983 and have been in my current position since 1985.

Q. Please outline the evidence you will be presenting to the Board.

A. My evidence will cover:

1. Hydro’s actual financial performance in 1992 compared to estimates presented to the Board during the last rate hearing;
2. Hydro’s actual results for 2000;
3. Hydro’s estimate of its financial performance for 2001;
4. Hydro’s projected revenue requirement for 2002;
5. Hydro’s Rate Base Calculation for 2002;
6. Hydro’s Cost of Capital for 2002;
7. The status of the Rate Stabilization Plan since the last hearing;
8. The treatment of the realized foreign exchange losses; and
9. Results of Hydro’s recent depreciation study and the implications on this application.

Q. How is Hydro’s revenue requirement determined?

A. Schedule I of my evidence shows all of the components making up the revenue requirement including margin, but excluding some non-regulatory costs (donations and costs related to Muskrat Falls), the effect of export sales by Hydro to Hydro-Québec and Hydro's investments in subsidiary companies. The cost of service allocates certain costs to an unregulated Labrador industrial customer and as a result, the projected margin from this customer has been included in the revenue requirement calculation.

Q. How does Hydro's actual financial performance in 1992 compare to the forecast presented by Hydro to the Board for 1992?

A. In 1992 Hydro achieved a margin of $17.1 million compared to the forecast of $10.8 million which provided an interest coverage of 1.12 compared to the forecast of 1.08. The actual results include the effect of taking over the distribution system in Labrador City on May 1, 1992.

Schedule I to my evidence gives a comparison of the actual and forecast costs used in the last rate referral for 1992.

Q. Would you please summarize Hydro's actual financial results for 2000?

A. In 2000, Hydro achieved a margin of $5.8 million which provided an interest coverage of 1.06. Schedule I to my evidence shows the actual costs for 2000.

Q. Would you please summarize Hydro's estimate of its financial performance for 2001?

A. Our estimate for 2001 shows that Hydro is projecting a margin of $13.7 million, which provides an interest coverage of 1.14. Schedule I to my evidence shows the forecast costs for 2001.

Q. What is your forecast revenue requirement for 2002?

A The forecast revenue requirement for 2002 is $322.3 million. This is the first year that the revenue requirement has been determined based on a rate base/rate of return approach established by legislation. Schedule I of my evidence outlines all costs associated with determining the revenue requirement for 2002.

Q Would you please outline Hydro's rate base for 2002?

A. Schedule II of my evidence outlines Hydro's forecast rate base for 2002 which has been prepared in consultation with our consultants, Foster Associates Inc. Pages 2 and 3 of Schedule II provide an outline of how the rate base components were determined.

Q. Please elaborate on the analysis Hydro undertook to determine its revenue and expense lag and the determination of the net cash working capital allowance to be included in rate base for 2002.

A. One of the components of rate base is a cash working capital allowance and in her evidence, Ms. McShane discussed the procedure to be followed in determining a cash working capital allowance by analyzing the leads and lags in cash flows related to revenues and operating expenditures.

Schedule III of my evidence shows the calculation of the cash working capital allowance and the related lead lag analysis is detailed in Schedules IV, V and VI.

Hydro's main revenue is derived from one retail customer, five Industrial Customers and approximately 35,000 Rural Customers. Based on actual results for 2000, a revenue lag was calculated for each of the above noted customers or customer group which was then multiplied by the percentage each contributes to total forecast revenue for 2002 in order to arrive at a weighted average. The total of the weighted averages is an estimated revenue lag for 2002 of 39.46 days.

Hydro's 2002 total operating expenditures excluding fuel but including power purchases is approximately $104.2 million (Schedule V). The lag for each expenditure, which was primarily determined from a review and analysis of actual costs for 2000, was multiplied by the percentage each expenditure was of the total for 2002 to arrive at a weighted average. The lag for the salaries and fringe benefits grouping and power purchases which are 68% of the total for 2002 were subjected to a detailed analysis of the actual costs for 2000. In the case of system equipment maintenance, professional services and miscellaneous expenses which are 24% of the total for 2002, a sample of actual major supplier charges for 2000 was reviewed in order to calculate an expense lag. Insurance and property rentals had leads which are consistent with payments being made in advance, and all other expenditure categories were assigned an expense lag of 45 days. The total of the weighted averages is an estimated expense lag of 20.09 days. Consequently, we have a net lag of 19.37 days between the time expenditures are made and the time payment is received and when the net lag is divided by the number of days in the year, it equals 5.31%. This percentage multiplied by the total 2002 forecast expenditures of $104.2 million results in a gross working capital allowance of $5.5 million.

The Harmonized Sales Tax (HST) is collected from customers, paid to suppliers (input tax credits), and the net amount remitted to government. Generally, HST is paid to suppliers prior to being collected from customers.

In order to determine the effect of the HST on the cash working capital requirement an estimate of the HST receivable and payable for 2002 was calculated. The lag days associated with each component were calculated based on the amount of time funds were available. The HST adjustment to be made to cash working capital based on this analysis, is a reduction of $2.4 million.

When the $2.4 million HST adjustment is subtracted from the gross working capital allowance of $5.5 million, the net cash working capital allowance is $3.1 million.

Q. What is Hydro's forecast return on rate base for 2002?

A. Hydro's forecast return on rate base for 2002 is $100.8 million as outlined in Schedule VII of my evidence. As a result of a previous recommendation of the Board, Hydro can recover only the cost of debt on its Rural Island Interconnected and Isolated assets. For all other rate base assets, the weighted average cost of capital is used to arrive at the return on rate base.

Q. What is Hydro's forecast weighted average cost of capital for 2002?

A. Hydro's capital structure is comprised of debt, equity and employee future benefits. The embedded cost of debt for 2002 is projected to be 8.35% and Hydro is also proposing a return on equity for 2002 of 3%. As a result, Hydro's forecast of its weighted average cost of capital for 2002 is 7.40% as outlined in Schedule VIII of my evidence.

Q. How is Hydro's embedded cost of debt for 2002 derived?

A. Schedule IX of my evidence shows the calculation of the projected embedded cost of debt for 2002. The rate of 8.35% for 2002 was determined by dividing the estimated debt costs for 2002 by the average amount of debt outstanding in 2002.

Q. What is Hydro’s projected long-term debt for 2001 and 2002?

A. Schedule X of my evidence provides specific details on Hydro’s long-term debt for 2001 and 2002.

Hydro’s borrowing strategy encompasses both a short-term promissory note program, and longer-term debentures which are usually issued in the domestic market and denominated in Canadian currency. Pursuant to Section 33 of the Hydro Corporation Act, our short-term debt as prescribed by Order in Council may not exceed $300 million, and our positioning within that range is impacted by factors such as market conditions and our expected cash requirements. When the total short-term debt reaches an amount which indicates that some or all of the balance should be funded long-term, we would consider doing a debenture issue. Hydro thus utilizes the flexibility afforded us within the $300 million limit to ensure the appropriateness of our timing in our approaches to the capital market, rather than being driven by an absolute requirement for funds.

Q. How were the interest rates for new long-term debt issues determined?

A. In order to arrive at the interest rate projections for 2001 and 2002, Hydro received projections from five investment dealers on 5-year, 10-year and 30-year Government of Canada Bonds. A simple average of these projections was computed and the current spreads applicable to our credit as provided by a lead manager was added to this average in order to determine projected interest rates.

Q. What return on equity and interest coverage are forecast for 2002?

A. Hydro is forecasting a return on equity for 2002 of $9.6 million as shown in Schedule I of my evidence which provides an interest coverage of 1.10.

Q. What is Hydro's forecast financial position for 2002?

A. Schedule XI of my evidence shows Hydro's projected balance sheet for 2002.

Schedule XII of my evidence is a statement of retained earnings and outlines the margin/return on equity and projected dividend payments.

Schedule XIII of my evidence is a statement of cash flows and outlines the sources of funds generated internally from operations and externally through promissory notes and long-term borrowings and how these funds will be expended.

Q. Would you please outline the status of the Rate Stabilization Plan (RSP) since the last rate hearing?

A. Schedule XIV of my evidence outlines the actual plan results for the years 1992 to 2000 and our projections for 2001 and 2002.

Normally in a test year there would be no variations in the RSP. However, because the cost of fuel is not being rebased in this application to the projected cost for 2002, there will be a fuel cost variation in the RSP for 2002 of approximately $25.5 million excluding carrying charges. Hydro is also proposing an increase in the current RSP cap for Newfoundland Power as outlined in the evidence of Mr. Osmond.

Q. Will the implementation of the rate base/rate of return model of regulation impact the amount of carrying charges associated with the RSP and Construction Work in Progress (CWIP)?

A. Yes. Although the RSP and CWIP are not part of the rate base, as outlined in the prefiled testimony of Ms. McShane, these assets are financed by the same proportions of debt and equity that finance the rate base assets, as opposed to being financed exclusively with debt. Therefore, effective January 1, 2002 the weighted average cost of capital will be used to calculate carrying charges for the RSP and CWIP, rather than the embedded cost of debt.

Q. Would you please outline to the Board the current status of Hydro's foreign long-term debt?

A. Hydro had a Japanese Yen and a Swiss Franc Loan which were both refinanced in 1995 and one of the terms of the refinancing was that a minimum of 20% of the original principal amount of each loan would be retired each year. By June 1997, both of these loans were fully repaid and a total foreign exchange loss of $96.3 million had been realized.

Q. How is Hydro proposing to treat the realized foreign exchange loss?

A. At the 1992 rate hearing, the Board recommended that Hydro commence recording an amortization of $1.0 million per annum related to the exchange loss on the Swiss Franc Loan. As of January 1, 2002, the amortization provision which amounts to $10.0 million has been netted against the total loss of $96.3 million. The net amount of $86.3 million is being amortized over a 40-year period as stipulated in Section 17(3)e of the Hydro Corporation Act and the annual amortization is $2.16 million. The unamortized portion of the realized foreign exchange loss has been included in rate base because Hydro must continue to finance the outstanding balance until it is fully recovered.

Q. Has Hydro completed a recent depreciation policy review?

A. Hydro had a depreciation policy study completed by KPMG in 1986, which formed part of the 1989 rate referral, and an update of this study was finalized in 1998 (1998 Study) by KPMG, LLP. The issues addressed in the 1998 Study are as follows:

1. Should Hydro continue to use the sinking fund depreciation method for a large portion of its assets?
2. What approach should Hydro take in estimating and accounting for the net salvage value and predicted site restoration costs of assets?
3. Are the service lives that are currently used by Hydro for estimating depreciation expenses appropriate? and
4. Which of Hydro's assets shall be considered "prime assets", and therefore depreciated as total plants, rather than depreciating each of their components?

Q. Would you please outline the major findings of the 1998 Study?

A. The major findings of the 1998 Study are as follows:

On the first issue, the 1998 Study concluded that the sinking fund method of depreciation provides greater equity among present and future users of electric power, as it allows the power users to derive the same net benefits from the use of a particular asset throughout its entire service life. Hydro will continue to use the sinking fund method of depreciation for its hydroelectric generating plants, transmission lines and substations and will continue to use the straight-line method of depreciation for its thermal generating plants, vehicles, general plant and telecontrol equipment.

With respect to the second issue of accounting for the net salvage value of utility assets the recommendations are as follows:

For assets with an original acquisition cost of less than $500,000 and for all assets that have an estimated future salvage value (in inflated terms) of less than 10% of their original acquisition, it recommends that salvage should be recognized in Hydro's income statement at the time it is incurred.

For assets that have acquisition costs in excess of $500,000 and an estimated net salvage value in excess of 10% (referred to below as major assets) the following alternatives exist:

When the asset is expected to be replaced after retirement by an asset of the same nature at the same site (most likely in an upgraded or improved form) the net salvage value related to the retired asset should be combined with the acquisition and construction costs of the new asset.

When a significant major asset is retired without replacement at the same site, and net salvage costs are incurred as a consequence of the asset's removal and/or the rehabilitation of its site, they can be treated in two ways:

1. If the decision to abandon a site was the result of a feasibility study that indicated that after having included all removal and rehabilitation costs incurred at the old site into the feasibility study, the transfer of operations to a new site was still beneficial to Hydro

and its customers, it is equitable to charge future customers with the net salvage costs. The 1998 Study concludes that costs of less than $500,000 would be amortized over a five-year period and a ten-year period for larger amounts.

2. When the removal of an asset and the rehabilitation of its site is performed as an undertaking or commitment related to external reasons, the net salvage costs should be built into the depreciation rates of the asset throughout its service life. This should be done in the form of a percentage mark-up, calculated on the basis of engineering estimates, on the depreciation rate calculated on the basis of the asset's original acquisition cost. If properly calculated, there will be a surplus in accumulated depreciation by the end of the asset's service life that is equal to the estimated net salvage costs in inflated terms. The 1998 Study notes that it is not practical to apply this alternative to existing assets after they have passed a significant portion of their service lives.

The final alternative produces the same results as those described in the preceding paragraph except that in the financial statements, an explicit reserve account would be established for the accumulation of that portion of the depreciation reserve that is intended to cover future net salvage costs.

The recommendations related to the accounting for the net salvage value of utility assets will be implemented effective January 1, 2002 if approved by the Board.

Thirdly, the 1998 Study reviewed the estimated service lives of capital assets and concluded that these were generally within the range assigned by other electric utilities. The 1998 Study noted the service lives of passenger cars, snowmobiles and pick-up trucks should be extended and this change has been reflected for 2002. The 1998 Study also recommended that Engineering Condition Surveys be conducted for those thermal generating plants that are approaching the end of their presently estimated service lives.

The thermal generating plants that were approaching the end of their original estimated service lives were the Holyrood Thermal Units 1 and 2 and the Hardwoods and Stephenville Gas Turbines. Hydro's internal engineering staff undertook a Conditions Survey of these facilities during 1999 and their recommendation was that all of these facilities including Holyrood Unit 3 would have an additional service life of at least another 20 years. This recommendation has been implemented effective January 1, 2002.

The final issue deals with "prime assets" and the 1998 Study concludes that Hydro's current approach to depreciating prime assets is appropriate. It did suggest that Hydro consider coding its units of property in such a manner that it will be easy to determine the total number of like units and their total acquisition costs, by installation year, or in total. Hydro concurs with this recommendation and significant progress is being made in this regard.

Q. Have there been any other Condition Surveys completed that will impact the estimated service lives of capital assets?

A. As a result of the significant capital expenditures related to the Avalon Upgrade of Transmission Lines, Hydro's internal engineering staff were asked to complete a Conditions Survey of the transmission lines affected by the upgrade in order to determine what impact, if any, the upgrades would have on the original estimated service lives. The recommendation from the survey is that the transmission lines have a revised service life of

50 years once the upgrade was completed. This change is also reflected in this Rate Application.

Q. Does this conclude your evidence?

A. Yes.

NEWFOUNDLAND AND LABRADOR HYDRO
REVENUE REQUIREMENT
($thousands)

Line No.	Description	1992 Final C.O.S.	1992 Actuals	Increase (Decrease)	2000 Actuals	Increase (Decrease)	2001 Estimate	Increase (Decrease)	**2002 Forecast**	Increase (Decrease)
1	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	**(i)**	(j)
2										
3	Depreciation	25,173	23,713	(1,460)	35,469	11,756	32,738	(2,731)	**31,790**	(948)
4										
5	Fuel									
6	No. 6 Fuel	37,856	39,003	1,147	49,252	10,249	103,802	54,550	**100,585**	(3,217)
7	Additives & Indirects	279	259	(20)	84	(175)	180	96	**185**	5
8	Environmental fee				(26)	(26)	19	45	**102**	83
9	Ignition Fuel	73	118	45	156	38	127	(29)	**112**	(15)
10	Gas Turbine Fuel	259	350	91	142	(208)	364	222	**471**	107
11	Diesel Fuel and Wood Chips	7,717	7,325	(392)	6,123	(1,202)	6,678	555	**6,323**	(355)
12	Rate Stabilization Plan	0	(3,740)	(3,740)	(13,163)	(9,423)	(59,719)	(46,556)	**(25,490)**	34,229
13	TOTAL FUEL	46,184	43,315	(2,869)	42,568	(747)	51,451	8,883	**82,288**	30,837
14										
15	Power Purchased	3,248	3,398	150	15,961	12,563	15,333	(628)	**15,266**	(67)
16										
17	Other Costs									
18	Salaries and Fringe Benefits	56,444	55,316	(1,128)	61,266	5,950	60,272	(994)	**61,773**	1,501
19	System Equipment Maintenance	13,303	11,551	(1,752)	18,977	7,426	17,484	(1,493)	**16,763**	(721)
20	Insurance	1,040	1,178	138	1,037	(141)	849	(188)	**848**	(1)
21	Transportation	3,655	3,289	(366)	2,390	(899)	2,174	(216)	**1,923**	(251)
22	Office Supplies Expenses	3,625	3,201	(424)	2,081	(1,120)	1,943	(138)	**1,939**	(4)
23	Building Rentals and Maintenance	2,223	1,754	(469)	998	(756)	612	(386)	**626**	14
24	Professional Services	2,809	2,992	183	3,815	823	4,506	691	**4,340**	(166)
25	Travel Expenses	1,833	1,890	57	2,704	814	2,295	(409)	**2,375**	80
26	Equipment Rentals	1,924	1,668	(256)	1,400	(268)	1,488	88	**1,558**	70
27	Miscellaneous Expenses	2,930	3,031	101	5,179	2,148	4,970	(209)	**4,458**	(512)
28	Loss on Disposal of Fixed Assets	186	796	610	2,186	1,390	1,175	(1,011)	**791**	(384)
30	SUB-TOTAL	89,972	86,666	(3,306)	102,033	15,367	97,768	(4,265)	**97,394**	(374)
31										
32	Allocations									
33	Hydro Capitalized Expense	(5,071)	(6,296)	(1,225)	(7,219)	(923)	(5,658)	1,561	**(5,722)**	(64)
34	CF(L)Co	(2,440)	(2,388)	52	(1,670)	718	(1,906)	(236)	**(1,910)**	(4)
35	L.C.D.C.	(15)	0	15	0	0	0	0	**0**	0
37	SUB-TOTAL	(7,526)	(8,684)	(1,158)	(8,889)	(205)	(7,564)	1,325	**(7,632)**	(68)
38										
39	Total Other Costs	82,446	77,982	(4,464)	93,144	15,162	90,204	(2,940)	**89,762**	(442)
40	Interest	121,615	120,429	(1,186)	96,889	(23,540)	92,558	(4,331)	**93,584**	1,026
41	Margin/Return on Equity	10,825	17,094	6,269	5,829	(11,265)	13,727	7,898	**9,610**	(4,117)
42	Revenue Requirement	289,491	285,931	(3,560)	289,860	3,929	296,011	6,151	**322,300**	26,289

Newfoundland and Labrador Hydro
Rate Base
($thousands)

		2001	2002
Capital Assets		1,738,764	1,781,858
Less:	Contributions in Aid of Construction	88,859	87,205
	Accumulated Depreciation	410,700	439,714
	Muskrat Falls Assets	2,010	2,010
Net Capital Assets		1,237,195	1,252,929
Net Capital Assets Previous Year			1,237,195
Average Capital Assets			1,245,062
Cash Working Capital Allowance (Schedule III)			3,096
Fuel Inventory			16,018
Supplies Inventory			21,095
Deferred Realized Foreign Exchange Loss			85,200
Average Rate Base			1,370,471

NEWFOUNDLAND AND LABRADOR HYDRO

RATE BASE

1. Capital Assets

   These amounts reflect the actual capital asset balances as at December 31, 2000 and have been adjusted for the impact of the Board approved 2001 capital budget and the projected capital budget for 2002. Construction work in progress is not included in these numbers.

2. Contributions in Aid of Construction

   These funds have been received from customers and governments toward the cost of capital assets. Contributions are treated as a reduction to capital assets and the net capital assets are depreciated.

3. Accumulated Depreciation

   Accumulated depreciation has been calculated on the capital asset balances outlined in Item 1 above.

4. Muskrat Falls Assets

   These assets are fully contributed and are deducted from capital assets.

5. Net Capital Assets

   This is the net capital assets to be included in rate base.

NEWFOUNDLAND AND LABRADOR HYDRO

RATE BASE

6. Cash Working Capital Allowance

   This amount represents an allowance to cover the amount of capital which investors provide in order to bridge the gap between the time expenditures are made to provide service and the time payment is received for the service.

7. Fuel Inventory

   This amount is based on a thirteen-month average.

8. Supplies Inventory

   This amount is based on a thirteen-month average.

9. Deferred Realized Foreign Exchange Loss

   This amount is the average of the opening and closing balances of the account for 2002.

Newfoundland and Labrador Hydro
Cash Working Capital Allowance Calculation

	2002 Days
Revenue Lag (Schedule IV)	39.46
Less: Expense Lag (Schedule V)	20.09
Net Lag	19.37
Divide by 365 days	5.31%

	2002 ($thousands)
Operating Expenditures	88,971
Power Purchases	15,266
Total	104,237
Multiply by 5.31%	5,535
Less: HST Adjustment (Schedule VI)	2,439
Net Cash Working Capital Allowance	3,096

Newfoundland and Labrador Hydro
Revenue Lag
($thousands)

Customer	2002	Percent	Lag Days: Service	Lag Days: Billing	Lag Days: Collection	Total Lag	Weighted Average Days
NP	213,830	66.84%	15.2	7.6	13.0	35.8	23.93
Industry	56,440	17.63%	15.2	7.6	15.7	38.5	6.79
Rural	48,583	15.19%	15.2	7.0	34.7	56.9	8.64
Other	1,072	0.34%	(15.2)	6.0	38.8	29.69	0.10
TOTAL	319,925	100.00%					39.46

Newfoundland and Labrador Hydro
Operating Expenses Lag
($thousands)

	2002	Percent	Lag Days	Weighted Average Days
Salaries & Benefits (net of capitalized expense)	56,051	53.8%	12.6	6.77
System Equipment Maintenance	16,763	16.1%	45.5	7.32
Professional Services	4,340	4.2%	(8.7)	(0.37)
Miscellaneous	4,133	4.0%	0.9	0.03
Travel	2,375	2.3%	45.0	1.03
Transportation	1,923	1.8%	45.0	0.81
Office Supplies	1,939	1.8%	45.0	0.85
Equipment Rentals	1,558	1.5%	45.0	0.67
Insurance	848	0.8%	(182.5)	(1.47)
Property Rentals	626	0.6%	(30.0)	(0.18)
Customer Costs	325	0.3%	0.0	0.00
	90,881	87.2%		15.46
CF(L)Co Recoveries	(1,910)	(1.8%)	30.0	(0.55)
Power Purchases	15,266	14.6%	35.4	5.18
Total	104,237	100.0%		20.09

Newfoundland and Labrador Hydro
HST Adjustment
($thousands)

		2002	Estimated HST/GST	Lag Days	$
Revenue		317,464	47,620	31.28	4,081
O&M		29,017	4,353	(15.2)	(182)
Fuel	No. 6 (7% G.S.T.)	99,330	6,953	(30.4)	(579)
	Other	8,102	1,215	(15.2)	(51)
Power Purchases		15,266	2,290	(25.4)	(159)
Capital		107,453	16,118	(15.2)	(671)
					2,439

Newfoundland and Labrador Hydro
Return on Rate Base
($thousands)

Component Base	2002	Weighted Average Cost of Debt	Weighted Average Cost of Capital	Return on Rate Base
Rural Interconnected and Isolated Assets	134,308	6.941%		9,322
Other Rate Base Assets	1,236,163		7.399%	91,464
Average Rate Base	1,370,471			100,786

Schedule VIII
J. C. Roberts

Newfoundland and Labrador Hydro
Weighted Average Cost of Capital
($thousands)

	2001	2002	Average	Percent	Cost	Weighted Average
Promissory Notes	185,671	161,489				
Long-Term Debt (Schedule X)	1,159,721	1,352,761				
Less: Sinking Funds	80,575	94,151				
CF(L)Co Share Purchase Debt	27,546	25,609				
Unamortized Debt Discount and Issue Expenses	12,195	13,541				
Total Debt	1,225,076	1,380,949	1,303,012	83.18	8.345%	6.941%
Employee Future Benefits	23,554	25,123	24,339	1.55	0.000%	0.000%
Retained Earnings	269,367	208,830	239,099	15.27	3.000%	0.458%
	1,517,997	1,614,902	1,566,450	100.00		7.399%

Newfoundland and Labrador Hydro
Cost of Debt
($thousands)

	2002
Interest	101,662
Amortization of Foreign Exchange Loss	2,157
Amortization of Debt Discount and Issue Expense	1,175
Debt Guarantee Fee	11,993
	116,987
Less: Interest on Sinking Fund Assets	6,301
CF(L)Co Share Purchase Debt	1,951
Net Interest	108,735

$$\text{Embedded Cost of Debt} = \frac{\text{Net Interest}}{\text{Total Debt}}$$

$$= \frac{108{,}735}{1{,}303{,}012} = 8.345\%$$

Schedule X
J. C. Roberts

Newfoundland and Labrador Hydro
Schedule of Long-Term Debt
($thousands)

Series	Interest Rate %	Year of Issue	Year of Maturity	2001	2002
Z	5.25	1997	2002	100,000	-
AA	5.50	1998	2008	200,000	200,000
V	10.50	1989	2014	125,000	125,000
X	10.25	1992	2017	150,000	150,000
Y	8.40	1996	2026	300,000	300,000
	5.30	2001	2006	100,000	100,000
	6.25	2001	2031	150,000	150,000
	5.50	2002	2007	-	100,000
	6.10	2002	2012	-	200,000
				1,125,000	1,325,000
Government of Canada loans at 5.15% to 7.91%					
maturing in 2006 to 2014				31,009	25,118
Capital Leases				3,712	2,643
Total				1,159,721	1,352,761

Newfoundland and Labrador Hydro
Projected Balance Sheet
(Excluding CF(L)Co., LCDC and Contributed Capital - Muskrat Falls)

As at December 31 (thousands of dollars)

	2002	2001
ASSETS		
Capital assets		
Capital assets in service	1,692,643	1,647,895
Less accumulated depreciation	439,714	410,700
	1,252,929	1,237,195
Construction in progress	147,280	76,666
	1,400,209	1,313,861
Current assets		
Accounts receivable	42,974	41,632
Fuels and supplies at average cost	40,429	40,652
Prepaid expenses	2,615	2,936
	86,018	85,220
Rate stabilization plan	97,771	87,397
Unamortized debt discount and financing expense	13,541	12,195
Unamortized foreign exchange loss	84,121	96,278
	1,681,660	1,594,951
LIABILITIES AND SHAREHOLDER'S EQUITY		
Long-term debt	1,218,600	937,352
Current liabilities		
Accounts payable and accrued liabilities	25,729	29,499
Accrued interest	27,488	25,260
Long-term debt due within one year	14,401	114,248
Promissory notes	161,489	185,671
	229,107	354,659
Foreign exchange loss provision	0	10,000
Employee future benefits	25,123	23,554
Shareholder's equity		
Retained earnings	208,830	269,367
	1,681,660	1,594,951

Newfoundland and Labrador Hydro
Projected Statement of Retained Earnings
(Excluding CF(L)Co., LCDC and Contributed Capital - Muskrat Falls)

Year ended December 31 (thousands of dollars)

	2002	2001
Retained earnings, beginning of year	269,367	267,616
Margin/return on equity	9,610	13,727
	278,977	281,343
Dividends	70,147	11,976
Retained earnings, end of year	208,830	269,367

Newfoundland and Labrador Hydro
Projected Statement of Cash Flows
(Excluding CF(L)Co., LCDC and Contributed Capital - Muskrat Falls)

Year ended December 31 (thousands of dollars)

	2002	2001
Cash provided by (used in)		
Operating activities		
Net income	9,610	13,727
Adjusted for items not involving a cash flow		
Depreciation	31,790	32,738
Amortization of deferred charges	3,332	1,143
Rate stabilization plan	(10,374)	(51,795)
Other	1,331	2,101
	35,689	(2,087)
Change in working capital balances	(771)	(6,474)
	34,918	(8,560)
Financing activities		
Long-term debt issued	300,000	250,000
Long-term debt retired	(105,023)	(157,855)
Dividends	(70,147)	(11,976)
	124,830	80,169
Investing activities		
Net additions to capital assets	(119,469)	(92,916)
Decrease (increase) in sinking funds	(13,576)	(11,412)
Reduction (additions) to deferred charges	(2,521)	(1,782)
	(135,566)	(106,110)
Net decrease (increase) in promissory notes	24,182	(34,501)
Promissory notes, beginning of year	(185,671)	(151,170)
Promissory notes, end of year	(161,489)	(185,671)

Newfoundland and Labrador Hydro
Rate Stabilization Plan
($millions)

Year	Balance	Retail	Industrial
1992	4.1	0.6	3.5
1993	9.4	3.8	5.6
1994	(4.0)	(5.6)	1.6
1995	12.9	6.9	6.0
1996	30.2	21.0	9.2
1997	41.3	27.6	13.7
1998	48.8	33.0	15.8
1999	34.5	21.5	13.0
2000	35.6	22.7	12.9
2001 Forecast	87.4	61.3	26.1
2002 Forecast	97.8	72.0	25.8

D.W. Osmond

NEWFOUNDLAND AND LABRADOR HYDRO
EVIDENCE OF DEREK W. OSMOND

Q. Would you please give your name, address, qualifications and occupation?

A. My name is Derek Osmond and I live in St. John's. I am a member of the Institute of Chartered Accountants of Newfoundland and I am the Vice-President of Finance and Chief Financial Officer of the Hydro Group of Companies. I have been employed by Hydro since 1975 and have been a Vice-President since 1985.

Q. What is the purpose of your evidence?

A. The purpose of my evidence is to:

1. Outline the proposed price of No. 6 fuel to be included in Hydro's rates;
2. Outline the proposed financial targets recommended by Hydro;
3. Explain Hydro's current rate policies and the timeframe over which proposed revisions to these rates would take place;
4. Explain Hydro's review of, and position relating to oil price hedging; and
5. Explain how Hydro's 2002 Capital Budget compares to prior year capital budgets and how the 2002 Capital Budget will be financed.

Q. How does the price of No. 6 fuel affect Hydro's base rates and the Rate Stabilization Plan (RSP)?

A. The price of No. 6 fuel is a component in the determination of Hydro's base rates. When the actual fuel price differs from the price in the base rates, it impacts the annual recovery rates in the RSP. In 1992 the Board approved rates for Hydro, which included $12.50 per barrel as the price for No. 6 fuel consumed at Holyrood and which formed part of the base rates. The variance in the actual cost of fuel purchased since 1992, as compared to $12.50 per barrel, has been included in the RSP with one-third of the balances automatically recovered from customers through an annual RSP adjustment. Since 1992, fuel prices have been generally increasing and within the last twelve months Hydro has paid as high as $40 per barrel for No. 6 fuel. Based on the 2001 forecast balances for the RSP, a 5.9% increase in rates is projected for Newfoundland Power and a 7.4% increase in rates is projected for Island Industrial Customers in 2002, solely for the RSP adjustment.

Q. What is Hydro proposing regarding the price of No. 6 fuel to be included in Hydro's rates?

A. Mr. Henderson in his evidence has indicated that based on the expert advice provided to Hydro, the No. 6 fuel price in 2002 is projected to be approximately $28 per barrel, decreasing to $26 per barrel in 2003 and lower in 2004 and 2005. These projections are based on world prices and are also impacted by the value of the Canadian dollar versus the U.S. dollar, since all of Hydro's No. 6 fuel purchases are paid in U.S. dollars.

Hydro has given extensive consideration to the appropriate price of No. 6 fuel for inclusion in Hydro's 2002 rates. The current price of $12.50 per barrel, which was approved by the PUB in 1992, is too low considering the current and projected No. 6 fuel prices.

Were Hydro to include the current projected price of $28 per barrel for No. 6 fuel in its base rates, Newfoundland Power would see a general rate increase on January 1, 2002 in the order of 16% (9% at the end consumer level). As well, the projected 5.9% RSP adjustment (3.4% at the end consumer level) referred to earlier would occur on July 1, 2002. Also, effective January 1, 2002 Industrial Customers would see a general rate increase of 23%, plus a projected 7.4% RSP adjustment. It is Hydro's view that this approach does not appear to be reasonable, particularly when No. 6 fuel prices are projected to decrease in 2003 and beyond.

Due to the significance of these rate increases, Hydro is proposing to use a lower than projected price for No. 6 fuel and permit the RSP to absorb any increase or decrease due to price variations. Hydro is therefore proposing $20 per barrel as the No. 6 fuel price for inclusion in Hydro's 2002 base rates. This would result in 2002 base rate increases to Newfoundland Power of 6.7% (3.7% at the end consumer level) and 10.4% to the Industrial Customers. The previously mentioned projected RSP adjustments of 5.9% for Newfoundland Power (3.4% for Newfoundland Power's end consumers) and 7.4% to Industrial Customers would also apply.

Q. What impact would rebasing No. 6 fuel to $20 per barrel have on the 2002 RSP balance?

A. As outlined in Mr. Roberts' evidence Hydro's most recent projections indicate that the RSP balance at December 31, 2002 would be $98 million due from customers (Newfoundland Power $72 million and Island Industrial Customers $26 million). This assumes actual fuel purchases of $28 per barrel and average inflows into Hydro's reservoirs during 2002.

Q. Is Hydro proposing that the existing $50 million cap in the RSP for Newfoundland Power be revised?

A. Yes, Hydro is proposing that the current cap for Newfoundland Power of $50 million be increased to $100 million and that the existing principles that have applied for the operation of the RSP should continue in the future, except for a minor revision as outlined in Mr. Brickhill's evidence.

Q. Have you discussed the proposed RSP cap with Hydro's financial advisors?

A. Yes, Hydro has discussed the proposal with its financial advisors and they concur with Hydro's proposal on the basis that the RSP would continue to operate as it has historically, with automatic rate adjustments taking place each year to collect one-third of the balance in the RSP.

As well, the financial advisors do not foresee any credit rating agency, or capital attraction implications for the Province or Hydro, with Hydro's proposal.

Q. Do you concur with the financial targets as recommended by Hydro's financial advisors?

A. Hydro's financial advisors have outlined two financial targets that they recommend Hydro should be aiming to achieve as follows:

- Debt-to-equity ratio of 60:40
- Return on equity (ROE) of 11-11.5%

These financial targets represent a rate of return on rate base of 9.5%.

This view is based on the premise that Hydro should aim to achieve financial targets similar to the level maintained by commercially operated Crown-owned utilities and investor-owned utilities. This would mean that Hydro would have an investment grade credit rating and have financial targets similar to other commercially operated Crown-owned utilities. I agree with the financial advisors' view that one of Hydro's targets should be to receive an ROE commensurate with commercially operated Crown-owned utilities and investor-owned utilities currently projected to be in the 11-11.5% range. However, with regard to a long-term targeted debt-to-equity ratio of 60:40, there are other factors which should be considered that will influence Hydro's long-term financial objectives.

In 1998 the Government announced its intention to review the structure of the electric utility industry within an Energy Policy Review (EPR) that would be undertaken by the Provincial Department of Mines and Energy. Until this EPR is completed and policy direction received, I believe it would be premature for Hydro to recommend or commence a process to implement long-term financial targets with respect to a debt-to-equity ratio of 60:40.

Q. What is Hydro proposing as its financial targets for the test year 2002?

A. To limit the general rate increase, in addition to using a lower than forecast No. 6 fuel price, Hydro is proposing to temporarily lower its financial targets for the 2002 test year.

It is Hydro's view, supported by its financial advisors, that a temporary reduction in its financial targets would not be viewed negatively by the financial community, especially if Hydro's debt continued to be guaranteed by the Province. As long as these targets are viewed as short term in nature, they will not have any negative impact on the credit rating of the Province. The credit rating agencies are generally more concerned with the trends evidenced by operations than the absolute level of any single measure.

Hydro's recommendation is to use a debt-to-capital ratio of 83% and temporarily include a 3% ROE for 2002. Hydro's current objective would be to move toward an 80:20 debt equity ratio, which was established at previous hearings. The ROE recommendation is made in consideration of the overall magnitude of rate increases proposed for 2002 which includes the general rate increase, plus the Rate Stabilization Plan adjustment in 2002, combined with the uncertain outcome of the EPR. The 3% ROE is significantly lower than the 11-11.5% range recommended by Hydro's financial advisors as being appropriate for Hydro. However, were an 11.25% ROE used, rates to Newfoundland Power and Island Industrial Customers would increase by approximately a further 6%.

Given that the Board's decision influences the credit rating agencies and the financial community, we ask that the Board make it clear that Hydro should be allowed the opportunity to earn an appropriate ROE as outlined by Hydro's financial advisors. Hydro, at each of its future rate applications, would be outlining its recommendations to the Board for achieving reasonable medium and long-term financial targets.

Q. Would you please provide the summary of the forecast financial results for 2002?

A. The following summary outlines the forecast financial results for 2002:

Newfoundland and Labrador Hydro
2002
Financial Summary

	Regulated Basis	Overall Basis [(1)]
Debt	83%	83%
Return on Equity	3%[(2)]	4%
Return on Rate Base	7.40%[(2)]	N/A
Return	$5.7 million	$9.6 million

[(1)] Includes non-regulated sales, but excludes export sales by Hydro to Hydro-Quebec as well as costs not previously permitted by the Board.

[(2)] In previous hearings Hydro has been directed by the Board to not include any return or margin on Hydro's Rural Island Interconnected and Isolated Systems assets. Consequently the return on equity that Hydro has proposed of 3% results in a 2.7% return on equity and a 7.35% rate of return on rate base.

Q. Would you please outline the basis of Hydro's rate design policies?

A. In formulating the rate policies to be followed, Hydro considered past rate practices, as well as the views of the Board as expressed in its 1992 and 1993 Reports on Hydro's Rate Referral and Cost of Service Methodology (1993 Report) hearings, as well as the 1996 Report on Rural Electrical Service (1996 Report).

Q. Please outline Hydro's rate policies that were used in the determination of its rate design objectives.

A. Hydro's rate policies are as follows:

1. Rates charged to Newfoundland Power and Island Industrial Customers are to be based on the cost of service as outlined in the evidence of Mr. Brickhill of Foster Associates Inc.;

2. All customers in the same class and served from the same system, Island or Labrador Interconnected, should pay the same rates;
3. Domestic customers, in Isolated Rural Systems, should pay the Island Interconnected domestic rate for their lifeline block of energy (700 kWh/month); and
4. Hydro will use certain rate design measures to reduce the rural deficit.

Q. Would you please explain the basis for the rural deficit and the measures that Hydro has employed in reducing this deficit?

A. Historically it has been public policy that customers served on the Island Interconnected Rural System would be charged the same rates as Newfoundland Power's customers, which results in revenues being less than the cost of providing service in these areas. It has also been public policy that customers served on the Isolated Rural System would not be charged the full costs of providing service. The overall rural deficit of approximately $26 million is comprised of the deficit incurred in operating the Isolated Rural Systems (diesel generation) and the Island Interconnected Rural System and is derived from the Cost of Service Study.

Hydro is taking action to reduce this deficit through efficiency and cost control measures as outlined in Mr. Reeves' evidence. In addition, Hydro is recommending action to be taken through some rate alterations in the Isolated Rural Systems. These rate alterations, when fully implemented, would reduce the deficit from what it would otherwise have been, by approximately $2.6 million. The Isolated Rural Systems deficit is significantly higher per customer than the deficit incurred to serve Rural Customers on the Island Interconnected System. As explained in Mr. Hamilton's evidence the Cost of Service Study results provide an indicator of the level of cost recovery from the various classes.

Q. What specific rate design measures is Hydro proposing to reduce the overall rural deficit for 2002?

A. Considering the overall impact of Hydro's general rate increase on Isolated Rural Customers, combined with the projected increases for Isolated Rural Customers that would arise if all recommendations in the 1996 Report were implemented immediately, Hydro is not proposing to commence the implementation of all of these recommendations starting in 2002. As a first step however, Hydro is proposing to phase in cost based rates for Provincial and Federal Government departments and agencies as outlined in the 1996 Report. Hydro believes that it is appropriate that this rate adjustment be considered by the Board now and in the future in order to keep the rural deficit paid by Newfoundland Power customers and Hydro's Rural Customers on the Labrador Interconnected System, as low as practicable. Hydro will submit at its next Rate Application, for review and approval by the Board, a rate plan outlining alterations in rates over a maximum of five years that will address the remaining recommendations in the 1996 Report (including the phase out of preferential rates and increases in cost recovery from Isolated Rural Customers).

Q. Would you please describe how the proposed 2002 rates for Newfoundland Power were established?

A. The applicable rates for 2002 for Newfoundland Power are derived from the 2002 Cost of Service Study as outlined in Mr. Brickhill's evidence.

In 1992 the Board recommended that Hydro and Newfoundland Power review the implementation of a demand and energy charge pricing structure. Hydro and Newfoundland Power have reviewed this issue and both companies concur that an energy only rate to Newfoundland Power is still appropriate.

Q. Would you please describe how the proposed 2002 rates for Industrial Customers were determined?

A. In 1996 the Hydro Corporation Act was amended to remove the provision that had existed exempting Hydro from the jurisdiction of the Board and accordingly Industrial Customers' rates and power contracts are now fully regulated by the Board. The amendment also provided that the existing rates and power contracts would remain in force until altered under the Public Utilities Act.

Hydro currently has four regulated Industrial Customers, who were also Industrial Customers in 1996, as follows:

1. Abitibi-Consolidated Inc., - (Stephenville Division);
2. Abitibi-Consolidated Inc., - (Grand Falls Division);
3. Corner Brook Pulp and Paper Company Limited; and
4. North Atlantic Refining Limited.

Hydro is proposing power contracts, with uniform industrial rates based on the 2002 Cost of Service Study, for the supply of power and energy for each of these Industrial Customers. These contracts, which are attached to the Application, have been developed with common wording that would be equally applicable in either contract. Where there are specific items that apply only to that particular customer, then these items are included in the relevant power contracts.

The proposed rate structures and tariffs that would apply to firm power and energy, as well as the power and energy for other specific requirements, are determined based on the Cost of Service Study and will be outlined in Mr. Hamilton's evidence.

Q. Would you please describe how the proposed 2002 rates for Rural Customers on the Island Interconnected System were established?

A. Consistent with the policy that customers in the same class and served from the same grid pay the same rates, Hydro recommends that Hydro Rural Customers on the Island Interconnected System pay the same rates as Newfoundland Power customers.

Q. Would you please explain how the proposed 2002 rates for Rural Customers on the Isolated Rural Systems were established?

A. Hydro proposes that rates for domestic and general service customers on the Isolated Rural System be established based on the current policy. These rates can be categorized into two parts, the rate for the first 700 kWh/month (the lifeline portion) and the rates for consumption above 700 kWh/month. The lifeline rate policy was established in 1969 for domestic customers at 500 kWh/month, increased to 600 kWh/month in 1987 and subsequently revised in 1989 to 700 kWh/month. This policy ensures that domestic customers pay the same electricity rates as Newfoundland Power customers for the first 700 kWh/month. This is also in accordance with the Board's recommendation contained in its 1996 Report. In 1989 the lifeline rate policy for the first 700 kWh/month was extended to the general service customers. The issue of the lifeline block for general service customers will be addressed at Hydro's next Rate Application.

Regarding energy rates for consumption above the 700 kWh lifeline block, Hydro recommends that the existing policy of automatically changing these rates by the average percentage change in Newfoundland Power rates continue in the short term.

Q. What are the proposed changes to rates for Provincial and Federal Government departments and agencies on the Isolated Rural Systems?

A. The Board in its 1996 Report recommended, “that a new rate be designed for federal and provincial departments and agencies and these rates, phased in over five years, should recover full costs, (i.e. 100% cost recovery)”. Hydro accepts this recommendation to move to full cost recovery.

On average, rates for Government agencies and departments would increase by approximately 280%, in order to achieve full cost recovery. It is Hydro’s recommendation that these customers receive an overall initial 20% increase in rates, including the general rate increase, effective January 1, 2002 and that Hydro will submit in its next Rate Application, for review and approval by the Board, a rate plan outlining alterations in rates over a maximum of five years in order to reach 100% cost recovery. Mr. Hamilton outlines in his evidence the percentage increases and dollar changes in annual costs to these customers.

Q Would you please quantify the overall dollar impact of this proposed change in the Isolated Rural System rates after the phase in period for Government agencies and departments?

A. Hydro would receive approximately $2 million in additional revenue after the phase in period is completed.

Q. Please describe the proposed changes to rates for the Labrador Interconnected System.

A. The Board in its 1993 Report recommended one Cost of Service Study for the Labrador Interconnected System. Consistent with this, Hydro is proposing to simplify rate classes and structures and to implement interconnected rates to include customers in Labrador City, Wabush and the Happy Valley/Goose Bay area. Any rate changes beyond those currently proposed, that arise as a result of these actions, would be included in a five-year plan to be submitted to the Board in Hydro's next Rate Application.

Currently there are three sets of rates, rules and regulations for the Labrador Interconnected System that have evolved over time as follows:

- Rates in the Happy Valley/Goose Bay area were frozen in 1981 at the Island Interconnected rates. These rates remain in effect today. The Rules and Regulations used on the Island Interconnected System also apply in the Happy Valley/Goose Bay area;
- In 1985 Hydro acquired from Wabush Mines the distribution assets associated with serving the Town of Wabush and the Board subsequently approved the Rates, Rules and Regulations that would apply; and
- In 1992, Hydro acquired from the Iron Ore Company of Canada the distribution assets associated with serving the Town of Labrador City and the Board subsequently approved the Rates, Rules and Regulations that would apply.

At the present time, the average rates are approximately 2.0¢/kWh in Wabush, 1.5¢/kWh in Labrador City and 3.8¢/kWh in the Happy Valley/Goose Bay area.

For the current rate hearing, Hydro is presenting one Cost of Service Study for the Labrador Interconnected System. This cost of service will identify the cost of serving each customer class. In order to facilitate the development of this cost of service, it was necessary to consolidate the 24 different rate classes presently in effect in Labrador City, Wabush and the

Happy Valley/Goose Bay area into six classes as identified in Mr. Hamilton's evidence. Similarly Hydro is proposing that there will be one set of Rules and Regulations that will apply to all Hydro Rural Customers.

