IN THE MATTER OF the *Public Utilities Act,* (the "Act"); and

IN THE MATTER OF capital expenditures and rate base of Newfoundland Power Inc.; and

IN THE MATTER OF an application by Newfoundland Power Inc. for an order pursuant to Sections 41 and 78 of the Act:

(a) approving its 2004 Capital Budget of $53,909,000; and

(b) fixing and determining its average rate base for 2002 in the amount of $573,337,000.

BRIEF OF ARGUMENT
OF
NEWFOUNDLAND POWER INC.

SEPTEMBER 17, 2003

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1. INTRODUCTION

This is the completion of the hearing into Newfoundland Power's 2004 Capital Budget application.

Newfoundland Power's brief of argument will be divided into 5 parts.

First, we will review the basis of the application and how it is integrated with this Board's regulation of Newfoundland Power's capital expenditures on an ongoing basis.

Such a review provides the necessary context for the Board's considerations upon the application. From Newfoundland Power's perspective, capital budget applications are a snapshot in time of a continuing activity, namely, the Company's investment in assets necessary to provide service to its customers.

Second, we will review the projects comprising the 2004 Capital Budget application.

Third, we will deal with the issue of fixing and determining Newfoundland Power's 2002 average rate base.

Fourth, we will refer to the reports and evidence that Newfoundland Power was required to file in conjunction with its 2004 Capital Budget Application, being:

1) A Status Report on the 2003 capital expenditures;
2) An updated Information Technology Strategy report for the period 2004 – 2008;
3) A Capital Budget Plan;
4) Evidence relating to changes in deferred charges, including pension costs; and
5) A reconciliation of average rate base to average invested capital.

Finally, we will provide our concluding remarks.

2. THE BASIS OF THE APPLICATION

2.1 Overview

The electrical utility industry is capital intensive. Newfoundland Power currently has approximately $1 billion invested in capital plant and equipment.

Capital investment is required for Newfoundland Power to provide service to its customers. The capital is required to be invested on a continual basis, in every year, at all times of the year, and in all economic conditions.

Approval of the annual capital budget applications is a key means by which the Board exercises its regulatory jurisdiction over Newfoundland Power's capital expenditures. However, this approval process is not the only means used by the Board to discharge that regulatory jurisdiction.

A review and discussion of how the Board discharges its regulatory jurisdiction over Newfoundland Power's capital expenditures is necessary to provide the context for the consideration of this Application.

A convenient starting point for this outline is the legislative framework governing Newfoundland Power's capital expenditure.

2.2 The Legislative Framework

Section 37 (1) of the *Public Utilities Act* states that a utility such as Newfoundland Power shall provide service and facilities that are reasonably safe and adequate and just and reasonable. Section 37 (1) is a cornerstone of Newfoundland Power's obligation to serve its customers.

Section 3 (b) of the *Electrical Power Control Act, 1994* states that all sources and facilities for the production, transmission, and distribution of power in the province should be managed and operated in a manner that would result in:

i. the most efficient production, transmission, and distribution of power,
ii. consumers in the province having equitable access to an adequate supply of power, and
iii. power being delivered to customers in the province at the lowest possible cost consistent with reliable service.

It is important to note that Section 3 (b) does not create a hierarchy between these three principles; rather, each is equally important in the management and operation of electrical facilities in the province.

Section 41 (1) of the *Public Utilities Act*, under which this Application is brought, requires that Newfoundland Power submit to this Board "an annual capital budget of proposed improvements and additions to its property" for this Board's approval.

Section 41 (3) of the *Public Utilities Act* prohibits a utility from proceeding with an improvement or addition in excess of $50,000 or a lease in excess of $5,000 per year without this Board's prior approval.

Section 41 (4) of the *Public Utilities Act* requires a public utility to submit a report to the Board on its actual expenditures on improvements or additions to its property in the prior calendar year, together with an explanation for expenditures in excess of those approved, by April 1 in the following year.

The focus of this hearing is whether Newfoundland Power's proposal for $53.9 million in capital expenditures in 2004 is reasonably required for it to meet its statutory obligation to serve its 220,000 customers. The obligation to serve exists whether those customers are residential, commercial, rural or urban, and regardless of whether they happen to be in growth areas of the province, or in areas of out migration or declining population.

Newfoundland Power has considered these statutory requirements in the preparation of its 2004 Capital Budget and submits that this budget represents the capital expenditures necessary to maintain its electrical system and to continue to meet its statutory obligations under Section 37 (1) of the *Public Utilities Act* and Section 3 (b) of the *Electrical Power Control Act, 1994*.

Under Section 16 of the *Public Utilities Act*, the Board is charged with "the general supervision of all public utilities…" This supervisory power applies to capital expenditures as well as other parts of Newfoundland Power's regulated operations.

Many of Newfoundland Power's filing requirements for capital budget applications are found in the regulatory practice of the Board, which have evolved over many years, as well as the Board's specific direction in this respect in Newfoundland Power's 2003 Capital Budget Order, Order No. P.U. 36 (2002-2003). Similarly, the means of the Board's ongoing supervisory jurisdiction is to be found in the regulatory practice of the Board.

2.3 Regulatory Practice

2.3.1 Capital Budget Filing Requirements in General

The filing requirements applicable to Newfoundland Power's 2004 Capital Budget Application have their genesis in two prior Board orders, Order No. P.U. 7 (2002-2003), Newfoundland and Labrador Hydro's ("Hydro") 2002 General Rate Order, and Order No. P.U. 36 (2002-2003), Newfoundland Power's 2003 Capital Budget Order.

In Order No. P.U. 7 (2002-2003), at page 169, item 45, under the heading "Summary of Board Decisions", the Board ordered Hydro:

> "…commencing with its 2003 Capital Budget Application, to use a **net present value methodology** together with supporting justification to evaluate projects of a **material** amount. Where a project is not evaluated against other acceptable alternatives and/or, if the project does not produce a positive net present value, sufficient rationale must be provided to justify implementation. The Board has set out guidelines to be used by

> NLH in future capital budget applications in Schedule 3, attached to this decision." (Emphasis added)

Schedule 3 to Order No. P.U. 7 (2002-2003) reads in part as follows:

> "NLH shall file future capital budget applications in accordance with the following guidelines and conditions as outlined in Order No. P.U. 7 (2002-2003):
>
> viii) A **cost benefit analysis** of all alternatives, both internal and external, that have been considered, including any DSM measures that have been evaluated." (Emphasis added)

It can be seen in that in Schedule 3 the reference has been changed from a "net present value methodology" to a "cost benefit analysis", and the reference to a 'material amount' has been omitted.

In Order No. P.U. 36 (2002-2003), the Board made the following order with respect to Newfoundland Power:

> "4. Unless otherwise directed by the Board, NP shall follow the guidelines as set out in Schedule C attached to this Order, which may be amended from time to time by the Board."

In the body of Order No. P.U. 36 (2002-2003), at page 11, Schedule C is clearly tied to the guidelines established by the Board for Hydro in Order No. P.U. 7 (2002-2003). Schedule C is in all material respects identical to Schedule 3, other than an expansion of the requirements in item (ii).

The requirement to follow the guidelines set out in Schedule C follows from the review by the Board in the body of Order No. P.U. 36 (2002-2003) of the regulation of capital budgets under the *Public Utilities Act*, and in particular the role of the Board in that process.

At pages 9 and 10 of Order No. P.U. 36 (2002-2003), the Board specifically identifies certain significant issues, including:

1) The adequacy of existing tests and measures justifying to the Board the necessity and reasonableness of capital expenditures,
2) Independent technical reviews,
3) Fair and consistent regulatory practices between the two utilities,
4) Proper long-range planning,
5) The separation of issues pertaining to Capital Budget applications and General Rate applications, and
6) Enhanced project definition, format and justification.

Following the identification of the significant issues referred to above, the Board stated that Newfoundland Power would be required to attend a technical conference where these issues of process and filing requirements for capital budget applications would be addressed. The Board also stated that it expected that the technical conference should serve to clarify the responsibilities of the utilities and the Board with respect to the capital expenditure approval process as required under the Act.

As noted above, pending the technical conference, Newfoundland Power was required to follow the guidelines as set out in Schedule C.