The new rate classes that will be used are the same as those used on the Island Interconnected System, but the rates would reflect Labrador system costs. The implementation of these new rate classes for the Labrador Interconnected System will place all Labrador Interconnected Customers in the appropriate class based on each customer's load characteristics. There will also be a more equitable distribution of the Labrador Interconnected System costs amongst customers. Hydro will not receive any additional revenue from the consolidation of rate classes, but customers will receive increases or decreases depending on their load characteristics. One of the main reasons Hydro is proposing on average a decrease in rates of 13.1% for Rural Labrador Interconnected Customers is the treatment of secondary revenue from C.F.B. Goose Bay of approximately $3.0 million. This amount has been included in the 2002 Labrador Interconnected Cost of Service and in fact reduces the revenue requirement to be recovered in rates from Rural Labrador Interconnected Customers. If the C.F.B. Goose Bay secondary energy sales were not included in the Labrador Interconnected Cost of Service, rates for Rural Labrador Interconnected Customers would have been required to increase on average by approximately 10%*.* The guidelines used in the determination of rate structures are identified by Mr. Hamilton in his evidence.

As a first step towards implementing a uniform rate structure on the Labrador Interconnected System, Hydro is proposing that effective January 1, 2002, Labrador City and Wabush customers pay the same rates. This is generally achievable while limiting maximum increases to 20%, unless dollar amounts are deemed to be relatively small (less than

$250 annually) in which case increases will exceed the 20% limit. On average, domestic customers in Labrador West would see an increase of approximately 17.1%. However, 95% of these customers will have increases of less than $150 annually. Rates for general service customers in Labrador West are being decreased on average by 5.4%. Certain small general service customers will see relatively small increases, however most customers in the general service rate class will see significant decreases.

As mentioned previously, customers in the Happy Valley/Goose Bay area are categorized into the same six classes as other customers on the Labrador Interconnected System. However, the level of rates for Happy Valley/Goose Bay customers will differ. On average, in Happy Valley/Goose Bay, domestic customers would see a rate decrease of approximately 7.2%, while general service customers would see a rate decrease on average of approximately 37.7%.

Overall, on the Labrador Interconnected System, Hydro is proposing a rate decrease of approximately 13.1%. If this proposal is accepted, rates in Happy Valley/Goose Bay will remain higher than in Labrador West, however, substantial progress will have been made towards implementing uniform Labrador Interconnected rates. Hydro will submit at its next Rate Application, for review and approval by the Board, a rate plan outlining alterations in rates over a maximum of five years in order to complete the implementation of a Labrador Interconnected rate structure. Mr. Hamilton, in his evidence, outlines rates and rate classes for Labrador West and the Happy Valley/Goose Bay areas, as well as the percentage increases and dollar changes in annual costs to domestic and general service customers.

Q. Are there any other issues you wish to discuss related to the Labrador Interconnected System?

A. There is a matter with regard to the rates for Wabush customers. In an Interim Report dated November 10, 1988 the Board approved rates for Wabush effective January 1, 1989. The Board's Report also stated that "If, in future years, PDD achieves a surplus in Wabush, the surplus shall be refunded to customers". Since that time Hydro has been recording annually in its financial statements an estimate of the surplus based on the costing methodology used in setting Wabush rates for 1989.

Q. Please outline Hydro's proposed treatment of this surplus.

A. As outlined in Schedule I of my evidence there is a total amount of $2.9 million, including interest, for the years 1989 to 2001 using the costing methodology originally used to establish Wabush rates.

In a letter to the Board dated February 26, 1993, a copy of which is attached to my evidence as Schedule II, Hydro outlined two options with respect to dealing with the surplus that had accumulated for the years 1989 to 1992, inclusive. The first option was to refund this amount to customers based on each customer's proportionate share of the 1992 Wabush revenues. The second option was to defer the matter until the next rate referral. This option pointed out that "The Cost of Service Methodology recommended by the Board in its Report dated February, 1993 allocates more costs to Labrador Interconnected Customers than before, and the existing surplus could be used to offset increases in rates for these customers at the next rate hearing". In a reply dated March 19, 1993 (a copy of which is attached to my evidence as Schedule III), the Board deferred the matter and stated "At that time the existing surplus would be used to offset increases in rates for the customers in Wabush".

Due to the uncertainty surrounding the exact treatment of the issue, Hydro has tentatively recorded a surplus using methodology originally used to set Wabush rates until the issue could be formally addressed before the Board.

At this time, Hydro is proposing to refund the surplus accumulated for the years 1989 to 2001 of $2.9 million to Wabush customers in 2002, based on each customer's proportionate share of the 2001 revenues, unless Hydro is otherwise directed by the Board.

Q. Has Hydro given any consideration to development of an oil hedging program?

A. Yes. Hydro has been reviewing and investigating the merits of an oil price hedging program. Hydro presently consumes about 3 million barrels of No. 6 fuel oil annually (based on an average water year) at its Holyrood Generating Station which results in an annual cost of approximately $75 to $100 million. Variations between the price of fuel that is included in rates and the actual fuel prices flow directly into the RSP. Hydro has been reviewing appropriate financial tools, including the use of swaps, options and collars that could be used in an oil price hedging regime.

The goals of any oil hedging program would be to protect Hydro's customers from adverse, unexpected and random price fluctuations, that are short-term in nature and to provide a degree of price certainty. It would not be Hydro's intention to speculate in the marketplace by entering into arrangements for which there are no underlying obligation to purchase. It should be noted however that there are additional costs associated with any hedging program, which may not be offset in future fuel cost savings.

Q. Is Hydro recommending the implementation of an oil price hedging program at this time?

A. No. Hydro is presently protected from any annual financial variability arising from any variation in fuel prices due to the operation of the RSP. The RSP also provides protection to consumers from annual or seasonal rate spikes due to rising fuel prices, whereby the balance in the RSP is collected from, or repaid to customers, over a three-year period. The implementation of an oil hedging program may protect consumers from extreme increases in oil prices and the resultant increase in rates in any one year, thereby providing an added level of stability in addition to the RSP. Hydro is not proposing implementation of an oil price hedging program due to the existing operation of the RSP and the potential additional net cost of an oil hedging program over time. Hydro will continue to identify and assess its programs and measures to minimize fuel costs and will update the Board at future hearings, if it is recommending implementation of any new programs.

Q. How does the total Capital budget for 2002 compare with other years?

A. The 2002 Capital Budget of $48 million, excluding capital expenditures of approximately $71 million (exempted from the Board's jurisdiction), compares to the average capital budgets over the previous five years of approximately $42 million. The ten (10) year summary of Capital Expenditures is attached to Hydro's 2002 Capital Budget submission under Section E.

Q. Would you please explain how Hydro's 2002 Capital Budget will be financed?

A. Hydro's Capital Budget will be financed as part of Hydro's overall financing requirements. Schedule XIII (Statement of Changes in Cash Flows) which is attached to Mr. Roberts' evidence outlines the sources of funds generated internally from operations and externally through promissory notes and long term borrowings and how these funds would be expended on all activities in 2002.

Q. What is Hydro's 2002 long-term borrowing program?

A. In 2002 Hydro's borrowing program is projected to be approximately $300 million and $100 million of these proceeds would be used to retire its 5¼% Series Z $100 million bond which matures in October 2002. As indicated previously, Schedule XIII (Statement of Changes in Cash Flows), which is attached to Mr. Roberts' evidence, outlines the sources and expenditures of funds in 2002.

Q. Does this conclude your evidence?

A. Yes it does.

Schedule I
D. W. Osmond

Newfoundland and Labrador Hydro
Wabush Surplus

Year	Amount	Interest	Total	Interest Rate
1987[1]	($89,078)	-	-	n/a
1988[1]	(200,027)	-	-	n/a
1989	$41,356	-	$41,356	n/a
1990	35,244	4,549	81,149	11.00%
1991	34,033	8,926	124,109	11.00%
1992	114,554	13,652	252,315	11.00%
1993	118,176	27,501	397,991	10.39%
1994	147,953	40,978	586,922	9.84%
1995	123,771	62,810	773,503	10.21%
1996	74,019	74,998	922,520	9.29%
1997	119,587	88,443	1,130,551	9.19%
1998	267,865	101,153	1,499,568	8.60%
1999	302,723	126,239	1,928,530	8.45%
2000	312,104	164,636	2,405,271	8.22%
2001	315,000	202,484	2,922,755	8.11%
Total	**$2,006,385**	**$916,370**	**$2,922,755**	

1. Deficits shown were not included in any calculations or totals

HYDRO

File No. ____________

NEWFOUNDLAND AND LABRADOR HYDRO
Head Office: St. John's, Newfoundland P O Box 12400 A1B 4K7 • Telephone (709) 737-1400 • Fax (709) 737-1231

February 26, 1993

The Board of Commissioners of Public Utilities
Prince Charles Building
120 Torbay Road
P.O. Box 9188
St. John's, Newfoundland
A1A 2X9

ATTENTION: Mr. Reginald Good
Chairman

Dear Mr. Good,

RE: Electricity Rates Charged in Wabush

On October 22, 1991, the Board approved Hydro's proposal as set out in my letter of October 17, 1991 to credit the 1989 and 1990 surplus derived in Wabush of $41,356 and $35,244, respectively, to customers in Wabush on the first month's bill in 1992 after new rates became effective. The credit was to be based on the customers' consumption the previous month. At the time Hydro made this proposal, it anticipated that a rate referral would be filed in November, 1991 proposing increases in the rates charged in Wabush as of May 1, 1992 and, thus, the credit was to be effected in May, 1992. However, as you are aware, subsequent to Hydro filing its rate referral, it amended the referral to delete the increases requested with respect to electricity rates to be charged customers served from the Labrador interconnected electrical grid, including Wabush. Hydro anticipated that it would file a separate rate referral later in 1992 with respect to rates to be charged to these customers. However, for a variety of reasons, this did not occur and at the present time Hydro does not plan in 1993 to request changes in the rates charged to customers served from the Labrador interconnected electrical grid.

As rates were not increased in Wabush in 1992 and given the uncertainty with respect to the timing of the rate referral to adjust rates for the Labrador interconnected grid, Hydro did not refund the 1989 and 1990 surplus in Wabush of $41,356 and $35,244, respectively, which had originally been intended to be credited after the proposed increase in rates in 1992. Hydro has determined that there is also a surplus for 1991 of $34,033. The 1992 surplus is forecast to be $120,000.

In its report dated April 13, 1992, which did not deal with the issue of the rates to be charged to customers served from the Labrador interconnected grid, the Board recommended that Hydro's proposed cost of service methodology be used until it was examined more fully. As you are aware, a separate hearing on the cost of service methodology was held in the fall of 1992. As the 1992 main rate hearing did not deal with the rates to be charged to customers served from the Labrador interconnected grid and as it would not be possible to establish the surplus for Wabush alone using the proposed cost of service methodology, Hydro proposes that the surplus for 1992 for Wabush be determined on the same basis as used to determine the surpluses for 1989, 1990 and 1991. The actual 1992 surplus will be finalized in March, once the audit of Hydro's 1992 financial records has been completed.

There are two options to deal with the surplus in Wabush. The surplus for 1989, 1990, 1991 and 1992 could be refunded to customers as soon as the 1992 surplus has been finalized. If this first option is approved by the Board, Hydro proposes that the credit for these customers be determined by dividing the amount paid by each customer in Wabush in 1992 by the total revenue received by Hydro in 1992 from Wabush customers to determine each customer's proportionate share. Each customer would then be given a credit determined by multiplying the total amount of the surplus to be refunded by each customer's proportionate share of 1992 revenue. The credit would be applied to a customer's account once the manner of refund is approved by the Board. Interest at the R.S.P. rate will be applied to each surplus balance from the following January 1.

The second option to deal with the surplus is to defer the matter until such time as there is a rate referral to review electricity rates for customers served from the Labrador interconnected grid. As noted above, no specific time frame has been identified yet for this referral. The Cost of Service Methodology recommended by the Board in its Report dated February, 1993 allocates more costs to Labrador interconnected customers than before, and the existing surplus could be used to offset increases in rates for these customers at the next rate hearing.

Hydro requests the Board consider this matter and advise which option it approves to deal with the 1989, 1990, 1991 and 1992 surplus in Wabush as proposed. We look forward to hearing from you on this matter.

Yours truly,

Maureen P. Greene

Maureen P. Greene
Vice-President Human Resources, General Counsel & Corporate Secretary

MPG/mgw

NEWFOUNDLAND AND LABRADOR

BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

St. John's, Nfld. P.O. Box 9188, A1A 2X9 Telephone (709) 726-6432 Fax (709) 726-9604

1993 03 19

Ms. Maureen P. Greene,
Vice-President Human Resources,
General Counsel & Corporate Secretary,
Newfoundland and Labrador Hydro,
P.O. Box 12400,
St. John's, NF
A1B 4K7

Dear Ms. Greene:

RE: Electricity Rates Charged in Wabush

Further to your letter of February 26, 1993, the Board believes the most appropriate way of dealing with the 1989, 1990, 1991 and 1992 surplus in Wabush is to defer the matter until such time as there is a rate referral to review electricity rates for customers served from the Labrador interconnected grid. At that time the existing surplus would be used to offset increases in rates for the customers in Wabush.

Yours truly,

R. E. Good,
Chairperson.

J.A. Brickhill

NEWFOUNDLAND AND LABRADOR HYDRO
EVIDENCE OF JOHN A. BRICKHILL

Q. Please state your name, title, and business address.

A. My name is John A. Brickhill and I am President and CEO of Foster Associates, Inc. Foster Associates is an economic consulting firm, and it also publishes *The Foster Natural Gas Report* and *The Foster Electric Report*. Our main office is at 4550 Montgomery Avenue, Suite 350N, Bethesda, Maryland 20814.

Q. Briefly describe your education and professional background.

A. I received a BA in Economics from the University of Virginia and an MBA in Finance from American University. I have been employed by Foster Associates since 1968. I have testified on cost allocation, rate design and regulatory policy numerous times before the U.S. Federal Energy Regulatory Commission and State Commissions. I have also testified before the Canadian National Energy Board, Federal and State courts, and the U.S. Congress on other energy-related matters. Further details on my experience are attached as Schedule I to this evidence.

Q. What evidence will you be presenting to the Board?

A. I will present the following evidence to the Board:

1. Results from the "Study of Distribution System Cost Classification" (Distribution Study) completed by Foster Associates for Newfoundland and Labrador Hydro;

2. Outline of Cost of Service (COS) methodology changes from the Generic Methodology outlined in the Board's 1993 Report on the Cost of Service Methodology Inquiry (1993 Board Report); and
3. The 2002 Test Year Cost of Service Study.

Distribution System Cost Classification

Q. Please describe the Distribution Study.

A. The Distribution Study was originally prepared by Foster Associates for Hydro in 1996 as a result of the Board's decision in 1993 stating:

> "(t)hat Hydro's proposed classification of distribution cost be accepted for interim use and that Hydro prepare a revised study of distribution cost for presentation to the Board at the time of its next rate referral."

The study was updated in 1998 and the zero-intercept study was further updated in 2000 for purposes of this filing. The study describes a process to determine the customer and demand classification splits for certain portions of the distribution plant. This plant includes distribution poles, primary and secondary conductor and distribution transformers.

Q. Please describe how distribution costs are split.

A. There are two methods ordinarily utilized to split certain distribution costs between the customer and the demand component. These are the "zero-intercept" and the "minimum system" methods.

Q. What is the zero-intercept method?

A. The zero-intercept method assigns the customer-related component of distribution plant using regression analysis to determine the relationship between the capacity of different sizes of facilities and the unit cost thereof. In order to remove the effects of inflation, either current costs of new facilities or price-level adjusted average unit costs are usually employed in this calculation.

Basically, a line is estimated relating the cost of the equipment to a characteristic of the equipment (size, capacity, etc.). The characteristic chosen should vary with the amount of load on the equipment. Normally, when plotted, this line slopes upward away from the origin of the graph, meaning that costs increase as the equipment characteristic is changed to accommodate larger loads. For the zero-intercept, this sloping line is extended backward to the cost axis (y-axis). The cost represented by where the line crosses the cost-axis is the theoretical cost of a piece of equipment sized to meet a zero load. This cost is considered to be customer-related. Any other costs are considered to be demand-related since, theoretically, the equipment is larger to handle the demand placed on the system by the customers.

The same regression analysis also produces the unit cost of the average size facility in service. The ratio of the zero-size unit cost to the average size unit cost produces the customer-related percentage of the total.

As part of the Distribution Study, a zero-intercept analysis was done for poles, primary and secondary conductor, and for distribution transformers. The results of the analyses were used to complete the classification process described in the Distribution Study.

Q. What is the minimum system method?

A. The minimum system method includes the full cost of a minimum size pole, conductor and transformer. Unlike the zero-intercept method, the load is not zero but rather the load corresponding to the capacity of the minimum sized equipment. It is for this reason that the minimum system method is sometimes criticized for including a demand component and thereby overstating the amount of customer-related costs. Since the cost of facilities is generally greater under the minimum system method, the approach will result in a somewhat larger customer component.

Q. Have you attempted to prepare a minimum system study for the demand/customer split of distribution costs?

A. In order to compare the results of the zero-intercept method with an alternative minimum system study, Hydro's plant data was examined. The data currently available are inadequate to perform a reliable minimum system study. The current zero-intercept results compared favorably with the similar analysis used in the 1992 rate hearing and was implemented in accordance with the recommendation of the Distribution Study.

Q. Please describe the process outlined in the study.

A. The first part of the study discusses the treatment of distribution costs by selected U.S. state regulatory commissions and practiced by a number of Canadian utilities.

The second part of the study outlines the basis for the calculations which determined the demand/customer splits, based on data obtained from Hydro. As a first step, any distribution plant that is considered to be 100% demand-related is identified. Remaining plant is split using the zero-intercept method. For example, three-phase primary lines are considered to be 100% demand-related while the remaining primary conductor is split based on the zero-intercept analysis. Secondary conductor is split based on the zero-intercept analysis.

Q. What did the 1998 Distribution Study report recommend and has Hydro adopted this recommendation?

A. Foster recommended use of the zero-intercept method because it avoids the classification of small components of total cost to demand, as is inherent in the minimum system method. Moreover, data availability then (and now) impairs the preparation of a minimum system study.

As for the components of distribution costs, we recommended:

- Substation costs be classified 100% to demand;
- Three-phase primary lines be classified 100% to demand and that the remaining primary customer investment be split between demand-related and customer-related costs using the zero-intercept method;
- Poles (both primary and secondary) be split based on the use of the zero-intercept method that uses pole diameter at ground level;
- Use of the zero-intercept method for secondary conductor;
- Distribution transformers be split based on the zero-intercept method; and
- Services drops and meters be classified entirely to the customer component.

Hydro has adopted these recommendations in the COS. The result is a somewhat lower proportionate classification to the customer component than generally used by Canadian utilities.

Current plant data was obtained from Hydro in order to update the zero-intercept analyses.

Q. Please outline the steps taken to prepare a COS Study.

A. There are generally three steps involved in preparing a COS study: functionalization, classification and allocation. The corporate revenue requirement is first functionalized into generation, transmission, distribution and customer-related. The functionalized amounts are then classified between demand, energy and customer. The final step is to allocate classified costs to the rate classes based on demand usage, energy usage and number of customers.

Q. Please explain how Hydro applied this COS methodology.

A. Prior to functionalization, Hydro's costs were first systemized into five geographic areas. Each system or group of systems is identified by a letter in the COS study attached as Exhibit JAB-1:

- Island Interconnected (A)
- Island Isolated (B)
- Labrador Isolated (C)
- L'Anse au Loup (D) and
- Labrador Interconnected (E).

The following sections outline the functionalization, classification and allocation steps by system. The various rate classes are summarized on Schedule 1.2 of Exhibit JAB-1 for all systems.

<u>Island Interconnected System</u>

Q. Please address Island Interconnected System COS issues. Does the functionalization incorporated in the model follow the Board's directions?

A. Yes. These recommendations have been followed, although, as discussed in the testimony of Mr. Budgell, system changes have resulted in particular transmission plant being moved from common to specifically assigned and vice versa. As a result, the associated costs have shifted.

Also, to clarify one issue with regard to the functionalization of Holyrood, the Holyrood gas turbine has been functionalized with all other gas turbines rather than with the Holyrood thermal assets in order to facilitate Board Recommendation 11 of the 1993 Board Report. This recommendation provided that all plant costs relating to gas turbine and diesel generation on the Island Interconnected System be classified as demand.

Q. Have the costs for the Island Interconnected System been classified according to the 1993 Board Report?

A. Yes. All Board Recommendations have been followed, but a few require further comment.

1. Pursuant to Board Recommendation 9, hydraulic plant costs were apportioned to energy and demand based on the system load factor for the Island Interconnected System. The system load factor for the test year is projected to be 59.14%. Consequently, 59.14% of hydraulic plant costs have been classified as energy-related and 40.86% of hydraulic plant costs have been classified as demand-related.
2. Pursuant to Board Recommendation 10, the Holyrood plant costs are classified to energy and demand based on the average of its capacity factor in the preceding five years. The average capacity factor used in this study is 32.59%.
3. Secondary power (as available, purchased from industrials) is classified as energy, consistent with Hydro's historical practice.

4. Purchases from non-utility generators (NUGs) began in 1998. These purchases have been classified in the same manner as Hydro's hydraulic plant – on the basis of system load factor.

Q. Have the costs for the Island Interconnected system, as functionalized and classified, been allocated according to the Board's 1993 Report?

A. With the exception of the allocation of generation costs, the Board's recommendations have been followed.

Generation demand costs have been allocated among rate classes by means of a 2CP (coincident peak) allocator. In the Board's 1993 Report, Hydro was directed to present to the Board, at the time of its next rate hearing, an analysis of the relationship between load factor and system reserve requirement, together with a recommendation regarding the number of peaks on which the CP allocator for generation demand costs should be based.

Hydro has prepared a loss of load hours (LOLH) study which indicates a greater risk of loss of load hours largely in two winter months. The probabilities for those months increase as load factor increases. Thus, the study supports use of a 2CP allocator.

I have reviewed the results of not only a 2CP, but also 1CP, 3CP and 4CP allocation over time, as shown in Schedule II of this evidence. The results of using a 2CP allocator do not vary importantly over time. One test of a cost allocation method is variation in results over time. All other things being equal, a method that produces significant variation over time should be avoided. Thus, this analysis buttresses use of the 2CP method.

Non-generation demand costs are allocated among rate classes by means of a 1CP allocator (peak use, in kW, in the peak month) pursuant to the Board's recommendations.

Q. Did the Board suggest Hydro conduct any studies other than the foregoing?

A. Yes, in Board Recommendation 14, it said that Hydro should examine the practicability of attributing system energy losses to rate classes on a time-differentiated basis and report its conclusions as to both practicality and impact at the time of its next rate referral.

Hydro has studied the impact and practicality of attributing losses to rate classes on a time-differentiated basis and I have reviewed the study and findings. There is a small difference – less than 2% – between the allocated losses. This would amount to less than a tenth of a percent difference in the allocation of energy costs. This difference should not be deemed material since the variations are within reasonable meter tolerances for generation and the results can be importantly influenced by the location of the generation.

Island Isolated Systems and Labrador Isolated Systems

Q. Now turn to COS issues for Island Isolated Systems and Labrador Isolated Systems. How was generation classified for these two groups of systems?

A. These two groups of systems are served by diesel plants which, like the hydraulic units and the Holyrood plant, provide both peak and energy service. The plant costs for the diesel plants were split between energy and demand based on the load factor of each system group, similar to the Island Interconnected System.

For the Island Isolated System, 34.66% of plant costs were classified to energy and 63.54% of plant costs were classified to demand. For the Labrador Isolated System, 43.87% of plant costs were classified to energy and 56.13% were classified to demand.

Q. How were generation demand costs allocated for the Island Isolated System and Labrador Isolated System?

A. Generation demand costs were allocated on the basis of a 1CP allocator. Use of a CP allocator was chosen to provide consistency among systems.

Q. How were generation fuel costs classified and allocated for the Island Isolated System and Labrador Isolated System?

A. Generation fuel costs for the diesel plants were classified as energy and allocated to rate classes by kWh of use. This is consistent with the treatment of No. 6 fuel used by Holyrood on the Island Interconnected System.

Q. How were all other functionalization, classification and allocation matters treated?

A. In all other respects, the treatment of these groups of systems followed the Board’s recommendations.

L’Anse au Loup System

Q. Now turn to the COS study for L'Anse au Loup. What is the source of power for L’Anse au Loup?

A. L’Anse au Loup is usually served by purchased power from Hydro Quebec. The power is purchased on a secondary basis (as available). L'Anse au Loup still has its diesel generators in place, and operational, for those times when purchased power is unavailable.

Q. How has purchased power been classified for L’Anse au Loup?

A. Purchased power is classified entirely to energy -- “as billed.” It is purchased entirely on an energy basis with no capacity charges. The price is based on avoided fuel costs for Hydro’s diesel plant, which would be classified to energy if the thermal plant were used in lieu of the purchased power. All of the thermal plant costs are classified to demand, since the plant is used as a peaking/backup facility.

Q. How were all other functionalization, classification and allocation matters treated for L’Anse au Loup?

A. In all other respects, these matters were treated similarly to the other isolated systems.

Labrador Interconnected System

Q. Now for the Labrador Interconnected System, how were generation costs classified?

A. For the Labrador Interconnected System, power is primarily obtained by purchase from CF(L)Co. The system also includes a diesel plant and a gas turbine.

For the test year the annual cost of power purchased from CF(L)Co applicable to the Labrador Interconnected System is classified to energy and demand based on the system load factor for the Labrador Interconnected System.

For the test year, based on system load factor, 62.18% of regulated purchased power costs are classified as energy and 37.82% are classified as demand-related.

Q. How are the plant costs for the diesel unit and the gas turbine classified?

A. Since these are peaking/backup units, the costs are classified entirely to demand, consistent with the treatment of peaking units on the Island Interconnected System.

Q. How were generation demand costs allocated by rate class?

A. Generation demand costs were allocated by a 1CP allocator. The seasonal peak, based largely on heating load, supports 1CP. Additionally, there is *de minimis* likelihood of a loss of firm load on the Labrador Interconnected System. As indicated in Mr. Budgell's evidence, there is sufficient capacity available in the agreement with CF(L)Co well into the future. Thus, use of 1CP is deemed appropriate for the Labrador Interconnected System.

Cost of Service Study

Q. What was the process for developing Hydro's cost of service study?

A. For the test year Hydro systemized and functionalized costs, i.e., developed the costs for each geographic area by function: production, transmission, distribution and customer-related.

Classification (demand, energy, customer) was performed by Foster personnel in conjunction with Hydro, following the Board's 1993 Report as outlined earlier. Foster personnel developed the COS model and the allocation factors therein contained, following the Board's 1993 Report as outlined earlier.

Q. Please outline the structure of the COS Study.

A. The COS Study is presented in seven sections as identified in the Table of Contents to the Study (Exhibit JAB-1). The first section, Summaries, presents results for the total system and/or across all systems. It is comprised of the following schedules:

- Schedule 1.1, Revenue Requirement and Return on Rate Base;
- Schedule 1.2, Comparison of Revenue and Allocated Revenue Requirement;
- Schedule 1.2.1, Rural Deficit Allocation;
- Schedule 1.3, Unit Demand, Energy and Customer Amounts;
- Schedule 1.3.1, Total Demand, Energy and Customer Amounts;
- Schedule 1.3.2, Demands, Sales and Number of Bills;
- Schedule 1.4, Calculation of Firming Up Charge; and
- Schedule 1.5, Calculation of Transmission Wheeling Charge.

The subsequent five sections deal with the detailed COS studies for each of the geographic areas identified earlier. The last section contains various supplementary calculations such as load and capacity factors.

Q. Before continuing with the description of the COS study, could you explain any major changes in this study *vis-à-vis* COS studies Hydro has submitted in the past?

A. Yes. First, it should be noted that the revenue requirement (Schedule 1.1) is based on return on rate base, not the margin approach used in the past. Second (Schedule 1.2), revenues from regulated secondary and non-firm sales are credited to (deducted from) the regulated firm customers' revenue requirement. In the past, these sales were not regulated.

Also, the rural deficit has been allocated to Newfoundland Power and to the Labrador Interconnected System customers as shown on Schedule 1.2.1. This method has been changed to reflect the change in methodology from AED-based to CP-based. Also, a portion of the deficit is no longer allocated to the Industrial Customers, pursuant to the EPCA.

Q. Are there separate schedules for each system?

A. The results for each of the five systems are presented separately but exhibit parallel construction. The following schedules are presented for each system:

- Schedule 2.1, Functional Classification of Revenue Requirement;
- Schedule 2.2, Functional Classification of Plant in Service for the Allocation of O&M Expense;
- Schedule 2.3, Functional Classification of Net Book Value;
- Schedule 2.4, Functional Classification of Operating and Maintenance Expense;

- Schedule 2.5, Functional Classification of Depreciation Expense;
- Schedule 2.6, Functional Classification of Rate Base;
- Schedule 3.1, Basis of Allocation to Classes of Service;
- Schedule 3.2, Allocation of Functionalized Amounts to Classes of Service; and,
- Schedule 3.3, Allocation of Specifically Assigned Amounts to Classes of Service (Island Interconnected only).

Schedules 2.1, 2.2, 2.4 and 2.6 have corresponding documentation schedules detailing the basis of the functional classification.

Q. Is Hydro proposing any changes in its RSP?

A. Yes. The RSP has historically been split between participating customer groups based on Hydro's COS. The current COS methodological changes permit the activity to be split based upon transmission energy only. Also, the primary components of the RSP – variations related to the price of oil, hydraulic production and the kWh consumption of customers – are energy-related hence properly reflected in the energy cost component.

Q. Does this conclude your evidence?

A. Yes.

FOSTER ASSOCIATES INCORPORATED
ECONOMIC CONSULTANTS

JOHN A. BRICKHILL

Profession: **Economist**

Position with Firm: **President and Chief Executive Officer**

Years with Firm: **32**

Key Qualifications:

Mr. Brickhill is President and Chief Executive Officer of Foster Associates, Inc. He received his B.A. degree (Economics) from the University of Virginia and his M.B.A. (Finance) from American University. Over the years he has prepared a large number of strategic planning studies with respect to energy and utility issues, particularly in the natural gas area for government agencies and private clients. Mr. Brickhill also provides consulting services as both an agent and consultant for buyers and sellers of natural gas, including contract negotiation and contract preparation. He has assisted numerous buyers and sellers of hydrocarbon assets (pipelines, storage fields and reserves) in sale and purchase evaluations. Also he has conducted management audits of gas operations and purchasing of utilities and industrials. As an expert witness, Mr. Brickhill has been involved in diverse energy litigation, including rate and certificate proceedings, contract disputes and antitrust.

During the 1990's he was responsible for a variety of cost analyses, both embedded and incremental, for operations ranging from gas distribution and transportation, propane distribution and transmission, and power generation. Other studies included demand for electric transformers and appraisals of oil and gas properties and pipelines. He testified in a number of market power controversies and numerous disputes over oil, natural gas and natural gas liquids.

During the 1980s, he was responsible for numerous studies with respect to both interstate and intrastate gas markets. Publicly available studies include "Pricing Disparities under NGPA," "The Impact of the NGPA on Intrastate Markets in Louisiana," "A Comparison and Appraisal of Ten Natural Gas Deregulation Studies," "An Analysis of Section 104 Contracts," "Economic Cost Rates: An Assessment of DOE's Rate Design Proposals," "Transition to Decontrol: An Analysis of Flyup", "Producer and Pipeline Marketing Programs and the Transition to Decontrol," "Natural Gas Pipeline Ratemaking," and "Market Power in Primary and Secondary Natural Gas Transportation Markets." Other projects have related to provisions of interstate and intrastate contracts, the duration of the deliverability surplus, the outlook for the Alaskan gas project, gas supply, demand and price in interstate and intrastate markets, gas prices to the ammonia industry, the cushions of individual pipelines, redetermination of field prices, negotiation of gas purchase contracts and acquisition and divestiture of assets. In 1985 he completed a multi-client study entitled "Gas Supply, Demand and Price in Louisiana, Oklahoma and Texas 1985-1995" which updated a similar study released in early 1983. Mr. Brickhill authored "Design of Natural Gas Transportation Tariffs" in 1987.

During the 1970s, Mr. Brickhill prepared numerous energy and financial studies for both the Federal government and private industry. For the Environmental Protection Agency, he was project manager of various studies: fossil fuel transportation costs for electric utilities, short-term forecasts of gas supply and demand, the impact of gas curtailments on electric utilities and the impact of the gas shortage on major industrial fuel burning installations. He was co-project manager of a study for the Department of Interior entitled "Regional Markets for Coal and Conversion Plants Projected to 1980 and 1985." For the Energy Regulatory Administration, he was responsible for projections for gas supply and demand as part of their review of curtailment options.

For the private sector during the 1970s, Mr. Brickhill prepared a number of studies including the cost of finding and producing gas, financial characteristics of the oil and utility industries, gas market studies, pricing of LNG, and the impact of incremental pricing. He was co-author of a study entitled "Natural Gas Pricing Alternatives" which analyzed the impact of various legislative proposals leading up to the passage of the NGPA.

Before the Federal Power Commission and Federal Energy Regulatory Commission, he testified in numerous proceedings with respect to policy, rate design, transportation tariffs, supplemental gas supply and price, gas transportation and distribution costs, natural gas and energy supply/demand and price, the cost of storage and peak shaving, cost-benefit (net national economic benefit) analysis and individual pipeline supply forecasts. He has testified before State Commissions in regard to rate design and gas pricing and Federal and State Courts in regard to oil and gas contracts, regulatory practices and gas supply, demand and price. He has also testified in regulatory proceedings before the Canadian National Energy Board concerning the price elasticity of gas supply.

Mr. Brickhill is a member of the Society of Petroleum Engineers. Over his career he has chaired or made speeches at numerous conferences on energy and rate design issues.

COMPARISON OF ALLOCATION FACTORS

Island Interconnected

Test Year - 2002	1CP	2CP	3CP	4CP
Newfoundland Power	79.99%	80.12%	79.79%	79.44%
Industrial	13.07%	13.09%	13.27%	13.63%
Rural Bulk	6.94%	6.80%	6.94%	6.93%

	Avg	Std Dev	Avg	Std Dev	Avg	Std Dev	Avg	Std Dev
Newfoundland Power	81.35%	1.22%	81.65%	1.26%	81.15%	0.96%	80.48%	1.12%
Industrials	12.64%	1.47%	11.99%	1.07%	12.69%	0.70%	13.31%	0.73%
Rural Bulk	6.02%	0.63%	6.36%	0.56%	6.17%	0.54%	6.21%	0.62%

Based on 1994, 1996, 1997, 1998, 1999, 2000
Unadjusted for generation credits, losses, and other minor corrections.

Source: Hydro

Table of Contents

NEWFOUNDLAND AND LABRADOR HYDRO
2002 Forecast Cost of Service

TABLE OF CONTENTS

NEWFOUNDLAND AND LABRADOR HYDRO
2002 Forecast Cost of Service

TABLE OF CONTENTS

NEWFOUNDLAND AND LABRADOR HYDRO
2002 Forecast Cost of Service

TABLE OF CONTENTS

Summaries

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Total System
Revenue Requirement

	1	2	3	4	5	6	7	8
Line No.	Description	Total Amount ($)	Island Interconnected ($)	Island Isolated ($)	Labrador Isolated ($)	L'Anse au Loup ($)	Labrador Interconnected ($)	Basis of Proration
	Revenue Requirement							
	Expenses							
1	Operating, Maintenance and Admin.	88,971,093	70,564,190	4,634,141	8,838,930	1,076,934	3,856,898	Detailed Analysis
2	Fuels - No. 6 Fuel	75,493,351	75,493,351	-	-	-	-	Detailed Analysis
3	Fuels - Diesel	6,323,748	34,032	1,448,725	4,759,820	81,171	-	Detailed Analysis
4	Fuels - Gas Turbine	471,018	401,495	-	-	-	69,523	
5	Power Purchases -CF(L)Co	2,756,850	-	-	-	-	2,756,850	Detailed Analysis
6	Power Purchases - Other	12,509,032	11,748,829	-	-	625,131	135,072	Detailed Analysis
7	Depreciation	31,790,287	26,041,302	864,523	1,953,604	375,733	2,555,125	Detailed Analysis
	Expense Credits:							
8	Sundry	(444,000)	(352,142)	(23,126)	(44,110)	(5,374)	(19,247)	Total O&M Expenses
9	Building Rental Income	(26,927)	(13,402)	-	-	-	(13,525)	Detailed Analysis
10	Tax Refunds	-	-	-	-	-	-	Total O&M Expenses
11	Suppliers' Discounts	(54,232)	(43,012)	(2,825)	(5,388)	(656)	(2,351)	Total O&M Expenses
12	Pole Attachments	(468,042)	(471,791)	(14,359)	(23,963)	(21,629)	63,700	Detailed Analysis
13	Secondary Energy Revenues	-	-	-	-	-	-	Island Interconnected
14	Wheeling Revenues	(6,950)	(6,950)	-	-	-	-	Island Interconnected
15	Application Fees	(51,065)	(23,000)	(988)	(4,233)	(636)	(22,208)	Detailed Analysis
16	**Total Expense Credits**	**(1,051,216)**	**(910,297)**	**(41,298)**	**(77,693)**	**(28,296)**	**6,369**	
17	**Subtotal Expenses**	**217,264,163**	**183,372,901**	**6,906,091**	**15,474,661**	**2,130,673**	**9,379,838**	
18	Disposal Gain/Loss	790,549	775,831	39,385	8,318	-	(32,985)	Detailed Analysis
19	**Subtotal Rev Reqt Excl Return**	**218,054,712**	**184,148,732**	**6,945,476**	**15,482,979**	**2,130,673**	**9,346,853**	
20	Return on Debt	95,129,413	88,395,562	922,797	1,844,972	371,139	3,594,943	Rate Base
21	Return on Equity	5,662,858	5,425,608	-	-	-	237,250	Rate Base
22	**Total Revenue Requirement**	**318,846,984**	**277,969,902**	**7,868,273**	**17,327,951**	**2,501,812**	**13,179,046**	

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Total System
Return on Rate Base

Line No	1	2 Total $	3 Island Interconnected $	4 Island Isolated $	5 Labrador Isolated $	6 L'Anse au Loup $	7 Labrador Interconnected $	8 Basis of Proration
	Rate Base:							
1	Average Net Book Value	1,245,061,475	1,157,885,215	12,047,451	22,906,419	4,857,642	47,364,748	Schedule 2.3
2	Cash Working Capital	3,095,594	2,878,848	29,954	56,952	12,078	117,763	Prorated on Average Net Book Value - L. 1
3	Fuel Inventory - No. 6 Fuel	13,429,718	13,429,718	-	-	-	-	Specifically Assigned - Holyrood
4	Fuel Inventory - Diesel	1,758,439	28,884	161,764	1,524,736	21,110	21,945	Detailed Fuel Analysis
5	Fuel Inventory - Gas Turbine	830,254	758,563	-	-	-	71,691	Detailed Fuel Analysis
6	Inventory/Supplies	21,095,000	19,244,334	230,580	523,765	123,534	972,787	Prorated on Total Plant in Service, Schedule 2.2
7	Deferred Charges: Foreign Exchange Loss	85,199,611	79,234,136	824,408	1,567,487	332,409	3,241,172	Prorated on Average Net Book Value - L. 1
8	Total Rate Base	**1,370,470,091**	**1,273,459,698**	**13,294,156**	**26,579,360**	**5,346,772**	**51,790,106**	
9	Less: Rural Portion	(134,308,087)	(89,087,799)	(13,294,156)	(26,579,360)	(5,346,772)	-	Schedule 2.6, L. 9
10	Rate Base Available for Equity Return	**1,236,162,004**	**1,184,371,899**	**-**	**-**	**-**	**51,790,106**	
	Corporate Targets:							
11	Capital Structure: Percent of Debt	83.18% (1)						
12	Return	8.345%						
13	Weighted Average Return: Debt	**6.941%**						
14	Capital Structure: Percent of Equity	15.27% (1)						
15	Return	3.000%						
16	Weighted Average Return: Equity	**0.458%**						
17	Weighted Average Cost of Capital	**7.399%**						
	Return on Rate Base by System (%):							
18	Return on Rate Base - Debt Component	-	6.941%	6.941%	6.941%	6.941%	6.941%	
19	Return on Rate Base - Equity Component	-	0.458%	-	-	-	0.458%	
	Return on Rate Base ($):							
20	Return on Debt	95,129,413	88,395,562	922,797	1,844,972	371,139	3,594,943	Schedule 2.6, L.11
21	Return on Equity	5,662,858	5,425,608	-	-	-	237,250	Schedule 2.6, L.12
22	Return on Rate Base ($)	**100,792,272**	**93,821,170**	**922,797**	**1,844,972**	**371,139**	**3,832,194**	Schedule 2.6, L.13
	Return on Total Rate Base (%):							
23	Return on Rate Base - Debt Component	6.941%	6.941%	6.941%	6.941%	6.941%	6.941%	L. 20 divided by L.8
24	Return on Rate Base - Equity Component	0.413%	0.426%	0.000%	0.000%	0.000%	0.458%	L. 21 divided by L.8
25	Return on Rate Base (%)	**7.355%**	**7.367%**	**6.941%**	**6.941%**	**6.941%**	**7.399%**	L. 22 divided by L.8

(1) Debt and equity weightings reflect a 1.55% component for Employee Future Benefits at 0% cost.

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Total System
Comparison of Revenue & Allocated Revenue Requirement

	1	2	3	4	5	6	7
Line No.	Rate Class	Revenues	Cost of Service Before Deficit and Revenue Credit Allocation	Revenue Credits	Deficit	Revenue Requirement After Deficit and Revenue Credit Allocation	Revenue to Cost Coverage (Col.2/3)
		($)	($)	($)	($)	($)	
	Total System						
1	Newfoundland Power	213,830,400	191,058,434	(154,073)	22,911,093	213,815,455	1.12
2	Island Industrial	50,356,509	50,162,971	183,707	-	50,346,678	1.00
3	Labrador Industrial	3,084,575	3,084,575	-	-	3,084,575	1.00
4	CFB - Goose Bay Secondary	2,991,483	138,430	2,808,526	44,527	2,991,483	21.61
5	Rural Labrador Interconnected	10,351,585	9,956,042	(2,808,526)	3,202,457	10,349,973	1.04
	Rural Deficit Areas						
6	Island Interconnected	31,639,918	36,748,497	(29,635)	(5,078,944)	31,639,918	0.86
7	Island Isolated	1,277,117	7,868,273	-	(6,591,156)	1,277,117	0.16
8	Labrador Isolated	4,205,660	17,327,951	-	(13,122,291)	4,205,660	0.24
9	L'Anse au Loup	1,136,125	2,501,812	-	(1,365,687)	1,136,125	0.45
10	**Subtotal**	**38,258,820**	**64,446,532**	**(29,635)**	**(26,158,078)**	**38,258,820**	**0.59**
11	**Total**	**318,873,372**	**318,846,984**	**-**	**-**	**318,846,984**	**1.00**

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Island Interconnected
Comparison of Revenue & Allocated Revenue Requirement

	1	2	3	4	5	6	7
Line No.	Rate Class	Revenues ($)	Cost of Service Before Deficit and Revenue Credit Allocation ($)	Revenue Credit ($)	Deficit Allocation ($)	Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5) ($)	Revenue to Cost Coverage (Col.2/3)
	Island Interconnected						
1	Newfoundland Power	213,830,400	191,058,434	(154,073)			
2	NLP RSP Activity	-					
3	**Subtotal Newfoundland Power**	**213,830,400**	**191,058,434**	**(154,073)**	**22,911,093**	**213,815,455**	**1.12**
4	Industrial - Firm	49,975,388	50,005,883	(40,326)		49,965,557	
5	Industrial - Non-Firm	381,121	157,088	224,033		381,121	
6	Industrial RSP Activity	-				-	
7	**Subtotal Industrial**	**50,356,509**	**50,162,971**	**183,707**	**-**	**50,346,678**	**1.00**
	Rural						
8	1.1 Domestic	9,928,516	12,396,209	(9,997)	(2,457,697)	9,928,516	0.80
9	1.12 Domestic All Electric	9,012,212	12,893,120	(10,397)	(3,870,511)	9,012,212	0.70
10	1.3 Special	10,175	20,080	(16)	(9,889)	10,175	0.51
11	2.1 General Service 0-10 kW	1,876,268	1,814,946	(1,464)	62,786	1,876,268	1.03
12	2.2 General Service 10-100 kW	4,851,683	4,317,060	(3,481)	538,104	4,851,683	1.12
13	2.3 General Service 110-1,000 kVa	3,174,877	2,475,820	(1,997)	701,053	3,174,877	1.28
14	2.4 General Service Over 1,000 kVa	2,007,061	2,218,755	(1,789)	(209,905)	2,007,061	0.90
15	4.1 Street and Area Lighting	779,126	612,505	(494)	167,115	779,126	1.27
16	**Subtotal Rural**	**31,639,918**	**36,748,497**	**(29,635)**	**(5,078,944)**	**31,639,918**	**0.86**
17	**Total Island Interconnected**	**295,826,827**	**277,969,902**	**-**	**17,832,149**	**295,802,051**	**1.06**

Note1:
Calculation of Island Industrial Non-Firm Revenue Credit

Island Industrial Non-Firm Revenues, Ln 5, Col 2	381,121
Island Industrial Non-Firm Allocated Cost of Service, Ln 5, Col 3	(157,088)
Credit to be allocated to Firm Customers	224,033

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Island Isolated
Comparison of Revenue & Allocated Revenue Requirement

	1	2	3	4	5	6	7
Line No.	Rate Class	Revenues ($)	Cost of Service Before Deficit and Revenue Credit Allocation ($)	Revenue Credit ($)	Deficit ($)	Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5) ($)	Revenue to Cost Coverage (Col.2/3)
	Island Isolated						
1	1.2 Domestic Diesel	740,271	5,717,975		(4,977,704)	740,271	0.13
2	1.2G Government Domestic Diesel	12,678	77,247		(64,569)	12,678	0.16
3	1.23 Churches & Community Halls	12,886	65,782		(52,896)	12,886	0.20
4	2.2 GS 10-100 kW	0	0		0	0	0.00
5	2.3 GS 110-1,000 kVa	45,006	233,461		(188,455)	45,006	0.19
6	2.5 GS Diesel	245,849	962,966		(717,117)	245,849	0.26
7	2.5G Gov't General Service Diesel	185,489	691,229		(505,740)	185,489	0.27
8	4.1 Street and Area Lighting	33,376	111,433		(78,057)	33,376	0.30
9	4.1G Gov't Street and Area Lighting	1,562	8,180		(6,618)	1,562	0.19
10	**Total**	**1,277,117**	**7,868,273**		**(6,591,156)**	**1,277,117**	**0.16**

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Labrador Isolated
Comparison of Revenue & Allocated Revenue Requirement

	1	2	3	4	5	6	7
Line No.	Rate Class	Revenues	Cost of Service Before Deficit and Revenue Credit Allocation	Revenue Credit	Deficit	Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5)	Revenue to Cost Coverage (Col.2/3)
		($)	($)	($)	($)	($)	
	Labrador Isolated						
1	1.2 Domestic Diesel	1,833,178	9,699,956		(7,866,778)	1,833,178	0.19
2	1.2G Government Domestic Diesel	83,320	346,976		(263,656)	83,320	0.24
3	1.23 Churches & Community Halls	54,749	192,328		(137,579)	54,749	0.28
4	2.2 GS 10-100 kW	45,942	506,058		(460,116)	45,942	0.09
5	2.3 GS 110-1,000 kVa	304,116	1,532,554		(1,228,438)	304,116	0.20
6	2.5 GS Diesel	1,286,816	3,464,113		(2,177,297)	1,286,816	0.37
7	2.5G Gov't General Service Diesel	531,181	1,434,798		(903,617)	531,181	0.37
8	4.1 Street and Area Lighting	63,866	142,499		(78,633)	63,866	0.45
9	4.1G Gov't Street and Area Lighting	2,492	8,668		(6,176)	2,492	0.29
10	**Total**	**4,205,660**	**17,327,951**		**(13,122,291)**	**4,205,660**	**0.24**

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
L'Anse au Loup
Comparison of Revenue & Allocated Revenue Requirement

Line No.	1 Rate Class	2 Revenues ($)	3 Cost of Service Before Deficit and Revenue Credit Allocation ($)	4 Revenue Credit ($)	5 Deficit ($)	6 Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5) ($)	7 Revenue to Cost Coverage (Col.2/3)
	L'Anse au Loup						
1	1.1 Domestic	634,530	1,640,124		(1,005,594)	634,530	0.39
2	1.12 Domestic All Electric	28,505	86,866		(58,361)	28,505	0.33
3	2.1 General Service 0-10 kW	148,252	277,002		(128,750)	148,252	0.54
4	2.2 General Service 10-100 kW	220,335	399,911		(179,576)	220,335	0.55
5	2.3 General Service 110-1,000 kVa	68,686	53,312		15,374	68,686	1.29
6	4.1 Street and Area Lighting	35,817	44,598		(8,781)	35,817	0.80
7	**Total L'Anse Au Loup**	**1,136,125**	**2,501,812**		**(1,365,687)**	**1,136,125**	**0.45**

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Labrador Interconnected
Comparison of Revenue & Allocated Revenue Requirement

	1	2	3	4	5	6	7
Line No.	Rate Class	Revenues	Cost of Service Before Deficit and Revenue Credit Allocation	Revenue Credit	Deficit Allocation	Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5)	Revenue to Cost Coverage (Col.2/3)
		($)	($)	($)	($)	($)	
	Labrador Interconnected						
1	Industrial IOCC Firm	3,007,393	3,007,393		-	3,007,393	1.00
2	Industrial IOCC Non-Firm	77,182	77,182		-	77,182	1.00
3	**Subtotal Industrial**	**3,084,575**	**3,084,575**		**-**	**3,084,575**	**1.00**
4	**CFB - Goose Bay Secondary**	2,991,483	138,430	2,808,526	44,527	2,991,483	21.61
	Rural						
5	1.1 Domestic	188,642	300,979	(84,904)	96,813	312,888	0.63
6	1.1A Domestic All Electric	5,521,102	7,160,506	(2,019,926)	2,303,246	7,443,826	0.77
7	2.1 General Service 0-10 kW	217,095	241,493	(68,124)	77,679	251,049	0.90
8	2.2 General Service 10-100 kW	1,448,893	907,148	(255,900)	291,793	943,042	1.60
9	2.3 General Service 110-1,000 kVa	1,997,144	859,223	(242,381)	276,377	893,220	2.32
10	2.4 General Service Over 1,000 kVa	816,016	362,052	(102,132)	116,458	376,377	2.25
11	4.1 Street and Area Lighting	162,693	124,640	(35,160)	40,092	129,572	1.31
12	**Subtotal Rural**	**10,351,585**	**9,956,042**	**(2,808,526)**	**3,202,457**	**10,349,973**	**1.04**
13	**Total Labrador Interconnected**	**16,427,643**	**13,179,046**	**0**	**3,246,984**	**16,426,031**	**1.25**

Note1:
Calculation of CFB - Goose Bay Secondary Revenue Credit

CFB - Goose Bay Secondary Revenues, Ln 4, Col 2	2,991,483
CFB - Goose Bay Secondary Allocated Cost of Service, Ln 4, Col 3	(138,430)
CFB - Goose Bay Secondary Allocated Deficit, Ln 4, Col 5	(44,527)
Credit to be allocated to Firm Regulated Customers	2,808,526

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Total System
Rural Deficit Allocation

Line No.	Rate Class	Allocated Revenue Reqt ($)	Demand ($)	Energy ($)	Customer ($)	Source
	1	2	3	4	5	6
		Before Deficit and Revenue Credit Allocation				
	CLASSIFICATION TO DEMAND, ENERGY, CUSTOMERS:					
1	Newfoundland Power	191,058,434	86,897,814	102,941,606	1,219,015	Schedule 1.3.1, p. 1
2	CFB - Goose Bay Secondary	138,430	-	137,707	723	Schedule 1.3.1, p. 5
3	Rural Labrador Interconnected	9,956,042	6,785,580	895,899	2,274,563	Schedule 1.3.1, p. 5
4	**Total**	**201,152,906**	**93,683,394**	**103,975,211**	**3,494,301**	
5	Deficit Classified	26,158,078	12,182,660	13,521,016	454,402	Prorated on Line 4
	UNIT COSTS OF DEFICIT:		CP kW	MWH	Customers *	
	Island Interconnected:					
6	Newfoundland Power		989,280	4,602,195	4,619	
7	**Subtotal Island Interconnected**		**989,280**	**4,602,195**	**4,619**	
	Labrador Interconnected:					
8	CFB - Goose Bay Secondary		0	83,734	3	
9	Rural Labrador Interconnected		120,407	544,760	9,015	
10	**Subtotal Labrador Interconnected**		**120,407**	**628,494**	**9,018**	
11	**Total**		**1,109,686**	**5,230,689**	**13,637**	
12	Deficit Unit Costs		$10.98 $/KW	$2.58 $/MWH	$33.32 $/Customer	Line 5 / Line 11

* Specifically assigned costs are converted to equivalent unweighted customers
by dividing the assigned cost by the allocated customer cost per unweighted customer.

Rural Customer Costs per Rural Customer:	
Island Interconnected:	$263.91
Labrador Interconnected:	$252.31

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Total System
Rural Deficit Allocation

Line No.	1	2	3	4	5	6
			Deficit Allocation			
	Rate Class	Allocated Revenue Reqt ($)	Demand ($)	Energy ($)	Customer ($)	Source
	ALLOCATION OF DEFICIT:					
13	Island Interconnected	22,911,093	10,860,781	11,896,397	153,915	Line 7 x Line 12
14	Labrador Interconnected	3,246,984	1,321,880	1,624,618	300,486	Line 10 x Line 12
15	**Allocated Totals**	**26,158,078**	**12,182,660**	**13,521,016**	**454,402**	
	CUSTOMER DEFICIT ALLOCATION:					
	Island Interconnected:					
16	Newfoundland Power	22,911,093				
17	Sub-Total Island Interconnected	22,911,093				
	Labrador Interconnected:					
18	CFB - Goose Bay Secondary	44,527				
19	Rural Labrador Interconnected	3,202,457				
20	Subtotal Labrador Interconnected	3,246,984				
21	**Total**	**26,158,078**				

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Island Interconnected
Unit Demand, Energy & Customer Amounts

	1	2	3	4	5	6	7	8	9	10	11
	Rate Class	Before Deficit and Revenue Credit Allocation					After Deficit and Revenue Credit Allocation				
Line No.		Demand		Non-Demand			Demand		Non-Demand		
		Demand ($/kW)	Non-Demand ($/kWh)	Energy ($/kWh)	Demand & Energy ($/kWh)	Customer ($/Bill)	Demand ($/kW)	Non-Demand ($/kWh)	Energy ($/kWh)	Demand & Energy ($/kWh)	Customer ($/Bill)
	Island Interconnected										
1	Newfoundland Power	-	0.01951	0.02311	0.04261	101,584.57	-	0.02183	0.02586	0.04769	113,684.34
2	Industrial - Firm	7.01	-	0.02311	-	8,731.65	7.01	-	0.02309	-	8,724.60
3	Industrial - Non-Firm	-	-	0.02311	0.02311	-	-	-	-	-	-
	Rural							-	-		
4	1.1 Domestic	-	0.06223	0.02492	0.08715	20.73	-	-	-	-	-
5	1.12 Domestic All Electric	-	0.07720	0.02492	0.10212	20.73	-	-	-	-	-
6	1.3 Special	-	0.06410	0.02492	0.08901	20.73	-	-	-	-	-
7	2.1 General Service 0-10 kW	-	0.05611	0.02492	0.08103	23.21	-	-	-	-	-
8	2.2 General Service 10-100 kW	13.72	-	0.02492	-	38.25	-	-	-	-	-
9	2.3 General Service 110-1,000 kVa	8.83	-	0.02484	-	38.82	-	-	-	-	-
10	2.4 General Service Over 1,000 kVa	15.69	-	0.02472	-	35.94	-	-	-	-	-
11	4.1 Street and Area Lighting	-	0.06580	0.02492	0.09072	29.12	-	-	-	-	-

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Island Isolated
Unit Demand, Energy & Customer Amounts

	1	2	3	4	5	6	7	8	9	10	11
	Rate Class	Before Deficit and Revenue Credit Allocation					After Deficit and Revenue Credit Allocation				
Line		Demand		Non-Demand			Demand		Non-Demand		
No.		Demand ($/kW)	Non-Demand ($/kWh)	Energy ($/kWh)	Demand & Energy ($/kWh)	Customer ($/Bill)	Demand ($/kW)	Non-Demand ($/kWh)	Energy ($/kWh)	Demand & Energy ($/kWh)	Customer ($/Bill)
	Island Isolated										
1	1.2 Domestic Diesel	-	0.44478	0.29974	0.74452	46.69	-	-	-	-	-
2	1.2G Government Domestic Diesel	-	0.44275	0.29974	0.74249	46.69	-	-	-	-	-
3	1.23 Churches & Community Halls	-	0.25144	0.29974	0.55118	46.69	-	-	-	-	-
4	2.2 GS 10-100 kW	-	-	-	-	-	-	-	-	-	-
5	2.3 GS 110-1,000 kVa	37.07	-	0.29974	-	98.33	-	-	-	-	-
6	2.5 GS Diesel	-	0.34732	0.29974	0.64706	53.51	-	-	-	-	-
7	2.5G Gov't General Service Diesel	-	0.36041	0.29974	0.66015	53.51	-	-	-	-	-
8	4.1 Street and Area Lighting	-	0.46073	0.29974	0.76047	80.69	-	-	-	-	-
9	4.1G Gov't Street and Area Lighting	-	0.42863	0.29974	0.72837	80.69	-	-	-	-	-

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Labrador Isolated
Unit Demand, Energy & Customer Amounts

	1	2	3	4	5	6	7	8	9	10	11
	Rate Class	Before Deficit and Revenue Credit Allocation					After Deficit and Revenue Credit Allocation				
		Demand			Non-Demand		Demand			Non-Demand	
Line No.		Demand ($/kW)	Non-Demand ($/kWh)	Energy ($/kWh)	Demand & Energy ($/kWh)	Customer ($/Bill)	Demand ($/kW)	Non-Demand ($/kWh)	Energy ($/kWh)	Demand & Energy ($/kWh)	Customer ($/Bill)
	Labrador Isolated										
1	1.2 Domestic Diesel	-	0.23567	0.29635	0.53202	22.20	-	-	-	-	-
2	1.2G Government Domestic Diesel	-	0.23539	0.29635	0.53173	22.20	-	-	-	-	-
3	1.23 Churches & Community Halls	-	0.13637	0.29635	0.43271	22.20	-	-	-	-	-
4	2.2 GS 10-100 kW	113.83	-	0.29635	-	44.87	-	-	-	-	-
5	2.3 GS 110-1,000 kVa	19.42	-	0.29635	-	46.48	-	-	-	-	-
6	2.5 GS Diesel	-	0.18330	0.29635	0.47965	25.41	-	-	-	-	-
7	2.5G Gov't General Service Diesel	-	0.18220	0.29635	0.47855	25.41	-	-	-	-	-
8	4.1 Street and Area Lighting	-	0.24422	0.29635	0.54057	38.71	-	-	-	-	-
9	4.1G Gov't Street and Area Lighting	-	0.21312	0.29635	0.50946	38.71	-	-	-	-	-

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
L'Anse au Loup
Unit Demand, Energy & Customer Amounts

	1	2	3	4	5	6	7	8	9	10	11
	Rate Class	Before Deficit and Revenue Credit Allocation					After Deficit and Revenue Credit Allocation				
Line		Demand		Non-Demand			Demand		Non-Demand		
No.		Demand ($/kW)	Non-Demand ($/kWh)	Energy ($/kWh)	Demand & Energy ($/kWh)	Customer ($/Bill)	Demand ($/kW)	Non-Demand ($/kWh)	Energy ($/kWh)	Demand & Energy ($/kWh)	Customer ($/Bill)
	L'Anse au Loup										
1	1.1 Domestic	-	0.12948	0.06029	0.18977	35.24	-	-	-	-	-
2	1.12 Domestic All Electric	-	0.16309	0.06029	0.22338	35.24	-	-	-	-	-
3	2.1 General Service 0-10 kW	-	0.10522	0.06029	0.16551	38.42	-	-	-	-	-
4	2.2 General Service 10-100 kW	24.68	-	0.06029	-	57.72	-	-	-	-	-
5	2.3 General Service 110-1,000 kVa	1.69	-	0.06029	-	59.31	-	-	-	-	-
6	4.1 Street and Area Lighting	-	0.13990	0.06029	0.20018	49.94	-	-	-	-	-

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Labrador Interconnected
Unit Demand, Energy & Customer Amounts

	1	2	3	4	5	6	7	8	9	10	11
	Rate Class	Before Deficit and Revenue Credit Allocation					After Deficit and Revenue Credit Allocation				
Line		Demand		Non-Demand			Demand		Non-Demand		
No.		Demand ($/kW)	Non-Demand ($/kWh)	Energy ($/kWh)	Demand & Energy ($/kWh)	Customer ($/Bill)	Demand ($/kW)	Non-Demand ($/kWh)	Energy ($/kWh)	Demand & Energy ($/kWh)	Customer ($/Bill)
	Labrador Interconnected										
1	Industrial - IOCC Firm	3.23	-	0.00186	-	0.00	3.23	-	0.00186	-	0.00
2	Industrial - IOCC Non-Firm	-	-	0.00186	0.00186	0.00	-	-	-	-	0.00
3	CFB - Goose Bay Secondary	-	-	0.00187	0.00187	60.25	-	-	0.00247	0.00247	79.63
	Rural							-	-		
4	1.1 Domestic	-	0.01698	0.00194	0.01892	19.30	-	0.01765	0.00202	0.01967	20.06
5	1.1A Domestic All Electric	-	0.01989	0.00194	0.02183	19.30	-	0.02067	0.00202	0.02269	20.06
								-	-		
6	Domestic	-	0.01980	0.00194	0.02175	19.30	-	0.02059	0.00202	0.02261	20.06
								-	-		
7	2.1 General Service 0-10 kW	-	0.01634	0.00195	0.01828	21.56	-	0.01698	0.00202	0.01901	22.42
8	2.2 General Service 10-100 kW	2.58	-	0.00195	-	35.32	2.68	-	0.00202	-	36.72
9	2.3 General Service 110-1,000 kVa	2.13	-	0.00194	-	36.45	2.21	-	0.00202	-	37.89
10	2.4 General Service Over 1,000 kVa	2.86	-	0.00188	-	36.45	2.97	-	0.00196	-	37.89
11	4.1 Street and Area Lighting	-	0.01664	0.00195	0.01859	36.20	0.00	0.01730	0.00202	0.01932	37.64

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Island Interconnected
Total Demand, Energy & Customer Amounts

	1	2	3	4	5	6	7	8	9
Line No.	Rate Class	Before Deficit and Revenue Credit Allocation				After Deficit and Revenue Credit Allocation			
		Total ($)	Demand ($)	Energy ($)	Customer ($)	Total ($)	Demand ($)	Energy ($)	Customer ($)
	Island Interconnected								
1	Newfoundland Power	191,058,434	86,897,814	102,941,606	1,219,015	213,815,455	97,248,235	115,203,008	1,364,212
2	Industrial - Firm	50,005,883	15,734,208	33,852,555	419,119	49,965,557	15,721,520	33,825,256	418,781
3	Industrial - Non-Firm	157,088	-	157,088	-	-	-	-	-
	Rural								
4	1.1 Domestic	12,396,209	6,675,056	2,672,662	3,048,491	-	-	-	-
5	1.12 Domestic All Electric	12,893,120	8,471,698	2,734,256	1,687,167	-	-	-	-
6	1.3 Special	20,080	14,101	5,482	497	-	-	-	-
7	2.1 General Service 0-10 kW	1,814,946	884,450	392,761	537,735	-	-	-	-
8	2.2 General Service 10-100 kW	4,317,060	2,582,184	1,353,872	381,003	-	-	-	-
9	2.3 General Service 110-1,000 kVa	2,475,820	1,463,453	979,761	32,606	-	-	-	-
10	2.4 General Service Over 1,000 kVa	2,218,755	1,443,064	772,241	3,450	-	-	-	-
11	4.1 Street and Area Lighting	612,505	197,415	74,750	340,341	-	-	-	-
12	**Subtotal Rural**	**36,748,497**	**21,731,422**	**8,985,785**	**6,031,290**				
13	**Total Island Interconnected**	**277,969,902**	**124,363,444**	**145,937,034**	**7,669,424**				

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Island Isolated
Total Demand, Energy & Customer Amounts

	1	2	3	4	5	6	7	8	9
Line No.	Rate Class	Before Deficit and Revenue Credit Allocation				After Deficit and Revenue Credit Allocation			
		Total ($)	Demand ($)	Energy ($)	Customer ($)	Total ($)	Demand ($)	Energy ($)	Customer ($)
	Island Isolated								
1	1.2 Domestic Diesel	5,717,975	3,110,324	2,096,090	511,562	-	-	-	-
2	1.2G Government Domestic Diesel	77,247	43,390	29,375	4,482	-	-	-	-
3	1.23 Churches & Community Halls	65,782	24,641	29,375	11,766	-	-	-	-
4	2.2 GS 10-100 kW	-	-	-	-	-	-	-	-
5	2.3 GS 110-1,000 kVa	233,461	97,397	134,884	1,180	-	-	-	-
6	2.5 GS Diesel	962,966	481,383	415,441	66,141	-	-	-	-
7	2.5G Gov't General Service Diesel	691,229	365,458	303,938	21,833	-	-	-	-
8	4.1 Street and Area Lighting	111,433	51,086	33,235	27,112	-	-	-	-
9	4.1G Gov't Street and Area Lighting	8,180	1,965	1,374	4,841	-	-	-	-
10	**Total Island Isolated**	**7,868,273**	**4,175,644**	**3,043,710**	**648,919**				

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Labrador Isolated
Total Demand, Energy & Customer Amounts

	1	2	3	4	5	6	7	8	9
Line No.	Rate Class	Before Deficit and Revenue Credit Allocation				After Deficit and Revenue Credit Allocation			
		Total ($)	Demand ($)	Energy ($)	Customer ($)	Total ($)	Demand ($)	Energy ($)	Customer ($)
	Labrador Isolated								
1	1.2 Domestic Diesel	9,699,956	4,070,524	5,118,474	510,958	-	-	-	-
2	1.2G Government Domestic Diesel	346,976	149,000	187,587	10,390	-	-	-	-
3	1.23 Churches & Community Halls	192,328	58,093	126,243	7,992	-	-	-	-
4	2.2 GS 10-100 kW	506,058	367,694	135,133	3,231	-	-	-	-
5	2.3 GS 110-1,000 kVa	1,532,554	527,631	1,000,461	4,462	-	-	-	-
6	2.5 GS Diesel	3,464,113	1,283,303	2,074,713	106,097	-	-	-	-
7	2.5G Gov't General Service Diesel	1,434,798	535,486	870,959	28,354	-	-	-	-
8	4.1 Street and Area Lighting	142,499	51,788	62,841	27,871	-	-	-	-
9	4.1G Gov't Street and Area Lighting	8,668	2,072	2,880	3,716	-	-	-	-
10	**Total Labrador Isolated**	**17,327,951**	**7,045,590**	**9,579,291**	**703,070**				

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
L'Anse au Loup
Total Demand, Energy & Customer Amounts

	1	2	3	4	5	6	7	8	9
Line No.	Rate Class	Before Deficit and Revenue Credit Allocation				After Deficit and Revenue Credit Allocation			
		Total ($)	Demand ($)	Energy ($)	Customer ($)	Total ($)	Demand ($)	Energy ($)	Customer ($)
	L'Anse au Loup								
1	1.1 Domestic	1,640,124	911,313	424,299	304,512	-	-	-	-
2	1.12 Domestic All Electric	86,866	57,246	21,161	8,459	-	-	-	-
3	2.1 General Service 0-10 kW	277,002	131,840	75,539	69,623	-	-	-	-
4	2.2 General Service 10-100 kW	399,911	233,033	137,092	29,786	-	-	-	-
5	2.3 General Service 110-1,000 kVa	53,312	9,688	42,201	1,424	-	-	-	-
6	4.1 Street and Area Lighting	44,598	17,347	7,476	19,775	-	-	-	-
7	**Total L'Anse au Loup**	**2,501,812**	**1,360,467**	**707,767**	**433,578**				

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Labrador Interconnected
Total Demand, Energy & Customer Amounts

	1	2	3	4	5	6	7	8	9
Line No.	Rate Class	Before Deficit and Revenue Credit Allocation				After Deficit and Revenue Credit Allocation			
		Total ($)	Demand ($)	Energy ($)	Customer ($)	Total ($)	Demand ($)	Energy ($)	Customer ($)
	Labrador Interconnected								
1	Industrial - IOCC Firm	3,007,393	2,404,039	603,354	-	3,007,393	2,404,039	603,354	-
2	Industrial - IOCC Non-Firm	77,182	-	77,182	-	77,182	-	-	-
3	CFB - Goose Bay Secondary	138,430	-	137,707	723	182,957	-	182,001	956
	Rural								
4	1.1 Domestic	300,979	125,429	14,371	161,179	312,888	130,392	14,939	167,556
5	1.1A Domestic All Electric	7,160,506	5,055,202	493,749	1,611,555	7,443,826	5,255,221	513,285	1,675,320
6	**Subtotal Domestic**	**7,461,485**	**5,180,631**	**508,120**	**1,772,734**	**7,756,713**	**5,385,613**	**528,224**	**1,842,876**
7	2.1 General Service 0-10 kW	241,493	106,081	12,637	122,775	251,049	110,278	13,138	127,633
8	2.2 General Service 10-100 kW	907,148	553,598	116,058	237,492	943,042	575,503	120,650	246,889
9	2.3 General Service 110-1,000 kVa	859,223	638,956	177,325	42,942	893,220	664,238	184,341	44,641
10	2.4 General Service Over 1,000 kVa	362,052	282,626	78,989	437	376,377	293,809	82,114	455
11	4.1 Street and Area Lighting	124,640	23,688	2,770	98,183	129,572	24,625	2,879	102,067
12	**Subtotal Rural**	**9,956,042**	**6,785,580**	**895,899**	**2,274,563**	**10,349,973**	**7,054,066**	**931,347**	**2,364,560**
13	**Total Labrador Interconnected**	**13,179,046**	**9,189,620**	**1,714,141**	**2,275,286**	**13,617,505**	**9,458,105**	**1,716,702**	**2,364,560**

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Island Interconnected
Demands, Sales, & Number of Bills

Line No.	1 Rate Class	2 Units Billing Demands (kW)	3 Sales (MWh)	4 Bills (Total No)
	Island Interconnected			
1	Newfoundland Power	-	4,454,800	12
2	Incustrial - Firm	2,244,000	1,464,970	48
3	Incustrial - Non-Firm		6,798	-
	Rural			
4	1.1 Domestic	-	107,264	147,072
5	1.12 Domestic All Electric	-	109,736	81,396
6	1.3 Special	-	220	24
7	2.1 General Service 0-10 kW	-	15,763	23,172
8	2.2 General Service 10-100 kW	188,235	54,336	9,960
9	2.3 General Service 110-1,000 kVa	165,655	39,444	840
10	2.4 General Service Over 1,000 kVa	91,946	31,237	96
11	4.1 Street and Area Lighting	-	3,000	11,688
12	**Subtotal Rural**	**445,836**	**361,000**	**274,248**
13	**Total Island Interconnected**	**2,689,836**	**6,287,568**	**274,308**

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Island Isolated
Demands, Sales, & Number of Bills

	1	2	3	4
		Units		
Line No.	Rate Class	Billing Demands (kW)	Sales (MWh)	Bills (Total No)
	Island Isolated			
1	1.2 Domestic Diesel	-	6,993	10,956
2	1.2G Government Domestic Diesel	-	98	96
3	1.23 Churches & Community Halls	-	98	252
4	2.2 GS 10-100 kW	-	-	-
5	2.3 GS 110-1,000 kVa	2,627	450	12
6	2.5 GS Diesel	-	1,386	1,236
7	2.5G Gov't General Service Diesel	-	1,014	408
8	4.1 Street and Area Lighting	-	111	336
9	4.1G Gov't Street and Area Lighting	-	5	60
10	**Total Island Isolated**	**2,627**	**10,154**	**13,356**

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Labrador Isolated
Demands, Sales, & Number of Bills

	1	2	3	4
		Units		
Line No.	Rate Class	Billing Demands (kW)	Sales (MWh)	Bills (Total No)
	Labrador Isolated			
1	1.2 Domestic Diesel	-	17,272	23,016
2	1.2G Government Domestic Diesel	-	633	468
3	1.23 Churches & Community Halls	-	426	360
4	2.2 GS 10-100 kW	3,230	456	72
5	2.3 GS 110-1,000 kVa	27,167	3,376	96
6	2.5 GS Diesel	-	7,001	4,176
7	2.5G Gov't General Service Diesel	-	2,939	1,116
8	4.1 Street and Area Lighting	-	212	720
9	4.1G Gov't Street and Area Lighting	-	10	96
10	**Total Labrador Isolated**		**32,325**	**30,120**

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
L'Anse au Loup
Demands, Sales, & Number of Bills

	1	2	3	4
		Units		
Line No.	Rate Class	Billing Demands (kW)	Sales (MWh)	Bills (Total No)
	L'Anse au Loup			
1	1.1 Domestic	-	7,038	8,640
2	1.12 Domestic All Electric	-	351	240
3	2.1 General Service 0-10 kW	-	1,253	1,812
4	2.2 General Service 10-100 kW	9,441	2,274	516
5	2.3 General Service 110-1,000 kVa	5,745	700	24
6	4.1 Street and Area Lighting	-	124	396
7	**Total L'Anse au Loup**		**11,740**	**11,628**

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Labrador Interconnected
Demands, Sales, & Number of Bills

	1	2	3	4
		Units		
Line No.	Rate Class	Billing Demands (kW)	Sales (MWh)	Bills (Total No)
	Labrador Interconnected			
1	Industrial - IOCC Firm	744,000	325,200	12
2	Industrial - IOCC Non-Firm	-	41,600	
3	CFB - Goose Bay Secondary	-	73,700	12
	Rural			
4	1.1 Domestic	-	7,389	8,352
5	1.1A Domestic All Electric	-	254,208	83,508
6	**Subtotal Domestic**	-	**261,597**	**91,860**
7	2.1 General Service 0-10 kW	-	6,493	5,694
8	2.2 General Service 10-100 kW	214,857	59,614	6,724
9	2.3 General Service 110-1,000 kVa	299,982	91,175	1,178
10	2.4 General Service Over 1,000 kVa	98,875	42,000	12
11	4.1 Street and Area Lighting	-	1,423	2,712
12	**Subtotal Rural**	**613,714**	**462,302**	**108,180**
13	**Total Labrador Interconnected**	**1,357,714**	**902,802**	**108,204**

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Island Interconnected
Calculation of Firming Up Charge

	1	2	3	4
Line No.	Description	Total	Gas Turbine	Transmission & Terminals
1	Operating & Maintenance	9,525,036	513,566	9,011,470
2	O&M Overhead	7,045,021	398,632	6,646,389
3	Depreciation	8,986,808	225,214	8,761,594
4	Return (Note 1)	19,642,937	208,571	19,434,367
5	**Total**	**45,199,802**	**1,345,982**	**43,853,820**
6	Capacity (kW)		118,000	1,485,600
7	Cost ($/kW)	$40.93	$11.41	$29.52
8	Rate ($/kWh)	$0.00876		

Note 1 Gas Turbine Return	
Gas Turbine NBV - Sch.2.3A L.9	2,423,405
NBV Including Alloc General, Telecontrol & Feasibility Study	2,582,497
Percent of Total Prod Demand NBV - Schedule 2.3A, L.40, C.3	0.73%

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Island Interconnected
Calculation of Transmission Wheeling Charge

	1	2
Line No.	Description	
1	Island Interconnected Transmission Revenue Requirement	43,918,606
2	Transmission Energy Output (MWh)	6,315,428
3	Rate ($/kWh)	$0.00695

Island Interconnected

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Island Interconnected
Functional Classification of Revenue Requirement

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
				Production and		Rural	Distribution											Specifically
Line		Total	Production	Transmission	Transmission	Transmission	Substations	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting	Assigned
No.	Description	Amount	Demand	Energy	Demand	Demand	Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
		($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)
	Expenses																	
1	Operating & Maintenance	70,564,190	26,091,029	19,636,908	15,657,859	2,127,833	559,066	2,092,889	479,568	101,856	180,294	264,140	289,741	166,889	302,296	36,475	2,190,751	386,595
2	Fuels-No. 6 Fuel	75,493,351	-	75,493,351	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Fuels-Diesel	34,032	34,032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Fuels-Gas Turbine	401,495	401,495	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Power Purchases -CF(L)Co	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Power Purchases-Other	11,748,829	5,395,765	6,353,064	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Depreciation	26,041,302	6,037,610	5,274,886	8,761,594	1,321,719	491,384	1,962,360	421,831	101,992	180,534	228,663	251,267	110,358	94,349	40,836	213,605	548,314
	Expense Credits																	
8	Sundry	(352,142)	(130,204)	(97,996)	(78,139)	(10,619)	(2,790)	(10,444)	(2,393)	(508)	(900)	(1,318)	(1,446)	(833)	(1,509)	(182)	(10,933)	(1,929)
9	Building Rental Income	(13,402)	(4,497)	(4,899)	(2,584)	(316)	(149)	(467)	(107)	(23)	(40)	(59)	(65)	(37)	(21)	(8)	-	(130)
10	Tax Refunds	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Suppliers' Discounts	(43,012)	(15,904)	(11,970)	(9,544)	(1,297)	(341)	(1,276)	(292)	(62)	(110)	(161)	(177)	(102)	(184)	(22)	(1,335)	(236)
12	Pole Attachments	(471,791)	-	-	-	-	-	(272,859)	(93,250)	-	-	(48,296)	(57,385)	-	-	-	-	-
13	Secondary Energy	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Wheeling Revenues	(6,950)	-	-	(6,950)	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Application Fees	(23,000)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(23,000)	-
16	**Total Expense Credits**	**(910,297)**	**(150,605)**	**(114,864)**	**(97,216)**	**(12,231)**	**(3,280)**	**(285,046)**	**(96,043)**	**(593)**	**(1,050)**	**(49,835)**	**(59,072)**	**(972)**	**(1,714)**	**(212)**	**(35,268)**	**(2,295)**
17	**Subtotal Expenses**	**183,372,901**	**37,809,325**	**106,643,345**	**24,322,237**	**3,437,321**	**1,047,170**	**3,770,202**	**805,356**	**203,255**	**359,778**	**442,969**	**481,936**	**276,276**	**394,932**	**77,098**	**2,369,038**	**932,614**
18	Disposal Gain / Loss	775,831	236,664	316,762	162,002	15,025	6,467	18,788	4,123	1,082	1,915	2,164	2,394	1,076	912	439	215	5,803
19	**Subtotal Revenue Requirement Ex. Return**	**184,148,732**	**38,045,989**	**106,960,107**	**24,484,239**	**3,452,345**	**1,053,638**	**3,788,990**	**809,479**	**204,337**	**361,693**	**445,133**	**484,330**	**277,352**	**395,843**	**77,537**	**2,369,303**	**938,418**
20	Return on Debt	88,395,562	26,760,190	36,563,872	18,231,188	1,698,406	732,229	2,129,508	467,775	122,243	216,380	245,776	271,852	122,987	103,170	49,503	24,087	656,397
21	Return on Equity	5,425,608	1,736,055	2,413,055	1,203,178	-	-	-	-	-	-	-	-	-	-	-	-	43,319
22	**Total Revenue Reqmt**	**277,969,902**	**66,572,234**	**145,937,034**	**43,918,606**	**5,150,752**	**1,785,867**	**5,918,498**	**1,277,253**	**326,580**	**578,073**	**690,908**	**756,181**	**400,339**	**499,013**	**127,040**	**2,393,390**	**1,638,134**

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Island Interconnected
Functional Classification of Revenue Requirement - Documentation

Line No.	1 Description	2 Basis of Functional Classification
	Expenses	
1	Operating & Maintenance	Carryforward from Sch.2.4 L.23
2	Fuels-No. 6 Fuel	Production - Energy
3	Fuels-Diesel	Production - Demand
4	Fuels-Gas Turbine	Production - Demand
5	Power Purchases -CF(L)Co	
6	Power Purchases-Other	Carryforward from Sch.4.4 L.7
7	Depreciation	Carryforward from Sch.2.5 L.40
	Expense Credits	
8	Sundry	Prorated on Total Operating & Maintenance Expenses - Sch 2.4 L.23
9	Building Rental Income	Prorated on General Plant - Sch.2.2 L.34
10	Tax Refunds	Prorated on Total Operating & Maintenance Expenses - Sch 2.4 L.23
11	Suppliers' Discounts	Prorated on Total Operating & Maintenance Expenses - Sch 2.4 L.23
12	Pole Attachments	Prorated on Distribution Poles - Sch.4.1 L.33
13	Secondary Energy	Production - Energy
14	Wheeling Revenues	Transmission - Demand
15	Application Fees	Accounting - Customer
16	**Total Expense Credits**	
17	**Subtotal Expenses**	
18	Disposal Gain / Loss	Prorated on Total Net Book Value - Sch.2.3 L.40
19	**Subtotal Revenue Requirement Ex. Return**	
20	Return on Debt	Prorated on Rate Base - Sch.2.6 L.8
21	Return on Equity	Prorated on Rate Base - Sch.2.6 L.10
22	**Total Revenue Reqmt**	

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Island Interconnected
Functional Classification of Plant in Service for the Allocation of O&M Expense

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
							Distribution											
				Production and		Rural		Primary Lines		Line Transformers		Secondary Lines						Specifically
Line		Total	Production	Transmission	Transmission	Transmission	Substations							Services	Meters	Street Lighting	Accounting	Assigned
No.	Description	Amount	Demand	Energy	Demand	Demand	Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
	Production	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)
	Hydraulic																	
1	Bay D'Espoir	184,846,259	75,524,940	109,321,319	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Upper Salmon	169,006,835	69,053,229	99,953,606	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Hinds Lake	79,515,743	32,488,738	47,027,005	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Cat Arm	263,761,529	107,768,336	155,993,193	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Paradise River	21,618,100	8,832,777	12,785,323	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Other Hydraulic	2,113,835	863,676	1,250,159	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	**Subtotal Hydraulic**	**720,862,300**	**294,531,696**	**426,330,605**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Holyrood	181,843,583	122,580,759	59,262,824	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Gas Turbines	23,338,362	23,338,362	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Roddickton	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Diesel	8,037,152	8,037,152	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	**Subtotal Production**	**934,081,398**	**448,487,969**	**485,593,428**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Transmission																	
13	Lines	232,584,234	-	-	201,808,410	30,461,136	-	168,000	-	-	-	-	-	-	-	-	-	146,688
14	Lines - Hydraulic	39,384,654	16,091,879	23,292,775	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Terminal Stations	94,544,637	275,895	298,721	76,535,769	3,539,279	-	-	-	-	-	-	-	-	-	-	-	13,844,973
16	Term Stns - Hydraulic	26,091,049	10,660,345	15,430,704	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Term Stns - Holyrood	9,970,601	6,721,182	3,249,419	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	Term Stns - Gas Tur/Dsl	1,183,617	1,183,617	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Term Stns - Distribution	9,322,905	-	-	-	-	9,322,905	-	-	-	-	-	-	-	-	-	-	-
20	**Subtotal Term Stns**	**141,112,809**	**18,841,039**	**18,978,844**	**76,535,769**	**3,539,279**	**9,322,905**	-	-	-	-	-	-	-	-	-	-	**13,844,973**
21	**Subtotal Transmission**	**413,081,697**	**34,932,918**	**42,271,618**	**278,394,179**	**34,000,415**	**9,322,905**	**168,000**	-	-	-	-	-	-	-	-	-	**13,991,661**
	Distribution																	
22	Substations	7,979,031	1,204,121	-	-	-	6,774,910	-	-	-	-	-	-	-	-	-	-	-
23	Land & Land Improvements	684,743	-	-	-	-	-	516,262	65,770	-	-	59,881	42,831	-	-	-	-	-
24	Poles	50,169,547	-	-	-	-	-	29,015,457	9,916,111	-	-	5,135,756	6,102,222	-	-	-	-	-
25	Primary Conductor & Eqpt	13,912,809	-	-	-	-	-	12,340,662	1,572,147	-	-	-	-	-	-	-	-	-
26	Submarine Conductor	8,281,760	-	-	-	-	-	8,281,760	-	-	-	-	-	-	-	-	-	-
27	Transformers	6,797,726	-	-	-	-	-	-	-	2,453,979	4,343,747	-	-	-	-	-	-	-
28	Secondary Conductor&Eqpt	2,003,732	-	-	-	-	-	-	-	-	-	1,168,176	835,556	-	-	-	-	-
29	Services	4,020,793	-	-	-	-	-	-	-	-	-	-	-	4,020,793	-	-	-	-
30	Meters	2,278,852	-	-	-	-	-	-	-	-	-	-	-	-	2,278,852	-	-	-
31	Street Lighting	878,783	-	-	-	-	-	-	-	-	-	-	-	-	-	878,783	-	-
32	**Subtotal Distribution**	**97,007,777**	**1,204,121**	-	-	-	**6,774,910**	**50,154,141**	**11,554,028**	**2,453,979**	**4,343,747**	**6,363,813**	**6,980,609**	**4,020,793**	**2,278,852**	**878,783**	-	-
33	**Subttl Prod, Trans, & Dist**	**1,444,170,872**	**484,625,008**	**527,865,047**	**278,394,179**	**34,000,415**	**16,097,815**	**50,322,141**	**11,554,028**	**2,453,979**	**4,343,747**	**6,363,813**	**6,980,609**	**4,020,793**	**2,278,852**	**878,783**	-	**13,991,661**
34	General	95,358,053	31,999,605	34,854,728	18,332,262	2,245,034	1,062,933	3,322,752	762,908	162,035	286,816	420,200	460,927	265,491	150,472	58,026	-	923,864
35	Telecontrol - Common	47,054,653	17,062,473	18,631,142	9,825,999	1,200,054	329,054	5,930	-	-	-	-	-	-	-	-	-	-
36	Telecontrol - Specific	9,144	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9,144
37	Feasibility Studies	467,568	250,291	-	217,277	-	-	-	-	-	-	-	-	-	-	-	-	-
38	Software - General	4,062,087	1,353,127	1,484,751	733,052	95,635	45,279	141,543	32,499	6,902	12,218	17,900	19,635	11,309	6,410	2,472	-	39,355
39	Software - Cust Acctng	320,408	-	-	-	-	-	-	-	-	-	-	-	-	-	-	320,408	-
40	**Total Plant**	**1,591,442,784**	**535,300,504**	**582,835,668**	**307,602,770**	**37,541,139**	**17,535,082**	**53,792,366**	**12,349,435**	**2,622,917**	**4,642,781**	**6,801,912**	**7,461,171**	**4,297,594**	**2,435,734**	**939,281**	**320,408**	**14,964,024**

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Island Interconnected
Functional Classification of Plant in Service for the Allocation of O&M Expense - Documentation

Line No.	1 Description	2 Basis of Functional Classification
	Production	
	Hydraulic	
1	Bay D'Espoir	Production - Demand, Energy ratios Sch.4.1 L.1
2	Upper Salmon	Production - Demand, Energy ratios Sch.4.1 L.1
3	Hinds Lake	Production - Demand, Energy ratios Sch.4.1 L.1
4	Cat Arm	Production - Demand, Energy ratios Sch.4.1 L.1
5	Paradise River	Production - Demand, Energy ratios Sch.4.1 L.1
6	Other Hydraulic	Production - Demand, Energy ratios Sch.4.1 L.1
7	**Subtotal Hydraulic**	
8	Holyrood	Production - Demand, Energy ratios Sch.4.1 L.2
9	Gas Turbines	Production - Demand, Energy ratios Sch.4.1 L.3
10	Roddickton	Production - Demand, Energy ratios Sch.4.1 L.2
11	Diesel	Production - Demand, Energy ratios Sch.4.1 L.3
12	**Subtotal Production**	
	Transmission	
13	Lines	Transmission - Demand; Distribution - Primary Demand; Spec Assigned - Custmr
14	Lines - Hydraulic	Production - Demand, Energy ratios Sch.4.1 L.14
15	Terminal Stations	Production - Demand, Energy subtotals, L. 12; Transmission - Demand; Spec Assigned - Custmr
16	Term Stns - Hydraulic	Production - Demand, Energy ratios Sch.4.1 L.17
17	Term Stns - Holyrood	Production - Demand, Energy ratios Sch.4.1 L.18
18	Term Stns - Gas Tur/Dsl	Production - Demand, Energy ratios Sch.4.1 L.19
19	Term Stns - Distribution	Distribution - Substations Demand
20	**Subtotal Term Stns**	
21	**Subtotal Transmission**	
	Distribution	Distribution plant other than Substations, Meters and Submarine prorated to functions based on special analysis
22	Substations	Production - Demand; Dist Substns - Demand
23	Land & Land Improvements	Primary, Secondary - Demand, Customer - zero intercept ratios Sch.4.1 L.28
24	Poles	Primary, Secondary - Demand, Customer - zero intercept ratios Sch.4.1 L.33
25	Primary Conductor & Eqpt	Primary - Demand, Customer - zero intercept ratios Sch.4.1 L.34
26	Submarine Conductor	Primary - Demand, Customer - zero intercept ratios Sch.4.1 L.35
27	Transformers	Transformers - Demand, Customer - zero intercept ratios Sch.4.1 L.36
28	Secondary Conductor&Eqpt	Secondary - Demand, Customer - zero intercept ratios Sch. 4.1 L 37
29	Services	Services Customer
30	Meters	Meters - Customer
31	Street Lighting	Street Lighting - Customer
32	**Subtotal Distribution**	
33	**Subttl Prod, Trans, & Dist**	
34	General	Prorated on subtotal Production, Transmission, & Distribution plant - L.33
35	Telecontrol - Common	Prorated on functionalized Production & Transmission plant - L. 12, 21
36	Telecontrol - Specific	Specifically Assigned - Customer
37	Feasibility Studies	Production, Transmission - Demand
38	Software - General	Prorated on subtotal Production, Transmission, & Distribution plant - L.33
39	Software - Cust Acctng	Customer Accounting
40	**Total Plant**	

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Island Interconnected
Functional Classification of Net Book Value

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
							Distribution											
				Production and		Rural												Specifically
Line		Total	Production	Transmission	Transmission	Transmission	Substations	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting	Assigned
No.	Description	Amount	Demand	Energy	Demand	Demand	Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
	Production	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)
	Hydraulic																	
1	Bay D'Espoir	149,220,897	60,969,042	88,251,855	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Upper Salmon	163,902,358	66,967,629	96,934,728	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Hinds Lake	74,355,426	30,380,323	43,975,103	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Cat Arm	259,607,448	106,071,051	153,536,397	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Paradise River	21,057,954	8,603,911	12,454,043	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Other Small Hydraulic	825,686	337,361	488,325	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	**Subtotal Hydraulic**	**668,969,768**	**273,329,317**	**395,640,451**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
8	Holyrood	36,853,424	24,842,893	12,010,531	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Gas Turbines	2,423,405	2,423,405	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Roddickton	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Diesel	1,756,348	1,756,348	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	**Subtotal Production**	**710,002,946**	**302,351,964**	**407,650,982**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Transmission																	
13	Lines	189,233,904	-	-	170,530,355	18,103,022	-	78,788	-	-	-	-	-	-	-	-	-	521,738
14	Lines - Hydraulic	38,009,822	15,530,147	22,479,675	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Terminal Stations	67,557,264	215,897	291,087	56,299,943	2,953,147	-	-	-	-	-	-	-	-	-	-	-	7,797,190
16	Term Stns - Hydraulic	20,022,364	8,180,787	11,841,577	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Term Stns - Holyrood	5,078,335	3,423,306	1,655,030	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	Term Stns - Gas Tur/Dsl	988,177	988,177	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Term Stns - Distribution	5,891,977	-	-	-	-	5,891,977	-	-	-	-	-	-	-	-	-	-	-
20	**Subtotal Term Stns**	**99,538,118**	**12,808,167**	**13,787,693**	**56,299,943**	**2,953,147**	**5,891,977**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**7,797,190**
21	**Subtotal Transmission**	**326,781,843**	**28,338,314**	**36,267,368**	**226,830,299**	**21,056,169**	**5,891,977**	**78,788**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**8,318,928**
	Distribution																	
22	Substations	4,003,496	759,364	-	-	-	3,244,132	-	-	-	-	-	-	-	-	-	-	-
23	Land & Land Improvements	429,511	-	-	-	-	-	323,830	41,255	-	-	37,561	26,866	-	-	-	-	-
24	Poles	25,055,664	-	-	-	-	-	14,490,893	4,952,302	-	-	2,564,898	3,047,571	-	-	-	-	-
25	Primary Conductor & Eqpt	8,111,216	-	-	-	-	-	7,194,649	916,567	-	-	-	-	-	-	-	-	-
26	Submarine Conductor	4,841,735	-	-	-	-	-	4,841,735	-	-	-	-	-	-	-	-	-	-
27	Transformers	4,296,494	-	-	-	-	-	-	-	1,551,034	2,745,460	-	-	-	-	-	-	-
28	Secondary Conductor&Eqpt	856,613	-	-	-	-	-	-	-	-	-	499,405	357,207	-	-	-	-	-
29	Services	1,542,491	-	-	-	-	-	-	-	-	-	-	-	1,542,491	-	-	-	-
30	Meters	1,306,635	-	-	-	-	-	-	-	-	-	-	-	-	1,306,635	-	-	-
31	Street Lighting	629,429	-	-	-	-	-	-	-	-	-	-	-	-	-	629,429	-	-
32	**Subtotal Distribution**	**51,073,283**	**759,364**	**-**	**-**	**-**	**3,244,132**	**26,851,106**	**5,910,124**	**1,551,034**	**2,745,460**	**3,101,864**	**3,431,644**	**1,542,491**	**1,306,635**	**629,429**	**-**	**-**
33	**Subttl Prod, Trans, & Dist**	**1,087,858,072**	**331,449,641**	**443,918,351**	**226,830,299**	**21,056,169**	**9,136,110**	**26,929,895**	**5,910,124**	**1,551,034**	**2,745,460**	**3,101,864**	**3,431,644**	**1,542,491**	**1,306,635**	**629,429**	**-**	**8,318,928**
34	General	40,600,338	12,370,150	16,567,635	8,455,614	785,845	340,972	1,005,060	220,574	57,887	102,464	115,766	128,074	57,568	48,765	23,491	-	310,474
35	Telecontrol - Common	24,489,343	7,874,241	10,570,374	5,401,176	501,380	140,297	1,876	-	-	-	-	-	-	-	-	-	-
36	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
37	Feasibility Studies	467,568	250,291	-	217,277	-	-	-	-	-	-	-	-	-	-	-	-	-
38	Software - General	4,149,485	1,254,269	1,693,266	855,213	80,316	34,848	102,720	22,543	5,916	10,472	11,832	13,090	5,884	4,984	2,401	-	31,731
39	Software - Cust Acctng	320,408	-	-	-	-	-	-	-	-	-	-	-	-	-	-	320,408	-
40	**Total Net Book Value**	**1,157,885,215**	**353,208,591**	**472,749,625**	**241,779,579**	**22,423,709**	**9,652,227**	**28,039,551**	**6,153,241**	**1,614,837**	**2,858,396**	**3,229,461**	**3,572,807**	**1,605,942**	**1,360,384**	**655,321**	**320,408**	**8,661,133**