In Board Hearing Counsel's written submissions on Hydro's 2004 Capital Budget Application, at paragraph 17, he stated that while the technical conference was originally planned for 2003, it is now scheduled to take place in the early part of 2004.

The timing of the technical conference in early 2004 was confirmed by the Board in its recent decision with respect to Hydro's capital budget for 2004, Order No. P.U. 29 (2003).

Newfoundland Power believes that it is very important that the technical conference proceed early in 2004 as it will enable Newfoundland Power to incorporate the outcome of the technical conference into its capital budget process in time for the 2005 Capital Budget Application. A successful technical conference will ensure that the Board is receiving information from the Company that truly assists the Board in performing its regulatory obligations with respect to the approval of the capital budgets of Newfoundland Power, as well as those of Hydro.

The technical conference will also enable all of the parties who participate in the capital budget approval process to clarify the intentions of the Board with respect to the 12 guidelines and conditions set out in Schedule C, or Schedule 3 in the case of Hydro, and to ensure that there is a common understanding of the expectations of the parties with respect to the filing requirements of the Board for future capital budget applications.

2.3.2 Cost Benefit Analysis

As noted above, Schedule C calls for a cost benefit analysis of all alternatives, both internal and external, that have been considered. However, in its Summary of Board Decisions in Order No. P.U. 7 (2002-2003), the Board indicated that this type of analysis would only apply where material amounts were involved.

A good example of the need for a cost benefit analysis would be the New Chelsea Hydro Plant, a 46 year old hydro plant with an estimated project cost of $3,973,000. As will be discussed in greater detail below, a cost benefit analysis was performed and established that the levelized cost of electricity generated from the New Chelsea plant following completion of the refurbishment project, over the next 25 years, would be 3.19 cents per kWh, or approximately 60% of the cost of additional power from the Holyrood thermal plant that would have to be generated if New Chelsea were shut down.

Other projects where material expenditures were contemplated and cost benefit analyses were performed and provided to the Board include:

1) Increase Corner Brook Transformer Capacity ($1,184,000),
2) Feeder Addition & Upgrade to Accommodate Growth (Chamberlains) $628,000, and
3) Rebuild Distribution Lines; Install Lightning Arrestors (approximately $300,000 annually, but over five years the cost to complete the installation is approximately $1,500,000).

In other cases, the cost benefit analysis showed that not engaging in a project represented the preferable choice. One example is the results of the CSS Replacement Study, contained in Volume IV, Information Systems, Appendix 3, Attachment A.

However, cost benefit analysis is only applicable where viable alternatives exist. For example, projects such as Extensions and Services are necessary to meet customer growth requirements and have no viable alternatives.

Large expenditures on projects that are principally justified on the basis of productivity gains generally merit a detailed cost benefit analysis. Often, however, productivity is not the principal justification for a capital project. The proposed purchase of a number of AMR meters in this year's Meters project, for example, is justified principally with reference to improvements in employee safety and the ability to access meters. If the meter reader cannot access a meter, the bill is estimated. Avoiding estimated bills improves customer service. While this reduces customer complaints and call centre traffic, such projects cannot be judged on cost considerations alone.

Moreover, the accuracy of a cost benefit analysis depends on the validity of the inputs. Information technology investments in customer service processes will improve those processes by reducing or eliminating manual intervention. However, these are complex processes. In many cases, it is not possible to accurately quantify the incremental productivity improvements that would flow directly from specific capital expenditures.

In many other cases, the least cost alternative is obvious without a formal NPV or cost benefit analysis having to be performed. The project to rewind Generator G1 at Rattling Brook (Volume I, Energy Supply, Schedule B, page 10 ($407,000)) is a case in point. Given the concerns surrounding this generator, as described in Volume II, Energy Supply, Appendix 1, page 3 and 4, and in NLH-11 NP, where the generator has the potential to produce $1,780,000 in energy annually, as noted in NLH-7 NP, the expenditure of $407,000 to rewind this generator is obviously sound, and represents the least cost alternative. The only other alternatives would be to shut down the generator, and lose the value of its generation, or replace the generator at a cost many times that of the rewind project.

The objective of least possible cost consistent with reliable service is often met by normal commercial means. For example, in cases where no viable alternatives exist, the least cost objective may be met through competitive tendering.

2.3.3 2004 Capital Budget Application Filing

Newfoundland Power filed its 2004 Capital Budget Application in compliance with the guidelines set out in Schedule C of Order No. P.U. 36 (2002-2003).

Newfoundland Power has presented the 2004 Capital Budget with justifications provided in Schedule B, supported by additional information and reports in the appendices contained in Volumes II, III and IV. The justifications also give an indication of how each project is to be executed on a least cost basis.

Project costs have been broken down in the manner set out in the guidelines. Additional detail of the capital projects has been provided, as well as reports, reasonable alternatives and economic analyses where appropriate, all in keeping with the dictum of the Board in Order No. P.U. 7 (2002-2003) and Schedule C of Order No. P.U. 36 (2002-2003).

In addition to the filing requirements set out in Schedule C, the format of Newfoundland Power's filing has been modified over the course of time to reflect instances where the Board has previously sought additional information.

Furthermore, following the filing of the 2004 Capital Budget Application, Newfoundland Power received questions in the form of Requests For Information, 194 from the Board Hearing Counsel and 89 from the Intervenor, Hydro. This process provides a further mechanism for the Board to obtain any additional information that it requires in order to fulfill its regulatory mandate.

2.3.4 Ongoing Supervision

After the Board approves a capital budget under section 41 of the *Public Utilities Act,* it then supervises the execution of the budget under Section 16 of the *Public Utilities Act*.

Some key elements of this supervisory role include:

- The Capital Expenditure Progress Reports submitted to the Board within 45 days of the end of each quarter which indicate actual capital expenditure by quarter;
- The Capital Expenditure Status Report for the current year which is filed with each Capital Budget Application and details forecast variances by project;
- The Capital Expenditure Summary Report which is filed annually within 60 days of year end and details actual variances by project;
- Return 4A of the Company's Annual Returns which are filed before April 2 of each year. In accordance with Newfoundland Power's System of Accounts (which were approved by the Board pursuant to section 58 of the *Public Utilities Act*), this return includes actual capital expenditures compared to those approved by the Board. Its accuracy is attested under affidavit by an officer of Newfoundland Power;
- Periodically, the Board commissions an independent engineer to review Newfoundland Power's technical operations. The most recent review was completed in 1998; and
- Applications for approval of capital expenditures supplemental to an approved capital budget are also considered under Section 41 (3) of the *Public Utilities Act* as required.

2.4 Submissions

It is Newfoundland Power's submission that its 2004 Capital Budget Application meets the requirements of:

- Section 41 of *the Public Utilities Act;*
- Section 3(b) of *the Electrical Power Control Act, 1994;*
- Schedule C of Order No. P.U. 36 (2002-2003) and the dictum of the Board in Order No. P.U. 7 (2002-2003);
- Regulatory practice evolved over many years relating to capital budget applications; and
- Regulatory practice which exists relating to the Board's ongoing supervision of Newfoundland Power's capital expenditures.

3. THE 2004 CAPITAL BUDGET

3.1 2004 Capital Budget Overview

Newfoundland Power's 2004 Capital Budget in the amount of $53.9 million has been summarized in Schedule A and outlined in detail in Schedule B to the Application. Additional supporting information is found in the appendices in Volumes II, III and IV.

The Company's electrical system consists of 23 hydro plants, 5 diesel plants, 3 gas turbine facilities, 137 substations and approximately 300 feeders. The Company must also operate and maintain approximately 10,000 km of transmission and distribution lines. Many of these electrical system assets are old, and are subjected to some of the harshest weather conditions in North America.

The vast majority of property, plant and equipment in which Newfoundland Power must invest in order to provide safe reliable service are engineered assets. On-going investment to replace, refurbish and repair these assets necessarily requires sound engineering judgment.

A review of the capital budget by origin: plant replacement; customer sales growth; information systems; Aliant pole purchase; GEC and Unforeseen Items, shows consistency with previous years.