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Island Interconnected
Functional Classification of Operating & Maintenance Expense

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
				Producton and		Rural	Distribution											Specifically
Line		Total	Production	Transmission	Transmission	Transmission	Substations	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting	Assigned
No.	Description	Amount	Demand	Energy	Demand	Demand	Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
		($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)
	Production																	
1	Hydraulic	7,376,414	3,013,873	4,362,541	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Holyrood / Thermal	15,161,407	10,220,304	4,941,102	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Roddickton	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Gas Turbine/Diesel	513,566	513,566	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	**Subtotal Production**	**23,051,386**	**13,747,743**	**9,303,643**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Transmission																	
6	Transmission Lines	10,570,170	625,417	905,282	7,843,358	1,183,883	-	6,529	-	-	-	-	-	-	-	-	-	5,701
7	Terminal Stations	2,152,301	237,370	289,472	1,168,113	53,982	142,196	-	-	-	-	-	-	-	-	-	-	211,168
8	**Subtotal Transmission**	**12,722,472**	**912,787**	**1,194,754**	**9,011,470**	**1,237,866**	**142,196**	**6,529**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**216,869**
	Distribution																	
9	Other	2,256,044	28,677	-	-	-	161,350	1,194,461	275,168	58,443	103,450	151,559	166,249	95,758	-	20,929	-	-
10	Meters	184,449	-	-	-	-	-	-	-	-	-	-	-	-	184,449	-	-	-
11	**Subtotal Distribution**	**2,440,494**	**28,677**	**-**	**-**	**-**	**161,350**	**1,194,461**	**275,168**	**58,443**	**103,450**	**151,559**	**166,249**	**95,758**	**184,449**	**20,929**	**-**	**-**
12	**Subttl Prod, Trans, & Dist**	**38,214,351**	**14,689,207**	**10,498,397**	**9,011,470**	**1,237,866**	**303,546**	**1,200,990**	**275,168**	**58,443**	**103,450**	**151,559**	**166,249**	**95,758**	**184,449**	**20,929**	**-**	**216,869**
13	Customer Accounting	1,372,783	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,372,733	-
	Overheads																	
	Plant-Related:																	
14	Production	1,363,734	654,781	708,954	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Transmission	395,204	33,421	40,442	266,346	32,529	8,919	161	-	-	-	-	-	-	-	-	-	13,386
16	Distribution	213,390	2,649	-	-	-	14,903	110,325	25,416	5,398	9,555	13,999	15,355	8,845	5,013	1,933	-	-
17	Prod, Trans, Distn	130,900	43,927	47,846	25,234	3,082	1,459	4,561	1,047	222	394	577	633	364	207	80	-	1,268
18	Telecontrol Plant	2,807,225	1,017,729	1,111,296	536,094	71,580	19,627	354	-	-	-	-	-	-	-	-	-	545
19	Prod, Trans, Distn and General Plant	1,751,351	539,087	641,399	338,511	41,313	19,297	59,197	13,590	2,886	5,109	7,485	8,211	4,729	2,680	1,034	353	16,468
	Expense Related:																	
20	Property Insurance	737,551	311,484	335,834	63,064	4,203	10,525	2,003	459	98	173	253	277	160	91	35	-	8,893
21	Other Expense Related	23,577,700	8,748,744	6,252,740	5,367,141	737,260	180,789	715,298	163,887	34,808	61,614	90,267	99,016	57,033	109,856	12,465	817,616	129,165
22	**Subtotal Overheads**	**30,977,056**	**11,401,822**	**9,138,511**	**6,646,389**	**889,967**	**255,520**	**891,899**	**204,400**	**43,413**	**76,844**	**112,581**	**123,492**	**71,131**	**117,847**	**15,546**	**817,968**	**169,726**
23	**Total Operating & Maintenance Expenses**	**70,564,190**	**26,091,029**	**19,636,908**	**15,657,859**	**2,127,833**	**559,066**	**2,092,889**	**479,568**	**101,856**	**180,294**	**264,140**	**289,741**	**166,889**	**302,296**	**36,475**	**2,190,751**	**386,595**

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Island Interconnected
Functional Classification of Operating & Maintenance Expense - Documentation

Line No.	1 Description	2 Basis of Functional Classification
	Production	
1	Hydraulic	Production - Demand, Energy ratios Sch.4.1 L.1
2	Holyrood / Thermal	Production - Demand, Energy ratios Sch.4.1 L.2
3	Roddickton	Production - Demand, Energy ratios Sch.4.1 L.2
4	Gas Turbine/Diesel	Production - Demand, Energy ratios Sch.4.1 L.3
5	**Subtotal Production**	
	Transmission	
6	Transmission Lines	Prorated on Transmission Lines Plant in Service - Sch.2.2 L.13, 14
7	Terminal Stations	Prorated on Transmission Terminal Stations Plant in Service - Sch.2.2 L.20
8	**Subtotal Transmission**	
	Distribution	
9	Other	Production, Distribution, except Meters- ratios Sch. 4.1 L. 42
10	Meters	Meters - Customer
11	**Subtotal Distribution**	
12	**Subttl Prod, Trans, & Dist**	
13	Customer Accounting	Accounting - Customer
	Overheads	
	Plant-Related:	
14	Production	Prorated on Production Plant in Service - Sch.2.2 L.12
15	Transmission	Prorated on Transmission Plant in Service - Sch.2.2 L.21
16	Distribution	Prorated on Distribution Plant in Service - Sch.2.2 L.32
17	Prod, Trans, Distn	Prorated on Prod, Trans & Distribution Plant in Service - Sch.2.2 L.33
18	Telecontrol Plant	Prorated on Telecontrol Plant in Service - Sch.2.2 L.35, 36
19	Prod, Trans, Distn and General Plant	Prorated on Total Plant in Service, Sch. 2.2, L. 40
	Expense Related:	
20	Property Insurance	Prorated on Prod., Trans. Terminal, Dist. Sub & General Plant in Service - Sch.2.2 L.12, 20, 22, 34 - 36
21	Other Expense Related	Prorated on Subtotal Production, Transmission, Distribution, Accounting Expenses - L 12, 13
22	**Subtotal Overheads**	
23	**Total Operating & Maintenance Expenses**	

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Island Interconnected
Functional Classification of Depreciation Expense

Line No.	1 Description	2 Total Amount ($)	3 Production Demand ($)	4 Production and Transmission Energy ($)	5 Transmission Demand ($)	6 Rural Transmission Demand ($)	7 Distribution Substations Demand ($)	8 Primary Lines Demand ($)	9 Primary Lines Customer ($)	10 Line Transformers Demand ($)	11 Line Transformers Customer ($)	12 Secondary Lines Demand ($)	13 Secondary Lines Customer ($)	14 Services Customer ($)	15 Meters Customer ($)	16 Street Lighting Customer ($)	17 Accounting Customer ($)	18 Specifically Assigned Customer ($)
	Production																	
	Hydraulic																	
1	Bay D'Espoir	1,388,037	567,128	820,910	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Upper Salmon	695,931	284,345	411,586	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Hinds Lake	348,191	142,265	205,926	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Cat Arm	644,961	263,520	381,441	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Paradise River	81,570	33,328	48,242	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Other Small Hydraulic	26,458	10,810	15,648	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	**Subtotal Hydraulic**	**3,185,150**	**1,301,396**	**1,883,753**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
8	Holyrood	2,017,940	1,360,293	657,647	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Gas Turbines	133,054	133,054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Roddickton	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Diesel	180,231	180,231	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	**Subtotal Production**	**5,516,374**	**2,974,974**	**2,541,400**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Transmission																	
13	Lines	3,968,108	-	-	3,221,372	695,736	-	7,685	-	-	-	-	-	-	-	-	-	43,315
14	Lines - Hydraulic	179,171	73,206	105,965	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Terminal Stations	2,399,404	4,848	4,142	1,964,477	92,148	-	-	-	-	-	-	-	-	-	-	-	333,789
16	Term Stns - Hydraulic	680,352	277,980	402,372	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Term Stns - Holyrood	277,730	187,218	90,512	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	Term Stns - Gas Tur/Dsl	10,890	10,890	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Term Stns - Distribution	122,690	-	-	-	-	122,690	-	-	-	-	-	-	-	-	-	-	-
20	**Subtotal Term Stns**	**3,491,066**	**480,936**	**497,026**	**1,964,477**	**92,148**	**122,690**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**333,789**
21	**Subtotal Transmission**	**7,638,345**	**554,142**	**602,991**	**5,135,849**	**787,885**	**122,690**	**7,685**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**377,103**
	Distribution																	
22	Substations	234,232	37,834	-	-	-	196,398	-	-	-	-	-	-	-	-	-	-	-
23	Land & Land Improvements	19,793	-	-	-	-	-	14,923	1,901	-	-	1,731	1,238	-	-	-	-	-
24	Poles	1,246,058	-	-	-	-	-	720,655	246,286	-	-	127,556	151,561	-	-	-	-	-
25	Primary Conductor & Eqpt	371,039	-	-	-	-	-	329,111	41,927	-	-	-	-	-	-	-	-	-
26	Submarine Conductor	276,059	-	-	-	-	-	276,059	-	-	-	-	-	-	-	-	-	-
27	Transformers	194,307	-	-	-	-	-	-	-	70,145	124,162	-	-	-	-	-	-	-
28	Secondary Conductor&Eqpt	47,986	-	-	-	-	-	-	-	-	-	27,976	20,010	-	-	-	-	-
29	Services	75,899	-	-	-	-	-	-	-	-	-	-	-	75,899	-	-	-	-
30	Meters	64,889	-	-	-	-	-	-	-	-	-	-	-	-	64,889	-	-	-
31	Street Lighting	28,085	-	-	-	-	-	-	-	-	-	-	-	-	-	28,085	-	-
32	**Subtotal Distribution**	**2,558,346**	**37,834**	**-**	**-**	**-**	**196,398**	**1,340,748**	**290,114**	**70,145**	**124,162**	**157,263**	**172,809**	**75,899**	**64,889**	**28,085**	**-**	**-**
33	**Subttl Prod, Trans, & Dist**	**15,713,065**	**3,566,951**	**3,144,391**	**5,135,849**	**787,885**	**319,088**	**1,348,433**	**290,114**	**70,145**	**124,162**	**157,263**	**172,809**	**75,899**	**64,889**	**28,085**	**-**	**377,103**
34	General	5,555,116	1,231,041	1,111,652	1,833,378	273,545	112,809	476,718	102,566	24,799	43,896	55,598	61,094	26,833	22,940	9,929	-	133,319
35	Telecontrol - Common	2,856,293	738,895	702,893	1,159,238	176,123	27,426	1,718	-	-	-	-	-	-	-	-	-	-
36	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
37	Feasibility Studies	124,364	62,313	-	62,051	-	-	-	-	-	-	-	-	-	-	-	-	-
38	Software - General	1,578,858	358,409	315,950	521,077	79,167	32,062	135,491	29,151	7,048	12,476	15,802	17,364	7,626	6,520	2,822	-	37,892
39	Software - Cust Acctng	213,605	-	-	-	-	-	-	-	-	-	-	-	-	-	-	213,605	-
40	**Total Deprecn Expense**	**26,041,302**	**6,037,610**	**5,274,886**	**8,751,594**	**1,321,719**	**491,384**	**1,962,360**	**421,831**	**101,992**	**180,534**	**228,663**	**251,267**	**110,358**	**94,349**	**40,836**	**213,605**	**548,314**

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Island Interconnected
Functional Classification of Rate Base

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
				Production and		Rural	Distribution											Specifically
Line		Total	Production	Transmission	Transmission	Transmission	Substations	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting	Assigned
No.	Description	Amount	Demand	Energy	Demand	Demand	Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
		($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)
1	Average Net Book Value	1,157,885,215	353,208,591	472,749,625	241,779,579	22,423,709	9,652,227	28,039,551	6,153,241	1,614,837	2,858,396	3,229,461	3,572,807	1,605,942	1,360,384	655,321	320,408	8,661,133
2	Cash Working Capital	2,878,848	878,182	1,175,397	601,136	55,752	23,998	69,715	15,299	4,015	7,107	8,029	8,883	3,993	3,382	1,629	797	21,534
3	Fuel Inventory - No. 6 Fuel	13,429,718	-	13,429,718	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Fuel Inventory - Diesel	28,884	28,884	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Fuel Inventory - Gas Turbine	758,563	758,563															
6	Inventory/Supplies	19,244,334	6,473,058	7,047,872	3,719,650	453,962	212,041	650,478	149,334	31,717	56,142	82,251	90,223	51,968	29,454	11,358	3,874	180,951
7	Deferred Charges: Foreign Exchange Loss	79,234,136	24,170,079	32,350,277	16,544,987	1,534,455	660,502	1,918,748	421,067	110,503	195,600	220,992	244,487	109,895	93,091	44,844	21,926	592,682
8	Total Rate Base	**1,273,459,698**	**385,517,358**	**526,752,888**	**262,645,353**	**24,467,879**	**10,548,769**	**30,678,492**	**6,738,941**	**1,761,073**	**3,117,246**	**3,540,734**	**3,916,401**	**1,771,798**	**1,486,311**	**713,152**	**347,005**	**9,456,300**
9	Less: Rural Asset Portion	89,087,799	-	-	-	24,467,879	10,548,769	30,678,492	6,738,941	1,761,073	3,117,246	3,540,734	3,916,401	1,771,798	1,486,311	713,152	347,005	-
10	Rate Base Available for Equity Return	**1,184,371,899**	**385,517,358**	**526,752,888**	**262,645,353**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**9,456,300**
11	Return on Debt	88,395,562	26,790,190	36,563,872	18,231,188	1,698,406	732,229	2,129,508	467,775	122,243	216,380	245,776	271,852	122,987	103,170	49,503	24,037	656,397
12	Return on Equity	5,425,608	1,736,055	2,413,055	1,203,178	-	-	-	-	-	-	-	-	-	-	-	-	43,319
13	Return on Rate Base	**93,821,170**	**28,526,245**	**38,976,927**	**19,434,367**	**1,698,406**	**732,229**	**2,129,508**	**467,775**	**122,243**	**216,380**	**245,776**	**271,852**	**122,987**	**103,170**	**49,503**	**24,037**	**699,716**

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Island Interconnected
Functional Classification of Rate Base - Documentation

	1	2
Line No.	Description	Basis of Functional Classification
1	Average Net Book Value	Sch. 2.3 , L. 40
2	Cash Working Capital	Prorated on Average Net Book Value, L. 1
3	Fuel Inventory - No. 6 Fuel	Production - Energy
4	Fuel Inventory - Diesel	Production - Demand
5	Fuel Inventory - Gas Turbine	Production - Demand
6	Inventory/Supplies	Prorated on Total Plant in Service, Sch. 2.2, L. 40
	Deferred Charges:	
7	Foreign Exchange Loss	Prorated on Average Net Book Value, L. 1
8	Total Rate Base	
9	Less: Rural Asset Portion	Rural Transmission and Distribution Rate Base
10	Rate Base Available for Equity Return	
11	Return on Debt	L.8 x Sch.1.2,p2,L.13
12	Return on Equity	L.10 x Sch.1.2,p2,L.16
13	Return on Rate Base	

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Island Interconnected
Basis of Allocation to Classes of Service

Line No.	1 Description	2 Total Amount	3 Production Demand	4 Production and Transmission Energy	5 Transmission Demand	6 Rural Transmission Demand	7 Distribution Substations Demand	8 Distribution Primary Lines Demand	9 Distribution Primary Lines Customer	10 Distribution Line Transformers Demand	11 Distribution Line Transformers Customer	12 Distribution Secondary Lines Demand	13 Distribution Secondary Lines Customer	14 Distribution Services Customer	15 Distribution Meters Customer	16 Distribution Street Lighting Customer	17 Accounting Customer	18 Specifically Assigned Customer
			(2 CP kW)	(MWh @ Gen)	(CP kW)	(CP kW)	(CP kW)	(CP kW)	(Rural Cust)	(CP kW)	(Rural Cust)	(CP kW)	(Rural Cust)	(Wtd Rural Cust)			(Rural Cust)	
	Amounts																	
1	Newfoundland Power	-	1,978,568	4,602,195	953,251	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Industrial - Firm	-	358,251	1,513,441	172,601	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Industrial - Non-Firm	-	-	7,023	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural																	
4	1.1 Domestic	-	54,650	119,486	26,801	26,801	26,639	25,293	12,256	24,934	12,256	24,230	12,256	12,256	12,256	-	12,256	-
5	1.12 Domestic All Electric	-	69,359	122,240	34,015	34,015	33,808	32,101	6,783	31,645	6,783	30,752	6,783	6,783	6,783	-	6,733	-
6	1.3 Special	-	115	245	57	57	56	53	2	53	2	51	2	2	2	-	2	-
7	2.1 GS 0-10 kW	-	7,044	17,559	3,578	3,578	3,556	3,377	1,931	3,329	1,931	3,235	1,931	3,862	3,862	-	1,931	-
8	2.2 GS 10-100 kW	-	21,869	60,527	10,269	10,269	10,207	9,691	830	9,553	830	9,284	830	6,699	6,699	-	830	-
9	2.3 GS 110-1,000 kVa	-	10,994	43,802	6,079	6,079	6,042	5,737	70	4,632	70	4,501	70	557	600	-	70	-
10	2.4 GS Over 1,000 kVa	-	11,363	34,524	6,028	6,028	5,991	5,689	8	3,033	8	2,948	8	43	69	-	8	-
11	4.1 Street and Area Lighting	-	1,616	3,342	793	793	788	748	974	737	974	717	974	-	-	1	974	-
12	**Subtotal Rural**	**-**	**177,010**	**401,726**	**87,619**	**87,619**	**87,087**	**82,689**	**22,854**	**77,916**	**22,854**	**75,717**	**22,854**	**30,202**	**30,271**	**1**	**22,854**	**-**
13	**Total**	**-**	**2,513,829**	**6,524,385**	**1,213,471**	**87,619**	**87,087**	**82,689**	**22,854**	**77,916**	**22,854**	**75,717**	**22,854**	**30,202**	**30,271**	**1**	**22,854**	**-**
	Ratios Excluding Return on Equity																	
14	Newfoundland Power	-	0.7871	0.7054	0.7856	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Industrial - Firm	-	0.1425	0.2320	0.1422	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Industrial - Non-Firm	-	-	0.0011	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural																	
17	1.1 Domestic	-	0.0217	0.0183	0.0221	0.3059	0.3059	0.3059	0.5363	0.3200	0.5363	0.3200	0.5363	0.4058	0.4049	-	0.5363	-
18	1.12 Domestic All Electric	-	0.0276	0.0187	0.0280	0.3882	0.3882	0.3882	0.2968	0.4061	0.2968	0.4061	0.2968	0.2246	0.2241	-	0.2968	-
19	1.3 Special	-	0.0000	0.0000	0.0000	0.0006	0.0006	0.0006	0.0001	0.0007	0.0001	0.0007	0.0001	0.0001	0.0001	-	0.0001	-
20	2.1 GS 0-10 kW	-	0.0028	0.0027	0.0029	0.0408	0.0408	0.0408	0.0845	0.0427	0.0845	0.0427	0.0845	0.1279	0.1276	-	0.0845	-
21	2.2 GS 10-100 kW	-	0.0087	0.0093	0.0085	0.1172	0.1172	0.1172	0.0363	0.1226	0.0363	0.1226	0.0363	0.2218	0.2213	-	0.0363	-
22	2.3 GS 110-1,000 kVa	-	0.0044	0.0067	0.0050	0.0694	0.0694	0.0694	0.0031	0.0594	0.0031	0.0594	0.0031	0.0184	0.0198	-	0.0031	-
23	2.4 GS Over 1,000 kVa	-	0.0045	0.0053	0.0050	0.0688	0.0688	0.0688	0.0004	0.0389	0.0004	0.0389	0.0004	0.0014	0.0023	-	0.0004	-
24	4.1 Street and Area Lighting	-	0.0006	0.0005	0.0007	0.0090	0.0090	0.0090	0.0426	0.0095	0.0426	0.0095	0.0426	-	-	1.0000	0.0426	-
25	**Subtotal Rural**	**-**	**0.0704**	**0.0616**	**0.0722**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**-**
26	**Total**	**-**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**-**

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Island Interconnected
Allocation of Functionalized Amounts to Classes of Service

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
				Production and		Rural	Distribution											Specifically
Line		Total	Production	Transmission	Transmission	Transmission	Substations	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting	Assigned
No.	Description	Amount	Demand	Energy	Demand	Demand	Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
		($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)
	Allocated Revenue Requirement Excluding Return																	
1	Newfoundland Power	125,297,339	29,944,985	75,447,916	19,233,772	-	-	-	-	-	-	-	-	-	-	-	-	670,665
2	Industrial - Firm	33,983,536	5,422,008	24,811,200	3,432,575	-	-	-	-	-	-	-	-	-	-	-	-	267,753
3	Industrial - Non-Firm	115,133	-	115,133	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural																	
4	1.1 Domestic	8,503,080	827,105	1,958,846	540,772	1,056,021	322,292	1,158,996	434,102	65,389	193,967	142,446	259,733	112,549	160,268	-	1,270,595	-
5	1.12 Domestic All Electric	8,569,599	1,049,727	2,003,989	636,324	1,340,257	409,039	1,470,948	240,251	82,989	107,350	180,786	143,748	62,289	88,699	-	703,202	-
6	1.3 Special	13,103	1,747	4,018	1,142	2,231	681	2,448	71	138	32	301	42	18	26	-	207	-
7	2.1 GS 0-10 kW	1,259,174	106,601	287,863	72,194	140,981	43,027	154,728	68,395	8,730	30,561	19,017	40,922	35,465	50,502	-	200,139	-
8	2.2 GS 10-100 kW	2,877,559	330,986	992,279	207,197	404,614	123,486	444,069	29,398	25,054	13,136	54,578	17,590	61,520	87,605	-	86,047	-
9	2.3 GS 110-1,000 kVa	1,646,485	156,392	718,086	122,647	239,505	73,096	262,859	2,479	12,148	1,108	26,463	1,483	5,116	7,846	-	7,257	-
10	2.4 GS Over 1,000 kVa	1,458,227	171,976	565,990	121,623	237,505	72,485	260,665	283	7,955	127	17,329	170	394	897	-	829	-
11	4.1 Street and Area Lighting	425,496	24,462	54,786	15,993	31,232	9,532	34,277	34,499	1,934	15,415	4,213	20,641	-	-	77,537	100,976	-
12	**Subtotal Rural**	**24,752,724**	**2,678,996**	**6,585,857**	**1,757,891**	**3,452,345**	**1,053,638**	**3,788,990**	**809,479**	**204,337**	**361,693**	**445,133**	**484,330**	**277,352**	**395,843**	**77,537**	**2,369,303**	**-**
13	**Total**	**184,033,599**	**38,045,989**	**106,844,974**	**24,434,239**	**3,452,345**	**1,053,638**	**3,788,990**	**809,479**	**204,337**	**361,693**	**445,133**	**484,330**	**277,352**	**395,843**	**77,537**	**2,369,303**	**938,418**
	Allocated Return on Debt																	
14	Newfoundland Power	61,689,837	21,062,233	25,791,560	14,321,643	-	-	-	-	-	-	-	-	-	-	-	-	514,402
15	Industrial - Firm	15,030,406	3,813,647	8,481,607	2,593,157	-	-	-	-	-	-	-	-	-	-	-	-	141,995
16	Industrial - Non-Firm	39,358	-	39,358	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural																	
17	1.1 Domestic	3,783,969	581,756	669,623	402,664	519,517	223,978	651,385	250,855	39,119	116,039	78,650	145,787	49,908	41,771	-	12,917	-
18	1.12 Domestic All Electric	4,195,857	738,340	685,056	511,043	659,349	284,263	826,710	138,834	49,648	64,221	99,819	80,685	27,621	23,118	-	7,149	-
19	1.3 Special	6,749	1,229	1,373	851	1,097	473	1,376	41	83	19	166	24	8	7	-	2	-
20	2.1 GS 0-10 kW	540,782	74,979	98,405	53,756	69,356	29,901	86,961	39,524	5,222	18,283	10,500	22,970	15,726	13,163	-	2,035	-
21	2.2 GS 10-100 kW	1,391,569	232,804	339,207	154,280	199,053	85,817	249,578	16,988	14,988	7,858	30,135	9,873	27,280	22,833	-	875	-
22	2.3 GS 110-1,000 kVa	799,385	117,034	245,475	91,324	117,826	50,798	147,734	1,433	7,267	663	14,611	833	2,269	2,045	-	74	-
23	2.4 GS Over 1,000 kVa	733,799	120,962	193,481	90,561	116,842	50,374	146,500	164	4,759	76	9,568	95	175	234	-	8	-
24	4.1 Street and Area Lighting	183,852	17,205	18,728	11,909	15,365	6,624	19,265	19,936	1,157	9,222	2,326	11,586	-	-	49,503	1,027	-
25	**Subtotal Rural**	**11,635,961**	**1,884,310**	**2,251,348**	**1,316,388**	**1,698,406**	**732,229**	**2,129,508**	**467,775**	**122,243**	**216,380**	**245,776**	**271,852**	**122,987**	**103,170**	**49,503**	**24,037**	**-**
26	**Total**	**88,356,204**	**26,760,190**	**36,524,514**	**18,231,188**	**1,698,406**	**732,229**	**2,129,508**	**467,775**	**122,243**	**216,380**	**245,776**	**271,852**	**122,987**	**103,170**	**49,503**	**24,037**	**656,397**

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Island Interconnected
Allocation of Functionalized Amounts to Classes of Service

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
				Producton and		Rural	Distribution											Specifically
Line		Total	Production	Transmission	Transmission	Transmission	Substations	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting	Assigned
No.	Description	Amount	Demand	Energy	Demand	Demand	Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
		($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)
	Allocated Return on Equity																	
27	Newfoundland Power	4,071,258	1,390,015	1,702,130	945,166	-	-	-	-	-	-	-	-	-	-	-	-	33,948
28	Industrial - Firm	991,941	251,684	559,749	171,137	-	-	-	-	-	-	-	-	-	-	-	-	9,371
29	Industrial - Non-Firm	2,597	-	2,597	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural																	
30	1.1 Domestic	109,160	38,393	44,192	26,574	-	-	-	-	-	-	-	-	-	-	-	-	-
31	1.12 Domestic All Electric	127,665	48,727	45,211	33,727	-	-	-	-	-	-	-	-	-	-	-	-	-
32	1.3 Special	228	81	91	56	-	-	-	-	-	-	-	-	-	-	-	-	-
33	2.1 GS 0-10 kW	14,990	4,948	6,494	3,548	-	-	-	-	-	-	-	-	-	-	-	-	-
34	2.2 GS 10-100 kW	47,932	15,364	22,386	10,182	-	-	-	-	-	-	-	-	-	-	-	-	-
35	2.3 GS 110-1,000 kVa	29,951	7,724	16,200	6,027	-	-	-	-	-	-	-	-	-	-	-	-	-
36	2.4 GS Over 1,000 kVa	26,729	7,983	12,769	5,977	-	-	-	-	-	-	-	-	-	-	-	-	-
37	4.1 Street and Area Lighting	3,157	1,135	1,236	786	-	-	-	-	-	-	-	-	-	-	-	-	-
38	**Subtotal Rural**	**359,811**	**124,356**	**148,579**	**86,876**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
39	**Total**	**5,423,010**	**1,766,055**	**2,410,458**	**1,203,178**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**43,319**
	Total Allocated Revenue Requirement																	
40	Newfoundland Power	191,058,434	52,397,233	102,941,606	34,500,581	-	-	-	-	-	-	-	-	-	-	-	-	1,219,015
41	Industrial - Firm	50,005,883	9,487,338	33,852,555	6,246,870	-	-	-	-	-	-	-	-	-	-	-	-	419,119
42	Industrial - Non-Firm	157,088	-	157,088	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural																	
43	1.1 Domestic	12,396,209	1,447,255	2,672,662	970,009	1,575,538	546,270	1,810,380	684,957	104,508	310,005	221,096	405,520	162,456	202,039	-	1,283,512	-
44	1.12 Domestic All Electric	12,893,120	1,836,794	2,734,256	1,231,094	1,999,606	693,303	2,297,658	379,085	132,637	171,570	280,605	224,432	89,910	111,817	-	710,351	-
45	1.3 Special	20,080	3,057	5,482	2,049	3,328	1,154	3,824	112	221	51	467	66	27	33	-	209	-
46	2.1 GS 0-10 kW	1,814,946	136,529	392,761	129,498	210,337	72,928	241,689	107,919	13,952	48,843	29,517	63,892	51,192	63,665	-	202,224	-
47	2.2 GS 10-100 kW	4,317,060	579,154	1,353,872	371,659	603,667	209,303	693,647	46,387	40,042	20,994	84,713	27,463	88,801	110,437	-	86,922	-
48	2.3 GS 110-1,000 kVa	2,475,820	291,150	979,761	219,997	357,331	123,894	410,593	3,912	19,415	1,771	41,074	2,316	7,385	9,891	-	7,331	-
49	2.4 GS Over 1,000 kVa	2,218,755	300,921	772,241	218,161	354,347	122,859	407,165	447	12,714	202	26,897	265	568	1,130	-	838	-
50	4.1 Street and Area Lighting	612,505	42,803	74,750	28,688	46,597	16,156	53,542	54,434	3,091	24,637	6,539	32,227	-	-	127,040	102,002	-
51	**Subtotal Rural**	**36,748,497**	**4,687,663**	**8,985,785**	**3,171,155**	**5,150,752**	**1,785,867**	**5,918,498**	**1,277,253**	**326,580**	**578,073**	**690,908**	**756,181**	**400,339**	**499,013**	**127,040**	**2,393,390**	**-**
52	**Total**	**277,812,813**	**66,572,234**	**145,779,946**	**43,918,606**	**5,150,752**	**1,785,867**	**5,918,498**	**1,277,253**	**326,580**	**578,073**	**690,908**	**756,181**	**400,339**	**499,013**	**127,040**	**2,393,390**	**1,638,134**

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Island Interconnected
Allocation of Specifically Assigned Amounts to Classes of Service

	1	2	2	3	4	5	5	6	7	8	9	10	11	12	13	14
			OM&A				Depreciation				Expense Credits			Subtotal		
Line			Transmission		Administrative &		Transmission		Telecontrol &		Rental			Excluding		
No.	Description	Total	Lines	Terminals	General	Other	Lines	Terminals	Feasibility Study	General	Income	Other	Gains/Losses	Return	Return on Debt	Return on Equity
		Amount	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)
		($)	(Plant)	(Plant)	(C2 & C3)	(Direct)	(Plant)	(Plant)	(Plant)		(Plant)	(C4 + C5)	(NBV)		(NBV)	(NBV)
	Basis of Allocation - Amounts															
1	Newfoundland Power		(3)	8,088,259	8,088,256	-	-	-	-	306,097	8,088,259	8,088,256	6,508,485	-	6,508,485	6,508,485
	Industrial															
2	Abitibi Consolidated - S'ville		122,926	489,197	612,123	-	-	-	-	13,818	489,197	612,123	507,734	-	507,734	507,734
3	Abitibi Consolidated - GF		-	2,308,767	2,308,767	-	-	-	-	16,129	2,308,767	2,308,767	250,228	-	250,228	250,228
4	Corner Brook P& P - CB		-	1,757,055	1,757,055	-	-	-	-	1,723	1,757,055	1,757,055	240,180	-	240,180	240,180
5	Corner Brook P& P - DL		-	23,100	23,100	-	-	-	-	157	23,100	23,100	22,049	-	22,049	22,049
6	North Atlantic Refining Limited		-	1,178,595	1,178,595	-	-	-	-	38,562	1,178,595	1,178,595	776,409	-	776,409	776,409
7	**Subtotal Industrial**		**122,926**	**5,756,714**	**5,879,640**	**-**	**-**	**-**	**-**	**70,388**	**5,756,714**	**5,879,640**	**1,796,600**	**-**	**1,796,600**	**1,796,600**
8	**Total**		**122,923**	**13,844,973**	**13,967,896**	**-**	**-**	**-**	**-**	**376,486**	**13,844,973**	**13,967,896**	**8,305,085**	**-**	**8,305,085**	**8,305,085**
9	**Basis of Allocation - Ratios**															
10	Newfoundland Power		(0.0000)	0.5842	0.5791	-	-	-	-	0.8130	0.5842	0.5791	0.7837	-	0.7837	0.7837
	Industrial															
11	Abitibi Consolidated - S'ville		1.0000	0.0353	0.0438	-	-	-	-	0.0367	0.0353	0.0438	0.0611	-	0.0611	0.0611
12	Abitibi Consolidated - GF		-	0.1668	0.1653	-	-	-	-	0.0428	0.1668	0.1653	0.0301	-	0.0301	0.0301
13	Corner Brook P& P - CB		-	0.1269	0.1258	-	-	-	-	0.0046	0.1269	0.1258	0.0289	-	0.0289	0.0289
14	Corner Brook P& P - DL		-	0.0017	0.0017	-	-	-	-	0.0004	0.0017	0.0017	0.0027	-	0.0027	0.0027
15	North Atlantic Refining Ltd.		-	0.0851	0.0844	-	-	-	-	0.1024	0.0851	0.0844	0.0935	-	0.0935	0.0935
16	**Subtotal Industrial**		**1.0000**	**0.4158**	**0.4209**	**-**	**-**	**-**	**-**	**0.1870**	**0.4158**	**0.4209**	**0.2163**	**-**	**0.2163**	**0.2163**
17	**Total**		**1.0000**	**1.0000**	**1.0000**	**-**	**-**	**-**	**-**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**-**	**1.0000**	**1.0000**
	Amounts Allocated															
18	Newfoundland Power	1,219,015	(0)	123,365	98,281	-	41,510	264,588	-	139,703	(76)	(1,254)	4,548	670,665	514,402	33,948
	Industrial														-	-
19	Abitibi Consolidated - S'ville	83,759	5,701	7,461	7,438	-	1,188	12,631	-	6,307	(5)	(95)	355	40,981	40,129	2,648
20	Abitibi Consolidated - GF	107,635	-	35,214	28,054	-	-	16,129	-	7,361	(22)	(358)	175	86,553	19,777	1,305
21	Corner Brook P& P - CB	70,773	-	26,799	21,350	-	-	1,723	-	786	(16)	(272)	168	50,538	18,983	1,253
22	Corner Brook P& P - DL	2,731	-	352	281	-	-	157	-	72	(0)	(4)	15	873	1,743	115
23	North Atlantic Refining Ltd.	154,221	-	17,976	14,321	-	-	38,562	-	17,600	(11)	(183)	543	88,808	61,364	4,050
24	**Subtotal Industrial**	**419,119**	**5,701**	**87,803**	**71,444**	**-**	**1,188**	**69,201**	**-**	**32,125**	**(54)**	**(911)**	**1,255**	**267,753**	**141,995**	**9,371**
25	**Total**	**1,638,134**	**5,701**	**211,168**	**169,726**	**-**	**42,697**	**333,789**	**-**	**171,828**	**(130)**	**(2,165)**	**5,803**	**938,418**	**656,397**	**43,319**

Island Isolated

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Island Isolated
Functional Classification of Revenue Requirement

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
						Distribution											
				Production and			Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting	Specifically Assigned
Line No.	Description	Total Amount ($)	Production Demand ($)	Transmission Energy ($)	Transmission Demand ($)	Substations Demand ($)	Demand ($)	Customer ($)	Demand ($)	Customer ($)	Demand ($)	Customer ($)	Customer ($)	Customer ($)	Customer ($)	Customer ($)	Customer ($)
	Expenses																
1	Operating & Maintenance	4,634,141	1,955,094	1,023,266	-	107,091	820,216	191,297	40,582	71,833	107,223	117,103	67,719	13,735	14,567	104,415	-
2	Fuels	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Fuels-Diesel	1,448,725	-	1,448,725	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Fuels-Gas Turbine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Power Purchases -CF(L)Co	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Power Purchases-Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Depreciation	864,523	517,862	269,897	-	-	29,403	9,638	1,690	2,991	6,647	7,055	5,294	2,921	724	10,403	-
	Expense Credits																
8	Sundry	(23,126)	(9,757)	(5,106)	-	(534)	(4,093)	(955)	(203)	(358)	(535)	(584)	(338)	(69)	(73)	(521)	-
9	Building Rental Income	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Tax Refunds	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Suppliers' Discounts	(2,825)	(1,192)	(624)	-	(65)	(500)	(117)	(25)	(44)	(65)	(71)	(41)	(8)	(9)	(64)	-
12	Pole Attachments	(14,359)	-	-	-	-	(8,304)	(2,838)	-	-	(1,470)	(1,747)	-	-	-	-	-
13	Secondary Energy Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Wheeling Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Application Fees	(988)	-	-	-	-	-	-	-	-	-	-	-	-	-	(988)	-
16	**Total Expense Credits**	**(41,298)**	**(10,948)**	**(5,730)**	**-**	**(600)**	**(12,898)**	**(3,909)**	**(227)**	**(402)**	**(2,070)**	**(2,402)**	**(379)**	**(77)**	**(82)**	**(1,573)**	**-**
17	**Subtotal Expenses**	**6,906,091**	**2,462,008**	**2,736,157**	**-**	**106,491**	**836,721**	**197,026**	**42,044**	**74,422**	**111,799**	**121,756**	**72,634**	**16,579**	**15,209**	**113,245**	**-**
18	Disposal Gain / Loss	39,385	23,637	12,287	-	-	1,455	477	104	183	341	358	279	174	39	51	-
19	**Subtotal Revenue Requirement Ex. Return**	**6,945,476**	**2,485,645**	**2,748,444**	**-**	**106,491**	**838,176**	**197,503**	**42,148**	**74,605**	**112,140**	**122,113**	**72,913**	**16,753**	**15,248**	**113,296**	**-**
20	Return on Debt	922,797	546,528	295,267	-	-	34,103	11,174	2,422	4,287	7,991	8,382	6,508	4,046	916	1,173	-
21	Return on Equity	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	**Total Revenue Requirement**	**7,868,273**	**3,032,173**	**3,043,710**	**-**	**106,491**	**872,279**	**208,677**	**44,570**	**78,892**	**120,131**	**130,496**	**79,421**	**20,800**	**16,164**	**114,469**	**-**

NEWFOUNDLAND & LABRADOR HYDRO
1999 Actual Cost of Service - Interim Methodology
Island Isolated
Functional Classification of Revenue Requirement - Documentation

Line No.	1 Description	Basis of Functional Classification
	Expenses	
1	Operating & Maintenance	Carryforward from Sch.2.4 L.20
2	Fuels	Production - Energy
3	Fuels-Diesel	Production - Energy
4	Fuels-Gas Turbine	Production - Energy
5	Power Purchases -CF(L)Co	
6	Power Purchases-Other	
7	Depreciation	Carryforward from Sch.2.5 L.24
	Expense Credits	
8	Sundry	Prorated on Total Operating & Maintenance Expenses - Sch 2.4 L.20
9	Building Rental Income	Prorated on General Plant - Sch.2.2 L.18
10	Tax Refunds	Prorated on Total Operating & Maintenance Expenses - Sch 2.4 L.20
11	Suppliers' Discounts	Prorated on Total Operating & Maintenance Expenses - Sch 2.4 L.20
12	Pole Attachments	Prorated on Distribution Poles - Sch.4.1 L.33
13	Secondary Energy Revenues	Production - Energy
14	Wheeling Revenues	Transmission - Demand, Energy ratios Sch.4.1 L.13
15	Application Fees	Accounting - Customer
16	**Total Expense Credits**	
17	**Subtotal Expenses**	
18	Disposal Gain / Loss	Prorated on Total Net Book Value - Sch.2.3 L.24
19	**Subtotal Revenue Requirement Ex. Return**	
20	Return on Debt	Prorated on Rate Base - Sch.2.6 L.8
21	Return on Equity	Prorated on Rate Base - Sch.2.6 L.10
22	**Total Revenue Requirement**	

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Island Isolated
Functional Classification of Plant in Service for the Allocation of O&M Expense

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
				Production and		Distribution											Specifically
Line		Total	Production	Transmission	Transmission	Substations	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting	Assigned
No.	Description	Amount	Demand	Energy	Demand	Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
		($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)
	Production																
1	Diesel	15,748,304	10,289,181	5,459,123	-	-	-	-	-	-	-	-	-	-	-	-	-
2	**Subtotal Production**	**15,748,304**	**10,289,181**	**5,459,123**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Transmission																
3	Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	**Subtotal Transmission**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Distribution																
6	Substation Structures & Equipment	317,197	317,197	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Land & Land Improvements	20,028	-	-	-	-	15,100	1,924	-	-	1,751	1,253	-	-	-	-	-
8	Poles	1,818,802	-	-	-	-	1,051,900	359,490	-	-	186,187	221,225	-	-	-	-	-
9	Primary Conductor & Equipment	146,333	-	-	-	-	129,797	16,536	-	-	-	-	-	-	-	-	-
10	Submarine Conductor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Transformers	216,575	-	-	-	-	-	-	78,184	138,391	-	-	-	-	-	-	-
12	Secondary Conductors & Equipment	173,803	-	-	-	-	-	-	-	-	101,327	72,476	-	-	-	-	-
13	Services	181,620	-	-	-	-	-	-	-	-	-	-	181,620	-	-	-	-
14	Meters	92,188	-	-	-	-	-	-	-	-	-	-	-	92,188	-	-	-
15	Street Lighting	29,489	-	-	-	-	-	-	-	-	-	-	-	-	29,489	-	-
16	**Subtotal Distribution**	**2,996,035**	**317,197**	**-**	**-**	**-**	**1,196,798**	**377,949**	**78,184**	**138,391**	**289,266**	**294,953**	**181,620**	**92,188**	**29,489**	**-**	**-**
17	**Subttl Prod, Trans, & Dist**	**18,744,339**	**10,606,378**	**5,459,123**	**-**	**-**	**1,196,798**	**377,949**	**78,184**	**138,391**	**289,266**	**294,953**	**181,620**	**92,188**	**29,489**	**-**	**-**
18	General	249,474	141,164	72,657	-	-	15,929	5,030	1,041	1,842	3,850	3,926	2,417	1,227	392	-	-
19	Telecontrol - Common	6,064	3,962	2,102	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Feasibility Studies	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Software - General	52,723	29,833	15,355	-	-	3,366	1,063	220	389	814	830	511	259	83	-	-
23	Software - Cust Acctng	15,604	-	-	-	-	-	-	-	-	-	-	-	-	-	15,604	-
24	**Total Plant**	**19,068,204**	**10,781,336**	**5,549,237**	**-**	**-**	**1,216,093**	**384,042**	**79,444**	**140,623**	**293,929**	**299,709**	**184,548**	**93,675**	**29,964**	**15,604**	**-**

NEWFOUNDLAND & LABRADOR HYDRO
1999 Actual Cost of Service - Interim Methodology
Island Isolated
Functional Classification of Plant in Service for the Allocation of O&M Expense - Documentation

Line No.	Description	Basis of Functional Classification
	Production	
1	Diesel	Production - Demand, Energy ratios Sch.4.1 L.4
2	**Subtotal Production**	
	Transmission	
3	Lines	Production, Transmission - Demand, Energy; Distribution - Primary Demand; Spec Assigned - Custmr
4	Terminal Stations	Production, Transmission - Demand, Energy; Spec Assigned - Custmr
5	**Subtotal Transmission**	
	Distribution	
6	Substation Structures & Equipment	Production - Demand; Dist Substns - Demand
7	Land & Land Improvements	Primary, Secondary - Demand, Customer - zero intercept ratios Sch.4.1 L.28
8	Poles	Primary, Secondary - Demand, Customer - zero intercept ratios Sch.4.1 L.33
9	Primary Conductor & Equipment	Primary - Demand, Customer - zero intercept ratios Sch.4.1 L.34
10	Submarine Conductor	Primary - Demand, Customer - zero intercept ratios Sch.4.1 L.35
11	Transformers	Transformers - Demand, Customer - zero intercept ratios Sch.4.1 L.36
12	Secondary Conductors & Equipment	Secondary - Demand, Customer - zero intercept ratios Sch. 4.1 L.37
13	Services	Services Customer
14	Meters	Meters - Customer
15	Street Lighting	Street Lighting - Customer
16	**Subtotal Distribution**	
17	**Subttl Prod, Trans, & Dist**	
18	General	Prorated on subtotal Production, Transmission, & Distribution plant - L.17
19	Telecontrol - Common	Prorated on functionalized Production & Transmission plant - L. 2, 5
20	Telecontrol - Specific	Specifically Assigned - Customer
21	Feasibility Studies	Production, Transmission - Demand
22	Software - General	Prorated on subtotal Production, Transmission, & Distribution plant - L.17
23	Software - Cust Acctng	Customer Accounting
24	**Total Plant**	

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Island Isolated
Functional Classification of Net Book Value

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
				Production and		Distribution											Specifically
Line		Total	Production	Transmission	Transmission	Substations	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting	Assigned
No.	Description	Amount	Demand	Energy	Demand	Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
		($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)
	Production																
1	Diesel	10,736,975	7,015,021	3,721,954	-	-	-	-	-	-	-	-	-	-	-	-	-
2	**Subtotal Production**	**10,736,975**	**7,015,021**	**3,721,954**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Transmission																
3	Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	**Subtotal Transmission**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Distribution																
6	Substation Structures & Equipment	145,362	145,362	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Land & Land Improvements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Poles	713,187	-	-	-	-	412,470	140,963	-	-	73,008	86,746	-	-	-	-	-
9	Primary Conductor & Equipment	31,859	-	-	-	-	28,259	3,600	-	-	-	-	-	-	-	-	-
10	Submarine Conductor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Transformers	86,914	-	-	-	-	-	-	31,376	55,538	-	-	-	-	-	-	-
12	Secondary Conductors & Equipment	51,735	-	-	-	-	-	-	-	-	30,161	21,573	-	-	-	-	-
13	Services	84,637	-	-	-	-	-	-	-	-	-	-	84,637	-	-	-	-
14	Meters	52,858	-	-	-	-	-	-	-	-	-	-	-	52,858	-	-	-
15	Street Lighting	11,868	-	-	-	-	-	-	-	-	-	-	-	-	11,868	-	-
16	**Subtotal Distribution**	**1,178,420**	**145,362**	**-**	**-**	**-**	**440,729**	**144,563**	**31,376**	**55,538**	**103,169**	**108,320**	**84,637**	**52,858**	**11,868**	**-**	**-**
17	**Subttl Prod, Trans, & Dist**	**11,915,394**	**7,160,383**	**3,721,954**	**-**	**-**	**440,729**	**144,563**	**31,376**	**55,538**	**103,169**	**108,320**	**84,637**	**52,858**	**11,868**	**-**	**-**
18	General	71,003	42,668	22,179	-	-	2,626	861	187	331	615	645	504	315	71	-	-
19	Telecontrol - Common	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Feasibility Studies	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Software - General	45,450	27,312	14,197	-	-	1,681	551	120	212	394	413	323	202	45	-	-
23	Software - Cust Acctng	15,604	-	-	-	-	-	-	-	-	-	-	-	-	-	15,604	-
24	**Total Net Book Value**	**12,047,451**	**7,230,363**	**3,758,330**	**-**	**-**	**445,037**	**145,976**	**31,683**	**56,081**	**104,177**	**109,378**	**85,464**	**53,375**	**11,984**	**15,604**	**-**

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Island Isolated
Functional Classification of Operating & Maintenance Expense

Line No.	1 Description	2 Total Amount ($)	3 Production Demand ($)	4 Production and Transmission Energy ($)	5 Transmissior Demand ($)	6 Distribution Substations Demand ($)	7 Primary Lines Demand ($)	8 Primary Lines Customer ($)	9 Line Transformers Demand ($)	10 Line Transformers Customer ($)	11 Secondary Lines Demand ($)	12 Secondary Lines Customer ($)	13 Services Customer ($)	14 Meters Customer ($)	15 Street Lighting Customer ($)	16 Accounting Customer ($)	17 Specifically Assigned Customer ($)
	Production																
1	Diesel	1,672,998	1,093,056	579,942	-	-	-	-	-	-	-	-	-	-	-	-	-
2	**Subtotal Production**	**1,672,998**	**1,093,056**	**579,942**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Transmission																
3	Transmission Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	**Subtotal Transmission**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Distribution																
6	Other	961,390	12,220	-	-	68,758	509,007	117,260	24,905	44,084	64,585	70,845	40,806	-	8,919	-	-
7	Meters	7,462	-	-	-	-	-	-	-	-	-	-	-	7,462	-	-	-
8	**Subtotal Distribution**	**968,851**	**12,220**	**-**	**-**	**68,758**	**509,007**	**117,260**	**24,905**	**44,084**	**64,585**	**70,845**	**40,806**	**7,462**	**8,919**	**-**	**-**
9	**Subttl Prod, Trans, & Dist**	**2,641,849**	**1,105,276**	**579,942**	**-**	**68,758**	**509,007**	**117,260**	**24,905**	**44,084**	**64,585**	**70,845**	**40,806**	**7,462**	**8,919**	**-**	**-**
10	Customer Accounting	66,841	-	-	-	-	-	-	-	-	-	-	-	-	-	66,841	-
	Overheads																
	Plant-Related:																
11	Production	14,980	9,787	5,193	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Distribution	7,378	781	-	-	-	2,947	931	193	341	712	726	447	227	73	-	-
14	Prod, Trans, Distn Plant	4,531	2,564	1,320	-	-	289	91	19	33	70	71	44	22	7	-	-
15	Telecontrol Plant	362	236	125	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Prod, Trans, Distn and Gen Plt	379,230	214,420	110,364	-	-	24,186	7,638	1,580	2,797	5,846	5,961	3,670	1,863	596	310	-
	Expense Related:																
17	Property Insurance	8,840	5,823	2,997	-	-	9	3	1	1	2	2	1	1	0	-	-
18	Other Expense Related	1,510,131	616,207	323,325	-	38,333	283,778	65,374	13,885	24,577	36,007	39,497	22,750	4,160	4,972	37,264	-
19	**Subtotal Overheads**	**1,925,451**	**849,818**	**443,324**	**-**	**38,333**	**311,209**	**74,037**	**15,677**	**27,749**	**42,637**	**46,258**	**26,913**	**6,273**	**5,648**	**37,575**	**-**
20	**Total Operating & Maintenance Expenses**	**4,634,141**	**1,955,094**	**1,023,266**	**-**	**107,091**	**820,216**	**191,297**	**40,582**	**71,833**	**107,223**	**117,103**	**67,719**	**13,735**	**14,567**	**104,415**	**-**

NEWFOUNDLAND & LABRADOR HYDRO
1999 Actual Cost of Service - Interim Methodology
Island Isolated
Functional Classification of Operating & Maintenance Expense - Documentation

1

Line No.	Description	Basis of Functional Classification
	Production	
1	Diesel	Production - Demand, Energy ratios Sch.4.1 L4
2	**Subtotal Production**	
	Transmission	
3	Transmission Lines	Prorated on Transmission Lines Plant in Service - Sch.2.2 L.3
4	Terminal Stations	Prorated on Transmission Terminal Stations Plant in Service - Sch.2.2 L.4
5	**Subtotal Transmission**	
	Distribution	
6	Other	Production, Distribution, except Meters- ratios Sch. 4.1 L.42
7	Meters	Meters - Customer
8	**Subtotal Distribution**	
9	**Subttl Prod, Trans, & Dist**	
10	Customer Accounting	Accounting - Customer
	Overheads	
	Plant-Related:	
11	Production	Prorated on Production Plant in Service - Sch.2.2 L.2
12	Transmission	Prorated on Transmission Plant in Service - Sch.2.2 L.5
13	Distribution	Prorated on Distribution Plant in Service - Sch.2.2 L.16
14	Prod, Trans, Distn Plant	Prorated on Distribution Plant in Service - Sch.2.2 L.17
15	Telecontrol Plant	Prorated on Telecontrol Plant in Service - Sch.2.2 L.19, 20
16	Prod, Trans, Distn and Gen Plt	Prorated on Production, Transmission, Distribution & General Plant in Service - Sch.2.2 L.24
	Expense Related:	
17	Property Insurance	Prorated on Prod., Trans. Terminal, Dist. Sub & General Plant in Service - Sch.2.2 L.2, 4, 6, 18 - 20
18	Other Expense Related	Prorated on Subtotal Production, Transmission, Distribution, Accounting Expenses - L.9, 10
19	**Subtotal Overheads**	
20	**Total Operating & Maintenance Expenses**	

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Island Isolated
Functional Classification of Depreciation Expense

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
				Production and		Distribution											Specifically
Line		Total	Production	Transmission	Transmission	Substations	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting	Assigned
No.	Description	Amount	Demand	Energy	Demand	Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
		($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)
	Production																
1	Diesel	699,654	457,120	242,534	-	-	-	-	-	-	-	-	-	-	-	-	-
2	**Subtotal Production**	**699,654**	**457,120**	**242,534**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Transmission																
3	Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	**Subtotal Transmission**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Distribution																
6	Substn Struct & Eqpt	8,240	8,240	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Land & Land Improvements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Poles	42,711	-	-	-	-	24,702	8,442	-	-	4,372	5,195	-	-	-	-	-
9	Primary Conductor & Equipment	1,939	-	-	-	-	1,720	219	-	-	-	-	-	-	-	-	-
10	Submarine Conductor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Transformers	4,206	-	-	-	-	-	-	1,518	2,687	-	-	-	-	-	-	-
12	Secondary Conductors & Equipment	2,746	-	-	-	-	-	-	-	-	1,601	1,145	-	-	-	-	-
13	Services	4,757	-	-	-	-	-	-	-	-	-	-	4,757	-	-	-	-
14	Meters	2,625	-	-	-	-	-	-	-	-	-	-	-	2,625	-	-	-
15	Street Lighting	650	-	-	-	-	-	-	-	-	-	-	-	-	650	-	-
16	**Subtotal Distribution**	**67,874**	**8,240**	**-**	**-**	**-**	**26,422**	**8,661**	**1,518**	**2,687**	**5,973**	**6,340**	**4,757**	**2,625**	**650**	**-**	**-**
17	**Subtotal Prod Tran & Dist**	**767,528**	**465,360**	**242,534**	**-**	**-**	**26,422**	**8,661**	**1,518**	**2,687**	**5,973**	**6,340**	**4,757**	**2,625**	**650**	**-**	**-**
18	General	9,471	5,742	2,993	-	-	326	107	19	33	74	78	59	32	8	-	-
19	Telecontrol - Common	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Feasibility Studies	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Software - General	77,122	46,760	24,370	-	-	2,655	870	153	270	600	637	478	264	65	-	-
23	Software - Cust Acctng	10,403	-	-	-	-	-	-	-	-	-	-	-	-	-	10,403	-
24	**Total Depreciation Expense**	**864,523**	**517,862**	**269,897**	**-**	**-**	**29,403**	**9,638**	**1,690**	**2,991**	**6,647**	**7,055**	**5,294**	**2,921**	**724**	**10,403**	**-**

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Island Isolated
Functional Classification of Rate Base

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
						Distribution											
				Production and													Specifically
Line		Total	Production	Transmission	Transmission	Substations	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting	Assigned
No.	Description	Amount	Demand	Energy	Demand	Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
		($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)
1	Average Net Book Value	12,047,451	7,230,363	3,758,330	-	-	445,037	145,976	31,683	56,081	104,177	109,378	85,464	53,375	11,984	15,604	-
2	Cash Working Capital	29,954	17,977	9,344	-	-	1,106	363	79	139	259	272	212	133	30	39	-
3	Fuel Inventory - No. 6 Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Fuel Inventory - Diesel	161,764	-	161,764	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Fuel Inventory - Gas Turbine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Inventory/Supplies	230,580	130,372	67,103	-	-	14,705	4,644	961	1,700	3,554	3,624	2,232	1,133	362	189	-
7	Deferred Charges: Foreign Exchange Loss	824,408	494,774	257,183	-	-	30,454	9,989	2,168	3,838	7,129	7,485	5,848	3,652	820	1,068	-
8	Total Rate Base	**13,294,156**	**7,873,486**	**4,253,724**	**-**	**-**	**491,303**	**160,972**	**34,890**	**61,758**	**115,119**	**120,759**	**93,756**	**58,293**	**13,196**	**16,899**	**-**
9	Less: Rural Portion	(13,294,156)	(7,873,486)	(4,253,724)	-	-	(491,303)	(160,972)	(34,890)	(61,758)	(115,119)	(120,759)	(93,756)	(58,293)	(13,196)	(16,899)	-
10	Rate Base Available for Equity Return	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
11	Return on Debt	922,797	546,528	295,267	-	-	34,103	11,174	2,422	4,287	7,991	8,382	6,508	4,046	916	1,173	-
12	Return on Equity	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Return on Rate Base	**922,797**	**546,528**	**295,267**	**-**	**-**	**34,103**	**11,174**	**2,422**	**4,287**	**7,991**	**8,382**	**6,508**	**4,046**	**916**	**1,173**	**-**

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Island Isolated
Functional Classification of Rate Base - Documentation

Line No.	1 Description	2 Basis of Functional Classification
1	Average Net Book Value	Sch. 2.3 , L. 24
2	Cash Working Capital	Prorated on Average Net Book Value, L. 1
3	Fuel Inventory - No. 6 Fuel	
4	Fuel Inventory - Diesel	Production - Energy
5	Fuel Inventory - Gas Turbine	
6	Inventory/Supplies	Prorated on Total Plant in Service, Sch. 2.2, L. 24
7	Deferred Charges: Foreign Exchange Loss	Prorated on Average Net Book Value, L. 1
8	Total Rate Base	
9	Less: Rural Portion	
10	Rate Base Available for Equity Return	
11	Return on Debt	L.8 x Sch.1.2,p2,L.13
12	Return on Equity	L.10 x Sch.1.2,p2,L.16
13	Return on Rate Base	

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Island Isolated
Basis of Allocation to Classes of Service

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
				Production and		Distribution											Specifically
Line		Total	Production	Transmission	Transmission	Substations	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting	Assigned
No.	Description	Amount	Demand	Energy	Demand	Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
			(CP kW)	(MWh @ Gen)	(CP kW)	(CP kW)	(CP kW)	(Rural Cust)	(CP kW)	(Rural Cust)	(CP kW)	(Rural Cust)	(Wtd Rural Cust)		(Rural Cust)	(Rural Cust)	
	Amounts																
1	1.2 Domestic Diesel	-	2,787	7,824	2,769	2,769	2,491	913	2,449	913	2,310	913	913	913	-	913	-
2	1.2G Government Domestic Diesel		39	110	39	39	35	8	34	8	32	8	8	8	-	8	-
3	1.23 Churches & Community Halls	-	22	110	22	22	20	21	19	21	18	21	21	21	-	21	-
4	2.2 GS 10-100 kW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	2.3 GS 110-1,000 kVa	-	87	504	87	87	78	1	77	1	72	1	9	9	-	1	-
6	2.5 GS Diesel	-	431	1,551	429	429	385	103	379	103	358	103	206	206	-	103	-
7	2.5G Gov't General Service Diesel		327	1,135	325	325	293	34	288	34	271	34	68	68	-	34	-
8	4.1 Street and Area Lighting	-	46	124	45	45	41	28	40	28	38	28	-	-	28	28	-
9	4.1G Gov't Street and Area Lighting		2	5	2	2	2	5	2	5	1	5	-	-	5	5	-
10	**Total**	**-**	**3,742**	**11,362**	**3,717**	**3,717**	**3,344**	**1,113**	**3,288**	**1,113**	**3,102**	**1,113**	**1,225**	**1,225**	**33**	**1,113**	**-**
	Ratios																
11	1.2 Domestic Diesel	-	0.7449	0.6887	0.7449	0.7449	0.7449	0.8203	0.7449	0.8203	0.7449	0.8203	0.7456	0.7456	-	0.8203	-
12	1.2G Government Domestic Diesel		0.0104	0.0097	0.0104	0.0104	0.0104	0.0072	0.0104	0.0072	0.0104	0.0072	0.0065	0.0065	-	0.0072	-
13	1.23 Churches & Community Halls	-	0.0059	0.0097	0.0059	0.0059	0.0059	0.0189	0.0059	0.0189	0.0059	0.0189	0.0171	0.0171	-	0.0189	-
14	2.2 GS 10-100 kW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	2.3 GS 110-1,000 kVa	-	0.0233	0.0443	0.0233	0.0233	0.0233	0.0009	0.0233	0.0009	0.0233	0.0009	0.0070	0.0070	-	0.0009	-
16	2.5 GS Diesel	-	0.1153	0.1365	0.1153	0.1153	0.1153	0.0925	0.1153	0.0925	0.1153	0.0925	0.1682	0.1682	-	0.0925	-
17	2.5G Gov't General Service Diesel		0.0875	0.0999	0.0875	0.0875	0.0875	0.0305	0.0875	0.0305	0.0875	0.0305	0.0555	0.0555	-	0.0305	-
18	4.1 Street and Area Lighting	-	0.0122	0.0109	0.0122	0.0122	0.0122	0.0252	0.0122	0.0252	0.0122	0.0252	-	-	0.8485	0.0252	-
19	4.1G Gov't Street and Area Lighting		0.0005	0.0005	0.0005	0.0005	0.0005	0.0045	0.0005	0.0045	0.0005	0.0045	-	-	0.1515	0.0045	-
20	**Total**	**-**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**-**

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Island Isolated
Allocation of Functionalized Amounts to Classes of Service

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
				Production and		Distribution											Specifically
Line		Total	Production	Transmission	Transmission	Substations	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting	Assigned
No.	Description	Amount	Demand	Energy	Demand	Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
		($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)
	Allocated Revenue Requirement Excluding Return																
1	1.2 Domestic Diesel	5,045,994	1,851,490	1,892,750	-	79,322	624,335	162,013	31,395	61,199	83,530	100,170	54,362	12,491	-	92,938	-
2	1.2G Government Domestic Diesel	68,007	25,829	26,525	-	1,107	8,710	1,420	438	536	1,165	878	476	109	-	814	-
3	1.23 Churches & Community Halls	58,792	14,668	26,525	-	628	4,946	3,726	249	1,408	662	2,304	1,250	287	-	2,138	-
4	2.2 GS 10-100 kW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	2.3 GS 110-1,000 kVa	206,493	57,978	121,799	-	2,484	19,551	177	983	67	2,616	110	510	117	-	102	-
6	2.5 GS Diesel	850,436	286,554	375,140	-	12,277	96,628	18,277	4,859	6,904	12,928	11,301	12,266	2,818	-	10,485	-
7	2.5G Gov't General Service Diesel	608,665	217,547	274,453	-	9,320	73,358	6,033	3,689	2,279	9,815	3,730	4,049	930	-	3,461	-
8	4.1 Street and Area Lighting	99,571	30,410	30,011	-	1,303	10,254	4,969	516	1,877	1,372	3,072	-	-	12,938	2,850	-
9	4.1G Gov't Street and Area Lighting	7,518	1,170	1,241	-	50	394	887	20	335	53	549	-	-	2,310	509	-
10	**Total**	**6,945,476**	**2,485,645**	**2,748,444**	**-**	**106,491**	**838,176**	**197,503**	**42,148**	**74,605**	**112,140**	**122,113**	**72,913**	**16,753**	**15,248**	**113,296**	**-**
	Allocated Return on Debt																
11	1.2 Domestic Diesel	671,981	407,094	203,339	-	-	25,403	9,166	1,804	3,517	5,952	6,876	4,852	3,017	-	962	-
12	1.2G Government Domestic Diesel	9,240	5,679	2,850	-	-	354	80	25	31	83	60	43	26	-	8	-
13	1.23 Churches & Community Halls	6,990	3,225	2,850	-	-	201	211	14	81	47	158	112	69	-	22	-
14	2.2 GS 10-100 kW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	2.3 GS 110-1,000 kVa	26,967	12,748	13,085	-	-	795	10	56	4	186	8	46	28	-	1	-
16	2.5 GS Diesel	112,530	63,006	40,301	-	-	3,932	1,034	279	397	921	776	1,095	681	-	109	-
17	2.5G Gov't General Service Diesel	82,564	47,833	29,485	-	-	2,985	341	212	131	699	256	361	225	-	36	-
18	4.1 Street and Area Lighting	11,862	6,686	3,224	-	-	417	281	30	108	98	211	-	-	777	30	-
19	4.1G Gov't Street and Area Lighting	663	257	133	-	-	16	50	1	19	4	38	-	-	139	5	-
20	**Total**	**922,797**	**546,528**	**295,267**	**-**	**-**	**34,103**	**11,174**	**2,422**	**4,287**	**7,991**	**8,382**	**6,508**	**4,046**	**916**	**1,173**	**-**
	Allocated Return on Equity																
21	All Classes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total Allocated Revenue Requirement																
22	1.2 Domestic Diesel	5,717,975	2,258,584	2,096,090	-	79,322	649,737	171,179	33,199	64,716	89,482	107,046	59,214	15,508	-	93,900	-
23	1.2G Government Domestic Diesel	77,247	31,508	29,375	-	1,107	9,064	1,500	463	567	1,248	938	519	136	-	823	-
24	1.23 Churches & Community Halls	65,782	17,893	29,375	-	628	5,147	3,937	263	1,489	709	2,462	1,362	357	-	2,160	-
25	2.2 GS 10-100 kW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26	2.3 GS 110-1,000 kVa	233,461	70,726	134,884	-	2,484	20,346	187	1,040	71	2,802	117	556	146	-	103	-
27	2.5 GS Diesel	962,966	349,560	415,441	-	12,277	100,559	19,311	5,138	7,301	13,849	12,076	13,360	3,499	-	10,593	-
28	2.5G Gov't General Service Diesel	691,229	265,380	303,938	-	9,320	76,343	6,375	3,901	2,410	10,514	3,986	4,410	1,155	-	3,497	-
29	4.1 Street and Area Lighting	111,433	37,096	33,235	-	1,303	10,672	5,250	545	1,985	1,470	3,283	-	-	13,715	2,880	-
30	4.1G Gov't Street and Area Lighting	8,180	1,427	1,374	-	50	410	937	21	354	57	586	-	-	2,449	514	-
31	**Total**	**5,717,975**	**2,258,584**	**2,096,090**	**-**	**79,322**	**649,737**	**171,179**	**33,199**	**64,716**	**89,482**	**107,046**	**59,214**	**15,508**	**-**	**93,900**	**-**

Labrador Isolated

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Labrador Isolated
Functional Classification of Revenue Requirement

Line No.	Description (1)	Total Amount ($) (2)	Production Demand ($) (3)	Production and Transmission Energy ($) (4)	Transmission Demand ($) (5)	Distribution: Substations Demand ($) (6)	Distribution: Primary Lines Demand ($) (7)	Distribution: Primary Lines Customer ($) (8)	Distribution: Line Transformers Demand ($) (9)	Distribution: Line Transformers Customer ($) (10)	Distribution: Secondary Lines Demand ($) (11)	Distribution: Secondary Lines Customer ($) (12)	Distribution: Services Customer ($) (13)	Distribution: Meters Customer ($) (14)	Distribution: Street Lighting Customer ($) (15)	Accounting Customer ($) (16)	Specifically Assigned Customer ($) (17)
	Expenses																
1	Operating & Maintenance	8,838,930	4,384,780	3,388,852	-	59,219	412,669	100,613	21,737	38,476	56,628	61,930	35,840	34,374	8,456	235,359	-
2	Fuels	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Fuels-Diesel	4,759,820	-	4,759,820	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Fuels-Gas Turbine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Power Purchases -CF(L)Co	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Power Purchases-Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Depreciation	1,953,604	992,274	728,219	-	21,003	90,861	26,318	6,149	10,884	15,304	16,704	11,730	7,239	3,460	23,460	-
	Expense Credits																
8	Sundry	(44,110)	(21,882)	(16,912)	-	(296)	(2,059)	(502)	(108)	(192)	(283)	(309)	(179)	(172)	(42)	(1,175)	-
9	Building Rental Income	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Tax Refunds	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Suppliers' Discounts	(5,388)	(2,673)	(2,066)	-	(36)	(252)	(61)	(13)	(23)	(35)	(38)	(22)	(21)	(5)	(143)	-
12	Pole Attachments	(23,963)	-	-	-	-	(13,859)	(4,736)	-	-	(2,453)	(2,915)	-	-	-	-	-
13	Secondary Energy Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Wheeling Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Application Fees	(4,233)	-	-	-	-	-	-	-	-	-	-	-	-	-	(4,233)	-
16	**Total Expense Credits**	**(77,693)**	**(24,554)**	**(18,977)**	**-**	**(332)**	**(16,170)**	**(5,300)**	**(122)**	**(215)**	**(2,770)**	**(3,261)**	**(201)**	**(192)**	**(47)**	**(5,551)**	**-**
17	**Subtotal Expenses**	**15,474,661**	**5,352,499**	**8,857,914**	**-**	**79,890**	**487,360**	**121,631**	**27,764**	**49,144**	**69,162**	**75,372**	**47,369**	**41,420**	**11,869**	**253,268**	**-**
18	Disposal Gain / Loss	8,318	4,047	2,931	-	168	552	161	40	71	91	101	77	48	20	13	-
19	**Subtotal Revenue Requirement Ex. Return**	**15,482,979**	**5,356,545**	**8,860,845**	**-**	**80,059**	**487,911**	**121,792**	**27,804**	**49,215**	**69,254**	**75,473**	**47,446**	**41,468**	**11,889**	**253,280**	**-**
20	Return on Debt	1,844,972	845,785	718,446	-	34,905	115,797	33,762	8,355	14,789	19,175	21,139	16,028	9,946	4,200	2,645	-
21	Return on Equity	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	**Total Revenue Requirement**	**17,327,951**	**6,202,331**	**9,579,291**	**-**	**114,964**	**603,708**	**155,554**	**36,158**	**64,003**	**88,428**	**96,611**	**63,474**	**51,414**	**16,088**	**255,926**	**-**

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Labrador Isolated
Functional Classification of Revenue Requirement - Documentation

Line No.	Description (1)	Basis of Functional Classification (2)
	Expenses	
1	Operating & Maintenance	Carryforward from Sch.2.4 L.20
2	Fuels	Production - Energy
3	Fuels-Diesel	Production - Energy
4	Fuels-Gas Turbine	Production - Energy
5	Power Purchases -CF(L)Co	
6	Power Purchases-Other	Carryforward from Sch.4.4 L.11
7	Depreciation	Carryforward from Sch.2.5 L.24
	Expense Credits	
8	Sundry	Prorated on Total Operating & Maintenance Expenses - Sch 2.4 L.20
9	Building Rental Income	Prorated on General Plant - Sch.2.2 L.18
10	Tax Refunds	Prorated on Total Operating & Maintenance Expenses - Sch 2.4 L.20
11	Suppliers' Discounts	Prorated on Total Operating & Maintenance Expenses - Sch 2.4 L.20
12	Pole Attachments	Prorated on Distribution Poles - Sch.4.1 L.33
13	Secondary Energy Revenues	Production - Energy
14	Wheeling Revenues	Transmission - Demand, Energy ratios Sch.4.1 L.13
15	Application Fees	Accounting - Customer
16	**Total Expense Credits**	
17	**Subtotal Expenses**	
18	Disposal Gain / Loss	Prorated on Total Net Book Value - Sch.2.3 L.24
19	**Subtotal Revenue Requirement Ex. Return**	
20	Return on Debt	Prorated on Rate Base - Sch.2.6 L.8
21	Return on Equity	Prorated on Rate Base - Sch.2.6 L.10
22	**Total Revenue Requirement**	

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Labrador Isolated
Functional Classification of Plant in Service for the Allocation of O&M Expense - Documentation

Line No.	Description (1)	Total Amount ($) (2)	Production Demand ($) (3)	Production and Transmission Energy ($) (4)	Transmission Demand ($) (5)	Distribution: Substations Demand ($) (6)	Distribution: Primary Lines Demand ($) (7)	Distribution: Primary Lines Customer ($) (8)	Distribution: Line Transformers Demand ($) (9)	Distribution: Line Transformers Customer ($) (10)	Distribution: Secondary Lines Demand ($) (11)	Distribution: Secondary Lines Customer ($) (12)	Distribution: Services Customer ($) (13)	Distribution: Meters Customer ($) (14)	Distribution: Street Lighting Customer ($) (15)	Accounting Customer ($) (16)	Specifically Assigned Customer ($) (17)
	Production																
1	Diesel	33,441,396	18,771,012	14,670,384	-	-	-	-	-	-	-	-	-	-	-	-	-
2	**Subtotal Production**	**33,441,396**	**18,771,012**	**14,670,384**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Transmission																
3	Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	**Subtotal Transmission**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Distribution																
6	Substation Structures & Equipment	2,055,713	1,493,704	-	-	562,009	-	-	-	-	-	-	-	-	-	-	-
7	Land & Land Improvements	11,816	-	-	-	-	8,909	1,135	-	-	1,033	739	-	-	-	-	-
8	Poles	4,397,954	-	-	-	-	2,543,548	869,264	-	-	450,210	534,932	-	-	-	-	-
9	Primary Conductor & Equipment	828,250	-	-	-	-	734,658	93,592	-	-	-	-	-	-	-	-	-
10	Submarine Conductor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Transformers	605,084	-	-	-	-	-	-	218,435	386,649	-	-	-	-	-	-	-
12	Secondary Conductors & Equipment	214,236	-	-	-	-	-	-	-	-	124,900	89,337	-	-	-	-	-
13	Services	366,297	-	-	-	-	-	-	-	-	-	-	366,297	-	-	-	-
14	Meters	224,792	-	-	-	-	-	-	-	-	-	-	-	224,792	-	-	-
15	Street Lighting	103,260	-	-	-	-	-	-	-	-	-	-	-	-	103,260	-	-
16	**Subtotal Distribution**	**8,807,403**	**1,493,704**	**-**	**-**	**562,009**	**3,287,115**	**963,992**	**218,435**	**386,649**	**576,143**	**625,008**	**366,297**	**224,792**	**103,260**	**-**	**-**
17	**Subttl Prod, Trans, & Dist**	**42,248,799**	**20,264,715**	**14,670,384**	**-**	**562,009**	**3,287,115**	**963,992**	**218,435**	**386,649**	**576,143**	**625,008**	**366,297**	**224,792**	**103,260**	**-**	**-**
18	General	895,712	429,630	311,025	-	11,915	69,690	20,437	4,631	8,197	12,215	13,251	7,766	4,766	2,189	-	-
19	Telecontrol - Common	15,100	8,476	6,624	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Feasibility Studies	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Software - General	118,835	57,000	41,264	-	1,581	9,246	2,711	614	1,088	1,621	1,758	1,030	632	290	-	-
23	Software - Cust Acctng	35,190	-	-	-	-	-	-	-	-	-	-	-	-	-	35,190	-
24	**Total Plant**	**43,313,636**	**20,759,821**	**15,029,298**	**-**	**575,505**	**3,366,050**	**987,141**	**223,681**	**395,934**	**589,978**	**640,016**	**375,093**	**230,190**	**105,740**	**35,190**	**-**

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NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Labrador Isolated
Functional Classification of Plant in Service for the Allocation of O&M Expense

Line No.	Description	Basis of Functional Classification
	Production	
1	Diesel	Production - Demand, Energy ratios Sch.4.1 L.5
2	**Subtotal Production**	
	Transmission	
3	Lines	Production, Transmission - Demand, Energy; Distribution - Primary Demand; Spec Assigned - Custmr
4	Terminal Stations	Production, Transmission - Demand, Energy; Spec Assigned - Custmr
5	**Subtotal Transmission**	
	Distribution	
6	Substation Structures & Equipment	Production - Demand; Dist Substns - Demand
7	Land & Land Improvements	Primary, Secondary - Demand, Customer - zero intercept ratios Sch.4.1 L.28
8	Poles	Primary, Secondary - Demand, Customer - zero intercept ratios Sch.4.1 L.33
9	Primary Conductor & Equipment	Primary - Demand, Customer - zero intercept ratios Sch.4.1 L.34
10	Submarine Conductor	Primary - Demand, Customer - zero intercept ratios Sch.4.1 L.35
11	Transformers	Transformers - Demand, Customer - zero intercept ratios Sch.4.1 L.36
12	Secondary Conductors & Equipment	Secondary - Demand, Customer - zero intercept ratios Sch. 4.1 L.37
13	Services	Services Customer
14	Meters	Meters - Customer
15	Street Lighting	Street Lighting - Customer
16	**Subtotal Distribution**	
17	**Subttl Prod, Trans, & Dist**	
18	General	Prorated on subtotal Production, Transmission, & Distribution plant - L.17
19	Telecontrol - Common	Prorated on functionalized Production & Transmission plant - L. 2, 5
20	Telecontrol - Specific	Specifically Assigned - Customer
21	Feasibility Studies	Production, Transmission - Demand
22	Software - General	Prorated on subtotal Production, Transmission, & Distribution plant - L.17
23	Software - Cust Acctng	Customer Accounting
24	**Total Plant**	

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Labrador Isolated
Functional Classification of Net Book Value

Line No.	1 Description	2 Total Amount ($)	3 Production Demand ($)	4 Production and Transmission Energy ($)	5 Transmission Demand ($)	6 Distribution: Substations Demand ($)	7 Distribution: Primary Lines Demand ($)	8 Distribution: Primary Lines Customer ($)	9 Distribution: Line Transformers Demand ($)	10 Distribution: Line Transformers Customer ($)	11 Distribution: Secondary Lines Demand ($)	12 Distribution: Secondary Lines Customer ($)	13 Distribution: Services Customer ($)	14 Distribution: Meters Customer ($)	15 Distribution: Street Lighting Customer ($)	16 Accounting Customer ($)	17 Specifically Assigned Customer ($)
	Production																
1	Diesel	18,065,810	10,140,532	7,925,278	-	-	-	-	-	-	-	-	-	-	-	-	-
2	**Subtotal Production**	**18,065,810**	**10,140,532**	**7,925,278**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Transmission																
3	Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	**Subtotal Transmission**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Distribution																
6	Substation Structures & Equipment	1,256,594	801,666	-	-	454,928	-	-	-	-	-	-	-	-	-	-	-
7	Land & Land Improvements	3,027	-	-	-	-	2,282	291	-	-	265	189	-	-	-	-	-
8	Poles	1,976,639	-	-	-	-	1,143,185	390,687	-	-	202,345	240,423	-	-	-	-	-
9	Primary Conductor & Equipment	391,856	-	-	-	-	347,577	44,280	-	-	-	-	-	-	-	-	-
10	Submarine Conductor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Transformers	298,996	-	-	-	-	-	-	107,937	191,058	-	-	-	-	-	-	-
12	Secondary Conductors & Equipment	75,922	-	-	-	-	-	-	-	-	44,262	31,659	-	-	-	-	-
13	Services	207,673	-	-	-	-	-	-	-	-	-	-	207,673	-	-	-	-
14	Meters	128,890	-	-	-	-	-	-	-	-	-	-	-	128,890	-	-	-
15	Street Lighting	54,328	-	-	-	-	-	-	-	-	-	-	-	-	54,328	-	-
16	**Subtotal Distribution**	**4,393,925**	**801,666**	**-**	**-**	**454,928**	**1,493,044**	**435,257**	**107,937**	**191,058**	**246,872**	**272,271**	**207,673**	**128,890**	**54,328**	**-**	**-**
17	**Subttl Prod, Trans, & Dist**	**22,459,735**	**10,942,198**	**7,925,278**	**-**	**454,928**	**1,493,044**	**435,257**	**107,937**	**191,058**	**246,872**	**272,271**	**207,673**	**128,890**	**54,328**	**-**	**-**
18	General	315,828	153,869	111,445	-	6,397	20,995	6,121	1,518	2,687	3,471	3,829	2,920	1,812	764	-	-
19	Telecontrol - Common	9,998	5,612	4,386	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Feasibility Studies	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Software - General	85,670	41,738	30,230	-	1,735	5,695	1,660	412	729	942	1,039	792	492	207	-	-
23	Software - Cust Acctng	35,190	-	-	-	-	-	-	-	-	-	-	-	-	-	35,190	-
24	**Total Net Book Value**	**22,906,419**	**11,143,416**	**8,071,339**	**-**	**463,060**	**1,519,734**	**443,038**	**109,867**	**194,474**	**251,285**	**277,138**	**211,386**	**131,194**	**55,299**	**35,190**	**-**

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Labrador Isolated
Functional Classification of Operating & Maintenance Expense

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
				Production and		Distribution											Specifically
Line		Total	Production	Transmission	Transmission	Substations	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting	Assigned
No.	Description	Amount	Demand	Energy	Demand	Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
		($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)
	Production																
1	Diesel	4,224,379	2,371,189	1,853,190	-	-	-	-	-	-	-	-	-	-	-	-	-
2	**Subtotal Production**	**4,224,379**	**2,371,189**	**1,853,190**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Transmission																
3	Transmission Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	**Subtotal Transmission**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Distribution																
6	Other	393,421	5,001	-	-	28,137	208,297	47,985	10,192	18,040	26,430	28,991	16,699	-	3,650	-	-
7	Meters	18,195	-	-	-	-	-	-	-	-	-	-	-	18,195	-	-	-
8	**Subtotal Distribution**	**411,616**	**5,001**	**-**	**-**	**28,137**	**208,297**	**47,985**	**10,192**	**18,040**	**26,430**	**28,991**	**16,699**	**18,195**	**3,650**	**-**	**-**
9	**Subttl Prod, Trans, & Dist**	**4,635,995**	**2,376,190**	**1,853,190**	**-**	**28,137**	**208,297**	**47,985**	**10,192**	**18,040**	**26,430**	**28,991**	**16,699**	**18,195**	**3,650**	**-**	**-**
10	Customer Accounting	150,736	-	-	-	-	-	-	-	-	-	-	-	-	-	150,736	-
	Overheads																
	Plant-Related:																
11	Production	591,338	331,924	259,414	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Distribution	95,836	16,253	-	-	6,115	35,768	10,490	2,377	4,207	6,269	6,801	3,986	2,446	1,124	-	-
14	Prod, Trans, Distn Plant	10,214	4,899	3,547	-	136	795	233	53	93	139	151	89	54	25	-	-
15	Telecontrol Plant	901	506	395	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Prod, Trans, Distn and General Plt	663,713	318,111	230,300	-	8,819	51,579	15,126	3,428	6,067	9,040	9,807	5,748	3,527	1,620	539	-
	Expense Related:																
17	Property Insurance	20,080	11,418	8,266	-	317	38	11	3	5	7	7	4	3	1	-	-
18	Other Expense Related	2,670,118	1,325,478	1,033,740	-	15,695	116,191	26,767	5,685	10,063	14,743	16,172	9,315	10,149	2,036	84,083	-
19	**Subtotal Overheads**	**4,052,199**	**2,008,590**	**1,535,662**	**-**	**31,082**	**204,372**	**52,627**	**11,545**	**20,435**	**30,199**	**32,938**	**19,141**	**16,180**	**4,806**	**84,622**	**-**
20	**Total Operating & Maintenance Expenses**	**8,838,930**	**4,384,780**	**3,388,852**	**-**	**59,219**	**412,669**	**100,613**	**21,737**	**38,476**	**56,628**	**61,930**	**35,840**	**34,374**	**8,456**	**235,359**	**-**

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Labrador Isolated
Functional Classification of Operating & Maintenance Expense - Documentation

Line No.	Description	Basis of Functional Classification
	1	
	Production	
1	Diesel	Production - Demand, Energy ratios Sch.4.1 L5
2	**Subtotal Production**	
	Transmission	
3	Transmission Lines	Prorated on Transmission Lines Plant in Service - Sch.2.2 L.3
4	Terminal Stations	Prorated on Transmission Terminal Stations Plant in Service - Sch.2.2 L.4
5	**Subtotal Transmission**	
	Distribution	
6	Other	Production, Distribution, except Meters- ratios Sch. 4.1 L.42
7	Meters	Meters - Customer
8	**Subtotal Distribution**	
9	**Subttl Prod, Trans, & Dist**	
10	Customer Accounting	Accounting - Customer
	Overheads	
	Plant-Related:	
11	Production	Prorated on Production Plant in Service - Sch.2.2 L.2
12	Transmission	Prorated on Transmission Plant in Service - Sch.2.2 L.5
13	Distribution	Prorated on Distribution Plant in Service - Sch.2.2 L 16
14	Prod, Trans, Distn Plant	Prorated on Distribution Plant in Service - Sch.2.2 L 17
15	Telecontrol Plant	Prorated on Telecontrol Plant in Service - Sch.2.2 L.19, 20
16	Prod, Trans, Distn and General Plt	Prorated on Production, Transmission, Distribution & General Plant in Service - Sch.2.2 L.24
	Expense Related:	
17	Property Insurance	Prorated on Prod., Trans. Terminal, Dist. Sub & General Plant in Service - Sch.2.2 L.2, 4, 6, 18 - 20
18	Other Expense Related	Prorated on Subtotal Production, Transmission, Distribution, Accounting Expenses - L.9, 10
19	**Subtotal Overheads**	
20	**Total Operating & Maintenance Expenses**	

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Labrador Isolated
Functional Classification of Depreciation Expense

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
				Production and		Distribution											Specifically
Line		Total	Production	Transmission	Transmission	Substations	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting	Assigned
No.	Description	Amount	Demand	Energy	Demand	Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
		($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)
	Production																
1	Diesel	1,466,542	823,185	643,356	-	-	-	-	-	-	-	-	-	-	-	-	-
2	**Subtotal Production**	**1,466,542**	**823,185**	**643,356**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Transmission																
3	Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	**Subtotal Transmission**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Distribution																
6	Substn Struct & Eqpt	72,074	53,502	-	-	18,572	-	-	-	-	-	-	-	-	-	-	-
7	Land & Land Improvements	228	-	-	-	-	172	22	-	-	20	14	-	-	-	-	-
8	Poles	105,155	-	-	-	-	60,816	20,784	-	-	10,765	12,790	-	-	-	-	-
9	Primary Conductor & Equipment	21,823	-	-	-	-	19,357	2,466	-	-	-	-	-	-	-	-	-
10	Submarine Conductor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Transformers	15,062	-	-	-	-	-	-	5,437	9,624	-	-	-	-	-	-	-
12	Secondary Conductors & Equipment	4,715	-	-	-	-	-	-	-	-	2,749	1,966	-	-	-	-	-
13	Services	10,372	-	-	-	-	-	-	-	-	-	-	10,372	-	-	-	-
14	Meters	6,401	-	-	-	-	-	-	-	-	-	-	-	6,401	-	-	-
15	Street Lighting	3,060	-	-	-	-	-	-	-	-	-	-	-	-	3,060	-	-
16	**Subtotal Distribution**	**238,890**	**53,502**	**-**	**-**	**18,572**	**80,345**	**23,272**	**5,437**	**9,624**	**13,533**	**14,770**	**10,372**	**6,401**	**3,060**	**-**	**-**
17	**Subtotal Prod Tran & Dist**	**1,705,431**	**876,687**	**643,356**	**-**	**18,572**	**80,345**	**23,272**	**5,437**	**9,624**	**13,533**	**14,770**	**10,372**	**6,401**	**3,060**	**-**	**-**
18	General	51,840	26,649	19,556	-	565	2,442	707	165	293	411	449	315	195	93	-	-
19	Telecontrol - Common	1,510	848	662	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Feasibility Studies	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Software - General	171,363	88,090	64,645	-	1,866	8,073	2,338	546	967	1,360	1,484	1,042	643	307	-	-
23	Software - Cust Acctng	23,460	-	-	-	-	-	-	-	-	-	-	-	-	-	23,460	-
24	**Total Depreciation Expense**	**1,953,604**	**992,274**	**728,219**	**-**	**21,003**	**90,861**	**26,318**	**6,149**	**10,884**	**15,304**	**16,704**	**11,730**	**7,239**	**3,460**	**23,460**	**-**

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Labrador Isolated
Functional Classification of Rate Base

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
				Production and		Distribution											Specifically
Line		Total	Production	Transmission	Transmission	Substations	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting	Assigned
No.	Description	Amount	Demand	Energy	Demand	Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
		($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)
1	Average Net Book Value	22,906,419	11,143,416	8,071,339	-	463,060	1,519,734	443,038	109,867	194,474	251,285	277,138	211,386	131,194	55,299	35,190	-
2	Cash Working Capital	56,952	27,706	20,068	-	1,151	3,779	1,102	273	484	625	689	526	326	137	87	-
3	Fuel Inventory - No. 6 Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Fuel Inventory - Diesel	1,524,736	-	1,524,736	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Fuel Inventory - Gas Turbine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Inventory/Supplies	523,765	251,036	181,740	-	6,959	40,704	11,937	2,705	4,788	7,134	7,739	4,536	2,784	1,279	426	-
7	Deferred Charges: Foreign Exchange Loss	1,567,487	762,544	552,322	-	31,687	103,995	30,317	7,518	13,308	17,195	18,965	14,465	8,978	3,784	2,408	-
8	Total Rate Base	**26,579,360**	**12,184,702**	**10,350,205**	**-**	**502,858**	**1,668,212**	**486,393**	**120,363**	**213,053**	**276,239**	**304,531**	**230,912**	**143,281**	**60,500**	**38,111**	**-**
9	Less: Rural Portion	(26,579,360)	(12,184,702)	(10,350,205)	-	(502,858)	(1,668,212)	(486,393)	(120,363)	(213,053)	(276,239)	(304,531)	(230,912)	(143,281)	(60,500)	(38,111)	-
10	Rate Base Available for Equity Return	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
11	Return on Debt	1,844,972	845,785	718,446	-	34,905	115,797	33,762	8,355	14,789	19,175	21,139	16,028	9,946	4,200	2,645	-
12	Return on Equity	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Return on Rate Base	**1,844,972**	**845,785**	**718,446**	**-**	**34,905**	**115,797**	**33,762**	**8,355**	**14,789**	**19,175**	**21,139**	**16,028**	**9,946**	**4,200**	**2,645**	**-**

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Labrador Isolated
Functional Classification of Rate Base - Documentation

Line No.	1 Description	2 Basis of Functional Classification
1	Average Net Book Value	Sch. 2.3 , L. 24
2	Cash Working Capital	Prorated on Average Net Book Value, L. 1
3	Fuel Inventory - No. 6 Fuel	
4	Fuel Inventory - Diesel	Production - Energy
5	Fuel Inventory - Gas Turbine	
6	Inventory/Supplies	Prorated on Total Plant in Service, Sch. 2.2, L. 24
7	Deferred Charges:	
	Foreign Exchange Loss	Prorated on Average Net Book Value, L. 1
8	Total Rate Base	
9	Less: Rural Portion	
10	Rate Base Available for Equity Return	
11	Return on Debt	L.8 x Sch.1.2,p2,L.13
12	Return on Equity	L.10 x Sch.1.2,p2,L.16
13	Return on Rate Base	

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Labrador Isolated
Basis of Allocation to Classes of Service