The largest category of proposed capital spending for 2004 is required to replace existing plant and equipment, representing $30 million, or approximately 56% of the total proposed budget. This represents expenditures necessary for the refurbishment or replacement of the existing electrical system and includes projects that reflect:

- The deteriorated condition of the plant and equipment, for example, the New Chelsea hydro plant,
- The suitability of the plant and equipment, for example upgrading transmission lines 16L and 38L with higher capacity conductor, and
- The adequacy of operating performance, for example the upgrade to the WES-02 distribution feeder in the Lumsden / Cape Freels area.

Newfoundland Power's approach to capital investment in the electrical system balances the maximization of asset life with the proactive replacement of deteriorated or inefficient plant. Optimizing the operating life of assets tends to lower overall costs. Newfoundland Power has been successful in managing its operations through a combination of prudent capital investment and operating cost reduction. This point is made in the Information Technology Strategy Report 2004 - 2008, Appendix B, where it is shown that:

- operating expenses per customer served have been reduced from $243 in 1998 to $223 in 2002.
- The Company's workforce has decreased by approximately 15 per cent since 1998.

Furthermore, as noted by Mr. Perry in his testimony, since 1993 and including the proposed 2004 capital expenditures, Newfoundland Power has invested approximately

$500 million on capital expenditures. During the same period, Newfoundland Power's contribution to the rates paid by its customers has actually decreased, in absolute terms, by approximately 1 per cent.

The next largest driver of 2004 capital expenditures, representing approximately $12 million, or 22% of the proposed capital expenditure, is growth in energy sales and the number of customers.

- Two examples of 2004 proposed capital spending required due to growth are the Increase Corner Brook Transformer Capacity project and the additional Feeder in Conception Bay South, referred to at pages 30 and 54 of Schedule B, respectively.
- Distribution accounts such as Extensions, Transformers, Meters and Services are principally (but not exclusively) related to growth in the number of customers.

These expenditures are necessary for the Company to fulfill its obligation to serve under section 37 of the *Public Utilities Act*.

Approximately $3.9 million, or 7% of the proposed capital budget is in the area of Information Systems, and is justified on the basis of improving customer service or maintaining or increasing operational efficiencies, and management of the information technology infrastructure including hardware and software. This reduces the risks associated with functional and technological obsolescence.

The remaining 15% of the proposed 2004 capital budget is related to the Aliant Pole Purchase, General Expenses Capitalized and the Allowance for Unforeseen Items.

3.2 Sound Engineering Judgment

The provision of service and facilities which are "reasonably safe and adequate and just and reasonable" as required by section 37 of the *Public Utilities Act* requires the exercise of judgment. In particular, the timing, necessity and appropriateness of the investment to meet the obligation to serve on a least cost basis involves sound engineering judgment.

Newfoundland Power has in recent years adopted a proactive asset management approach which involves a greater level of judgment than a reactive, or breakdown approach. The Board's duty is to satisfy itself that Mr. Ludlow's division (Operations and Engineering) is doing a reasonable job in the exercise of this judgment.

To assist the Board in this determination, it should be stressed that there was no evidence presented to the Board that:

- Contradicts the engineering judgments reflected in the capital projects presented in the 2004 Capital Budget;
- Demonstrates reasonable alternatives that were not considered by Newfoundland Power; or
- Demonstrates that not proceeding with a particular capital project represented a preferable alternative.

3.3 The Issue of Equitable Access to Service

This issue arises from Section 3 (b) (ii) of the EPCA.

In response to NLH-57 NP, Newfoundland Power addressed how it balances reliability and costs. This response provides the policy position of Newfoundland Power on this important issue.

In the late 80s and early 90s Newfoundland Power focused on building the system. From 1993-1997 Newfoundland Power drastically reduced the level of investment to reflect the economic conditions of the day – the cod moratorium.

Mr. Dan Browne, (the Board's engineering expert) filed a report in 1998 stressing that Newfoundland Power should seek to improve its reliability performance. This was one indication to Newfoundland Power that reliability of service was an issue. Rural councils were complaining of service reliability in the period of low capital expenditure. That was another indication that reliability was a serious issue. Newfoundland Power undertook to address the issue.

Customers' satisfaction with reliability is indicated in the Customer Service Surveys, where reliability is ranked as one of the more important attributes of service and 13 per cent of customers indicate that reliability still needs some improvement.
Reference: PUB-13.

Global customer satisfaction surveys provide a representative sampling of customer opinion across the Company's service territory. They do not provide an accurate reflection of customers' views on reliability in specific areas. If a distribution feeder has experienced poor reliability performance over a specific period, the dissatisfaction of customers on that feeder will not be reflected in customer survey results, which are used to indicate trends, and not to assess detailed service or expenditure requirements.

Reference: Transcript, September 11, 2003, page 86, line 9 to page 91, line 11.

In the last 6 years (1998-2003) Newfoundland Power addressed specific electrical system reliability concerns with the result that, in certain rural areas, reliability has increased. However, at the corporate level, reliability is still below the Canadian average.

Reference: PUB-61.

In 2004, the three feeder reliability projects, in the Wesleyville, Torbay and Bay Roberts areas, are being performed in order to provide customers served by these under performing feeders electrical service that is more comparable to the electrical service received by other customers in the province, and in this way providing the residential and commercial customers served by these three feeders with more equitable access to reliable electrical service.

3.4 Reliability Targets and Capital Planning

SAIDI and SAIFI targets are set annually on a system-wide basis. Individual targets are not set by substation, transmission line or feeder. System-wide reliability statistics provide a global view of how well Newfoundland Power is doing in relation to service reliability. However, they do not indicate the reliability experience of specific customers.

Newfoundland Power monitors reliability performance at the distribution level against past performance, but does not set specific reliability targets below the system level.
Reference: Transcript, September 11, 2003, page 79, line 3 to page 80, line 18.

Through testing and analysis and with the support of information technology, Newfoundland Power proactively manages its assets so that their lives are extended to the extent possible without risking failure. Catastrophic failure of equipment can have safety and environmental ramifications, in addition to its impact on the provision of electrical service to customers.

Although necessary to maintain current reliability levels, capital expenditures of a proactive nature will not be reflected overtly in reliability statistics.
Reference: Transcript, September 11, 2003, page 91, line 19 to page 94, line 15.

In developing appropriate solutions for specific reliability problems, the Company considers the results of regular field inspections, material sampling, and non-destructive testing, as well as ongoing condition assessments conducted during regular maintenance of equipment. All of this information is considered, and the Company's engineers apply their experience and knowledge of industry developments to craft appropriate solutions.

Reference: Transcript, September 11, 2003, page 103, line 7 to page 107, line 22.

Capital expenditures to effect those solutions will improve reliability statistics. These improvements can be tracked on a historical basis, which enables the Company to judge the success of specific reliability initiatives, and to target future initiatives in specific areas. But, there are many variables that impact upon the service reliability of a transmission line or feeder. For example, any number of system components can fail under certain conditions and cause an outage. It is therefore not possible to forecast with precision what the reliability improvement will be on a statistical basis in advance of implementing specific initiatives. This limits the extent to which reliability targets can assist in developing capital budgets.

Reference: Transcript, September 11, 2003, page 96, line 9 to page 104, line 5.

3.5 Capital Project Commentary

3.5.1 Introduction

Schedule B to the Application contains detailed descriptions of proposed capital projects in nine categories. Following is a summary of those projects as presented to the Board as a part of the Application, with a listing of specific references to the projects in the record of the proceeding.

3.5.2 Energy Supply

3.5.2.1 Hydro Plants – Facility Rehabilitation

This project, described at Schedule B, page 10 of the Application, proposes an expenditure of $1,122,000 to rehabilitate or replace deteriorated hydro plant components identified through normal operations, routine inspections and non-destructive testing. The projected capital expenditure for 2004 is much lower than the annual amounts budgeted since 1999.

The majority of the proposed work is to take place at 6 of the Company's 23 small hydroelectric plants. Because the individual projects included in this category are smaller, and do not require complete plant refurbishments, a detailed cost analysis is not conducted. The projects are necessary for the continued safe and reliable operation of the plants, and to maintain environmental compliance. For example, the replacement of the 71 year old head gate at the Pierre's Brook Hydro Plant, is required so the Company is able to conduct the internal inspections and maintenance necessary to maintain the plant in safe operating condition. The seal replacement at the Morris Hydro Plant is necessary to restore the proper operation of the wicket gates, which will ensure the plant can continue to run safely, and that energy production levels are not compromised.