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
				Production and		Distribution											Specifically
Line		Total	Production	Transmission	Transmission	Substations	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting	Assigned
No.	Description	Amount	Demand	Energy	Demand	Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
			(CP kW)	(MWh @ Gen)	(CP kW)	(CP kW)	(CP kW)	(Rural Cust)	(CP kW)	(Rural Cust)	(CP kW)	(Rural Cust)	(Wtd Rural Cust)		(Rural Cust)	(Rural Cust)	
	Amounts																
1	1.2 Domestic Diesel	-	5,562	19,768	5,525	5,523	4,871	1,918	4,792	1,918	4,466	1,918	1,918	1,918	-	1,918	-
2	1.2G Government Domestic Diesel	-	204	724	202	202	178	39	175	39	163	39	39	39	-	39	-
3	1.23 Churches & Community Halls	-	79	488	79	79	70	30	68	30	64	30	30	30	-	30	-
4	2.2 GS 10-100 kW	-	502	522	499	499	440	6	433	6	403	6	48	48	-	6	-
5	2.3 GS 110-1,000 kVa	-	721	3,864	716	716	631	8	621	8	579	8	69	69	-	8	-
6	2.5 GS Diesel	-	1,754	8,013	1,742	1,741	1,536	348	1,511	348	1,408	348	696	696	-	348	-
7	2.5G Gov't General Service Diesel	-	732	3,364	727	727	641	93	630	93	587	93	186	186	-	93	-
8	4.1 Street and Area Lighting	-	71	243	70	70	62	60	61	60	57	60	-	-	60	60	-
9	4.1G Gov't Street and Area Lighting		3	11	3	3	2	8	2	8	2	8	-	-	8	8	-
10	**Total**	**-**	**9,627**	**36,996**	**9,563**	**9,560**	**8,430**	**2,510**	**8,294**	**2,510**	**7,730**	**2,510**	**2,986**	**2,986**	**68**	**2,510**	**-**
	Ratios																
11	1.2 Domestic Diesel	-	0.5777	0.5343	0.5777	0.5777	0.5777	0.7641	0.5777	0.7641	0.5777	0.7641	0.6423	0.6423	-	0.7641	-
12	1.2G Government Domestic Diesel	-	0.0211	0.0196	0.0211	0.0211	0.0211	0.0155	0.0211	0.0155	0.0211	0.0155	0.0131	0.0131	-	0.0155	-
13	1.23 Churches & Community Halls	-	0.0082	0.0132	0.0082	0.0082	0.0082	0.0120	0.0082	0.0120	0.0082	0.0120	0.0100	0.0100	-	0.0120	-
14	2.2 GS 10-100 kW	-	0.0522	0.0141	0.0522	0.0522	0.0522	0.0024	0.0522	0.0024	0.0522	0.0024	0.0162	0.0162	-	0.0024	-
15	2.3 GS 110-1,000 kVa	-	0.0749	0.1044	0.0749	0.0749	0.0749	0.0032	0.0749	0.0032	0.0749	0.0032	0.0230	0.0230	-	0.0032	-
16	2.5 GS Diesel	-	0.1821	0.2166	0.1821	0.1821	0.1821	0.1386	0.1821	0.1386	0.1821	0.1386	0.2331	0.2331	-	0.1386	-
17	2.5G Gov't General Service Diesel	-	0.0760	0.0909	0.0760	0.0760	0.0760	0.0371	0.0760	0.0371	0.0760	0.0371	0.0623	0.0623	-	0.0371	-
18	4.1 Street and Area Lighting	-	0.0074	0.0066	0.0074	0.0074	0.0074	0.0239	0.0074	0.0239	0.0074	0.0239	-	-	0.8824	0.0239	-
19	4.1G Gov't Street and Area Lighting		0.0003	0.0003	0.0003	0.0003	0.0003	0.0032	0.0003	0.0032	0.0003	0.0032	-	-	0.1176	0.0032	-
20	**Total**	**-**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**-**

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Labrador Isolated
Allocation of Functionalized Amounts to Classes of Service

Line No.	1 Description	2 Total Amount ($)	3 Production Demand ($)	4 Production and Transmission Energy ($)	5 Transmission Demand ($)	6 Distribution: Substations Demand ($)	7 Distribution: Primary Lines Demand ($)	8 Distribution: Primary Lines Customer ($)	9 Distribution: Line Transformers Demand ($)	10 Distribution: Line Transformers Customer ($)	11 Distribution: Secondary Lines Demand ($)	12 Distribution: Secondary Lines Customer ($)	13 Distribution: Services Customer ($)	14 Distribution: Meters Customer ($)	15 Distribution: Street Lighting Customer ($)	16 Accounting Customer ($)	17 Specifically Assigned Customer ($)
	Allocated Revenue Requirement Excluding Return																
1	1.2 Domestic Diesel	8,652,496	3,094,694	4,734,589	-	46,253	281,886	93,066	16,063	37,607	40,011	57,672	30,476	26,636	-	193,543	-
2	1.2G Government Domestic Diesel	309,788	113,280	173,518	-	1,693	10,318	1,892	588	765	1,465	1,173	620	542	-	3,935	-
3	1.23 Churches & Community Halls	173,291	44,166	116,775	-	660	4,023	1,456	229	588	571	902	477	417	-	3,027	-
4	2.2 GS 10-100 kW	441,888	279,546	124,998	-	4,178	25,463	291	1,451	118	3,614	180	770	673	-	605	-
5	2.3 GS 110-1,000 kVa	1,380,006	401,142	925,427	-	5,995	36,539	388	2,082	157	5,186	241	1,090	952	-	807	-
6	2.5 GS Diesel	3,105,909	975,656	1,919,109	-	14,582	88,869	16,886	5,064	6,823	12,614	10,464	11,059	9,666	-	35,116	-
7	2.5G Gov't General Service Diesel	1,287,350	407,114	805,637	-	6,085	37,083	4,513	2,113	1,823	5,263	2,796	2,955	2,583	-	9,384	-
8	4.1 Street and Area Lighting	124,825	39,373	58,128	-	588	3,586	2,911	204	1,176	509	1,804	-	-	10,490	6,055	-
9	4.1G Gov't Street and Area Lighting	7,426	1,575	2,664	-	24	143	388	8	157	20	241	-	-	1,399	807	-
10	**Total**	**15,482,979**	**5,356,545**	**8,860,845**	**-**	**80,059**	**487,911**	**121,792**	**27,804**	**49,215**	**69,254**	**75,473**	**47,446**	**41,468**	**11,889**	**253,280**	**-**
	Allocated Return on Debt																
11	1.2 Domestic Diesel	1,047,460	488,645	383,885	-	20,166	66,901	25,799	4,827	11,301	11,078	16,153	10,296	6,388	-	2,021	-
12	1.2G Government Domestic Diesel	37,188	17,887	14,069	-	738	2,449	525	177	230	406	328	209	130	-	41	-
13	1.23 Churches & Community Halls	19,037	6,974	9,468	-	288	955	404	69	177	158	253	161	100	-	32	-
14	2.2 GS 10-100 kW	64,170	44,140	10,135	-	1,822	6,043	81	436	35	1,001	51	260	161	-	6	-
15	2.3 GS 110-1,000 kVa	152,548	63,339	75,035	-	2,614	8,672	108	626	47	1,436	67	368	228	-	8	-
16	2.5 GS Diesel	358,204	154,054	155,603	-	6,358	21,092	4,681	1,522	2,050	3,493	2,931	3,736	2,318	-	367	-
17	2.5G Gov't General Service Diesel	147,448	64,282	65,322	-	2,653	8,801	1,251	635	548	1,457	783	998	620	-	98	-
18	4.1 Street and Area Lighting	17,675	6,217	4,713	-	257	851	807	61	354	141	505	-	-	3,705	63	-
19	4.1G Gov't Street and Area Lighting	1,242	249	216	-	10	34	108	2	47	6	67	-	-	494	8	-
20	**Total**	**1,844,972**	**845,785**	**718,446**	**-**	**34,905**	**115,797**	**33,762**	**8,355**	**14,789**	**19,175**	**21,139**	**16,028**	**9,946**	**4,200**	**2,645**	**-**
	Allocated Return on Equity																
21	All Classes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total Allocated Revenue Requirement																
22	1.2 Domestic Diesel	9,699,956	3,583,339	5,118,474	-	66,419	348,787	118,866	20,890	48,908	51,089	73,825	40,771	33,025	-	195,564	-
23	1.2G Government Domestic Diesel	346,976	131,166	187,587	-	2,431	12,767	2,417	765	994	1,870	1,501	829	672	-	3,977	-
24	1.23 Churches & Community Halls	192,328	51,140	126,243	-	948	4,978	1,859	298	765	729	1,155	638	517	-	3,059	-
25	2.2 GS 10-100 kW	506,058	323,686	135,133	-	6,000	31,506	372	1,887	153	4,615	231	1,029	834	-	612	-
26	2.3 GS 110-1,000 kVa	1,532,554	464,481	1,000,461	-	8,609	45,211	496	2,708	204	6,622	308	1,458	1,181	-	816	-
27	2.5 GS Diesel	3,464,113	1,129,709	2,074,713	-	20,940	109,961	21,567	6,586	8,874	16,107	13,395	14,795	11,984	-	35,483	-
28	2.5G Gov't General Service Diesel	1,434,798	471,396	870,959	-	8,738	45,884	5,764	2,748	2,371	6,721	3,580	3,954	3,203	-	9,483	-
29	4.1 Street and Area Lighting	142,499	45,590	62,841	-	845	4,437	3,718	266	1,530	650	2,309	-	-	14,195	6,118	-
30	4.1G Gov't Street and Area Lighting	8,668	1,824	2,880	-	34	177	496	11	204	26	308	-	-	1,893	816	-
31	**Total**	**17,327,951**	**6,202,331**	**9,579,291**	**-**	**114,964**	**603,708**	**155,554**	**36,158**	**64,003**	**88,428**	**96,611**	**63,474**	**51,414**	**16,088**	**255,926**	**-**

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
L'Anse au Loup
Functional Classification of Revenue Requirement

Line No.	1 Description	2 Total Amount ($)	3 Production Demand ($)	4 Production and Transmission Energy ($)	5 Transmission Demand ($)	6 Distribution Substations Demand ($)	7 Primary Lines Demand ($)	8 Primary Lines Customer ($)	9 Line Transformers Demand ($)	10 Line Transformers Customer ($)	11 Secondary Lines Demand ($)	12 Secondary Lines Customer ($)	13 Services Customer ($)	14 Meters Customer ($)	15 Street Lightin Customer ($)	16 Accounting Customer ($)	17 Specifically Assigned Customer ($)
	Expenses																
1	Operating & Maintenance	1,076,934	471,897	-	-	29,296	268,772	65,969	12,133	21,476	36,942	40,546	19,605	15,132	4,349	90,817	-
2	Fuels	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Fuels-Diesel	81,171	-	81,171	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Fuels-Gas Turbine		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Power Purchases -CF(L)Co	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Power Purchases-Other	625,131	-	625,131	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Depreciation	375,733	142,497	-	-	1,342	119,674	36,576	4,263	7,546	21,339	23,592	4,649	3,844	1,353	9,057	-
	Expense Credits																
8	Sundry	(5,374)	(2,355)	-	-	(146)	(1,341)	(329)	(61)	(107)	(184)	(202)	(98)	(76)	(22)	(453)	-
9	Building Rental Income	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Tax Refunds	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Suppliers' Discounts	(656)	(288)	-	-	(18)	(164)	(40)	(7)	(13)	(23)	(25)	(12)	(9)	(3)	(55)	-
12	Pole Attachments	(21,629)	-	-	-	-	(12,509)	(4,275)	-	-	(2,214)	(2,631)	-	-	-	-	-
13	Secondary Energy Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Wheeling Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Application Fees	(636)	-	-	-	-	-	-	-	-	-	-	-	-	-	(636)	-
16	**Total Expense Credits**	**(28,296)**	**(2,643)**	**-**	**-**	**(164)**	**(14,014)**	**(4,644)**	**(68)**	**(120)**	**(2,421)**	**(2,858)**	**(110)**	**(85)**	**(24)**	**(1,145)**	**-**
17	**Subtotal Expenses**	**2,130,673**	**611,752**	**706,302**	**-**	**30,474**	**374,432**	**97,901**	**16,328**	**28,901**	**55,861**	**61,281**	**24,144**	**18,892**	**5,678**	**98,729**	**-**
18	Disposal Gain / Loss	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	**Subtotal Revenue Requirement Ex. Return**	**2,130,673**	**611,752**	**706,302**	**-**	**30,474**	**374,432**	**97,901**	**16,328**	**28,901**	**55,861**	**61,281**	**24,144**	**18,892**	**5,678**	**98,729**	**-**
20	Return on Debt	371,139	85,774	1,465	-	1,758	153,203	47,426	4,368	7,731	26,519	29,867	5,807	4,802	1,400	1,021	-
21	Return on Equity	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	**Total Revenue Requirement**	**2,501,812**	**697,525**	**707,767**	**-**	**32,232**	**527,635**	**145,327**	**20,695**	**36,633**	**82,380**	**91,147**	**29,951**	**23,693**	**7,077**	**99,750**	**-**

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
L'Anse au Loup
Functional Classification of Revenue Requirement - Documentation

	1	2
Line No.	Description	Basis of Functional Classification
	Expenses	
1	Operating & Maintenance	Carryforward from Sch.2.4 L.20
2	Fuels	Production - Energy
3	Fuels-Diesel	Production - Energy
4	Fuels-Gas Turbine	Production - Energy
5	Power Purchases -CF(L)Co	
6	Power Purchases-Other	Carryforward from Sch.4.4 L.12
7	Depreciation	Carryforward from Sch.2.5 L.24
	Expense Credits	
8	Sundry	Prorated on Total Operating & Maintenance Expenses - Sch 2.4 L.20
9	Building Rental Income	Prorated on General Plant - Sch.2.2 L.18
10	Tax Refunds	Prorated on Total Operating & Maintenance Expenses - Sch 2.4 L.20
11	Suppliers' Discounts	Prorated on Total Operating & Maintenance Expenses - Sch 2.4 L.20
12	Pole Attachments	Prorated on Distribution Poles - Sch.4.1 L.33
13	Secondary Energy Revenues	Production - Energy
14	Wheeling Revenues	Transmission - Demand, Energy ratios Sch.4.1 L.13
15	Application Fees	Accounting - Customer
16	**Total Expense Credits**	
17	**Subtotal Expenses**	
18	Disposal Gain / Loss	Prorated on Total Net Book Value - Sch.2.3 L.24
19	**Subtotal Revenue Requirement Ex. Return**	
20	Return on Debt	Prorated on Rate Base - Sch.2.6 L.8
21	Return on Equity	Prorated on Rate Base - Sch.2.6 L.10
22	**Total Revenue Requirement**	

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
L'Anse au Loup
Functional Classification of Plant in Service for the Allocation of O&M Expense - Documentation

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
				Production and		Distribution											Specifically
Line		Total	Production	Transmission	Transmission	Substations	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lightin	Accounting	Assigned
No.	Description	Amount	Demand	Energy	Demand	Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
		($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)
	Production																
1	Diesel	3,136,635	3,136,635	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	**Subtotal Production**	**3,136,635**	**3,136,635**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Transmission																
3	Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	**Subtotal Transmission**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Distribution																
6	Substation Structures & Equipment	90,204	44,995	-	-	45,210	-	-	-	-	-	-	-	-	-	-	-
7	Land & Land Improvements	15,995	-	-	-	-	12,059	1,536	-	-	1,399	1,000	-	-	-	-	-
8	Poles	4,829,946	-	-	-	-	2,793,390	954,648	-	-	494,432	587,476	-	-	-	-	-
9	Primary Conductor & Equipment	740,458	-	-	-	-	656,786	83,672	-	-	-	-	-	-	-	-	-
10	Submarine Conductor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Transformers	300,697	-	-	-	-	-	-	108,552	192,145	-	-	-	-	-	-	-
12	Secondary Conductors & Equipment	194,187	-	-	-	-	-	-	-	-	113,211	80,976	-	-	-	-	-
13	Services	161,436	-	-	-	-	-	-	-	-	-	-	161,436	-	-	-	-
14	Meters	105,863	-	-	-	-	-	-	-	-	-	-	-	105,863	-	-	-
15	Street Lighting	39,120	-	-	-	-	-	-	-	-	-	-	-	-	39,120	-	-
16	**Subtotal Distribution**	**6,477,906**	**44,995**	**-**	**-**	**45,210**	**3,462,235**	**1,039,857**	**108,552**	**192,145**	**609,042**	**669,452**	**161,436**	**105,863**	**39,120**	**-**	**-**
17	**Subttl Prod, Trans, & Dist**	**9,614,541**	**3,181,630**	**-**	**-**	**45,210**	**3,462,235**	**1,039,857**	**108,552**	**192,145**	**609,042**	**669,452**	**161,436**	**105,863**	**39,120**	**-**	**-**
18	General	484,749	160,412	-	-	2,279	174,560	52,428	5,473	9,688	30,707	33,753	8,139	5,337	1,972	-	-
19	Telecontrol - Common	75,906	75,906	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Feasibility Studies	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Software - General	27,043	8,949	-	-	127	9,738	2,925	305	540	1,713	1,883	454	298	110	-	-
23	Software - Cust Acctng	13,585	-	-	-	-	-	-	-	-	-	-	-	-	-	13,585	-
24	**Total Plant**	**10,215,824**	**3,426,897**	**-**	**-**	**47,616**	**3,646,533**	**1,095,209**	**114,330**	**202,373**	**641,462**	**705,088**	**170,030**	**111,498**	**41,203**	**13,585**	**-**

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
L'Anse au Loup
Functional Classification of Plant in Service for the Allocation of O&M Expense

Line No.	1 Description	2 Basis of Functional Classification
	Production	
1	Diesel	Production - Demand, Energy ratios Sch.4.1 L.6
2	**Subtotal Production**	
	Transmission	
3	Lines	Production, Transmission - Demand, Energy; Distribution - Primary Demand; Spec Assigned - Custmr
4	Terminal Stations	Production, Transmission - Demand, Energy; Spec Assigned - Custmr
5	**Subtotal Transmission**	
	Distribution	
6	Substation Structures & Equipment	Production - Demand; Dist Substns - Demand
7	Land & Land Improvements	Primary, Secondary - Demand, Customer - zero intercept ratios Sch.4.1 L.28
8	Poles	Primary, Secondary - Demand, Customer - zero intercept ratios Sch.4.1 L.33
9	Primary Conductor & Equipment	Primary - Demand, Customer - zero intercept ratios Sch.4.1 L.34
10	Submarine Conductor	Primary - Demand, Customer - zero intercept ratios Sch.4.1 L.35
11	Transformers	Transformers - Demand, Customer - zero intercept ratios Sch.4.1 L.36
12	Secondary Conductors & Equipment	Secondary - Demand, Customer - zero intercept ratios Sch. 4.1 L.37
13	Services	Services Customer
14	Meters	Meters - Customer
15	Street Lighting	Street Lighting - Customer
16	**Subtotal Distribution**	
17	**Subttl Prod, Trans, & Dist**	
18	General	Prorated on subtotal Production, Transmission, & Distribution plant - L.17
19	Telecontrol - Common	Prorated on functionalized Producton & Transmission plant - L. 2, 5
20	Telecontrol - Specific	Specifically Assigned - Customer
21	Feasibility Studies	Production, Transmission - Demand
22	Software - General	Prorated on subtotal Production, Transmission, & Distribution plant - L.17
23	Software - Cust Acctng	Customer Accounting
24	**Total Plant**	

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
L'Anse au Loup
Functional Classification of Net Book Value

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
				Production and		Distribution											Specifically
							Primary Lines		Line Transformers		Secondary Lines						
Line No.	Description	Total Amount ($)	Production Demand ($)	Transmission Energy ($)	Transmission Demand ($)	Substations Demand ($)	Demand ($)	Customer ($)	Demand ($)	Customer ($)	Demand ($)	Customer ($)	Services Customer ($)	Meters Customer ($)	Street Lighting Customer ($)	Accounting Customer ($)	Assigned Customer ($)
	Production																
1	Diesel	1,028,552	1,028,552	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	**Subtotal Production**	**1,028,552**	**1,028,552**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Transmission																
3	Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	**Subtotal Transmission**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Distribution																
6	Substation Structures & Equipment	24,001	1,849	-	-	22,151	-	-	-	-	-	-	-	-	-	-	-
7	Land & Land Improvements	8,893	-	-	-	-	6,705	854	-	-	778	556	-	-	-	-	-
8	Poles	2,847,337	-	-	-	-	1,646,752	562,782	-	-	291,476	346,327	-	-	-	-	-
9	Primary Conductor & Equipment	318,229	-	-	-	-	282,269	35,960	-	-	-	-	-	-	-	-	-
10	Submarine Conductor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Transformers	152,557	-	-	-	-	-	-	55,073	97,484	-	-	-	-	-	-	-
12	Secondary Conductors & Equipment	73,252	-	-	-	-	-	-	-	-	42,706	30,546	-	-	-	-	-
13	Services	73,025	-	-	-	-	-	-	-	-	-	-	73,025	-	-	-	-
14	Meters	60,699	-	-	-	-	-	-	-	-	-	-	-	60,699	-	-	-
15	Street Lighting	17,598	-	-	-	-	-	-	-	-	-	-	-	-	17,598	-	-
16	**Subtotal Distribution**	**3,575,590**	**1,849**	**-**	**-**	**22,151**	**1,935,726**	**599,596**	**55,073**	**97,484**	**334,960**	**377,430**	**73,025**	**60,699**	**17,598**	**-**	**-**
17	**Subttl Prod, Trans, & Dist**	**4,604,141**	**1,030,401**	**-**	**-**	**22,151**	**1,935,726**	**599,596**	**55,073**	**97,484**	**334,960**	**377,430**	**73,025**	**60,699**	**17,598**	**-**	**-**
18	General	182,323	40,804	-	-	877	76,654	23,744	2,181	3,860	13,264	14,946	2,892	2,404	697	-	-
19	Telecontrol - Common	40,031	40,031	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Feasibility Studies	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Software - General	17,562	3,930	-	-	84	7,384	2,287	210	372	1,278	1,440	279	232	67	-	-
23	Software - Cust Acctng	13,585	-	-	-	-	-	-	-	-	-	-	-	-	-	13,585	-
24	**Total Net Book Value**	**4,857,642**	**1,115,166**	**-**	**-**	**23,113**	**2,019,764**	**625,627**	**57,464**	**101,716**	**349,502**	**393,815**	**76,195**	**63,334**	**18,362**	**13,585**	**-**

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
L'Anse au Loup
Functional Classification of Operating & Maintenance Expense

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
				Production and		Distribution											Specifically
Line		Total	Production	Transmission	Transmission	Substations	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting	Assigned
No.	Description	Amount ($)	Demand ($)	Energy ($)	Demand ($)	Demand ($)	Demand ($)	Customer ($)	Demand ($)	Customer ($)	Demand ($)	Customer ($)	Customer ($)	Customer ($)	Customer ($)	Customer ($)	Customer ($)
	Production																
1	Diesel	212,806	212,806	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	**Subtotal Production**	**212,806**	**212,806**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Transmission																
3	Transmission Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	**Subtotal Transmission**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Distribution																
6	Other	255,403	3,246	-	-	18,266	135,223	31,151	6,616	11,711	17,158	18,821	10,841	-	2,369	-	-
7	Meters	8,568	-	-	-	-	-	-	-	-	-	-	-	8,568	-	-	-
8	**Subtotal Distribution**	**263,972**	**3,246**	**-**	**-**	**18,266**	**135,223**	**31,151**	**6,616**	**11,711**	**17,158**	**18,821**	**10,841**	**8,568**	**2,369**	**-**	**-**
9	**Subttl Prod, Trans, & Dist**	**476,777**	**216,052**	**-**	**-**	**18,266**	**135,223**	**31,151**	**6,616**	**11,711**	**17,158**	**18,821**	**10,841**	**8,568**	**2,369**	**-**	**-**
10	Customer Accounting	58,193	-	-	-	-	-	-	-	-	-	-	-	-	-	58,193	-
	Overheads																
	Plant-Related:																
11	Production	105,970	105,970	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Distribution	68,591	476	-	-	479	36,660	11,011	1,149	2,035	6,449	7,088	1,709	1,121	414	-	-
14	Prod, Trans, Distn Plant	2,324	769	-	-	11	837	251	26	46	147	162	39	26	9	-	-
15	Telecontrol Plant	4,528	4,528	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Prod, Trans, Distn and General Plt	56,589	18,983	-	-	264	20,199	6,067	633	1,121	3,553	3,906	942	618	228	75	-
	Expense Related:																
17	Property Insurance	4,736	4,274	-	-	59	218	66	7	12	38	42	10	7	2	-	-
18	Other Expense Related	299,226	120,845	-	-	10,217	75,634	17,424	3,701	6,551	9,597	10,527	6,064	4,793	1,325	32,549	-
19	**Subtotal Overheads**	**541,963**	**255,845**	**-**	**-**	**11,030**	**133,549**	**34,818**	**5,516**	**9,765**	**19,785**	**21,725**	**8,764**	**6,563**	**1,980**	**32,624**	**-**
20	**Total Operating & Maintenance Expenses**	**1,076,934**	**471,897**	**-**	**-**	**29,296**	**268,772**	**65,969**	**12,133**	**21,476**	**36,942**	**40,546**	**19,605**	**15,132**	**4,349**	**90,817**	**-**

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
L'Anse au Loup
Functional Classification of Operating & Maintenance Expense - Documentation

Line No.	Description 1	Basis of Functional Classification
	Production	
1	Diesel	Production - Demand, Energy ratios Sch.4.1 L6
2	**Subtotal Production**	
	Transmission	
3	Transmission Lines	Prorated on Transmission Lines Plant in Service - Sch.2.2 L.3
4	Terminal Stations	Prorated on Transmission Terminal Stations Plant in Service - Sch.2.2 L.4
5	**Subtotal Transmission**	
	Distribution	
6	Other	Production, Distribution, except Meters- ratios Sch. 4.1 L.42
7	Meters	Meters - Customer
8	**Subtotal Distribution**	
9	**Subttl Prod, Trans, & Dist**	
10	Customer Accounting	Accounting - Customer
	Overheads	
	Plant-Related:	
11	Production	Prorated on Production Plant in Service - Sch.2.2 L.2
12	Transmission	Prorated on Transmission Plant in Service - Sch.2.2 L.5
13	Distribution	Prorated on Distribution Plant in Service - Sch.2.2 L.16
14	Prod, Trans, Distn Plant	Prorated on Distribution Plant in Service - Sch.2.2 L.17
15	Telecontrol Plant	Prorated on Telecontrol Plant in Service - Sch.2.2 L.19, 20
16	Prod, Trans, Distn and General Plt	Prorated on Production, Transmission, Distribution & General Plant in Service - Sch.2.2 L.24
	Expense Related:	
17	Property Insurance	Prorated on Prod., Trans. Terminal, Dist. Sub & General Plant in Service - Sch.2.2 L.2, 4, 6, 18 - 20
18	Other Expense Related	Prorated on Subtotal Production, Transmission, Distribution, Accounting Expenses - L.9, 10
19	**Subtotal Overheads**	
20	**Total Operating & Maintenance Expenses**	

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
L'Anse au Loup
Functional Classification of Depreciation Expense

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
				Production and		Distribution											Specifically
Line		Total	Production	Transmission	Transmission	Substations	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting	Assigned
No.	Description	Amount	Demand	Energy	Demand	Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
		($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)
	Production																
1	Diesel	106,655	106,655	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	**Subtotal Production**	**106,655**	**106,655**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Transmission																
3	Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	**Subtotal Transmission**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Distribution																
6	Substation Structures & Equipment	1,201	149	-	-	1,052	-	-	-	-	-	-	-	-	-	-	-
7	Land & Land Improvements	394	-	-	-	-	297	38	-	-	34	25	-	-	-	-	-
8	Poles	134,903	-	-	-	-	78,021	26,664	-	-	13,810	16,409	-	-	-	-	-
9	Primary Conductor & Equipment	17,494	-	-	-	-	15,517	1,977	-	-	-	-	-	-	-	-	-
10	Submarine Conductor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Transformers	9,259	-	-	-	-	-	-	3,342	5,917	-	-	-	-	-	-	-
12	Secondary Conductors & Equipment	4,953	-	-	-	-	-	-	-	-	2,888	2,065	-	-	-	-	-
13	Services	3,645	-	-	-	-	-	-	-	-	-	-	3,645	-	-	-	-
14	Meters	3,014	-	-	-	-	-	-	-	-	-	-	-	3,014	-	-	-
15	Street Lighting	1,061	-	-	-	-	-	-	-	-	-	-	-	-	1,061	-	-
16	**Subtotal Distribution**	**175,925**	**149**	**-**	**-**	**1,052**	**93,835**	**28,679**	**3,342**	**5,917**	**16,732**	**18,499**	**3,645**	**3,014**	**1,061**	**-**	**-**
17	**Subtotal Prod Tran & Dist**	**282,580**	**106,804**	**-**	**-**	**1,052**	**93,835**	**28,679**	**3,342**	**5,917**	**16,732**	**18,499**	**3,645**	**3,014**	**1,061**	**-**	**-**
18	General	49,420	18,679	-	-	184	16,411	5,016	585	1,035	2,926	3,235	638	527	186	-	-
19	Telecontrol - Common	6,283	6,283	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Feasibility Studies	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Software - General	28,394	10,732	-	-	106	9,429	2,882	336	594	1,681	1,859	366	303	107	-	-
23	Software - Cust Acctng	9,057	-	-	-	-	-	-	-	-	-	-	-	-	-	9,057	-
24	**Total Depreciation Expense**	**375,733**	**142,497**	**-**	**-**	**1,342**	**119,674**	**36,576**	**4,263**	**7,546**	**21,339**	**23,592**	**4,649**	**3,844**	**1,353**	**9,057**	**-**

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
L'Anse au Loup
Functional Classification of Rate Base

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
				Production and		Distribution											Specifically
Line		Total	Production	Transmission	Transmission	Substations	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lightin	Accounting	Assigned
No.	Description	Amount	Demand	Energy	Demand	Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
		($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)
1	Average Net Book Value	4,857,642	1,115,166	-	-	23,113	2,019,764	625,627	57,464	101,716	349,502	393,815	76,195	63,334	18,362	13,585	-
2	Cash Working Capital	12,078	2,773	-	-	57	5,022	1,555	143	253	869	979	189	157	46	34	-
3	Fuel Inventory - No. 6 Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Fuel Inventory - Diesel	21,110	-	21,110	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Fuel Inventory - Gas Turbine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Inventory/Supplies	123,534	41,439	-	-	576	44,095	13,244	1,383	2,447	7,757	8,526	2,056	1,348	498	164	-
7	Deferred Charges: Foreign Exchange Loss	332,409	76,311	-	-	1,582	138,213	42,812	3,932	6,960	23,916	26,949	5,214	4,334	1,256	930	-
8	Total Rate Base	**5,346,772**	**1,235,689**	**21,110**	**-**	**25,328**	**2,207,093**	**683,238**	**62,922**	**111,376**	**382,044**	**430,269**	**83,654**	**69,174**	**20,162**	**14,713**	**-**
9	Less: Rural Portion	(5,346,772)	(1,235,689)	(21,110)	-	(25,328)	(2,207,093)	(683,238)	(62,922)	(111,376)	(382,044)	(430,269)	(83,654)	(69,174)	(20,162)	(14,713)	-
10	Rate Base Available for Equity Return	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
11	Return on Debt	371,139	85,774	1,465	-	1,758	153,203	47,426	4,368	7,731	26,519	29,867	5,807	4,802	1,400	1,021	-
12	Return on Equity	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Return on Rate Base	**371,139**	**85,774**	**1,465**	**-**	**1,758**	**153,203**	**47,426**	**4,368**	**7,731**	**26,519**	**29,867**	**5,807**	**4,802**	**1,400**	**1,021**	**-**

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
L'Anse au Loup
Functional Classification of Rate Base - Documentation

Line No.	1 Description	2 Basis of Functional Classification
1	Average Net Book Value	Sch. 2.3 , L. 24
2	Cash Working Capital	Prorated on Average Net Book Value, L. 1
3	Fuel Inventory - No. 6 Fuel	
4	Fuel Inventory - Diesel	Production - Energy
5	Fuel Inventory - Gas Turbine	
6	Inventory/Supplies	Prorated on Total Plant in Service, Sch. 2.2, L. 24
7	Deferred Charges: Foreign Exchange Loss	Prorated on Average Net Book Value, L. 1
8	Total Rate Base	
9	Less: Rural Portion	
10	Rate Base Available for Equity Return	
11	Return on Debt	L.8 x Sch.1.2,p2,L.13
12	Return on Equity	L.10 x Sch.1.2,p2,L.16
13	Return on Rate Base	

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
L'Anse au Loup
Basis of Allocation to Classes of Service

Line No.	1 Description	2 Total Amount	3 Production Demand (CP kW)	4 Production and Transmission Energy (MWh @ Gen)	5 Transmission Demand (CP kW)	6 Distribution: Substations Demand (CP kW)	7 Primary Lines Demand (CP kW)	8 Primary Lines Customer (Rural Cust)	9 Line Transformers Demand (CP kW)	10 Line Transformers Customer (Rural Cust)	11 Secondary Lines Demand (CP kW)	12 Secondary Lines Customer (Rural Cust)	13 Services Customer (Wtd Rural Cust)	14 Meters Customer	15 Street Lighting Customer	16 Accounting Customer (Rural Cust)	17 Specifically Assigned Customer
	Amounts																
1	1.2 Domestic Diesel	-	2,075	8,007	2,071	2,071	1,846	720	1,815	720	1,702	720	720	720	-	720	-
2	1.12 Domestic Al Electric	-	130	399	130	130	116	20	114	20	107	20	20	20	-	20	-
3	2.1 GS 0-10 kW	-	300	1,426	300	300	267	151	263	151	246	151	302	302	-	151	-
4	2.2 GS 10-100 kW	-	530	2,587	530	530	472	43	464	43	435	43	347	347	-	43	-
5	2.3 GS 110-1,000 kVa	-	22	796	22	22	20	2	19	2	18	2	17	17	-	2	-
6	4.1 Street and Area Lighting	-	39	141	39	39	35	33	35	33	32	33	-	-	1	33	-
7	**Total**	**-**	**3,097**	**13,357**	**3,092**	**3,092**	**2,755**	**969**	**2,710**	**969**	**2,541**	**969**	**1,406**	**1,406**	**1**	**969**	**0**
	Ratios																
8	1.2 Domestic Diesel	-	0.6699	0.5995	0.6699	0.6699	0.6699	0.7430	0.6699	0.7430	0.6699	0.7430	0.5120	0.5120	-	0.7430	-
9	1.12 Domestic Al Electric	-	0.0421	0.0299	0.0421	0.0421	0.0421	0.0206	0.0421	0.0206	0.0421	0.0206	0.0142	0.0142	-	0.0206	-
10	2.1 GS 0-10 kW	-	0.0969	0.1067	0.0969	0.0969	0.0969	0.1558	0.0969	0.1558	0.0969	0.1558	0.2148	0.2148	-	0.1558	-
11	2.2 GS 10-100 kW	-	0.1713	0.1937	0.1713	0.1713	0.1713	0.0444	0.1713	0.0444	0.1713	0.0444	0.2468	0.2468	-	0.0444	-
12	2.3 GS 110-1,000 kVa	-	0.0071	0.0596	0.0071	0.0071	0.0071	0.0021	0.0071	0.0021	0.0071	0.0021	0.0122	0.0122	-	0.0021	-
13	4.1 Street and Area Lighting	-	0.0128	0.0106	0.0128	0.0128	0.0128	0.0341	0.0128	0.0341	0.0128	0.0341	-	-	1.0000	0.0341	-
14	**Total**	**-**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**0.0000**

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
L'Anse au Loup
Allocation of Functionalized Amounts to Classes of Service

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
				Production and		Distribution											Specifically
Line		Total	Production	Transmission	Transmsn	Substations	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lightin	Accounting	Assigned
No.	Description	Amount	Demand	Energy	Demand	Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
		($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)
	Allocated Revenue Requirement Excluding Return																
1	1.2 Domestic Diesel	1,387,933	409,784	423,420	-	20,413	250,815	72,744	10,937	21,475	37,418	45,534	12,362	9,673	-	73,359	-
2	1.12 Domestic All Electric	73,466	25,741	21,117	-	1,282	15,755	2,021	687	597	2,351	1,265	343	269	-	2,038	-
3	2.1 GS 0-10 kW	234,837	59,283	75,383	-	2,953	36,285	15,256	1,582	4,504	5,413	9,549	5,185	4,057	-	15,385	-
4	2.2 GS 10-100 kW	346,664	104,786	136,808	-	5,220	64,136	4,344	2,797	1,283	9,568	2,719	5,959	4,663	-	4,381	-
5	2.3 GS 110-1,000 kVa	50,983	4,356	42,113	-	217	2,666	202	116	60	398	126	294	230	-	204	-
6	4.1 Street and Area Lighting	36,789	7,800	7,460	-	389	4,774	3,334	208	984	712	2,087	-	-	5,678	3,362	-
7	**Total**	**2,130,673**	**611,752**	**706,302**	**-**	**30,474**	**374,432**	**97,901**	**16,328**	**28,901**	**55,861**	**61,281**	**24,144**	**18,892**	**5,678**	**98,729**	**-**
	Allocated Return on Debt																
8	1.2 Domestic Diesel	252,191	57,456	878	-	1,178	102,623	35,239	2,926	5,744	17,764	22,192	2,973	2,458	-	759	-
9	1.12 Domestic All Electric	13,400	3,609	44	-	74	6,447	979	184	160	1,116	616	83	68	-	21	-
10	2.1 GS 0-10 kW	42,165	8,312	156	-	170	14,847	7,390	423	1,205	2,570	4,654	1,247	1,031	-	159	-
11	2.2 GS 10-100 kW	53,246	14,692	284	-	301	26,242	2,105	748	343	4,542	1,325	1,433	1,185	-	45	-
12	2.3 GS 110-1,000 kVa	2,328	611	87	-	13	1,091	98	31	16	189	62	71	59	-	2	-
13	4.1 Street and Area Lighting	7,809	1,094	15	-	22	1,953	1,615	56	263	338	1,017	-	-	1,400	35	-
14	**Total**	**371,139**	**85,774**	**1,465**	**-**	**1,758**	**153,203**	**47,426**	**4,368**	**7,731**	**26,519**	**29,867**	**5,807**	**4,802**	**1,400**	**1,021**	**-**
	Allocated Return on Equity																
15	All Classes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total Allocated Revenue Requirement																
16	1.2 Domestic Diesel	1,640,124	467,240	424,299	-	21,591	353,438	107,983	13,863	27,219	55,182	67,725	15,335	12,131	-	74,118	-
17	1.12 Domestic All Electric	86,866	29,351	21,161	-	1,356	22,202	3,000	871	756	3,466	1,881	426	337	-	2,059	-
18	2.1 GS 0-10 kW	277,002	67,596	75,539	-	3,124	51,132	22,646	2,006	5,708	7,983	14,204	6,432	5,088	-	15,544	-
19	2.2 GS 10-100 kW	399,911	119,478	137,092	-	5,521	90,378	6,449	3,545	1,626	14,111	4,045	7,392	5,848	-	4,426	-
20	2.3 GS 110-1,000 kVa	53,312	4,967	42,201	-	230	3,757	300	147	76	587	188	365	289	-	206	-
21	4.1 Street and Area Lighting	44,598	8,894	7,476	-	411	6,728	4,949	264	1,248	1,050	3,104	-	-	7,077	3,397	-
22	**Total**	**2,501,812**	**697,525**	**707,767**	**-**	**32,232**	**527,635**	**145,327**	**20,695**	**36,633**	**82,380**	**91,147**	**29,951**	**23,693**	**7,077**	**99,750**	**-**

Labrador Interconnected

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Labrador Interconnected
Functional Classification of Revenue Requirement

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
				Production and		Distribution											Specifically
Line		Total	Production	Transmission	Transmission	Substations	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting	Assigned
No.	Description	Amount	Demand	Energy	Demand	Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
		($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)
	Expenses																
1	Operating & Maintenance	3,856,898	525,145	-	480,116	215,756	910,158	209,888	62,370	110,400	120,169	129,989	82,955	143,209	19,290	847,411	44
2	Fuels	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Fuels-Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Fuels-Gas Turbine	69,523	69,523	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Power Purchases -CF(L)Co	2,756,850	1,042,709	1,714,141	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Power Purchases-Other	135,072	-	-	-	135,072	-	-	-	-	-	-	-	-	-	-	-
7	Depreciation	2,555,125	1,209,866	-	521,428	149,970	237,374	54,448	51,655	91,434	39,679	39,833	44,098	17,846	13,128	84,278	88
	Expense Credits																
8	Sundry	(19,247)	(2,621)	-	(2,396)	(1,077)	(4,542)	(1,047)	(311)	(551)	(600)	(649)	(414)	(715)	(96)	(4,229)	(0)
9	Building Rental Income	(13,525)	(4,703)	-	(3,823)	(1,202)	(1,657)	(391)	(282)	(500)	(267)	(272)	(247)	(113)	(67)	-	(1)
10	Tax Refunds	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Suppliers' Discounts	(2,351)	(320)	-	(293)	(132)	(555)	(128)	(38)	(67)	(73)	(79)	(51)	(87)	(12)	(517)	(0)
12	Pole Attachments	63,700	-	-	-	-	36,841	12,590	-	-	6,521	7,748	-	-	-	-	-
13	Secondary Energy Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Wheeling Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Application Fees	(22,208)	-	-	-	-	-	-	-	-	-	-	-	-	-	(22,208)	-
16	**Total Expense Credits**	**6,369**	**(7,644)**	**-**	**(6,511)**	**(2,410)**	**30,087**	**11,024**	**(632)**	**(1,118)**	**5,581**	**6,748**	**(712)**	**(915)**	**(175)**	**(26,953)**	**(1)**
17	**Subtotal Expenses**	**9,379,838**	**2,839,600**	**1,714,141**	**995,032**	**498,387**	**1,177,619**	**275,360**	**113,393**	**200,716**	**165,429**	**176,570**	**126,341**	**160,140**	**32,243**	**904,735**	**131**
18	Disposal Gain / Loss	(32,985)	(10,387)	-	(12,744)	(1,933)	(3,300)	(724)	(650)	(1,151)	(509)	(513)	(597)	(215)	(172)	(88)	(3)
19	**Subtotal Revenue Requirement Ex. Return**	**9,346,853**	**2,829,213**	**1,714,141**	**982,289**	**496,454**	**1,174,319**	**274,636**	**112,743**	**199,565**	**164,920**	**176,057**	**125,744**	**159,925**	**32,071**	**904,647**	**128**
20	Return on Debt	3,594,943	1,138,862	-	1,379,531	212,183	360,412	79,211	70,767	125,263	55,595	56,101	64,984	23,479	18,685	9,503	367
21	Return on Equity	237,250	75,160	-	91,043	14,003	23,786	5,228	4,670	8,267	3,669	3,702	4,289	1,550	1,233	627	24
22	**Total Revenue Requirement**	**13,179,046**	**4,043,235**	**1,714,141**	**2,452,863**	**722,640**	**1,558,516**	**359,074**	**188,181**	**333,095**	**224,185**	**235,860**	**195,016**	**184,954**	**51,990**	**914,778**	**519**

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Labrador Interconnected
Functional Classification of Revenue Requirement - Documentation

	1	2
Line No.	Description	Basis of Functional Classification
	Expenses	
1	Operating & Maintenance	Carryforward from Sch.2.4 L.20
2	Fuels	
3	Fuels-Diesel	Production - Demand
4	Fuels-Gas Turbine	Production - Demand
5	Power Purchases -CF(L)Co	Carryforward from Sch.4.4 L.8
6	Power Purchases-Other	Carryforward from Sch.4.4 L.9
7	Depreciation	Carryforward from Sch.2.5 L.25
	Expense Credits	
8	Sundry	Prorated on Total Operating & Maintenance Expenses - Sch 2.4 L.20
9	Building Rental Income	Prorated on General Plant - Sch.2.2 L.19
10	Tax Refunds	Prorated on Total Operating & Maintenance Expenses - Sch 2.4 L.20
11	Suppliers' Discounts	Prorated on Total Operating & Maintenance Expenses - Sch 2.4 L.20
12	Pole Attachments	Prorated on Distribution Poles - Sch.4.1 L.33
13	Secondary Energy Revenues	Production - Energy
14	Wheeling Revenues	Transmission - Demand, Energy ratios Sch.4.1 L.13
15	Application Fees	Accounting - Customer
16	**Total Expense Credits**	
17	**Subtotal Expenses**	
18	Disposal Gain / Loss	Prorated on Total Net Book Value - Sch 2.3 L.25
19	**Subtotal Revenue Requirement Ex. Return**	
20	Return on Debt	Prorated on Rate Base - Sch.2.6 L.8
21	Return on Equity	Prorated on Rate Base - Sch.2.6 L.10
22	**Total Revenue Requirement**	

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Labrador Interconnected
Functional Classification of Plant in Service for the Allocation of O&M Expense

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
				Production and		Distribution											Specifically
Line		Total	Production	Transmission	Transmission	Substations	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting	Assigned
No.	Description	Amount	Demand	Energy	Demand	Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
		($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)
	Production																
1	Gas Turbines	22,455,036	22,455,036	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Diesel	3,573,831	3,573,831	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	**Subtotal Production**	**26,028,868**	**26,028,868**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Transmission																
4	Lines	17,228,235	-	-	16,774,039	-	454,196	-	-	-	-	-	-	-	-	-	-
5	Terminal Stations	4,714,188	-	-	4,422,544	-	286,590	-	-	-	-	-	-	-	-	-	5,054
6	**Subtotal Transmission**	**21,942,423**	-	-	**21,196,583**	-	740,785	-	-	-	-	-	-	-	-	-	**5,054**
	Distribution																
7	Substations	6,716,312	49,790	-	-	6,666,522	-	-	-	-	-	-	-	-	-	-	-
8	Land & Land Improvements	401,635	-	-	-	-	302,813	38,577	-	-	35,123	25,122	-	-	-	-	-
9	Poles	9,314,117	-	-	-	-	5,386,801	1,840,954	-	-	953,468	1,132,895	-	-	-	-	-
10	Primary Conductor & Eqpt	2,570,569	-	-	-	-	2,280,095	290,474	-	-	-	-	-	-	-	-	-
11	Submarine Conductor	475,797	-	-	-	-	475,797	-	-	-	-	-	-	-	-	-	-
12	Transformers	4,337,828	-	-	-	-	-	-	1,565,956	2,771,872	-	-	-	-	-	-	-
13	Secondary Conductor&Eqpt	840,746	-	-	-	-	-	-	-	-	490,155	350,591	-	-	-	-	-
14	Services	1,370,924	-	-	-	-	-	-	-	-	-	-	1,370,924	-	-	-	-
15	Meters	625,245	-	-	-	-	-	-	-	-	-	-	-	625,245	-	-	-
16	Street Lighting	371,648	-	-	-	-	-	-	-	-	-	-	-	-	371,648	-	-
17	**Subtotal Distribution**	**27,024,821**	**49,790**	-	-	6,666,522	**8,445,505**	**2,170,005**	**1,565,956**	**2,771,872**	**1,478,745**	**1,508,608**	**1,370,924**	**625,245**	**371,648**	**-**	**-**
18	**Subttl Prod, Trans, & Dist**	**74,996,111**	**26,078,658**	**-**	**21,196,583**	6,666,522	**9,186,291**	**2,170,005**	**1,565,956**	**2,771,872**	**1,478,745**	**1,508,608**	**1,370,924**	**625,245**	**371,648**	**-**	**5,054**
19	General	3,820,553	1,328,534	-	1,079,825	339,615	467,980	110,547	79,775	141,208	75,332	76,854	69,839	31,852	18,933	-	257
20	Telecontrol - Common	1,292,243	701,236	-	571,050	-	19,957	-	-	-	-	-	-	-	-	-	-
21	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Feasibility Studies	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Software - General	210,945	73,353	-	59,621	18,751	25,839	6,104	4,405	7,797	4,159	4,243	3,856	1,759	1,045	-	14
24	Software - Cust Acctng	126,416	-	-	-	-	-	-	-	-	-	-	-	-	-	126,416	-
25	**Total Plant**	**80,446,269**	**28,181,780**	**-**	**22,907,080**	**7,024,888**	**9,700,067**	**2,286,656**	**1,650,136**	**2,920,877**	**1,558,237**	**1,589,705**	**1,444,620**	**658,856**	**391,626**	**126,416**	**5,326**

18-May-2001

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Labrador Interconnected
Functional Classification of Plant in Service for the Allocation of O&M Expense - Documentation

Line No.	1 Description	2 Basis of Functional Classification
	Production	
1	Gas Turbines	Production - Demand, Energy ratios Sch.4.1 L.7
2	Diesel	Production - Demand, Energy ratios Sch.4.1 L.7
3	**Subtotal Production**	
	Transmission	
4	Lines	Production, Transmission - Demand, Energy; Distribution - Primary Demand; Spec Assigned - Custmr
5	Terminal Stations	Production, Transmission - Demand, Energy; Spec Assigned - Custmr
6	**Subtotal Transmission**	
	Distribution	Distribution plant other than Substations, Meters and Submarine prorated to functions based on special analysis
7	Substations	Production - Demand; Dist Substns - Demand
8	Land & Land Improvements	Primary, Secondary - Demand, Customer - zero intercept ratios Sch.4.1 L.28
9	Poles	Primary, Secondary - Demand, Customer - zero intercept ratios Sch.4.1 L.33
10	Primary Conductor & Eqpt	Primary - Demand, Customer - zero intercept ratios Sch.4.1 L.34
11	Submarine Conductor	Primary - Demand, Customer - zero intercept ratios Sch.4.1 L.35
12	Transformers	Transformers - Demand, Customer - zero intercept ratios Sch.4.1 L.36
13	Secondary Conductor&Eqpt	Secondary - Demand, Customer - zero intercept ratios Sch. 4.1 L.37
14	Services	Services Customer
15	Meters	Meters - Customer
16	Street Lighting	Street Lighting - Customer
17	**Subtotal Distribution**	
18	**Subttl Prod, Trans, & Dist**	
19	General	Prorated on subtotal Production, Transmission, & Distribution plant - L.18
20	Telecontrol - Common	Prorated on functionalized Production & Transmission plant - L. 3, 6
21	Telecontrol - Specific	Specifically Assigned - Customer
22	Feasibility Studies	Production, Transmission - Demand
23	Software - General	Prorated on subtotal Production, Transmission, & Distribution plant - L.18
24	Software - Cust Acctng	
25	**Total Plant**	

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Labrador Interconnected
Functional Classification of Net Book Value

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
				Production and		Distribution											Specifically
Line		Total	Production	Transmission	Transmission	Substations	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting	Assigned
No.	Description	Amount	Demand	Energy	Demand	Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
		($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)
	Production																
1	Gas Turbines	13,237,452	13,237,452	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Diesel	1,059,848	1,059,848	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	**Subtotal Production**	**14,297,300**	**14,297,300**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Transmission																
4	Lines	14,163,098	-	-	14,003,615	-	159,484	-	-	-	-	-	-	-	-	-	-
5	Terminal Stations	3,856,670	-	-	3,577,564	-	274,423	-	-	-	-	-	-	-	-	-	4,683
6	**Subtotal Transmission**	**18,019,769**	**-**	**-**	**17,581,179**	**-**	**433,906**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**4,683**
	Distribution																
7	Substations	2,717,463	32,364	-	-	2,685,099	-	-	-	-	-	-	-	-	-	-	-
8	Land & Land Improvements	158,571	-	-	-	-	119,555	15,231	-	-	13,867	9,919	-	-	-	-	-
9	Poles	4,284,914	-	-	-	-	2,478,171	846,922	-	-	438,638	521,183	-	-	-	-	-
10	Primary Conductor & Eqpt	1,273,490	-	-	-	-	1,129,585	143,904	-	-	-	-	-	-	-	-	-
11	Submarine Conductor	420,968	-	-	-	-	420,968	-	-	-	-	-	-	-	-	-	-
12	Transformers	2,501,655	-	-	-	-	-	-	903,097	1,598,558	-	-	-	-	-	-	-
13	Secondary Conductor&Eqpt	435,876	-	-	-	-	-	-	-	-	254,116	181,760	-	-	-	-	-
14	Services	830,068	-	-	-	-	-	-	-	-	-	-	830,068	-	-	-	-
15	Meters	298,416	-	-	-	-	-	-	-	-	-	-	-	298,416	-	-	-
16	Street Lighting	238,934	-	-	-	-	-	-	-	-	-	-	-	-	238,934	-	-
17	**Subtotal Distribution**	**13,160,355**	**32,364**	**-**	**-**	**2,685,099**	**4,148,280**	**1,006,057**	**903,097**	**1,598,558**	**706,621**	**712,862**	**830,068**	**298,416**	**238,934**	**-**	**-**
18	**Subttl Prod, Trans, & Dist**	**45,477,424**	**14,329,664**	**-**	**17,581,179**	**2,685,099**	**4,582,186**	**1,006,057**	**903,097**	**1,598,558**	**706,621**	**712,862**	**830,068**	**298,416**	**238,934**	**-**	**4,683**
19	General	1,349,909	425,348	-	521,863	79,702	136,013	29,863	26,807	47,450	20,975	21,160	24,639	8,858	7,092	-	139
20	Telecontrol - Common	237,531	105,085	-	129,222	-	3,189	-	-	-	-	-	-	-	-	-	34
21	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Feasibility Studies	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Software - General	173,467	54,659	-	67,061	10,242	17,478	3,837	3,445	6,097	2,695	2,719	3,166	1,138	911	-	18
24	Software - Cust Acctng	126,416	-	-	-	-	-	-	-	-	-	-	-	-	-	126,416	-
25	**Total Net Book Value**	**47,364,748**	**14,914,756**	**-**	**18,299,325**	**2,775,043**	**4,738,867**	**1,039,757**	**933,349**	**1,652,105**	**730,291**	**736,741**	**857,873**	**308,412**	**246,938**	**126,416**	**4,875**

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Labrador Interconnected
Functional Classification of Operating & Maintenance Expense

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
				Production and		Distribution											Specifically
Line		Total	Production	Transmission	Transmission	Substations	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting	Assigned
No.	Description	Amount	Demand	Energy	Demand	Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
		($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)
	Production																
1	Gas Turbine / Diesel	38,711	38,711	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	**Subtotal Production**	**38,711**	**38,711**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Transmission																
3	Transmission Lines	178,935	-	-	174,218	-	4,717.34	-	-	-	-	-	-	-	-	-	-
4	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	**Subtotal Transmission**	**178,935**	**-**	**-**	**174,218**	**-**	**4,717**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Distribution																
6	Other	917,517	11,663	-	-	65,620	485,778	111,909	23,769	42,072	61,638	67,612	38,944	-	8,512	-	-
7	Meters	85,165	-	-	-	-	-	-	-	-	-	-	-	85,165	-	-	-
8	**Subtotal Distribution**	**1,002,682**	**11,663**	**-**	**-**	**65,620**	**485,778**	**111,909**	**23,769**	**42,072**	**61,638**	**67,612**	**38,944**	**85,165**	**8,512**	**-**	**-**
9	**Subttl Prod, Trans, & Dist**	**1,220,328**	**50,374**	**-**	**174,218**	**65,620**	**490,496**	**111,909**	**23,769**	**42,072**	**61,638**	**67,612**	**38,944**	**85,165**	**8,512**	**-**	**-**
10	Customer Accounting	541,510	-	-	-	-	-	-	-	-	-	-	-	-	-	541,510	-
	Overheads																
	Plant-Related:																
11	Production	184,205	184,205	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Transmission	9,962	-	-	9,624	-	336	-	-	-	-	-	-	-	-	-	2
13	Distribution	236,372	435	-	-	58,309	73,868	18,980	13,697	24,244	12,934	13,195	11,991	5,469	3,251	-	-
14	Prod, Trans, Distn and General Plt	18,130	6,305	-	5,124	1,612	2,221	525	379	670	357	365	331	151	90	-	1
15	Telecontrol Plant	77,079	41,827	-	34,062	-	1,190	-	-	-	-	-	-	-	-	-	-
16	Generation, Transmission, Distribution and General Plant	539,508	189,000	-	153,625	47,112	65,053	15,335	11,067	19,589	10,450	10,661	9,688	4,419	2,626	848	36
	Expense Related:																
17	Property Insurance	37,294	24,623	-	5,320	6,137	678	97	70	124	66	67	61	28	17	-	5
18	Other Expense Related	992,510	28,377	-	98,143	36,966	276,315	63,043	13,390	23,701	34,723	38,088	21,939	47,977	4,795	305,053	-
19	**Subtotal Overheads**	**2,095,060**	**474,772**	**-**	**305,898**	**150,136**	**419,662**	**97,979**	**38,601**	**68,328**	**58,531**	**62,377**	**44,010**	**58,043**	**10,778**	**305,901**	**44**
20	**Total Operating & Maintenance Expenses**	**3,856,898**	**525,145**	**-**	**480,116**	**215,756**	**910,158**	**209,888**	**62,370**	**110,400**	**120,169**	**129,989**	**82,955**	**143,209**	**19,290**	**847,411**	**44**

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Labrador Interconnected
Functional Classification of Operating & Maintenance Expense - Documentation

	1	2
Line No.	Description	Basis of Functional Classification
	Production	
1	Gas Turbine / Diesel	Production - Demand, Energy ratios Sch.4.1 L.7
2	**Subtotal Production**	
	Transmission	
3	Transmission Lines	Prorated on Transmission Lines Plant in Service - Sch.2.2 L.4
4	Terminal Stations	Prorated on Transmission Terminal Stations Plant in Service - Sch.2.2 L.5
5	**Subtotal Transmission**	
	Distribution	
6	Other	Production, Distribution, except Meters- ratios Sch. 4.1 L.42
7	Meters	Meters - Customer
8	**Subtotal Distribution**	
9	**Subttl Prod, Trans, & Dist**	
10	Customer Accounting	Accounting - Customer
	Overheads	
	Plant-Related:	
11	Production	Prorated on Production Plant in Service - Sch.2.2 L.3
12	Transmission	Prorated on Transmission Plant in Service - Sch.2.2 L. 6
13	Distribution	Prorated on Distribution Plant in Service - Sch.2.2 L.17
14	Prod, Trans, Distn and General Plt	Prorated on Production, Transmission, Distribution Plant in Service - Sch.2.2 L. 18
15	Telecontrol Plant	Prorated on Production, Transmission, Distribution Plant in Service - Sch.2.2 L. 18
16	Generation, Transmission, Distribution and General Plant	Prorated on Production, Transmission, Distribution & General Plant in Service - Sch.2.2 L.25
	Expense Related:	
17	Property Insurance	Prorated on Prod., Trans. Terminal, Dist. Sub & General Plant in Service - Sch.2.2 L.3, 5, 7, 19 - 21
18	Other Expense Related	Prorated on Subtotal Production, Transmission, Distribution, Accounting Expenses - L 9, 10
19	**Subtotal Overheads**	
20	**Total Operating & Maintenance Expenses**	

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Labrador Interconnected
Functional Classification of Depreciation Expense

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
				Production and		Distribution											Specifically
Line		Total	Production	Transmission	Transmission	Substations	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting	Assigned
No.	Description	Amount	Demand	Energy	Demand	Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
		($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)
	Production																
1	Gas Turbines	898,893	898,893	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Diesel	70,156	70,156	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	**Subtotal Production**	**969,049**	**969,049**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Transmission																
4	Lines	342,871	-	-	327,918	-	14,953	-	-	-	-	-	-	-	-	-	-
5	Terminal Stations	92,448	-	-	90,412	-	1,963	-	-	-	-	-	-	-	-	-	73
6	**Subtotal Transmission**	**435,319**	**-**	**-**	**418,330**	**-**	**16,916**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**73**
	Distribution																
7	Substations	126,457	1,660	-	-	124,798	-	-	-	-	-	-	-	-	-	-	-
8	Land & Land Improvements	6,581	-	-	-	-	4,962	632	-	-	576	412	-	-	-	-	-
9	Poles	196,844	-	-	-	-	113,844	38,907	-	-	20,151	23,943	-	-	-	-	-
10	Primary Conductor & Eqpt	51,064	-	-	-	-	45,294	5,770	-	-	-	-	-	-	-	-	-
11	Submarine Conductor	15,886	-	-	-	-	15,886	-	-	-	-	-	-	-	-	-	-
12	Transformers	119,072	-	-	-	-	-	-	42,985	76,087	-	-	-	-	-	-	-
13	Secondary Conductor&Eqpt	21,086	-	-	-	-	-	-	-	-	12,293	8,793	-	-	-	-	-
14	Services	36,696	-	-	-	-	-	-	-	-	-	-	36,696	-	-	-	-
15	Meters	14,851	-	-	-	-	-	-	-	-	-	-	-	14,851	-	-	-
16	Street Lighting	10,925	-	-	-	-	-	-	-	-	-	-	-	-	10,925	-	-
17	**Subtotal Distribution**	**599,462**	**1,660**	**-**	**-**	**124,798**	**179,985**	**45,309**	**42,985**	**76,087**	**33,019**	**33,147**	**36,696**	**14,851**	**10,925**	**-**	**-**
18	**Subttl Prod, Trans, & Dist**	**2,003,830**	**970,708**	**-**	**418,330**	**124,798**	**196,901**	**45,309**	**42,985**	**76,087**	**33,019**	**33,147**	**36,696**	**14,851**	**10,925**	**-**	**73**
19	General	202,831	98,257	-	42,344	12,632	19,931	4,586	4,351	7,702	3,342	3,355	3,714	1,503	1,106	-	7
20	Telecontrol - Common	62,840	43,363	-	18,720	-	757	-	-	-	-	-	-	-	-	-	-
21	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Feasibility Studies	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Software - General	201,346	97,537	-	42,034	12,540	19,785	4,553	4,319	7,645	3,318	3,331	3,687	1,492	1,098	-	7
24	Software - Cust Acctng	84,278	-	-	-	-	-	-	-	-	-	-	-	-	-	84,278	-
25	**Total Depreciation Expense**	**2,555,125**	**1,209,866**	**-**	**521,428**	**149,970**	**237,374**	**54,448**	**51,655**	**91,434**	**39,679**	**39,833**	**44,098**	**17,846**	**13,128**	**84,278**	**88**

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Labrador Interconnected
Functional Classification of Rate Base

	1	2	3	4	5	7	8	9	10	11	12	13	14	15	16	17	18
				Production and		Distribution											Specifically
Line		Total	Production	Transmission	Transmission	Substations	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting	Assigned
No.	Description	Amount	Demand	Energy	Demand	Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
		($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)
1	Average Net Book Value	47,364,748	14,914,756	-	18,299,325	2,775,043	4,738,867	1,039,757	933,349	1,652,105	730,291	736,741	857,873	308,412	246,938	126,416	4,875
2	Cash Working Capital	117,763	37,083	-	45,498	6,900	11,782	2,585	2,321	4,108	1,816	1,832	2,133	767	614	314	12
3	Fuel Inventory - No. 6 Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Fuel Inventory - Diesel	21,945	21,945	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Fuel Inventory - Gas Turbine	71,691	71,691	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Inventory/Supplies	972,787	340,785	-	277,001	84,948	117,297	27,651	19,954	35,320	18,843	19,223	17,469	7,967	4,736	1,529	64
	Deferred Charges:																
7	Foreign Exchange Loss	3,241,172	1,020,617	-	1,252,224	189,896	324,281	71,151	63,869	113,054	49,974	50,415	58,704	21,105	16,898	8,651	334
8	Total Rate Base	**51,790,106**	**16,406,877**	**-**	**19,874,048**	**3,056,786**	**5,192,227**	**1,141,144**	**1,019,493**	**1,804,587**	**800,923**	**808,211**	**936,179**	**338,251**	**269,186**	**136,910**	**5,285**
9	Less: Rural Portion	-															
10	Rate Base Available for Equity Return	**51,790,106**	**16,406,877**	**-**	**19,874,048**	**3,056,786**	**5,192,227**	**1,141,144**	**1,019,493**	**1,804,587**	**800,923**	**808,211**	**936,179**	**338,251**	**269,186**	**136,910**	**5,285**
11	Return on Debt	3,594,943	1,138,862	-	1,379,531	212,183	360,412	79,211	70,767	125,263	55,595	56,101	64,984	23,479	18,685	9,503	367
12	Return on Equity	237,250	75,160	-	91,043	14,003	23,786	5,228	4,670	8,267	3,669	3,702	4,289	1,550	1,233	627	24
13	Return on Rate Base	**3,832,194**	**1,214,022**	**-**	**1,470,574**	**226,186**	**384,197**	**84,439**	**75,437**	**133,530**	**59,264**	**59,803**	**69,272**	**25,029**	**19,918**	**10,131**	**391**

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Labrador Interconnected
Functional Classification of Rate Base - Documentation

Line No.	1 Description	2 Basis of Functional Classification
1	Average Net Book Value	Sch. 2.3 , L. 25
2	Cash Working Capital	Prorated on Average Net Book Value, L 1
3	Fuel Inventory - No. 6 Fuel	
4	Fuel Inventory - Diesel	Production - Demand
5	Fuel Inventory - Gas Turbine	Production - Demand
6	Inventory/Supplies	Prorated on Total Plant in Service, Sch. 2.2, L. 25
	Deferred Charges:	
7	Foreign Exchange Loss	Prorated on Average Net Book Value, L 1
8	Total Rate Base	
9	Less: Rural Portion	
10	Rate Base Available for Equity Return	
11	Return on Debt	L.8 x Sch.1.2,p2,L.13
12	Return on Equity	L.10 x Sch.1.2,p2,L.16
13	Return on Rate Base	

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Labrador Interconnected
Basis of Allocation to Classes of Service

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
				Production and		Distribution											Specifically
Line		Total	Production	Transmission	Transmission	Substations	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting	Assigned
No.	Description	Amount	Demand	Energy	Demand	Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
	Amounts		(CP kW)	(MWh @ Gen)	(CP kW)	(CP kW)	(CP kW)	(Rural Cust)	(CP kW)	(Rural Cust)	(CP kW)	(Rural Cust)	(Wtd Rural Cust)			(Rural Cust)	
1	CFB - Goose Bay Secondary	-	-	83,734	-	-	-	1	-	1		1	-	-	-	1	1
2	IOCC Firm	-	70,955	366,875	62,000	-	-	-	-	-	-	-	-	-	-	-	-
3	IOCC Non-Firm	-	-	46,931	-	-	-	-	-	-		-	-	-	-	-	-
	Rural																
4	1.1Domestic	-	2,188	8,738	1,925	1,904	1,857	696	1,832	696	1,807	696	696	696	-	696	-
5	1.1A Domestic All Electric	-	88,127	300,229	77,565	76,721	74,920	6,959	73,906	6,959	72,950	6,959	6,959	6,959		6,959	
6	2.1GS 0-10 kW	-	1,849	7,684	1,630	1,611	1,571	474	1,549	474	1,527	474	949	949	-	474	-
7	2.2GS 10-100 kW	-	9,650	70,570	8,509	8,407	8,195	560	8,081	560	7,968	560	4,523	4,523	-	560	-
8	2.3GS 110-1,000 kVa	-	11,139	107,824	9,812	9,700	9,463	98	9,334	98	9,207	98	841	841	-	98	-
9	2.4GS Over 1,000 kVa	-	7,042	48,030	6,264	6,155	-	1	-	1	-	1	9	9	-	1	-
10	4.1Street and Area Lighting	-	413	1,684	364	360	351	226	346	226	341	226	-	-	1	226	-
11	**Subtotal Rural**		**120,407**	**544,760**	**106,071**	**104,858**	**96,357**	**9,015**	**95,048**	**9,015**	**93,801**	**9,015**	**13,977**	**13,977**	**1**	**9,015**	**-**
12	**Total Labrador Interconnected**		**191,362**	**1,042,300**	**168,071**	**104,858**	**96,357**	**9,016**	**95,048**	**9,016**	**93,801**	**9,016**	**13,977**	**13,977**	**1**	**9,016**	**1**
	Ratios																
13	CFB - Goose Bay Boiler	-	-	0.0803	-	-	-	0.0001	-	0.0001	-	0.0001	-	-	-	0.0001	1.0000
14	IOCC Firm	-	0.3708	0.3520	0.3689	-	-	-	-	-	-	-	-	-	-	-	-
15	IOCC Non-Firm	-	-	0.0450	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural																
16	1.1Domestic	-	0.0114	0.0084	0.0115	0.0182	0.0193	0.0772	0.0193	0.0772	0.0193	0.0772	0.0498	0.0498	-	0.0772	-
17	1.1A Domestic All Electric	-	0.4605	0.2880	0.4615	0.7317	0.7775	0.7719	0.7776	0.7719	0.7777	0.7719	0.4979	0.4979	-	0.7719	-
18	2.1GS 0-10 kW	-	0.0097	0.0074	0.0097	0.0154	0.0163	0.0526	0.0163	0.0526	0.0163	0.0526	0.0679	0.0679	-	0.0526	-
19	2.2GS 10-100 kW	-	0.0504	0.0677	0.0506	0.0802	0.0850	0.0622	0.0850	0.0622	0.0849	0.0622	0.3236	0.3236	-	0.0622	-
20	2.3GS 110-1,000 kVa	-	0.0582	0.1034	0.0584	0.0925	0.0982	0.0109	0.0982	0.0109	0.0982	0.0109	0.0602	0.0602	-	0.0109	-
21	2.4GS Over 1,000 kVa	-	0.0368	0.0461	0.0373	0.0587	-	0.0001	-	0.0001	-	0.0001	0.0006	0.0006	-	0.0001	-
22	4.1Street and Area Lighting	-	0.0022	0.0016	0.0022	0.0034	0.0036	0.0251	0.0036	0.0251	0.0036	0.0251	-	-	1.0000	0.0251	-
23	**Subtotal Rural**		**0.6292**	**0.5227**	**0.6311**	**1.0000**	**1.0000**	**0.9999**	**1.0000**	**0.9999**	**1.0000**	**0.9999**	**1.0000**	**1.0000**	**1.0000**	**0.9999**	**-**
24	**Total Labrador Interconnected**		**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**
	Ratios Excluding IOCC																
25	CFB - Goose Bay Boiler	-	-	0.1332	-	-	-	0.0001	-	0.0001	-	0.0001	-	-	-	0.0001	1.0000
	Rural																
26	1.1Domestic	-	0.0182	0.0139	0.0182	0.0182	0.0193	0.0772	0.0193	0.0772	0.0193	0.0772	0.0498	0.0498	-	0.0772	-
27	1.1A Domestic All Electric	-	0.7319	0.4777	0.7313	0.7317	0.7775	0.7719	0.7776	0.7719	0.7777	0.7719	0.4979	0.4979	-	0.7719	-
28	2.1GS 0-10 kW	-	0.0154	0.0122	0.0154	0.0154	0.0163	0.0526	0.0163	0.0526	0.0163	0.0526	0.0679	0.0679	-	0.0526	-
29	2.2GS 10-100 kW	-	0.0801	0.1123	0.0802	0.0802	0.0850	0.0622	0.0850	0.0622	0.0849	0.0622	0.3236	0.3236	-	0.0622	-
30	2.3GS 110-1,000 kVa	-	0.0925	0.1716	0.0925	0.0925	0.0982	0.0109	0.0982	0.0109	0.0982	0.0109	0.0602	0.0602	-	0.0109	-
31	2.4GS Over 1,000 kVa	-	0.0585	0.0764	0.0591	0.0587	-	0.0001	-	0.0001	-	0.0001	0.0006	0.0006	-	0.0001	-
32	4.1Street and Area Lighting	-	0.0034	0.0027	0.0034	0.0034	0.0036	0.0251	0.0036	0.0251	0.0036	0.0251	-	-	1.0000	0.0251	-
33	**Subtotal Rural**		**1.0000**	**0.8668**	**1.0000**	**1.0000**	**1.0000**	**0.9999**	**1.0000**	**0.9999**	**1.0000**	**0.9999**	**1.0000**	**1.0000**	**1.0000**	**0.9999**	**-**
34	**Total Labrador Interconnected**		**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Labrador Interconnected
Allocation of Functionalized Amounts to Classes of Service

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
				Production and		Distribution											Specifically
Line		Total	Production	Transmission	Transmission	Substations	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting	Assigned
No.	Description	Amount	Demand	Energy	Demand	Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
		($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)
	Allocated Revenue Requirement Excluding Return																
1	CFB - Goose Bay Boiler	138,007	-	137,707	-	-	-	30	-	22	-	20	-	-	-	100	128
2	IOCC Firm	2,014,760	1,049,047	603,354	362,359	-	-	-	-	-	-	-	-	-	-	-	-
3	IOCC Non-Firm	77,182	-	77,182	-	-	-	-	-	-	-	-	-	-	-	-	-
4	1.1Domestic	229,225	32,342	14,371	11,252	9,016	22,635	21,201	2,173	15,406	3,177	13,591	6,262	7,964	-	69,835	-
5	1.1A Domestic All Electric	5,084,614	1,302,919	493,749	453,328	363,237	913,068	211,978	87,666	154,034	128,261	135,889	62,607	79,626	-	698,252	-
6	2.1GS 0-10 kW	182,014	27,336	12,637	9,529	7,626	19,141	14,453	1,837	10,502	2,685	9,265	8,537	10,858	-	47,607	-
7	2.2GS 10-100 kW	660,809	142,668	116,058	49,733	39,802	99,870	17,069	9,586	12,403	14,009	10,942	40,691	51,752	-	56,225	-
8	2.3GS 110-1,000 kVa	622,007	164,689	177,325	57,347	45,927	115,329	2,990	11,071	2,173	16,188	1,917	7,570	9,628	-	9,850	-
9	2.4GS Over 1,000 kVa	249,201	104,110	78,989	36,611	29,143	-	30	-	22	-	20	77	98	-	100	-
10	4.1Street and Area Lighting	89,036	6,102	2,770	2,129	1,703	4,275	6,884	410	5,002	600	4,413	-	-	32,071	22,676	-
11	**Total**	**9,346,853**	**2,829,213**	**1,714,141**	**982,289**	**496,454**	**1,174,319**	**274,636**	**112,743**	**199,565**	**164,920**	**176,057**	**125,744**	**159,925**	**32,071**	**904,647**	**128**
	Allocated Return on Debt																
12	CFB - Goose Bay Boiler	397	-	-	-	-	-	9	-	14	-	6	-	-	-	1	367
13	IOCC Firm	931,179	422,280	-	508,899	-	-	-	-	-	-	-	-	-	-	-	-
14	IOCC Non-Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	1.1Domestic	67,311	13,019	-	15,803	3,854	6,947	6,115	1,364	9,670	1,071	4,331	3,236	1,169	-	734	-
16	1.1A Domestic All Electric	1,947,374	524,473	-	636,656	155,246	280,231	61,139	55,026	96,684	43,237	43,301	32,355	11,690	-	7,335	-
17	2.1GS 0-10 kW	55,797	11,004	-	13,383	3,259	5,875	4,168	1,153	6,592	905	2,952	4,412	1,594	-	500	-
18	2.2GS 10-100 kW	231,089	57,429	-	69,846	17,011	30,651	4,923	6,017	7,785	4,722	3,487	21,029	7,598	-	591	-
19	2.3GS 110-1,000 kVa	222,530	66,293	-	80,539	19,629	35,396	863	6,949	1,364	5,457	611	3,912	1,414	-	103	-
20	2.4GS Over 1,000 kVa	105,865	41,908	-	51,417	12,456	-	9	-	14	-	6	40	14	-	1	-
21	4.1Street and Area Lighting	33,400	2,456	-	2,990	728	1,312	1,986	258	3,140	202	1,406	-	-	18,685	238	-
22	**Total**	**3,594,943**	**1,138,862**	**-**	**1,379,531**	**212,183**	**360,412**	**79,211**	**70,767**	**125,263**	**55,595**	**56,101**	**64,984**	**23,479**	**18,685**	**9,503**	**367**

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Labrador Interconnected
Allocation of Functionalized Amounts to Classes of Service

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
						Distribution											
				Production and			Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting		Specifically
Line No.	Description	Total Amount ($)	Production Demand ($)	Transmission Energy ($)	Transmission Demand ($)	Substations Demand ($)	Demand ($)	Customer ($)	Demand ($)	Customer ($)	Demand ($)	Customer ($)	Customer ($)	Customer ($)	Customer ($)	Accounting Customer ($)	Assigned Customer ($)
	Allocated Return on Equity																
23	CFB - Goose Bay Boiler	26	-	-	-	-	-	1	-	1	-	0	-	-	-	0	24
24	IOCC Firm	61,454	27,869	-	33,585	-	-	-	-	-	-	-	-	-	-	-	-
25	IOCC Non-Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26	1.1Domestic	4,442	859	-	1,043	254	458	404	90	638	71	286	214	77	-	48	-
27	1.1A Domestic All Electric	128,518	34,613	-	42,016	10,246	18,494	4,035	3,631	6,381	2,853	2,858	2,135	771	-	484	-
28	2.1GS 0-10 kW	3,682	726	-	883	215	388	275	76	435	60	195	291	105	-	33	-
29	2.2GS 10-100 kW	15,251	3,790	-	4,610	1,123	2,023	325	397	514	312	230	1,388	501	-	39	-
30	2.3GS 110-1,000 kVa	14,686	4,375	-	5,315	1,295	2,336	57	459	90	360	40	258	93	-	7	-
31	2.4GS Over 1,000 kVa	6,987	2,766	-	3,393	822	-	1	-	1	-	0	3	1	-	0	-
32	4.1Street and Area Lighting	2,204	162	-	197	48	87	131	17	207	13	93	-	-	1,233	16	-
33	**Total**	**237,250**	**75,160**	**-**	**91,043**	**14,003**	**23,786**	**5,228**	**4,670**	**8,267**	**3,669**	**3,702**	**4,289**	**1,550**	**1,233**	**627**	**24**
	Total Allocated Revenue Requirement																
34	CFB - Goose Bay Boiler	138,430	-	137,707	-	-	-	40	-	37	-	26	-	-	-	101	519
35	IOCC Firm	3,007,393	1,499,196	603,354	904,843	-	-	-	-	-	-	-	-	-	-	-	-
36	IOCC Non-Firm	77,182	-	77,182	-	-	-	-	-	-	-	-	-	-	-	-	-
37	1.1Domestic	300,979	46,221	14,371	28,098	13,124	30,040	27,719	3,627	25,714	4,319	18,207	9,711	9,210	-	70,617	-
38	1.1A Domestic All Electric	7,160,506	1,862,004	493,749	1,132,000	528,729	1,211,793	277,151	146,323	257,100	174,352	182,049	97,097	92,087	-	706,071	-
39	2.1GS 0-10 kW	241,493	39,065	12,637	23,795	11,101	25,403	18,896	3,067	17,529	3,650	12,412	13,240	12,557	-	48,140	-
40	2.2GS 10-100 kW	907,148	203,888	116,058	124,188	57,936	132,544	22,317	16,000	20,702	19,043	14,659	63,107	59,851	-	56,855	-
41	2.3GS 110-1,000 kVa	859,223	235,358	177,325	143,201	66,851	153,061	3,910	18,479	3,627	22,006	2,568	11,741	11,135	-	9,961	-
42	2.4GS Over 1,000 kVa	362,052	148,783	78,989	91,422	42,421	-	40	-	37	-	26	120	113	-	101	-
43	4.1Street and Area Lighting	124,640	8,720	2,770	5,316	2,479	5,674	9,001	685	8,350	815	5,912	-	-	51,990	22,930	-
44	**Total**	**13,179,046**	**4,043,235**	**1,714,141**	**2,452,863**	**722,640**	**1,558,516**	**359,074**	**188,181**	**333,095**	**224,185**	**235,860**	**195,016**	**184,954**	**51,990**	**914,778**	**519**

Other

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Functionalization & Classification Ratios

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
				Production		Rural	Distribution											Specifically
Line		Total	Production	& Transmission	Transmission	Transmission	Substations	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting	Assigned
No.	Description	Amount	Demand	Energy	Demand	Demand	Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
	Generation	(%)	(%)	(%)	(%)	(%)	(%)	(%)	(%)	(%)	(%)	(%)	(%)	(%)	(%)	(%)	(%)	(%)
1	Hydraulic	100%	40.86%	59.14%														
2	Holyrood	100%	67.41%	32.59%														
3	Dsl / Gas Tur Island Intercnctd	100%	100.00%	0%														
4	Dsl / Gas Tur Island Isolated	100%	65.34%	34.66%														
5	Dsl / Gas Tur Labrador Isolated	100%	56.13%	43.87%														
6	Dsl / Gas Tur L'Anse au Loup	100%	100.00%	0%														
7	Dsl / Gas Tur Labrador Intercnctd	100%	100.00%	0%														
	Fuel																	
8	Bunker C	100%	0.00%	100%														
9	Dsl / Gas Tur Island Intercnctd	100%	100.00%	0%														
10	Dsl / Gas Tur Island / Lab Isolated	100%	0.00%	100%														
11	Dsl / Gas Tur L'Anse au Loup	100%	0.00%	100%														
12	Dsl / Gas Tur Labrador Intercnctd	100%	100.00%	0%														
	Transmission Lines & Terminals																	
13	Lines	100%		0%	100%													
14	Lines - Hydraulic	100%	40.86%	59.14%														
15	Lines - Customer Specific	100%																100%
16	Terminal Stations	100%		0%	100%													
17	Term Stns - Hydraulic	100%	40.86%	59.14%														
18	Term Stns - Holyrood	100%	67.41%	32.59%														
19	Term Stns - Gas Tur/Dsl	100%	100%															
20	Terminal Stations - Distribution	100%					100%											
21	Term Stns - Custmr Specific	100%																100%
22	Rural Lines	100%				100%												
23	Rural Terminal Stations	100%				100%												
	Distribution																	
24	Substation Structures & Equipment						100%											
25	Land & Land Improvements - by Sub-function:																	
26	Primary	85%						88.7%	11.3%									
27	Secondary	15%										58.3%	41.7%					
28	Land & Land Improvements	100%						75.4%	9.6%			8.7%	6.3%					
29	Poles - by Subfunction:																	
30	3 phase - Primary	41.2%						100.0%										
31	Other Primary	36.4%						45.7%	54.3%									
32	Secondary	22.4%										45.7%	54.3%					
33	Poles	100%						57.8%	19.8%			10.2%	12.2%					
34	Primary Condctr & Equip	100%						88.7%	11.3%									
35	Submarine Conductor	100%						100.0%										
36	Transformers	100%								36.1%	63.9%							
37	Secondary Condctr & Equip	100%										58.3%	41.7%					
38	Services	100%												100.0%				
39	Meters	100%													100.0%			
40	Street Lighting	100%														100.0%		
41	Customer Accounting	100%															100.0%	
42	Distribution excluding Meters	100%	1.27%				7.15%	52.94%	12.20%	2.59%	4.59%	6.72%	7.37%	4.24%		0.93%		

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology

System Load Factor

Line No.	1	2	3	4	5	6
		Island Interconnected	**Island Isolated**	**Labrador Isolated**	**L'Anse au Loup**	**Labrador Interconnected**
1	Sales+Losses for System Load Factor (MWh)	6,524,385	11,362	36,996	13,357	1,042,300
2	Hours in Year	8,760	8,760	8,760	8,760	8,760
3	Average Demand (kW)	744,793	1,297	4,223	1,525	118,984
4	Coincident Peak at Generation (kW)	1,259,335	3,742	9,627	3,097	191,362
5	System Load Factor	59.14%	34.66%	43.87%	49.23%	62.18%

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Holyrood Capacity Factor

	1	2	3	4	5
Line No.	Year	Net Production (kWh)	Net Capacity (MW)	Net Production Hours	Net Capacity Factor
1	1997 Actual	1,531,300,920	466	8,760	37.51%
2	1998 Actual	1,263,264,060	466	8,760	30.95%
3	1999 Actual	919,801,520	466	8,760	22.53%
4	2000 Actual	970,283,280	466	8,784	23.70%
5	2001 Forecast	1,971,340,000	466	8,760	48.29%
6	5-Year Average	1,331,197,956	466	8,765	32.59%

NEWFOUNDLAND & LABRADOR HYDRO
2002 Forecast Cost of Service - Proposed Methodology
Total System
Power Purchases

	1	2	3	4	5	6	
Line No.		Total ($)	Production Demand ($)	Production & Transmission Energy ($)	Transmission Demand ($)	Distribution Demand ($)	Basis of Functional Classification
	Island Interconnected:						
1	DLP Secondary	13,704		13,704			Production - Energy (Same as RSP Sec Load Var)
2	AP Secondary	-		-			Production - Energy (Secondary)
3	Wheeling	449,659		449,659			Transmission - Energy
4	Interruptible Demand	1,326,848	1,326,848	-			Production - Demand
5	Interruptible Energy	-		-			Production - Energy
6	Non-utility Generation	9,958,618	4,068,917	5,889,701			Energy: System Load Factor
7	**Subtotal**	**11,748,829**	**5,395,765**	**6,353,064**	**-**	**-**	
	Labrador Interconnected:						
8	CF(L)Co	2,756,850	1,042,709	1,714,141			Energy: System Load Factor
9	Other	135,072				135,072	
10	**Subtotal**	**2,891,922**	**1,042,709**	**1,714,141**	**-**	**135,072**	
	Isolated Systems:						
11	Mary's Harbour	-		-			Production - Energy
12	L'Anse au Loup	625,131		625,131			Production - Energy
13	**Subtotal**	**625,131**	**-**	**625,131**	**-**	**-**	
14	**Total**	**15,265,882**	**6,438,474**	**8,692,336**	**-**	**135,072**	

P.R. Hamilton

NEWFOUNDLAND AND LABRADOR HYDRO

EVIDENCE OF PAUL R. HAMILTON

Q. Please state your name, address, qualifications and occupation?

A. My name is Paul Hamilton, I live in St. John's and am a professional engineer. I also hold Master of Business Administration and Master of Applied Science in Environmental Engineering and Applied Science Degrees from Memorial University of Newfoundland. I have over 18 years of experience in the electric utility rates and regulatory activities areas and am presently employed as Regulatory Specialist in the Customer Services Department with Newfoundland and Labrador Hydro (Hydro).

Q. Have you previously appeared before this Board?

A. Yes. I appeared before this Board on several occasions from 1985 to 1992 on issues including rate design and cost of service.

Q. What is the nature of your evidence?

A. My evidence will review the following areas:

1. Hydro’s long-term rate design objectives and their relationship to sound rate design criteria;
2. The role of Hydro’s 2002 Cost of Service (COS) Study results in the rate design process;
3. Hydro’s proposed rates and the impacts they will have on our various customer classes; and,
4. Proposed changes to Hydro’s Rules and Regulations.

Q. Would you please identify the rate design criteria that a utility and its regulator should have in mind when developing rates?

A. In his acclaimed book, Principles of Public Utility Rates[1], James Bonbright describes several criteria of a sound rate structure. In the forty years since its release, this listing has become generally accepted as the benchmark in this area. From this list, Hydro believes the following reflect the desired rate design criteria:

REVENUE REQUIREMENT

Rates should effectively provide the total revenue requirement necessary to compensate the utility for expenses incurred and to provide a fair rate of return to its shareholders for all capital funds employed in the business.

MARKET EFFICIENCY

Rate classes and rate blocks should discourage wasteful use of service while promoting all types and amounts of use that are economically justified.

COST BASED RATES

Rates should allocate costs fully and fairly among customers avoiding undue discrimination within the limits of reasonable practicality.

STABILITY

To the extent possible, rates should be stable in two respects. Rates should generate the specific amount of the revenue requirement in a stable manner, from year to year and from month to month. The rates should also be relatively stable with a minimum of unexpected changes to facilitate both customer and company planning for the future.

ADMINISTRATIVE PRACTICALITY

Rates should be simple yet specific enough to be administered efficiently by the utility and understood by customers with a minimum of controversy.

[1] James C. Bonbright, *Principles of Public Utility Rates* (New York, N.Y.: Columbia University Press, 1961).

Q. Are there any local constraints that impact the application of these criteria for this hearing?

A. Yes. There are several unique circumstances that impact the application of the criteria. The historical linkages of Island Interconnected System and Isolated Rural Systems rates to Newfoundland Power (NP) rates impact several criteria particularly those related to revenue requirement and cost based rates. The use of lifeline energy blocks also impacts on cost based rates and market efficiency criteria.

These constraints therefore impact the relative priority of these criteria but do not require totally disregarding any specific criterion. Rate design requires balancing of the various criteria recognizing that they can at times be offsetting. The overall effect of rate design is the primary concern.

Q. How have the 2002 COS Study results been used in the rate design process?

A. The proposed 2002 COS Study as presented by Mr. Brickhill reflects the relative costs to serve the various classes of customers based on the forecast costs and usage patterns of each class. In addition to typical utility costs, Hydro has to deal with the allocation of the rural deficit. As has been discussed at past hearings before this Board, the rural deficit is not a typical COS item. Therefore, its allocation to demand, energy and customer cost components can cause rate design distortions if each rate component tries to track its relevant cost precisely.

Since the Industrial Class is no longer required to pay a portion of the rural deficit, it has been split between NP and the Labrador Interconnected System consistent with the Board's 1993 Report from the COS Methodology Hearing and reflecting the change in the COS methodology.

While the Labrador Interconnected System has been allocated a portion of the deficit since 1992, the rates had not been adjusted to recover this amount from Labrador customers.

Historically, NP's rate has been derived exactly from the test year COS Study results. Hydro proposes to continue this practice and to derive the Island Industrial class firm service rate in a similar manner.

Generally, COS Study results provide an indication of the approximate level of cost recovery from each rate class. The results can therefore be very useful in the rate design process by providing an indication of how to apply a general rate increase in order to move each customer class closer to the desired level of cost recovery. Table 1 below shows the level of cost recovery for the existing retail rates based on the standard rate categories.

Table 1
Cost Coverage Ratios at Existing Rates

	Island Interconnected	Isolated Systems	L'Anse au Loup	Labrador Interconnected
Domestic	0.72	0.16	0.37	0.75
GS 0 – 10 kW	1.00	-	0.52	1.06
GS 10 – 100 kW	1.08	-	0.53	2.24
GS 110–1000 kVA	1.24	-	1.24	3.06
GS Over 1000 kVA	0.87	-	-	3.44
GS Diesel	-	0.28	-	-
Street Lighting	1.10	0.36	0.77	1.13
System	0.83	0.21	0.44	1.20

As these coverage levels have a wide range, it is beneficial to set long-term target levels to guide rate design. The desired cost recovery levels should reflect the balancing of the various rate design criteria and any local constraints as referred to earlier. Cost recovery target levels have not been set for the Island Interconnected System and L'Anse au Loup System as these rates track NP Rates.

Hydro expects the following cost recovery levels for the Isolated Rural Systems may be achievable over the long-term:

Domestic	20%
General Service	45%
Government Agencies	100%
Street Lighting	50%

Hydro proposes the following long-term cost recovery targets for the Labrador Interconnected System. The proposed cost recovery targets are the same as those that have been accepted by the Board for NP. These are:

Domestic	95%
General Service	105 % to 115%
Street Lighting	100%

Schedule 1.2 of the 2002 COS Study shows the projected revenue to cost coverage before allocation of rural deficit and revenue credit for each rate class based on the proposed rates.

Q. What are Hydro's objectives regarding rate design?

A. Mr. Wells has indicated that one of Hydro's objectives is to minimize the rural deficit. A critical component for meeting this objective is increasing the level of cost recovery through redesigning the rates. Mr. Osmond has outlined Hydro's rate design policies for this application. The following guidelines have been developed consistent with these policies in the context of the criteria described above.

Newfoundland Power

The wholesale rate to NP should reflect the direct assigned costs from the COS study plus their portion of the rural deficit.

Industrial Customers

The firm power rates for Industrial Customers should reflect the direct assigned costs from the COS study with no allocation of the rural deficit. The non-firm rates should recover all incremental costs of providing the service and provide a contribution towards the fixed cost of the relevant generating plant.

Island Interconnected System and L'Anse au Loup System

The Island Interconnected System rates should continue to track the rates charged by NP to similar customers. These rates also apply to customers served by the L'Anse au Loup System as directed by the Board in its 1996 Report on Electrical Rates in the Labrador Straits Area from L'Anse au Clair to Red Bay.

Isolated Rural Systems

Mr. Osmond has indicated that Hydro proposes to submit a plan in Hydro's next Rate Application that will reflect the Board's directions regarding rate design and cost recovery targets. For this application, Hydro has used the following guidelines:

1. Rate classes for government agencies and departments should be established and an initial step made to move them to 100% cost recovery over time.
2. For rate classes other than government departments and agencies:
    a) The lifeline portion of the Domestic and General Service rates will continue to be the same as the respective Island Interconnected System rate; and

b) In the short-term, the energy blocks above the lifeline blocks will change by the average percentage change for NP's customers.

Labrador Interconnected System

To integrate the 24 existing rates in Labrador into a set of six uniform rates will require several interim steps. While the restructuring will in total result in the same overall revenue as the existing rates, there will be a wide range of increases and decreases due to rate structure changes and differences in customers' usage patterns. Hydro used the following guidelines for this first step in the plan to move to the cost recovery levels indicated earlier:

1. Move all customers to the relevant standard rate class;
2. No rate class (based on the standard rate class categories) should receive an increase of more than 20%;
3. No Domestic or small General Service customer should receive an increase of more than $20 per month;
4. Larger General Service customers should receive increases of no more than 20% unless the circumstances are unique; and
5. Street & Area Lighting Rates should move toward specific costs of providing the service.