The largest single expenditure in this category relates to the rewind of one of the two generating units at the Rattling Brook Hydro Plant. In 2002, there was a failure of the other unit, which is identical in vintage and operating experience. The repair took approximately 8 months and cost approximately $650,000. Based on the experience with the other generator and a partial discharge test that provided readings outside the parameters of the other unit and of other plants of similar vintage, it is necessary to refurbish the unit to avoid failure in service. Doing the work on a planned basis will cost approximately $400,000 and take about 4 months.

All of these plants produce energy at a cost that is significantly lower than the cost of available alternative sources, including thermal production at Holyrood. It is much less costly to perform the rehabilitation work on a planned basis than to do it when a major component fails. An unplanned failure can lead to a complete shutdown of a plant, and pose dangers to personal safety and to property. In addition, performing the work on a planned basis can minimize the spillage of valuable water.

Reference: Volume II, Energy Supply Appendix 1.
NLH-3; NLH-4; NLH-5; NLH-6; NLH-7; NLH-8; NLH-9; NLH-10; NLH-11; NLH-12.
Transcript, September 10, 2003, page 88, line 4 to page 90, line 15; page 91, line 3 to page 97, line 15; page 111, line 1 to page 119, line 10.

3.5.2.2 New Chelsea – Hydro Plant Refurbishment

This project, described at Schedule B, page 12 of the Application, involves a major refurbishment of a 46-year-old hydroelectric plant at a cost of $3,973,000. The plant has operated continuously, and has had little capital investment since its construction. The remaining undepreciated investment in the plant is estimated at approximately $100,000. Much of the equipment is now beyond its expected service life. Based on a detailed condition assessment, it is necessary to do a major refurbishment of the plant to ensure its continued safe and reliable operation.

The project includes replacement of the penstock, which is a combination of wood and steel. Non-destructive testing and inspections by an external consultant have revealed severe deterioration of the steel. If the penstock were to fail catastrophically, buildings and civil works such as the roadway, which are downstream of the plant, would be at risk. Based on the results of the testing and inspections, it is necessary to replace both the wood and steel portions of the penstock now.

The project also includes the replacement of the protection and control equipment. In the last 5 years, improper operation of the protection and control equipment has caused the plant to trip off line 92 times. When the plant is operating in isolation from the grid, the inability of the governor to maintain frequency stability results in power quality that is outside industry standards.

The New Chelsea plant produces very low cost energy. The levelized cost of future energy production at the plant, including the cost of the proposed refurbishment and all forecast capital and operating expenditures over the next 25 years, is 3.19 cents per kilowatt-hour, as compared to the short-run marginal cost of thermal production at Holyrood of 5.13 cents per kilowatt-hour. Calculated on the basis of a period of very efficient fuel consumption at Holyrood in 2002, the short-run marginal cost of energy at Holyrood is still only slightly less than 5 cents per kilowatt-hour.

In addition to the low cost supply of hydroelectric energy, the plant provides the added benefit of being available to supply customers isolated from the grid by either planned or unplanned transmission line work. A comprehensive refurbishment project is the most efficient way to restore the plant to sound operating condition.

Reference: Volume II, Energy Supply Appendix 2.
PUB-124; PUB-125; PUB-126; PUB-127.
NLH-13; NLH-14; NLH-15; NLH-16; NLH-17; NLH-18.
Transcript, September 10, 2003, page 85, line 11 to page 88, line 2; page 103, line 10 to page 104, line 20; page 121, line 8 to page 128, line 21; September 11, 2003, page 115, line 8 to page 116, line 8; September 12, 2003, page 150, line 7 to page 153, line 10; page 157, line 19 to page 159, line 6; page 203, line 5 to page 205, line 13.

3.5.2.3 Purchase 2.5 MW Standby Portable Diesel

The proposed purchase of a 2.5 MW portable diesel generator, at a cost of $1.7 million, fulfills the recommendation of a report filed with the Board last year (PUB-4.1, Attachment A, Newfoundland Power 2003 Capital Budget Application) that the Company acquire a total of 5 MW of portable generation. The project proposal is described at Schedule B, page 14 of the Application.

Because of typical loads on the Company's feeders, total capacity of approximately 5.0 MW is required. Because of weight limits associated with portability, the proposed units are sized at 2.5 MW. The design of the units will allow them to be operated in tandem to deal with larger loads; but having separate units provides more flexibility of use. The Company proposes to locate the second 2.5 MW unit at Trepassey. On the basis of outage statistics, this location will provide the greatest benefit in terms of security of supply. The unit will provide emergency backup during the winter months at the end of a long radial transmission line. The unit will also be available to provide timely emergency backup for other customers in the eastern portion of the island, complementing the 2.5 MW unit that is to be installed this year to fulfill similar requirements for customers in the western portion of the island. During the summer, when major outages are less likely, the unit will be used to support construction and repair projects.

A mobile generator is an economic alternative for providing security of supply for the Trepassey area. The construction of a second transmission line to create a looped system would be much more expensive.

Both mobile generators will be available for use by Newfoundland & Labrador Hydro under the Equipment Sharing Agreement between the two utilities.

Reference: PUB-21; PUB-22.
NLH-19; NLH-20; NLH-21; NLH-22; NLH-23; NLH-24; NLH-25.
Transcript, September 11, 2003, page 164, line 11 to page 173, line 17.

3.5.2.4 Major Electrical Equipment Repairs

As described in Schedule B, page 16 of the Application, this is a provision of $150,000 to cover capital costs associated with the unanticipated failure of major electrical components at the Company's generating facilities. An approved amount in respect of such costs enables the Company to act expeditiously in response to such unanticipated problems.

Reference: PUB-23.

3.5.3 Substations

3.5.3.1 Rebuild Substations

This project, described at Schedule B, page 18, of the Application, involves an expenditure of $1,023,000 to replace deteriorated and substandard substation equipment. The planned work is necessary to ensure reliable service and address safety concerns at 13 of the Company's 137 substations. The increase in expenditures in this category over previous years reflects an increase in deteriorated equipment and deficiencies identified through regular inspections and engineering studies.

Reference: Volume II, Substations Appendix 1
PUB-24; PUB-25; PUB-26.
NLH-26; NLH-27; NLH-28; NLH-29; NLH-30.

3.5.3.2 Replacement & Standby Substation Equipment

This project, described at Schedule B, page 20, of the Application, involves an expenditure of $1,314,000 to replace deteriorated equipment and to ensure appropriate spare equipment levels are maintained. New spares are required to replace existing spare equipment that has been used to replace equipment that is deteriorated or failed in the field.

Reference: Volume II, Substations Appendix 2
PUB-30.
NLH-31; NLH-32; NLH-33; NLH-34; NLH-35.

3.5.3.3 Transformer Cooling Refurbishment

This expenditure of $398,000, described at Schedule B, page 22, of the Application, involves replacing corroded radiators on power transformers. The replacement of these mild steel transformer radiators with galvanized ones will eliminate corrosion and extend the life of the power transformers. Corroded power transformer radiators will lead to oil leaks and result in the failure of the transformer, interrupting service to customers in addition to causing environmental damage.

Reference: PUB-31; PUB-32; PUB-33; PUB-34; PUB-153; PUB-154.
NLH-36; NLH-37; NLH-38.
Transcript, September 10, 2003, page 50, lines 12 to 17; page 141, line 2 to page 144, line 2.

3.5.3.4 Protection & Monitoring Improvements

This is an $80,000 expenditure, as described at Schedule B, page 24, of the Application, to replace or add protection and monitoring equipment at 3 substations. The equipment will help to maintain safe and reliable electrical system operations.

3.5.3.5 Distribution System Feeder Remote Control

This expenditure of $1.0 million, described at Schedule B, page 26, of the Application, is part of a project initiated in 2002 to replace aging electromechanical feeder relays and oil-filled reclosers with modern, multi-function electronic relays and reclosers. The replacement units allow feeders to be controlled remotely from the System Control Centre, which allows for more efficient operations by reducing the need to send crews to manually operate the equipment. This can also reduce the duration of outages in certain situations.

Reference: PUB-35.
NLH-39; NLH-40; NLH-41; NLH-42; NLH-43.

3.5.3.6 Feeder Additions Due to Load Growth and Reliability

This $200,000 project, described at Schedule B, page 28, of the Application, includes work at the Chamberlains Substation to accommodate a new feeder proposed for Conception Bay South and the transfer of load from the Kelligrews Substation, both of which are necessary to accommodate customer growth. It also includes work at the Pulpit Rock Substation, serving the Torbay area, which will accommodate the splitting of an existing feeder to reduce feeder length, thereby improving the reliability of service in the area.

The Conception Bay South feeder project is described at Schedule B, page 54, of the Application. The Pulpit Rock feeder project is included in the Distribution Reliability Initiative project described at Schedule B, page 52.

Reference: Volume II, Substations Appendix 3.

3.5.3.7 Increase Corner Brook Transformer Capacity

This project, described at Schedule B, page 30 (1st Revision), of the Application, involves the installation of a new 25 MVA transformer at the Walbournes Substation, which will replace a 15 MVA transformer that will be moved to the Bayview Substation. This was identified as the lowest cost alternative meeting the technical criteria in the Power Transformer Study: City of Corner Brook, found in Volume II, Substations Appendix 4, Attachment A of the Application. The increase in transformer capacity is necessary because overall substation transformer loading in the City of Corner Brook is forecast to exceed existing capacity in the 2003-2004 winter season.

During cross-examination by Board Hearing Counsel, it was determined that the table attached as Appendix A to the Power Transformer Study: City of Corner Brook was not correct, in that it was not based on existing transformer capacity. A revised table was filed containing the correct information.

Reference: Volume II, Substations Appendix 4.
Volume II, Substations Appendix 4, Attachment A, page 1 (1st Revision).
Transcript, September 11, 2003, page 72, line 12 to page 73, line 13; page 76, line 14 to page 78, line 20; September 12, 2003, page 1, line 12 to page 3, line 21.

3.5.4 Transmission

3.5.4.1 Rebuild Transmission Lines

This project, described at Schedule B, page 32, of the Application, requires an expenditure of $2,315,000 for the replacement of poles, crossarms, conductors, insulators and other equipment on the Company's transmission lines. Deficient equipment is identified through annual inspections and engineering reviews, as well as during day-to-day operations. Many of these lines are in excess of 40 years old. In addition to normal aging, there is a significant increase in the amount of corroded conductor in some locations. This is putting upward pressure on expenditure requirements in this category.

Reference: PUB-36; PUB-37; PUB-38; PUB-155;PUB-157.
Transcript, September 10, 2003, page 59, line 15 to page 62, line 11.

3.5.5 Distribution

3.5.5.1 Extensions

The Extensions category, described in Schedule B, page 34, of the Application, provides for the construction of primary and secondary distribution lines to connect new customers to the electrical system. It also provides for upgrades to existing distribution lines for customers who increase their electrical load. The forecast expenditure is based on historical data, but varies annually with customer growth. This year's Extensions expenditure is forecast at $4,956,000, which is somewhat lower than expenditures in the last 3 years.

Reference: PUB-39; PUB-40; PUB-158; PUB-159; PUB-160.

3.5.5.2 Meters

This category, described in Schedule B, page 36, of the Application, includes expenditures for new meters to serve new customers and to replace meters for existing customers. Expenditures for new meters are based on the forecast of new customers. Expenditures for replacement meters are forecast based on historical data and the results of sampling conducted in accordance with the requirements of the Electricity and Gas Inspection Act (Canada). The proposed expenditure for 2004 is $1,174,000, and is comprised of $814,000 for regular meters and associated equipment and $360,000 for AMR meters. The increase in the cost over previous years is primarily the result of the inclusion of the purchase of AMR meters.

For 2004, the Company is proposing to purchase 3,000 AMR meters, which can be read remotely using radio frequency transmission. The AMR meters, which are more expensive on a per unit basis than regular meters, are intended to address identified safety and access issues. In many instances, meter locations have been rendered inaccessible due to landscaping and fencing changes subsequent to their installation. Many customer premises, particularly commercial premises, have meters located inside buildings. AMR meters will allow these meters to be read without visual contact with the meter. This improves safety for the meter readers, improves productivity in relation to hard to access locations and reduces the need to estimate meter readings.

Reference: Volume III, Distribution Appendix 1.
PUB-41; PUB-42.
NLH-67; NLH-68.
Transcript, September 11, 2003, page 5, line 25 to page 13, line 8; page 16, line 9 to page 27, line 10; page 29, line 2 to page 32, line 3.

3.5.5.3 Services

This category, described at Schedule B, page 38, of the Application, provides for the installation of service wires for new customers. Service wires are the low voltage wires that connect customer premises to distribution transformers. This annual expenditure also includes the cost of replacing service wires due to damage or deterioration, or to accommodate additional load. Expenditures are forecast based on historical data, but vary with the Company's forecast of customer growth. The proposed expenditure for 2004 is $1,946,000.

Reference: PUB-43; PUB-44; PUB-162; PUB-163.

3.5.5.4 Street Lighting

This is a proposed expenditure of $1,242,000 for the installation of new area lighting fixtures and the replacement of existing fixtures. The project, described at Schedule B, page 40 of the Application, also includes the cost of the associated underground or overhead wiring. These expenditures are necessary to address customer requirements and are forecast based on historical data.

In recent years, in the course of normal streetlight replacement, Newfoundland Power has been replacing its older mercury vapour lighting fixtures with more energy efficient high-pressure sodium fixtures. This has had the effect of reducing annual street lighting energy sales per streetlight. The Company has not installed low-pressure sodium lighting, which uses even less energy than high-pressure sodium. The shortcomings associated with low-pressure sodium lighting include customer dissatisfaction with lighting levels and poor colour rendering, which have safety and security ramifications.

Reference: PUB-45; PUB-46; PUB-47; PUB-48; PUB-49; PUB-50; PUB-164; PUB-166.
Transcript, September 11, 2003, page 109, line 12 to page 114, line 11; page 116, line 16 to page 121, line 16.

3.5.5.5 Transformers

The Company is proposing capital expenditures of $4,965,000 on Transformers for 2004. This expenditure is described at Schedule B, page 42, of the Application, and is consistent with expenditure levels in recent years. The proposed expenditure for 2004 includes only the purchase cost of the transformers, and is based on estimates of new customer requirements for each of the Company's operating areas, as well as on the need to replace deteriorated equipment identified through field surveys. Also included is an estimate for conversions and upgrades related to planned projects and for storm damage.

Reference: PUB-51 (1st Revision); PUB-52; PUB-167; PUB-168.

3.5.5.6 Reconstruction

The proposed expenditure of $2,461,000 under this category is for the replacement of deteriorated or storm damaged distribution structures and equipment. The required expenditure, which is intended to address smaller reconstruction projects that cannot be deferred, is estimated each year based on historical expenditures. This project is described at Schedule B, page 44, of the Application.

Reference: PUB-53; PUB-169; PUB-170.
NLH-69.
Transcript, September 10, 2003, page 63, line 15 to page 65, line 10.

3.5.5.7 Aliant Pole Purchase

This expenditure of $4,044,000, as described at Schedule B, page 46, of the Application, is the 2004 installment associated with the purchase of joint-use poles from Aliant Telecom Inc. in 2001, which was approved by the Board in Order No. P.U. 17 (2001-2002). The final installment of $4,044,000, which will complete the purchase, will be paid in 2005.

3.5.5.8 Rebuild Distribution Lines

This category of capital expenditures, described in Schedule B, page 47 of the Application, provides for the replacement of deteriorated distribution structures and equipment. The specific requirements have been identified as a result of inspections, engineering reviews and day-to-day operations. These expenditures are necessary to maintain the reliability of 56 of the Company's approximately 300 distribution feeders and to keep them in safe operating condition. The total proposed expenditure for 2004 in this category is $4,137,000.