Hydro will include rate changes for subsequent periods in the five-year plan to be submitted at Hydro's next rate hearing.

Q. How is Hydro proposing to meet the revenue requirement for 2002?

A. The revenue requirement, excluding IOCC, of $315.8 million as outlined in the 2002 COS Study will require an average overall increase in Hydro's rates of 6.1%. The 2002 COS Study was used to allocate this revenue requirement to each system. Schedule 1.2, Exhibit JAB-1, p.3 provides a summary of the allocated revenue requirements.

The COS Study also identifies the amount of the rural deficit to be apportioned between NP and Labrador Interconnected System customers consistent with the method outlined in the Board's 1993 Report. Schedule 1.2.1 shows the calculations for this allocation. The deficit was first split into demand, energy and customer components based on the proportions of the total of these components for NP and the regulated customers on the Labrador Interconnected System. Each component was then allocated between NP and the regulated customers on the Labrador Interconnected System based on coincident peak, energy sales and equivalent customers respectively.

Customers in the various Hydro rural systems have been assigned their respective portion of the overall rate increase combined with increases or decreases consistent with the guidelines indicated earlier to achieve better equity.

Q. Would you please identify the estimated revenue that will be produced under the proposed rates effective January 1, 2002 for each rate schedule?

A. The following table summarizes the expected revenue by rate class based on the proposed rates being in effect for the full year 2002:

Table 2
Comparison of Revenue at Existing and Proposed Rates
Based on Full Year 2002

	Existing Rates	Proposed Rates	Change $	Change %
Newfoundland Power	$200,369,992	$213,830,400	$13,460,408	6.7%
Industrial				
- firm	45,266,225	49,975,388	4,709,163	10.4%
- non-firm	293,393	381,121	87,728	29.9%
- wheeling	6,490	6,950	460	7.1%
Rural Island Interconnected	30,517,104	31,639,918	1,122,814	3.7% *
Rural Isolated Systems				
Non-government	4,500,581	4,666,055	165,474	3.7% *
Government	680,603	816,722	136,119	20.0%
L'Anse au Loup	1,095,800	1,136,125	40,325	3.7% *
Rural Labrador Interconnected				
Domestic	5,613,755	5,709,744	95,989	1.7%
GS 2.1 0 - 10 kW	256,118	217,095	-39,023	-15.2%
GS 2.2 10 - 100 kW	2,027,972	1,448,893	-579,079	-28.6%
GS 2.3 110 - 1000 kVA	2,632,106	1,997,144	-634,962	-24.1%
GS 2.4 Over 1000 kVA	1,244,216	816,016	-428,200	-34.4%
Street & Area Lighting	140,495	162,693	22,198	15.8%
Labrador Interconnected Total	$11,914,662	$10,351,585	-$1,563,077	-13.1%
CFB Goose Bay - Secondary	2,991,483	2,991,483	0	0.0%
Total	$297,636,333	$315,795,747	$ 18,159,414	6.1%

* Estimated increase resulting from Newfoundland Power's subsequent pass-through hearing.

The proposed rates are summarized in Schedule I and will be discussed together with the impacts on customer's annual costs by system and customer group. Rural rates that will be set as a result of NP's pass-through hearing are not included in Schedule I.

Q. Please describe the proposed rate for NP.

A. Hydro proposes a rate of 48.0 mills per kWh effective January 1, 2002. The firming up charge for secondary energy from Corner Brook Pulp and Paper Limited is 8.76 mills per kWh as shown on Schedule 1.4 of the 2002 COS Study.

Q. Please describe the proposed rates to be charged Island Industrial Customers.

A. Hydro proposes a firm service rate effective January 1, 2002 comprised of a demand charge of $7.01 per kW of billing demand per month and an energy charge of 23.09 mills per kWh plus the appropriate specifically assigned charge as outlined in the following table.

Table 3

Industrial Customer Specifically Assigned Charges

	Annual Amount
ACI – Grand Falls	$ 107,549
ACI – Stephenville	83,691
Corner Brook Pulp and Paper	73,444
North Atlantic Refining	154,097

For Industrial Customers taking firm service, we also propose a rate for non-firm service. This rate is comprised of a demand charge of $1.50 per kW and a variable energy charge based on the calculation outlined on Page 3 of the proposed Schedule of Rates attached as Schedule A to the Application. It should be noted that the RSP does not apply to the non-firm service rate. In addition, Hydro currently wheels energy for Abitibi-Consolidated. The proposed rate for this wheeling on Hydro's transmission grid is 6.95 mills per kWh.

Q. Please describe the proposed rates for Island Interconnected Rural and L'Anse au Loup System customers.

A. Hydro has not designed specific rates for these customers, as the rates charged by NP will apply. We estimate the increase to NP will result in an average increase to their customers of 3.68% and have therefore included an allowance for an increase of 3.68% in the 2002 revenue from these customers.

Hydro currently offers fewer options for Street and Area Lighting service than are listed on the current rate sheet. A revised listing of the options that Hydro offers is shown on Page 8 of Schedule A to the Application. The rates themselves will continue to reflect those charged by NP.

Q. Please describe the rates Hydro is proposing for Isolated Rural Systems customers effective January 1, 2002.

A. Hydro has not designed specific rates for these customers, with the exception of Government rate classes. Rather we have included the estimated additional revenue in the 2002 COS based on an average increase of 3.68% on all rate components. The final rates will reflect the relevant NP rate for the lifeline portion of the rates while the other components will receive the average overall change in NP's rates resulting from this application.

A revised rate sheet for Street and Area Lighting Service is shown on Page 9 of Schedule A to the Application to reflect the options currently offered by Hydro similar to that outlined above. The rates themselves will continue to reflect those charged by NP.

The proposed rates effective January 1, 2002 for government agencies and departments are summarized in Schedule I. These rates were developed by increasing each component of the existing Isolated Rural Systems rates by 20% consistent with our rate design guideline to limit the level of increase to each rate class to 20%. Schedule II provides an analysis of the impacts on customers' annual costs resulting from this rate change. It should be noted that even though each component was increased approximately 20%, the increases range from approximately 19% to 21% due to rounding.

Q. Please explain the rates Hydro is proposing for the Labrador Interconnected System customers.

A. As indicated earlier Hydro is proposing to move to one set of rates for the Labrador Interconnected System consistent with having one COS for the System. As a starting point, a set of rates for Labrador was designed based on the existing rate categories in the Island Interconnected System. Rates were developed to provide the revenue requirement from each rate class based on the target recovery levels indicated earlier in my evidence. These rates, other than for Street and Area Lighting, are summarized in Schedule III.

A set of firm service rates was designed for 2002 that would move towards this long-term structure. As outlined in Mr. Brickhill's evidence, revenue from secondary sales in Labrador has been credited in the COS study to the other regulated rate classes on the Labrador Interconnected System. This revenue has reduced the revenue requirement for 2002 and resulted in an average overall decrease for Labrador retail rates of 13.1% from existing rates. These proposed rates, outlined in Schedule I, reflect the 2002 COS Study results.

While it was not possible at this time to develop a single rate for either rate class across the System, we were able to develop similar rates for Happy Valley/Goose Bay and the Labrador City/Wabush areas with some components the same. We were able to consolidate the rates in each of these areas into a single set of rates based on the proposed rate classes for each area. The move to one set of rates will require several interim steps.

The changes in rate categories and rate structures will cause different impacts on customers depending on the area in which a customer resides and the rate at which the customer is currently billed. Therefore analyses have been prepared for each area.

Schedule I summarizes the proposed rates effective January 1, 2002. Pages 3 to 7 outline the rates for the Happy Valley/Goose Bay area while Pages 8 to 12 outline the proposed rates for the Labrador City/Wabush area. Schedule IV shows the impacts of proposed rates, except Street and Area Lighting rates, for each area by rate class based on customer usage patterns in 2000. While customer's specific usage patterns tend to vary from year to year the analyses provide a good indication of the range of impacts customers may experience.

Schedule IV, Pages 1 to 4 show the impacts on customers in the Happy Valley/Goose Bay area. Most customers in this area will experience reductions because their existing rates are generally higher than the proposed rates identified in Schedule I.

Pages 5 to 8 of Schedule IV show the impacts on customers in the Labrador City/Wabush area. The range of impacts is quite broad because of the wide range of existing rate classes and rate structures. For example the Domestic class increases range from 3% to 193%. The latter reflects an annual increase of $38 because the customer used very little energy so the increase is due primarily to the increase in the basic customer charge from $1.15 to $3.75 per month.

In addition, the prompt payment discount has been expanded to all rate classes and is the same as on the Island Interconnected System. Minimum monthly charges and alternate energy rates similar to those on the Island Interconnected System are being proposed for all General Service rates.

Q. Are you proposing a secondary rate for Labrador at this time?

A. Yes, Hydro is proposing a Secondary Energy Rate to apply to customers serviced from the Labrador Interconnected System that can avail of fuel switching and can purchase a minimum of 1 MW load, such as an electric boiler, when it is available. Currently the CFB Goose Bay has a contract with Hydro for secondary service for their electric boiler plant. In developing the rate for this service, we used the greater of 90% of the value of the customer's avoided fuel cost or Hydro's opportunity cost based on the revenues we could receive by selling it elsewhere. CFB Goose Bay has the alternative to meet its heating requirements by burning oil in their boiler plant. The net revenue from this customer, estimated to be $2.8 million, has been applied against the overall 2002 revenue requirement for the Labrador Interconnected System to reduce firm service rates.

Q. Are there any other rates issues you wish to address at this time?

A. Yes. At past hearings, Hydro has been requested to provide a formula-based description of the Rate Stabilization Plan. A description of the calculation for each RSP component; hydraulic, load, No. 6 fuel cost and rural rate variations, has been included on Pages 5 to 7 of Schedule A to the Application.

Q. Please review the proposed Rules and Regulations.

A. There is currently one set of Rules and Regulations that apply to the Island Interconnected System, the Isolated Systems and the L'Anse au Loup System. A similar set has been applied in the Happy Valley-Goose Bay Area since 1981. Wabush and Labrador City have been administered based on sets of Rules and Regulations that had been in effect at the time Hydro acquired them in 1985 and 1992, respectively. Hydro proposes to use one set of Rules and Regulations for all areas which is attached to the Application as Schedule B. For the most part, the Regulations have been modified where necessary to make them the same as those approved for NP. This required a variety of minor wording changes for consistency such as “Rules” was changed to “Regulations” throughout. Also several Regulations in Section 6, Service Standards – Street and Area Lighting and Section 9, Charges, have been modified to remove references to providing underground wiring.

Schedule V includes several proposed Regulations that I would like to bring to Board’s attention.

Several definitions in Section 1, Interpretation, have been modified or added. Regulation 1(a)(i) has been modified to refer to the current citation for the Public Utilities Act. Regulation 1(a)(v) has been modified to remove the reference to Power Distribution District customers. Regulations 1(a)(ii) and (xii) are new definitions and result in renumbering several unchanged definitions.

There are three Regulations in Section 9, Charges, that have been revised. Regulations 9(a) and (d) have been revised to reflect that they now require Board approval. Regulation 9(k) has been revised to include different transformer ownership discounts for the Labrador Interconnected System from those offered on the other systems. The transformer ownership discounts for the Labrador Interconnected System are $0.25 and $0.60 per kVA for primary and transmission supply respectively while in other areas they are $0.40 and $0.90 per kVA respectively to reflect the relative rate levels between the systems.

Regulations 12(b) (iii), 12(c) and 13(c) have been revised to remove references to specific sections of the Hydro Corporation Act as these are no longer necessary with the advent of PUB regulation. The wording is now similar to that used by NP.

Hydro is also proposing to add wording to the rate descriptions for NP and Industrial Customers to ensure consistent treatment of transformer losses based on the location of metering equipment similar to that done for Hydro Rural Customers. Hydro rural rates are all based on secondary distribution voltage supply. Regulation 7(n) describes the proper adjustment to meter readings that are based on primary metering to ensure fairness. Similarly the rates for NP and Industrial Customers are based on transmission supply to the line side terminals of customer owned or specifically assigned transformers. Hydro has included a description of the necessary adjustment that must be made for situations where the metering is on the load side of the transformer to ensure fairness and proper cost recovery.

Q. Does this conclude your evidence?

A. Yes.

Newfoundland and Labrador Hydro
Comparison of Existing and Proposed Rates
Island Interconnected System

	Existing Rates	Proposed Rates
Newfoundland Power		
Firm Service	4.531 ¢ per kWh	4.800 ¢ per kWh
HST Credit	($123,083) per month	-
Secondary Firming up Charge	1.040 ¢ per kWh	0.876 ¢ per kWh
Island Industrial		
Firm Service		
Demand Charge	$7.36 per kW per month	$7.01 per kW per month
Energy Charge	1.934 ¢ per kWh	2.309 ¢ per kWh
Non-Firm Service		
Interuptible A		
Demand Charge	$7.36 per kW per month	$1.50 per kW per month
Energy Charge	1.934 ¢ per kWh	Fuel-based rate
Emergency Power		
Demand Charge	-	$1.50 per kW per month
Energy Charge	Fuel-based rate	Fuel-based rate
Exceptional Power		
Demand Charge	$7.36 per kW per month	$1.50 per kW per month
Energy Charge	Fuel-based rate	Fuel-based rate
Wheeling	0.649 ¢ per kWh	0.695 ¢ per kWh

Newfoundland and Labrador Hydro
Comparison of Existing and Proposed Rates
Isolated Systems - Government Departments and Agencies

	Existing Rates		Proposed Rates	
Domestic	**1.2**		**1.2G**	
Basic Customer Charge	$16.31	per month	$19.57	per month
Energy Charge				
- First 700 kWh	6.770	¢ per kWh	8.124	¢ per kWh
- Next 300 kWh	9.571	¢ per kWh	11.485	¢ per kWh
- Excess kWh	12.975	¢ per kWh	15.570	¢ per kWh
Minimum Monthly Charge	$16.31		$19.57	
Prompt Payment Discount	1.50%	- Minimum $1	1.50%	- Minimum $1
G.S. Diesel	**2.5**		**2.5G**	
Basic Customer Charge	$18.57	per month	$22.28	per month
Energy Charge				
- First 700 kWh	8.853	¢ per kWh	10.624	¢ per kWh
- Excess kWh	19.470	¢ per kWh	23.364	¢ per kWh
Minimum Monthly Charge	$18.57		$22.28	
Prompt Payment Discount	1.50%	- Minimum $1	1.50%	- Minimum $1; Maximum $500

Street & Area Lighting	**4.1**		**4.1G**
	Monthly Rates		**Monthly Rates**
Mercury Vapour	**Sentinel/ Standard**	**Post Top**	**Sentinel/ Standard**
175 Watt	$13.19	$14.56	-
250 Watt	$16.15	-	$19.38
400 Watt	$21.62	-	-
700 Watt	$33.99	-	-
1000 Watt	$50.57	-	-
High Pressure Sodium			
100 Watt	$13.19	$14.56	$15.83
150 Watt	$16.15	$17.80	$19.38
250 Watt	$21.23	-	$25.48
400 Watt	$28.00	-	$33.60
Poles			
Wood	$6.06	-	$7.27
30 ft. Concrete or Metal	$9.90	-	-
45 ft. Concrete or Metal	$14.28	-	-
25 ft. Concrete or Metal, Post Top	$8.63	-	-
Underground Wiring	$14.47	-	-

Newfoundland and Labrador Hydro
Comparison of Existing and Proposed Rates
Happy Valley-Goose Bay Area

	Existing Rates		Proposed Rates	
Domestic	**1.1A**		**1.1H**	
Basic Customer Charge	$6.00	per month	$7.00	per month
Energy Charge				
- First 600 kWh	4.100	¢ per kWh	-	
- Excess kWh	3.300	¢ per kWh	-	
- All kWh	-		3.190	¢ per kWh
Minimum Monthly Charge	$6.00		$7.00	
Prompt Payment Discount	10%	- Maximum $1	1.50%	- Minimum $1
G.S. 0 - 10 kW	**2.1A**		**2.1H**	
Basic Customer Charge	$9.10	per month	$9.10	per month
Energy Charge	5.400	¢ per kWh	3.220	¢ per kWh
Minimum Monthly Charge				
- Single Phase	$9.10		$9.10	
- Three Phase	$20.00		$20.00	
Prompt Payment Discount	10%	- Maximum $1	1.50%	- Minimum $1
G.S. 10 - 100 kW	**2.2A**		**2.2H**	
Demand Charge				
- Regular	$3.85	per kW of Annual Peak	$2.00	per kW of Current Month Demand
- Churches and Schools	$1.87	per kW of Annual Peak	$2.00	per kW of Current Month Demand
Energy Charge				
- First 100 kWh per kW	5.600	¢ per kWh	-	
- Excess kWh	2.900	¢ per kWh	-	
- All kWh	-		2.000	¢ per kWh
Maximum Monthly Charge	10.750	¢ per kWh	6.800	¢ per kWh; not less than the Minimum Charge
Minimum Monthly Charge	$1.25	per kW of Annual Peak	$1.05	per kW of Annual Peak
- Three Phase	$1.25	per kW of Annual Peak	$1.05	per kW of Annual Peak; not less than $20.00
Prompt Payment Discount				
- Regular	25.000	¢ per kW of Billing Demand	1.50%	- Minimum $1
- Churches and Schools	12.000	¢ per kW of Billing Demand	1.50%	- Minimum $1

Newfoundland and Labrador Hydro
Comparison of Existing and Proposed Rates
Happy Valley-Goose Bay Area (continued)

	Existing Rates		Proposed Rates	
G.S. 110 kVA and over	**2.3A**		**2.3H < 1000 kVa**	
Demand Charge	$3.50	per kVA of Annual Peak	$1.75	per kVA of Current Month Demand
Energy Charge				
- First 150 kWh per kVA; Maximum 90,000kWh	3.750	¢ per kWh	-	
- Excess kWh	2.100	¢ per kWh	-	
- All kWh	-		1.900	¢ per kWh
Maximum Monthly Charge	10.750	¢ per kWh (if < 350 kVA)	6.800	¢ per kWh; not less than the Minimum Charge
Minimum Monthly Charge				
- For Annual Peak < 350 kVA	$1.25	per kVA of Annual Peak	$1.05	per kVA of Annual Peak
- For Annual Peak ≥ 350 kVA	$3.50	per kVA of Annual Peak	$1.05	per kVA of Annual Peak
Prompt Payment Discount	-		1.50%	- Maximum $500
G.S. 1000 kVA and over	**(See 2.3A above)**		**2.4H**	
Demand Charge	-		$1.50	per kVA of Current Month Demand
Energy Charge	-		1.800	¢ per kWh
Maximum Monthly Charge	-		6.800	¢ per kWh; not less than the Minimum Charge
Minimum Monthly Charge	-		$1.05	per kVA of Annual Peak
Prompt Payment Discount	-		1.50%	- Maximum $500
Electric Heating G.S.	**3.1A**			
Demand Charge	$2.35	per kVA of Annual Peak		
Energy Charge	2.100	¢ per kWh		Applicable General Service Rate
Maximum Monthly Charge	10.750	¢ per kWh		Based on Load Characteristics
Minimum Monthly Charge	$1.25	per kVA of Annual Peak		
All-Electric G.S.	**3.2A**			
Demand Charge	$3.50	per kVA of Annual Peak		
Energy Charge				
- First 120 kWh per kVA; Maximum 22,000kWh	3.700	¢ per kWh		
- Excess kWh	2.100	¢ per kWh		
Minimum Monthly Charge	$3.50	per kVA of Annual Peak		Applicable General Service Rate
- Single Phase	$10.00			Based on Load Characteristics
- Three Phase	$20.00			
Alternate Rate if less than 350 kVA	10.750	¢ per kWh		
Minimum Monthly Charge	$1.25	per kVA of Annual Peak		
- Single Phase	$10.00			
- Three Phase	$20.00			

Newfoundland and Labrador Hydro
Comparison of Existing and Proposed Rates
Happy Valley-Goose Bay Area (continued)

	Existing Rates				Proposed Rates
Street & Area Lighting Less Than 20 kW	**4.11A**				**4.1H**
	Monthly Rates				**Monthly Rates**
	Sentinel	**Post Top**	**Standard**		**Sentinel/**
Mercury Vapour			**2 ft. Bracket**	**6 ft. Bracket**	**Standard**
175 Watt	$7.85	$9.18	$9.30	-	-
250 Watt	$9.99	$10.86	$11.09	-	$9.99
400 Watt	$13.80	$14.67	$14.96	-	-
700 Watt	-	-	$26.33	-	-
1000 Watt	-	-	$33.73	-	-
High Pressure Sodium					
100 Watt	-	$9.55	$8.75	$8.95	$8.75
150 Watt	-	$13.45	$12.10	$12.50	$12.10
250 Watt	-	-	-	$15.95	$15.95
400 Watt	-	-	-	$20.10	$20.10
Poles					
Wood Poles, direct buried		$1.67			$3.00
Steel poles, direct buried		$4.04			-
30 ft. concrete poles, direct buried		$2.19			-
40 ft. concrete poles, direct buried		$4.79			-
45 ft. concrete poles, direct buried		$5.66			-
50 ft. concrete poles, direct buried		$8.20			-
Steel poles for post top luminaries		$2.14			-
Concrete poles for post top luminaries		$2.02			-
Underground Wiring		$6.35			-

Newfoundland and Labrador Hydro
Comparison of Existing and Proposed Rates
Happy Valley-Goose Bay Area (continued)

	Existing Rates				Proposed Rates
Street & Area Lighting 20 kW - 350 kVa	**4.12A**				**4.1H**
	Monthly Rates				**Monthly Rates**
	Sentinel	**Post Top**	**Standard**		**Sentinel/**
Mercury Vapour			**2 ft. Bracket**	**6 ft. Bracket**	**Standard**
175 Watt	$7.33	$8.72	$8.84	-	-
250 Watt	$9.36	$10.22	$10.28	-	$9.99
400 Watt	$12.76	$13.57	$13.80	-	-
700 Watt	-	-	$24.31	-	-
1000 Watt	-	-	$31.07	-	-
High Pressure Sodium					
100 Watt	-	$9.55	$8.75	$8.95	$8.75
150 Watt	-	$13.45	$12.10	$12.50	$12.10
250 Watt	-	-	-	$15.95	$15.95
400 Watt	-	-	-	$20.10	$20.10
Poles					
Wood Poles, direct buried		$1.67			$3.00
Steel poles, direct buried		$4.04			-
30 ft. concrete poles, direct buried		$2.19			-
40 ft. concrete poles, direct buried		$4.79			-
45 ft. concrete poles, direct buried		$5.66			-
50 ft. concrete poles, direct buried		$8.20			-
Steel poles for post top luminaries		$2.14			-
Concrete poles for post top luminaries		$2.02			-
Underground Wiring		$6.35			-

Newfoundland and Labrador Hydro
Comparison of Existing and Proposed Rates
Happy Valley-Goose Bay Area (continued)

	Existing Rates				Proposed Rates
Street & Area Lighting 350 kVa and over	**4.13A**				**4.1H**
	Monthly Rates				**Monthly Rates**
	Sentinel	**Post Top**	**Standard**		**Sentinel/**
Mercury Vapour			**2 ft. Bracket**	**6 ft. Bracket**	**Standard**
175 Watt	$6.70	$8.14	$8.20	-	-
250 Watt	$8.49	$9.36	$9.47	-	$9.99
400 Watt	$11.49	$12.13	$12.47	-	-
700 Watt	-	-	$22.00	-	-
1000 Watt	-	-	$27.72	-	-
High Pressure Sodium					
100 Watt	-	$9.55	$8.75	$8.95	$8.75
150 Watt	-	$13.45	$12.10	$12.50	$12.10
250 Watt	-	-	-	$15.95	$15.95
400 Watt	-	-	-	$20.10	$20.10
Poles					
Wood Poles, direct buried		$1.67			$3.00
Steel poles, direct buried		$4.04			-
30 ft. concrete poles, direct buried		$2.19			-
40 ft. concrete poles, direct buried		$4.79			-
45 ft. concrete poles, direct buried		$5.66			-
50 ft. concrete poles, direct buried		$8.20			-
Steel poles for post top luminaries		$2.14			-
Concrete poles for post top luminaries		$2.02			-
Underground Wiring		$6.35			-

Newfoundland and Labrador Hydro
Comparison of Existing and Proposed Rates
Labrador City Area

	Existing Rates		Proposed Rates	
Domestic	**1.1**		**1.1W**	
Basic Customer Charge	-		$3.75	per month
Energy Charge				
0 - 20 kWh	$1.15	Minimum Charge	-	
21 - 60 kWh	2.780	¢ per kWh	-	
61 - 300 kWh	1.270	¢ per kWh	-	
Over 300 kWh	1.150	¢ per kWh	-	
All kWh	-		1.350	¢ per kWh
Minimum Monthly Charge	$1.15		$3.75	
Prompt Payment Discount	-		1.50%	- Minimum $1
G.S. - Single Phase (Commercial)	**2.2**			
Demand Charge (not less than 1 kW)	$1.15	per kW of Current Month Demand		
Energy Charge				
First 10 kWh per kW		Free		Applicable General Service Rate
Next 90 kWh per kW	4.620	¢ per kWh		Based on Load Characteristics
Next 50 kWh per kW	2.890	¢ per kWh		
Excess kWh	1.150	¢ per kWh		
G.S. - Three Phase (Industrial)	**2.3**			
Demand Charge (not less than 4 kW)	$1.90	per kW of Current Month Demand		
Energy Charge				Applicable General Service Rate
First 40 kWh per kW	4.620	¢ per kWh		Based on Load Characteristics
Excess kWh	1.150	¢ per kWh		
G.S. 0 - 10 kW			**2.1W**	
Basic Customer Charge	-		$9.10	per month
Energy Charge	-		2.200	¢ per kWh
Minimum Monthly Charge				
- Single Phase	-		$9.10	
- Three Phase	-		$20.00	
Prompt Payment Discount	-		1.50%	- Minimum $1
G.S. 10 - 100 kW			**2.2W**	
Demand Charge	-		$2.00	per kW of Current Month Demand
Energy Charge	-		1.600	¢ per kWh
Maximum Monthly Charge	-		6.800	¢ per kWh; not less than the Minimum Charge
Minimum Monthly Charge	-		$1.05	per kW of Annual Peak
- Three Phase	-		$1.05	per kW of Annual Peak; not less than $20.00
Prompt Payment Discount	-		1.50%	- Minimum $1

Newfoundland and Labrador Hydro
Comparison of Existing and Proposed Rates
Labrador City Area (continued)

	Existing Rates	Proposed Rates
G.S. 110 - 1000 kVA		**2.3W**
Demand Charge	-	$1.75 per kVA of Current Month Demand
Energy Charge	-	1.500 ¢ per kWh
Maximum Monthly Charge	-	6.800 ¢ per kWh; not less than the Minimum Charge
Minimum Monthly Charge	-	$1.05 per kVA of Annual Peak
Prompt Payment Discount	-	1.50% - Maximum $500
G.S. 1000 kVA and over		**2.4W**
Demand Charge	-	$1.50 per kVa of Current Month Demand
Energy Charge	-	1.400 ¢ per kWh
Maximum Monthly Charge	-	6.800 ¢ per kWh; not less than the Minimum Charge
Minimum Monthly Charge	-	$1.05 per kVA of Annual Peak
Prompt Payment Discount	-	1.50% - Maximum $500
Street and Area Lighting		**4.1W**
Installed after December 31, 2001		**Monthly Rates Sentinel/ Standard**
100 W	-	$7.11
150 W	-	$9.09
250 W	-	$10.36
400 W	-	$13.70
Wood Poles	-	$3.00
Installed as of December 31, 2001	**Labrador City Rate**	**4.11W**
High Pressure Sodium	**Monthly Rates Sentinel/ Standard**	**Monthly Rates Sentinel/ Standard**
150 W	$1.15	$2.65
Wood Poles	-	$3.00

Newfoundland and Labrador Hydro
Comparison of Existing and Proposed Rates
Wabush Area

	Existing Rates		Proposed Rates	
Domestic	**1.1**		**1.1W**	
Basic Customer Charge	$2.42	per month	$3.75	per month
Energy Charge	1.318	¢ per kWh	1.350	¢ per kWh
Minimum Monthly Charge	$2.42		$3.75	
Prompt Payment Discount	10%	- Maximum $1.00	1.50%	- Minimum $1
G.S. 0 - 10 kW	**2.1**		**2.1W**	
Basic Customer Charge	-		$9.10	per month
Demand Charge	$1.33	per kW of Current Demand	-	
Energy Charge				
- First 150 kWh per kW	4.309	¢ per kWh	-	
- Excess kWh	1.333	¢ per kWh	-	
- All kWh	-		2.200	¢ per kWh
Maximum Monthly Charge	6.800	¢ per kWh	-	
Minimum Monthly Charge				
- Single Phase	$1.15	per kW of Current Demand	$9.10	
- Three Phase	$1.15	per kW of Current Demand	$20.00	
Prompt Payment Discount	6.000	¢ per kW of Current Demand	1.50%	- Minimum $1
G.S. 10 kW and over (Single Phase)	**2.2**		**2.2W**	**(See 2.3W below if ≥ 100kW)**
Demand Charge	$1.33	per kW of Current Demand	$2.00	per kW of Current Month Demand
Energy Charge				
- First 150 kWh per kW	4.335	¢ per kWh	-	
- Excess kWh	1.333	¢ per kWh	-	
- All kWh	-		1.600	¢ per kWh
Maximum Monthly Charge	6.800	¢ per kWh	6.800	¢ per kWh; not less than the Minimum Charge
Minimum Monthly Charge	$1.15	per kW of Current Demand	$1.05	per kW of Annual Peak
Prompt Payment Discount	6.000	¢ per kW of Current Demand	1.50%	- Minimum $1
G.S. 10 - 100 kW (Three Phase)	**2.2A**		**2.2W**	
Demand Charge	$2.19	per kW of Current Demand	$2.00	per kW of Current Month Demand
Energy Charge				
- First 150 kWh per kW	2.402	¢ per kWh	-	
- Excess kWh	1.333	¢ per kWh	-	
- All kWh	-		1.600	¢ per kWh
Maximum Monthly Charge	6.450	¢ per kWh	6.800	¢ per kWh; not less than the Minimum Charge
Minimum Monthly Charge	$1.15	per kW of Current Demand	$1.05	per kW of Annual Peak; not less than $20.00
Prompt Payment Discount	10.000	¢ per kW of Current Demand	1.50%	- Minimum $1

Newfoundland and Labrador Hydro
Comparison of Existing and Proposed Rates
Wabush Area (continued)

	Existing Rates		Proposed Rates	
G.S. 100 kW and over (Three Phase)	**2.3**		**2.3W 110 kVA - 1000 kVA**	
Demand Charge	$2.19	per kW of Current Demand	$1.75	per kW of Current Month Demand
Energy Charge				
- First 150 kWh per kW	2.402	¢ per kWh	-	
- Excess kWh	1.333	¢ per kWh	-	
- All kWh	-		1.500	¢ per kWh
Maximum Monthly Charge	6.450	¢ per kWh	6.800	¢ per kWh; not less than the Minimum Charge
Minimum Monthly Charge	$1.15	per kW of Current Demand	$1.05	per kW of Annual Peak
Prompt Payment Discount	-		1.50%	- Maximum $500
G.S. 1000 kVA and over	**(See 2.3 above)**		**2.4W**	
Demand Charge	-		$1.50	per kW of Current Month Demand
Energy Charge				
- First 150 kWh per kW	-		-	
- Excess kWh	-		-	
- All kWh	-		1.400	¢ per kWh
Maximum Monthly Charge	-		6.800	¢ per kWh; not less than the Minimum Charge
Minimum Monthly Charge	-		$1.05	per kW of Annual Peak
Prompt Payment Discount	-		1.50%	- Maximum $500
G.S. All-Electric (Single Phase)	**3.2**			
Demand Charge	$1.33	per kW of Current Month Demand		
Energy Charge				
- First 150 kWh per kW	4.324	¢ per kWh		Applicable General Service Rate
- Excess kWh	1.333	¢ per kWh		Based on Load Characteristics
Maximum Monthly Charge	6.800	¢ per kWh		
Minimum Monthly Charge	$1.15	per kW of Current Month Demand		
	$4.95	Minimum		
G.S. All-Electric 0 - 100 kW (Three Phase)	**3.2A**			
Demand Charge	$2.19	per kW of Current Demand		
Energy Charge				
- First 150 kWh per kW	2.402	¢ per kWh		Applicable General Service Rate
- Excess kWh	1.333	¢ per kWh		Based on Load Characteristics
Maximum Monthly Charge	6.450	¢ per kWh		
Minimum Monthly Charge	$1.15	per kW of Current Demand		
	$9.90	Minimum		

	Existing Rates					Proposed Rates
G.S. All-Electric 100 kW & Over	**3.3**					
Demand Charge			$2.19 per kW of Current Month Demand			
Energy Charge						
- First 150 kWh per kW			2.402 ¢ per kWh			Applicable General Service Rate
- Excess kWh			1.333 ¢ per kWh			Based on Load Characteristics
Maximum Monthly Charge			6.450 ¢ per kWh			
Minimum Monthly Charge			$1.15 per kW of Current Month Demand			
Street and Area Lighting						**4.1W**
			Monthly Rates			**Monthly Rates**
			Standard			**Sentinel/**
Mercury Vapour [1]	**Sentinel**	**Post Top**	**2 ft. Bracket**	**6 ft. Bracket**		**Standard**
250 W	$5.04	-	$5.04	$5.04		$5.04
Mercury Vapour [2]						
250 W	$7.28	-	$7.28	$7.53		-
High Pressure Sodium						
100 W	-	$7.96	$7.11	$7.31		$7.11
150 W	-	$10.19	$9.09	$9.49		$9.09
250 W	-	-	-	$10.36		$10.36
400 W	-	-	-	$13.70		$13.70
Wood Poles		-				$3.00

[1] Originally owned by Wabush and transferred to Hydro in 1987.

[2] Originally owned by Hydro or installed after September 1, 1985

Newfoundland and Labrador Hydro
Impact of Proposed Rates on Annual Electricity Costs
Government Departments and Agencies
Domestic Diesel 1.2G

Change in Annual Costs ($)			Percentage Change 19% to 21%
50	to	400	73.17%
400	to	750	17.07%
750	to	1,100	2.44%
1,100	to	1,450	4.88%
1,450	to	1,800	2.44%
		Total	**100.00%**

Each number in the body of the table represents the proportion of customers with the combination of percent range at the top and dollar range to the left.

Notes: (1) The average number of customers for 2000 was 45.
(2) This analysis is based on 2000 usage patterns.

Newfoundland and Labrador Hydro
Impact of Proposed Rates on Annual Electricity Costs
Government Departments and Agencies
Domestic Diesel 1.2G (Schools)

Change in Annual Costs ($)			Percentage Change 19% to 21%
39	to	1,100	42.86%
1,100	to	2,100	25.00%
2,100	to	3,100	17.86%
3,100	to	4,100	7.14%
4,100	to	5,150	7.14%
		Total	**100.00%**

Each number in the body of the table represents the proportion of customers with the combination of percent range at the top and dollar range to the left.

Notes: (1) The average number of customers for 2000 was 30.
(2) This analysis is based on 2000 usage patterns.

Newfoundland and Labrador Hydro
Impact of Proposed Rates on Annual Electricity Costs
Government Departments and Agencies
General Service Diesel 2.5G

Change in Annual Costs ($)			Percentage Change 19% to 21%
40	to	2,500	91.40%
2,500	to	4,900	6.45%
4,900	to	7,300	1.08%
7,300	to	9,700	-
9,700	to	12,700	1.08%
		Total	**100.00%**

Each number in the body of the table represents the proportion of customers with the combination of percent range at the top and dollar range to the left.

Notes: (1) The average number of customers for 2000 was 88.
(2) This analysis is based on 2000 usage patterns.

Newfoundland and Labrador Hydro
Labrador Interconnected System
Long-Term Rate Structures

Domestic	
Basic Customer Charge	$8.45 per Month
Energy Charge – All kWh	2.020¢ per kWh
Minimum Monthly Charge	$8.45
General Service 0 – 10 kW	
Basic Customer Charge	$9.65 per Month
Energy Charge – All kWh	3.455¢ per kWh
Minimum Monthly Charge	
- Single phase	$9.65
- Three phase	$19.30
General Service 10 – 100 kW	
Demand Charge	$2.00 per kW
Energy Charge – All kWh	1.770¢ per kWh
Minimum Monthly Charge -Three phase	$19.30
General Service 110 – 1000 kVA	
Demand Charge	$1.75 per kVA
Energy Charge – All kWh	1.245¢ per kWh
General Service 1000 kVA and Over	
Demand Charge	$1.50 per kVA
Energy Charge – All kWh	1.200¢ per kWh

Newfoundland and Labrador Hydro
Impact of Proposed Rates on Annual Electricity Costs
Happy Valley-Goose Bay
Domestic Rate 1.1H

	Percentage Change in Annual Costs					
Change in Annual Costs ($)	**-15% to -10%**	**-10% to -5%**	**-5% to 0%**	**0% to 20%**	**20% to 40%**	**Total**
-192 to -128		0.39%	0.14%			0.54%
-128 to -64		77.67%				77.67%
-64 to 0	7.81%	9.20%	1.18%			18.19%
0 to 12				3.50%		3.50%
12 to 24				0.07%	0.04%	0.11%
Total:	**7.81%**	**87.26%**	**1.32%**	**3.57%**	**0.04%**	**100.00%**

Each number in the body of the table represents the proportion of customers with the combination of percent range at the top and dollar range to the left.

Notes: (1) The average number of customers for 2000 was 3,367.
(2) This analysis is based on 2000 usage patterns.

Newfoundland and Labrador Hydro
Impact of Proposed Rates on Annual Electricity Costs
Happy Valley-Goose Bay
General Service 2.1H

Change in Annual Costs ($)			Percentage Change in Annual Costs					
			-57% to -30%	**-30% to 0%**	**0% to 20%**	**20% to 30%**	**30% to 40%**	**Total**
-1,400	to	-700	2.39%					2.39%
-700	to	0	31.58%	48.33%	0.48%			80.38%
0	to	80		0.48%	10.05%			10.53%
80	to	160			3.35%	2.39%		5.74%
160	to	240					0.96%	0.96%
Total:			**33.97%**	**48.80%**	**13.88%**	**2.39%**	**0.96%**	**100.00%**

Each number in the body of the table represents the proportion of customers with the combination of percent range at the top and dollar range to the left.

Notes: (1) The average number of customers for 2000 was 258.
(2) This analysis is based on 2000 usage patterns.

Newfoundland and Labrador Hydro
Impact of Proposed Rates on Annual Electricity Costs
Happy Valley-Goose Bay
General Service 2.2H

			Percentage Change in Annual Costs						
Change in Annual Costs ($)			**-67% to -50%**	**-50% to -30%**	**-30% to -15%**	**-15% to 0%**	**0% to 12%**	**Total**
-6,300	to	-4,500		2.10%				2.10%
-4,500	to	-3,000	0.35%	8.74%	1.05%			10.14%
-3,000	to	-1,500	3.15%	22.03%	3.50%			28.67%
-1,500	to	0	2.45%	44.06%	10.84%	1.40%		58.74%
0	to	32					0.35%	0.35%
Total:			**5.94%**	**76.92%**	**15.38%**	**1.40%**	**0.35%**	**100.00%**

Each number in the body of the table represents the proportion of customers with the combination of percent range at the top and dollar range to the left.

Notes: (1) The average number of customers for 2000 was 316.
(2) This analysis is based on 2000 usage patterns.

Newfoundland and Labrador Hydro
Impact of Proposed Rates on Annual Electricity Costs
Happy Valley-Goose Bay
General Service 2.3H

Change in Annual Costs ($)			Percentage Change in Annual Costs -62% to -53%	-53% to -44%	-44% to -35%	-35% to -26%	-26% to -17%	Total
-28,500	to	-23,100	2.78%		2.78%	2.78%		8.33%
-23,100	to	-17,700		2.78%	2.78%			5.56%
-17,700	to	-12,300			11.11%	2.78%	2.78%	16.67%
-12,300	to	-6,900	2.78%	13.89%	19.44%	2.78%		38.89%
-6,900	to	-1,500	2.78%	8.33%	8.33%	2.78%	8.33%	30.56%
Total:			**8.33%**	**25.00%**	**44.44%**	**11.11%**	**11.11%**	**100.00%**

Each number in the body of the table represents the proportion of customers with the combination of percent range at the top and dollar range to the left.

Notes: (1) The average number of customers for 2000 was 45.
(2) This analysis is based on 2000 usage patterns.

Newfoundland and Labrador Hydro
Impact of Proposed Rates on Annual Electricity Costs
Labrador City/Wabush
Domestic 1.1W

Change in Annual Costs ($)	Percentage Change in Annual Costs: 3% to 20%	20% to 50%	50% to 100%	100% to 150%	150% to 193%	Total
6 to 53	19.10%	14.43%	2.01%	0.50%	0.42%	36.46%
53 to 100	7.05%	12.44%				19.50%
100 to 147	39.13%					39.13%
147 to 194	4.83%					4.83%
194 to 241	0.08%					0.08%
Total:	**70.20%**	**26.87%**	**2.01%**	**0.50%**	**0.42%**	**100.00%**

Each number in the body of the table represents the proportion of customers with the combination of percent range at the top and dollar range to the left.

Notes: (1) The average number of customers for 2000 was 4,250.
(2) This analysis is based on 2000 usage patterns.

Newfoundland and Labrador Hydro
Impact of Proposed Rates on Annual Electricity Costs
Labrador City/Wabush
General Service 2.1W

	Percentage Change in Annual Costs					
Change in Annual Costs ($)	**-36% to -20%**	**-20% to 0%**	**0% to 20%**	**20% to 50%**	**50% to 1150%**	**Total**
-230 to -115	2.63%					2.63%
-115 to 0	1.75%	14.91%				16.67%
0 to 75			21.93%	7.89%	14.91%	44.74%
75 to 150			3.51%	7.02%	19.30%	29.82%
150 to 245			0.88%	1.75%	3.51%	6.14%
Total:	**4.39%**	**14.91%**	**26.32%**	**16.67%**	**37.72%**	**100.00%**

Each number in the body of the table represents the proportion of customers with the combination of percent range at the top and dollar range to the left.

Notes: (1) The average number of customers for 2000 was 154.
(2) This analysis is based on 2000 usage patterns.

Newfoundland and Labrador Hydro
Impact of Proposed Rates on Annual Electricity Costs
Labrador City/Wabush
General Service 2.2W

Change in Annual Costs ($)			Percentage Change in Annual Costs: -43% to -23%	-23% to 0%	0% to 10%	10% to 20%	20% to 58%	Total
-2,200	to	-1,100	2.95%	0.42%				3.38%
-1,100	to	0	25.74%	53.16%				78.90%
0	to	250			11.81%	0.84%	0.42%	13.08%
250	to	500			2.95%	0.42%		3.38%
500	to	1,000				1.27%		1.27%
Total:			**28.69%**	**53.59%**	**14.77%**	**2.53%**	**0.42%**	**100.00%**

Each number in the body of the table represents the proportion of customers with the combination of percent range at the top and dollar range to the left.

Notes: (1) The average number of customers for 2000 was 271.
(2) This analysis is based on 2000 usage patterns.

Newfoundland and Labrador Hydro
Impact of Proposed Rates on Annual Electricity Costs
Labrador City/Wabush
General Service 2.3W

Change in Annual Costs ($)			Percentage Change in Annual Costs: -37% to -20%	-20% to 0%	0% to 2%	2% to 5%	5% to 7%	Total
-8,700	to	-6,000	1.61%	3.23%				4.84%
-6,000	to	-3,000	1.61%	6.45%				8.06%
-3,000	to	0	8.06%	56.45%				64.52%
0	to	600			8.06%	4.84%	1.61%	14.52%
600	to	1,200				6.45%	1.61%	8.06%
Total:			**11.29%**	**66.13%**	**8.06%**	**11.29%**	**3.23%**	**100.00%**

Each number in the body of the table represents the proportion of customers with the combination of percent range at the top and dollar range to the left.

Notes: (1) The average number of customers for 2000 was 68.
(2) This analysis is based on 2000 usage patterns.

Newfoundland and Labrador Hydro
Revisions to the Rules and Regulations

APPLICABILITY:

These general Rules and Regulations apply to all Hydro Rural Customers.

1. INTERPRETATION:

(a) (i) "***Act***" means The Public Utilities Act, R.S.N. 1990, c.P-47 as amended from time to time.

(ii) "***Board***" means the Board of Commissioners of Public Utilities of Newfoundland.

(v) ***"Hydro rural customers"*** means regulated customers served by Hydro other than industrial customers and Newfoundland Power.

(xii) ***"Government Departments and Agencies"*** means electric service accounts of Provincial or Federal government departments, agencies, boards, commissions, and crown corporations and includes schools and hospitals.

9. CHARGES:

(a) Every Customer shall pay Hydro the charges approved by the Board from time to time for the Service(s) provided to the Customer or provided to the Serviced Premises at the Customer's request.

(d) The Customer shall pay Hydro in advance or on such other terms approved by the Board from time to time any contribution in aid of construction as may be determined by the methods prescribed by the Board.

(k) Where a Customer's Service is at primary distribution or transmission voltage and the Customer provides his own transformation and all other facilities beyond the designated point of supply the monthly demand charge shall, subject to the minimum monthly charge, be reduced as follows:

For the Island Interconnected, L'Anse au Loup and Isolated service areas:

(i) for supply at 4 kV to 25 kV .... $0.40 per kVA

(ii) for supply at 33 kV to 138 kV .... $0.90 per kVA

For the Happy Valley-Goose Bay, Labrador City and Wabush service areas:

(iii) for supply at 4 kV to 25 kV .... $0.25 per kVA

(iv) for supply at 33 kV to 138 kV .... $0.60 per kVA

Newfoundland and Labrador Hydro
Revisions to the Rules and Regulations

12. DISCONNECTION OF SERVICE:

(b) (iii) where in the opinion of Hydro the Customer's electrical system is defective and represents a danger to life or property.

(c) Hydro may, in accordance with its collection policies, Disconnect a Service upon prior notice to the Customer if the Customer has a bill for any Service which is not paid in full 30 days or more after issuance.

13. PROPERTY RIGHTS:

(c) The Customer shall provide Hydro with access to the Serviced Premises at all reasonable hours for purposes of reading a meter or installing, replacing, removing or testing its equipment, and measuring or checking the connected load.