The proposed expenditure of $2,802,000 on feeder upgrades for 2004 includes an amount of approximately $300,000 to install lightning arrestors on distribution transformers. Newfoundland Power's operating experience has indicated an increase in transformer failures due to lightning in recent years. In areas where Newfoundland Power has installed lightning arrestors, transformer failures due to lightning have been significantly reduced. This was particularly evident during a lightning storm in the Grand Falls-Windsor area in 2002, where about 50 per cent of distribution transformers have lightning arrestors installed. On that occasion, Newfoundland Power experienced approximately 200 transformer failures on transformers without lightning arrestors, and only one on a transformer that had a lightning arrestor installed. The transformer that failed was hit directly by lightning. Lightning arrestors do not offer protection against direct lightning strikes on a transformer.

The economic analysis of the three alternatives considered in the report entitled Distribution Lightning Arrestors (Volume III, Distribution Appendix 2, Attachment B) supports the installation of lightning arrestors on transformers on select distribution feeders over a five-year period. In all scenarios posed in Requests for Information in relation to the economic analysis, the alternative proposed by Newfoundland Power is the most economic alternative. The installation of the lightning arrestors would be timed to coincide with other work on the transformers, thereby enabling the work to be performed in a cost-effective manner.

Reference: Volume III, Distribution Appendix 2.
Volume III, Distribution Appendix 2, Attachment B.
PUB-54; PUB-55; PUB-56; PUB-57; PUB-132; PUB-133; PUB-171.
NLH-48; NLH-49; NLH-50; NLH-51; NLH-52; NLH-53; NLH-54; NLH-55.
Transcript, September 11, 2003, page 32, line 4 to page 67, line 1; page 146, line 15 to page 149, line 11.

3.5.5.9 Relocate/Replace Distribution Lines for Third Parties

Third parties, such as governments, other utilities and customers, often require that distribution lines be relocated. The associated capital expenditures, as well as expenditures necessary to replace distribution lines damaged in motor vehicle accidents, are included in this budget category, which is described in Schedule B, page 50 of the Application. Much of the cost associated with this is recovered from the requesting parties. The project expenditure of $235,000 is based on historical expenditures and some individual project estimates.

3.5.5.10 Distribution Reliability Initiative

This is an initiative aimed at improving service reliability on feeders whose outage frequency or duration statistics are worse than the Company average. The feeders are prioritized for attention based on historical outage duration and frequency statistics. This year's expenditure of $949,000, which is described in Schedule B, page 52, of the Application, will focus on feeders serving the Lumsden/Cape Freels, Bay Roberts/Port de Grave and Torbay/Flatrock/Pouch Cove areas.

Reference: Volume III, Distribution Appendix 3.
PUB-58; PUB-59; PUB-60; PUB-61; PUB-135; PUB-172; PUB-173; PUB-194.
NLH-56; NLH-57; NLH-58; NLH-59; NLH-60; NLH-61; NLH-62.

3.5.5.11 Feeder Additions and Upgrades to Accommodate Growth

This project, described at Schedule B, page 54, of the Application, involves a proposed expenditure of $677,000 for the construction of a new feeder in Conception Bay South (Chamberlains), the reconductoring of a portion of the Glendale-01 feeder in Mount Pearl and the installation of voltage regulators on the Springdale-01 feeder in Conception Bay North. This work is required to accommodate forecast customer and energy sales growth and optimize the installed transformer capacity at several substations.

Reference: Volume III, Distribution Appendix 4.
PUB-62; PUB-63.
NLH-63; NLH-64; NLH-66.
Transcript, September 10, 2003, page 70, line 5 to page 71, line 20.

3.5.5.12 Switch Replacement & Upgrade Underground Distribution

This year's proposed expenditure of $750,000 will complete a program started in 2000 to replace aged oil-filled switches and platform-mounted transformers and to upgrade vaults in the underground distribution system serving Water Street, St. John's. The project, described at Schedule B, page 56, of the Application, is necessary to replace aged and deteriorated equipment and to address identified safety hazards.

Reference: PUB-64.
Transcript, September 10, 2003, page 72, line 17 to page 74, line 22.

3.5.5.13 Interest During Construction

This is an estimate of the interest during construction that will be charged on certain distribution work for which no provision has been made in the individual project category. The interest rate is calculated in accordance with Order No. P.U. 37 (1981).

3.5.6 General Property

3.5.6.1 Tools and Equipment

The proposed expenditure of $535,000 for 2004, which is described at Schedule B, page 59, of the Application, is to cover the cost of acquiring or replacing tools and equipment, including hot-line tools, used in the Company's day-to-day operations and to add or replace office furniture and equipment.

Reference: PUB-65; PUB-66.
Transcript, September 10, 2003, page 75, lines 8 to 23.

3.5.6.2 Additions to Real Property

The proposed expenditure of $174,000 for 2004, which is described at Schedule B, page 61, of the Application, includes a $65,000 expenditure to replace the roof of the Company's Stephenville office building that was damaged by high winds, as well as several smaller building improvements that are each projected to cost less than $50,000.

Reference: Volume III, General Property, Appendix 2.
PUB-67; PUB-68.
Transcript, September 10, 2003, page 74, line 23 to page 75, line 8.

3.5.7 Transportation

3.5.7.1 Purchase Vehicles and Aerial Devices

The proposed budget of $3,487,000 for 2004, summarized at Schedule B, page 62, of the Application, provides for the cost of replacing 15 passenger vehicles, 12 heavy fleet vehicles and 9 off-road vehicles such as snowmobiles and all-terrain vehicles. These vehicles have reached the end of their useful lives and must be replaced.

Reference: Transcript, September 10, 2003, page 76, lines 4 to 21.

3.5.8 Telecommunications

3.5.8.1 Replace/Upgrade Communications Equipment

The proposed expenditure of $70,000 for 2004 provides for the replacement of older mobile radios and for the correction of deficiencies in the Company's radio transmission towers identified during inspections.

Reference: PUB-69.
Transcript, September 10, 2003, page 77, lines 1 to 12.

3.5.8.2 Substation Telephone Circuit Protection

Personnel using or working on communication equipment in Company substations without circuit protection, or in telephone exchanges serving those substations, can be exposed to the danger of electrical shock due to excessive ground potential rise. Ground potential rise can also damage communication equipment of third parties sharing cables with Company equipment. The proposed expenditure of $50,000 for 2004, described at Schedule B, page 66, of the Application, will upgrade equipment at 5 of the Company's substations to address these dangers.

3.5.9 Information Systems

3.5.9.1 Application Enhancements

The Application Enhancements project provides for expenditures necessary to enhance existing computer applications to address changing business requirements or to take advantage of software product improvements. The proposed expenditure for 2004, described in Schedule B, page 68, of the Application, total $1,355,000. This project reflects the Company's information technology strategy of investing in existing technology to achieve or maintain customer service benefits and operational efficiencies while at the same time extending the life of existing assets.

One component of the project will introduce process improvements in finance, materials management and human resources that will enable the Company to gain additional benefits from the Microsoft Great Plains software. A bar coding project will increase accuracy of inventory tracking and improve productivity in the Company's stores by reducing manual data entry. Enhancements to the Customer Service System (CSS) will facilitate improvements in the Company's Equal Payment Plan and allow the CSS to accommodate AMR demand meters. Other enhancements will improve staff scheduling in the Customer Contact Centre.

The largest expenditure is proposed for enhancements in operations and engineering applications. These will improve project management, work order tracking and crew scheduling, as well as improve utilization of the Company's SCADA System.

Reference: Volume IV, Information Systems Appendix 1.
PUB-73; PUB-74; PUB-75; PUB-76; PUB-77; PUB-78; PUB-79; PUB-80; PUB-177; PUB-178; PUB-179; PUB-180.
NLH-70; NLH-71; NLH-72.
Transcript, September 12, 2003, page 15, lines 9 to 23; page 85, line 17 to page 104, line 12.

3.5.9.2 Application Environment

This project, described in Schedule B, page 70 (1st Revision), of the Application, involves an expenditure of $791,000 for 2004, which is necessary to sustain gains already obtained from investments in information technology. The proposed expenditure includes the cost of the Microsoft Enterprise Agreement, which the Company's analysis shows is the most cost-effective alternative for acquiring Microsoft software. Also included is the cost of software upgrades needed to maintain vendor support, and upgrades to the test environment used to test software before it is put into production.

Reference: Volume IV, Information Systems Appendix 2.
PUB-86; PUB-87; PUB-88; PUB-89; PUB-90 (1st Revision); PUB-91; PUB-92; PUB-93; PUB-94; PUB-95; PUB-96; PUB-97; PUB-98; PUB-181; PUB-182; PUB-183; PUB-184; PUB-185; PUB-186; PUB-187; PUB-188; PUB-189.
NLH-73; NLH-74.
Transcript, September 12, 2003, page 53, line 21 to page 85, line 16.

3.5.9.3 Customer Systems Replacement

The expenditure of $226,000 proposed for 2004 provides for the cost of enhancing the CSS to improve customer service and to enhance operational efficiency. One component of this project, described in Schedule B, page 72, of the Application, will change the way customer bills are designed and formatted. Newfoundland Power is aware of customer dissatisfaction with its bill format. The proposed change will make it easier to modify the format of the bill, enabling the Company to be more responsive to customer concerns.

The project will also reduce the effort involved in setting up and revising information letters to customers.

In keeping with the findings of the Customer Service System Replacement Analysis (Volume IV, Information Systems Appendix 3, Attachment A), this year's expenditures will reduce the dependence of the CSS on the OpenVMS operating system.

Reference: Volume IV, Information Systems Appendix 3.
PUB-99; PUB-100; PUB-101.
NLH-87; NLH-88; NLH-89.
Transcript, September 12, 2003, page 44, line 1 to page 53, line 20.

3.5.9.4 Network Infrastructure

The Network Infrastructure project, described in Schedule B, page 74, of the Application, completes a two-year project to replace obsolete technical components that connect the Company's computers and computer applications. The proposed expenditure of $393,000 for 2004 will ensure the continued reliable operation of the Company's network infrastructure, which is the foundation for such critical applications as the CSS, the Problem Call Logging System and the SCADA System. The network infrastructure also supports the transfer of corporate data, including VHF radio communications, among the Company's offices throughout the island.

Reference: Volume IV, Information Systems Appendix 4.
NLH-75; NLH-76; NLH-77; NLH-78; NLH-79; NLH-80; NLH-81.

3.5.9.5 Personal Computer Infrastructure

This project, described in Schedule B, page 76, of the Application, provides for the upgrading or replacing of personal computers (PCs), printers and associated equipment. This year's proposed expenditure of $539,000 is somewhat lower than the expenditure in the previous two years. The Company plans to replace 74 desktop and 35 laptop computers. In keeping with the Company's practice of "cascading" computers according to user requirements, the newest PCs will be assigned to those users with the most demanding computing requirements, while their existing PCs will be reassigned to users with lesser capacity requirements.

In the meantime, Newfoundland Power considers alternatives to purchasing PCs, such as "thin client" technology solutions. The Company has employed "thin client" software to extend the useful life of some existing PCs, and continues to monitor the development of "thin client" hardware.

Reference: PUB-102; PUB-190; PUB-191.
NLH-82; NLH-83.
Transcript, September 12, 2003, page 104, line 13 to page 109, line 11.

3.5.9.6 Shared Server Infrastructure

The Shared Server Infrastructure project, described in Schedule B, page 78, of the Application, proposes an expenditure of $644,000. In order to maintain the performance of the Company's servers, additional processing capacity is required to meet the needs of the Company's approximately thirty applications. Several of these applications will be enhanced or upgraded in 2004. The Company also plans to replace several obsolete servers with new servers.

The Company's process of assigning new servers is similar to the process for assigning PCs, whereby new, higher capacity models are assigned where the computing needs are greatest. Lower capacity models are reassigned to areas with lesser requirements.

It is not possible to replace the server capacity the Company is losing through retirements with a smaller purchase. The new servers are not direct replacements for the ones to be retired.

Reference: PUB-103; PUB-104.
NLH-84; NLH-85; NLH-86.
Transcript, September 12, 2003, page 112, line 16 to page 113, line 15; page 115, line 14 to page 118, line 12.

3.5.10 Unforeseen Items

This is an allowance of $750,000 that allows the Company to act expeditiously to deal with unforeseen events affecting the electrical system in advance of seeking the specific approval of the Board. The formal description is provided at Schedule B, page 80, of the Application.

Reference: PUB-121.
Transcript, September 10, 2003, page 77, line 25 to page 78, line7.

3.5.11 Submission

The projects presented in Newfoundland Power's 2004 Capital Budget Application are necessary to: respond to customer growth and changes in customer requirements; replace deteriorated, defective or obsolete equipment; address safety and environmental issues; and maintain or improve customer service levels and operational efficiency gains.

Newfoundland Power's proposed capital expenditures for 2004 are necessary to provide service to customers that is safe and adequate and just and reasonable, and they are consistent with the provision of least cost electrical service.

4. FIXING AND DETERMINING 2002 AVERAGE RATE BASE

Rate base, which is principally comprised of the Company's fixed assets, forms the basis of regulation of Newfoundland Power's returns. Changes to the Company's rate base are principally the result of two factors, capital expenditures and depreciation. Capital expenditures increase rate base while depreciation expense decreases rate base.

Reference: Pre-filed evidence: Perry and Hutchens, p.2, lines 5-6 and 11-14.

The capital expenditures that increase the 2002 average rate base were approved by the Board in Order No. P.U. 21 (2001-2002), and P.U. 15 (2002-2003). The depreciation rates and methodologies that determine the depreciation expense and, in turn, decrease the 2002 average rate base, were approved by the Board in Order No. P.U. 7 (1996-1997).

Schedule D to the Application shows the average rate base for 2001 and 2002. The 2001 average rate base of $545,162,000 was approved by the Board in Order No. P.U. 36 (2002 - 2003).

Reference: Schedule D.

The average rate base for 2002 is $573,337,000, as filed with the board on March 31 2003 in Return 3 of the Company's 2002 Annual Return, and set out in Schedule D. All of the elements of the average rate base for 2002, as shown in Schedule D, have been calculated in accordance with Board Orders and Board approved policies.

Reference: Schedule D;
Transcript, September 12, 2003, p.143, line 25 to p.144, line 33.

Grant Thornton LLP, the Board's financial consultant, has filed a report entitled "Newfoundland Power Inc., 2004 Capital Budget Hearing", and has confirmed that the 2002 average rate base is accurate and has been calculated in accordance with Order No. P.U. No. 36 (1998-1999).

Reference: Transcript, September 12, 2003, page 144, lines 3 - 8
Information Item # 1.

The balance of the weather normalization account component of rate base of $10,919,000 has already been approved by the Board in Order No. P.U. 22 (2003)

Reference: Transcript, September 12, 2003, page 146, line 24 to page 147 line 3.

4.1 Submission

Newfoundland Power has requested that the Board fix and determine the 2002 average rate base for the purpose of regulatory continuity and certainty, in the same manner as the Board has exercised this regulatory supervisory power since 1999.

Based upon the evidence before the Board and pursuant to section 78 of the Act, the Board should fix and determine Newfoundland Power’s average rate base for 2002 at $573,337,000.

5. REPORTS FILED IN CONJUNCTION WITH THE 2004 CAPITAL BUDGET APPLICATION

5.1 The Reports

In Order No. P.U. 36 (2002-2003), the Board ordered that Newfoundland Power file three reports in conjunction with this capital budget application:

1) A Status Report on the 2003 capital expenditures,
2) An updated Information Technology Strategy report for the period 2004 – 2008, and
3) A Capital Budget Plan.

These 3 reports are contained in Volume I of the Application materials.

In Order No. P.U. 19 (2003), the Board ordered Newfoundland Power to file annually with its capital budget application:

1) evidence relating to changes in deferred charges, including pension costs, and
2) a reconciliation of average rate base to average invested capital.

The evidence pertaining to the changes in deferred charges is contained in Volume I of the Application materials, and the reconciliation is contained in the prefiled testimony of Mr. Perry and Ms. Hutchens, also contained in Volume 1 of the Application materials.

5.2 2003 Capital Expenditure Status Report

The report describes in detail the variances in 2003 capital budget expenditures in the 10 budget categories.

As of July 31, 2003, the cumulative net variance with respect to the 2003 capital budget was $1,370,000, or 2.4%, above budget. A variance of 2.4% on a capital budget of $57.8 million is very reasonable. It is not appropriate to complete detailed engineering and competitive tendering prior to obtaining Board approval for capital projects. Changes as a result of these processes are inevitable.

Reference: Transcript, September 10, 2003, p.37, line 10 to p.38, line 4.
Transcript, September 12, 2003, p.195, line 24 to p.196, line 8.
Transcript, September 11, 2003, p.157, line 16 to p.160, line 24
Exhibit PJD #1.

5.3 Information Technology Strategy 2004-2008

This report states that Newfoundland Power' s Information Technology (“IT”) strategy remains unchanged since 1999 when the first IT strategy report was filed with the Board. The report reviews the Company's investments in IT since 1999 and how the investments have contributed to improvements in customer service and operating efficiency.

Looking forward, the report states that the principal focus of the Company's IT strategy for the next five years will be on enhancing existing technologies installed throughout the Company, in essence leveraging further benefits from these assets, rather than making investments in significant new technologies.

The principal risk to the Company's IT strategy for the next five years will be the continued viability of the CSS, and more specifically, the OpenVMS operating system upon which the CSS operates. Provided the OpenVMS operating system remains viable during the next five years as is presently indicated, the Company does not expect that it will be required to replace either of the CSS or any other application solely because of their dependence on OpenVMS.

However, the Company does plan to take opportunities that present themselves to move components off of OpenVMS when it makes sense to do so in order to limit overall risk.

5.4 2004 Capital Budget Plan

The 2004 Capital Budget Plan (the "Plan") reviews of the capital expenditures of Newfoundland Power for the years 1993 to 2003. The Plan also provides a five year forward looking plan with respect to capital expenditures based upon the information currently available to the Company with respect to customer forecasts and anticipated capital projects regarding the Company's assets over this period.

Over the past 10 years, capital investment dropped in the initial years following the cod moratorium. However, beginning in 1998 capital investment began to increase, principally in response to the need to replace deteriorated, defective or obsolete plant and equipment and increased customer demands for service. In these more recent years the Company adopted a more proactive approach that balances the maximization of the life of the asset with the delivery of electrical energy to customers at the lowest possible cost consistent with reliable service.

Overall, planned capital expenditures are forecast to be relatively stable during the 2004 to 2008 period. As shown in Appendix C of the Plan, the Distribution category reduces in 2006, following the last Aliant pole purchase payment being made in 2005. However, the forecast budget in 2006 remains above $55 million because of the major refurbishment project scheduled for the Rattling Brook Hydro plant in that year. In 2007 and 2008, the Plan forecasts that the capital budgets in both years will be below $50 million.

However, as noted in the Plan, circumstances can change and events can occur during the five-year period that would result in changes to the priorities for capital projects currently anticipated, new and currently unanticipated capital projects being required, or alternatively currently anticipated capital projects not being required to proceed at all.

5.5 Changes in Deferred Charges

In Order No. PU. 19 (2003), (page 71) the Board found that the asset rate base method should replace the invested capital approach currently used to calculate NP's rate base. The Board chose a 'stepped' approach to the change to the Asset Rate Base method. The first step ordered by the Board was the inclusion of deferred charges in rate base beginning in 2003, along with requiring evidence relating to changes in deferred charges be filed annually at the capital budget hearing.

Accordingly, for the purposes of this application, and in particular the request that the Board fix and determine the 2002 average rate base, deferred charges do not play a role and no specific Order is sought with respect to deferred charges at this time.

In 2004, the Company will request the Board to approve the deferred charges as of the end of 2003 in its average rate base calculation for 2003, in accordance with Order No. P.U. 19 (2003).

The Deferred Charges report indicates that none of the deferred charges that are to be incorporated into rate base for the first time in 2003 have changed since the General Rate Application. The Weather Normalization Reserve, which is already included in rate base, has changed since the General Rate Application, but only as a result of the normal operation of the reserve.

The Company's deferred pension costs are the largest component of both deferred charges and the change in deferred charges from year to year. Deferred pension costs are the cumulative difference between the Company's pension funding and pension expense and are accounted for in accordance with Order No. P.U. 17(1987)

References: Prefiled Evidence, Perry and Hutchens, p. 5, lines 16-19
Report on changes in deferred charges p. 4.
Information #1, Grant Thornton Report, page 4, first paragraph.

The pension funding and expense amounts have not changed from that presented in the Company's General Rate Application.

References: Prefiled Evidence, Perry and Hutchens, p. 6, lines 4-5
Information #1, Grant Thornton Report, page 5, second last paragraph.

5.6 Invested Capital – Rate Base Reconciliation

As the second part of the move towards the asset rate base method of determining rate base, Newfoundland Power was also required to provide a reconciliation of average rate base to average invested capital annually at its capital budget hearing. The reconciliation of Invested Capital to Rate Base is found in the pre-filed testimony of Mr. Perry and Ms. Hutchens as Table 1, on page 4. In keeping with the provisions of Order No. P.U. 19 (2003), Newfoundland Power will file no later than its next rate application a report on the appropriateness and approach to including in rate base the remaining reconciling items between rate base and invested capital, which would be the final move towards the asset rate base method of determining rate base.

Reference: PUB 123.

6. CONCLUSIONS

6.1 Capital Projects

The projects presented in Newfoundland Power's 2004 Capital Budget Application are necessary to: respond to customer growth and changes in customer requirements; replace deteriorated, defective or obsolete equipment; address reliability, safety and environmental issues; and maintain or improve customer service levels and operational efficiency gains.

Newfoundland Power's proposed capital expenditures for 2004 are necessary to provide service to customers that are safe and adequate and just and reasonable, and consistent with the provision of least cost electrical service.

No specific challenge has been made to the numerous engineering judgments and assessments that form the basis of the capital expenditures proposed in Newfoundland Power's 2004 Capital Budget.

Reliability and service are related concepts and in keeping with Newfoundland Power's statutory obligations under the Public Utilities Act and the Electric Power Control Act, the 2004 Capital Budget includes projects that will improve the reliability of the electrical service to customers affected by poorly performing plant and equipment located throughout the island portion of the province.

Newfoundland Power submits that the 2004 Capital Budget contained in this application represents the capital expenditures required to meet its statutory obligations, including the delivery of electrical power at the lowest possible cost consistent with reliable service and, pursuant to Section 41 of the Public Utilities Act, the 2004 Capital Budget should be approved in its entirety by the Board.

6.2 2002 Average Rate Base

Newfoundland Power has requested that the Board fix and determine the 2002 average rate base for the purpose of regulatory continuity and certainty, in the same manner as the Board has exercised this regulatory supervisory power since 1999.

Based upon the evidence before the Board and pursuant to section 78 of the Act, the Board should fix and determine Newfoundland Power's average rate base for 2002 at $573,337,000.

6.3 Filing Requirements/Technical Conference

Newfoundland Power has submitted its 2004 Capital Budget Application in compliance with the guidelines and conditions set out in Schedule C of Order No. P.U. 36 (2002-2003).

Nonetheless, based upon the Requests for Information filed by Board Hearing Counsel and Hydro, and upon the cross-examination conducted of its witnesses, it would appear that this may not be a position that is entirely shared by these two parties.

Newfoundland Power submits that issues surrounding the interpretation the Board's dictum in Order No. P.U. 7 (2002-2003), as well as Order No. P.U. 36 (2002-2003) and Schedule C attached thereto, and the resolution of the significant issues identified by the Board in Order No. P.U. 36 (2002-2003) are best left to the technical conference scheduled to occur in early 2004.

The technical conference will allow the Board and the parties who appear before it in the capital budget applications of Newfoundland Power and Hydro to fully develop a common understanding of meaningful filing requirements in capital budget applications.

This in turn will enable the Board to fulfill its regulatory mandate in the capital budget review process while maintaining a reasonable balance with the obligations and burden placed upon the utilities presenting the capital budget applications.