NEWFOUNDLAND POWER
A FORTIS COMPANY

Newfoundland Power Inc.

55 Kenmount Road
PO Box 8910
St. John's, Newfoundland
A1B 3P6
Business: (709) 737-5600
Facsimile: (709) 737-2974
www.newfoundlandpower.com

HAND DELIVERED

June 30, 2010

Board of Commissioners
of Public Utilities
P.O. Box 21040
120 Torbay Road
St. John's, NL A1A 5B2

Attention: Ms. Cheryl Blundon
Board Secretary

Ladies & Gentlemen:

Re: A Comprehensive Proposal on Other Post Employment Benefits

A. Application Background

In Order No. P.U. 43 (2009), the Board ordered Newfoundland Power to file a comprehensive proposal related to accounting for, and recovery of, other post employment benefits ("OPEBs") costs.

Enclosed are the original and 8 copies of an Application (the "Application") relating to this matter.

B. The Application

The Application addresses the several matters required by Order No. P.U. 43 (2009).

In summary, the Company recommends that, in 2011, it adopt accrual accounting for OPEBs for regulatory purposes; commence recovery over a 15-year period of the transitional balance, or regulatory asset, arising from the change in accounting; and adopt a deferral mechanism to capture annual OPEBs cost variances arising from changes in discount rates and other assumptions which is conceptually similar to that approved by the Board for annual pension expense.

Implementation of the recommendations would deal comprehensively with the Company's adoption of accrual accounting for OPEBs, including the recovery of the transitional balance or regulatory asset. Implementation of the recommendations would require an average increase in customer rates of approximately 1% for 2011.

C. Concluding

We trust the foregoing and enclosed are found to be in order. If you have any questions whatsoever, please feel free to contact us.

Copies of the Application have been forwarded directly to Mr. Thomas Johnson, the Consumer Advocate and Mr. Geoffrey Young, Counsel to Newfoundland & Labrador Hydro.

Yours very truly,

Peter Alteen
Vice President, Regulation and Planning

Enclosures

c. Mr. Thomas Johnson
Consumer Advocate

Mr. Geoff Young
Newfoundland & Labrador Hydro

Telephone: (709) 737-5859 *Email: palteen@newfoundlandpower.com* *Fax: (709) 737-2974*

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

IN THE MATTER OF a
comprehensive proposal for the
2011 adoption of accrual accounting
for other post employment benefit costs
for Newfoundland Power Inc.
("Newfoundland Power")

TO: The Board of Commissioners of Public Utilities (the "Board")

THE APPLICATION OF Newfoundland Power **SAYS**:

A. Background

1. Newfoundland Power is a corporation duly organized and existing under the laws of the province of Newfoundland and Labrador, is a public utility within the meaning of the Act, and is subject to the provisions of the *Electrical Power Control Act, 1994*.

2. By Order No. P.U. 43 (2009), the Board ordered Newfoundland Power to file with the Board, no later than June 30, 2010, a comprehensive proposal (the "Proposal") for adoption of the accrual method of accounting for other post employment benefits ("OPEBs") costs as of January 1, 2011. The Proposal was required to include alternatives and recommendations in relation to (i) a deferral mechanism to capture annual variances arising from changes in the discount rate and other assumptions; and (ii) the recovery of the transitional balance associated with the adoption of accrual accounting for OPEBs costs.

B. The Proposal

3. In the Proposal, Newfoundland Power recommends that, effective January 1, 2011:

   (i) it adopt, for regulatory purposes, the accrual method of accounting for OPEBs costs and income tax related to OPEBs;

   (ii) it recover the transitional balance, or regulatory asset, of approximately $68.6 million as at January 1, 2011, associated with the adoption of accrual accounting for OPEBs costs over a 15-year period; and

   (iii) it adopt an OPEBs Cost Variance Deferral Account to capture annual differences in OPEBs costs arising from changes in assumptions associated with the valuation of OPEBs obligations;

   all as described in Schedule A to this Application.

4. Implementation of the Proposal will require an average increase in Newfoundland Power's base rates of 1.04% effective January 1, 2011.

C. Order Requested

5. Newfoundland Power requests an Order from the Board:

   (a) approving Newfoundland Power's recommended:

      (i) adoption, for regulatory purposes, of the accrual method of accounting for OPEBs costs and income tax related to OPEBs;

      (ii) recovery of the transitional balance, or regulatory asset, of approximately $68.6 million as at January 1, 2011, over a 15-year period; and

      (iii) adoption of the OPEBs Cost Variance Deferral Account;

   all with effect from January 1, 2011 and as described in Schedule A to this Application.

   (b) directing Newfoundland Power to file revised rates, tolls and charges effective for service provided on and after January 1, 2011 which reflect the determinations of the Board on this Application; and

   (c) providing such other or alternate relief which may, upon review of the record of this Application, appear just and reasonable in the circumstances.

6. Communications with respect to this Application should be forwarded to the attention of Ian F. Kelly, Q.C. and Gerard M. Hayes, Counsel to Newfoundland Power.

DATED at St. John's, Newfoundland and Labrador, this 30th day of June, 2010.

NEWFOUNDLAND POWER INC.

Ian F. Kelly, Q.C. and Gerard M. Hayes
Counsel to Newfoundland Power
Newfoundland Power Inc.
P.O. Box 8910
55 Kenmount Road
St. John's, Newfoundland A1B 3P6

Telephone: (709) 737-5609
Telecopier: (709) 737-2974
Email: ghayes@newfoundlandpower.com

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

IN THE MATTER OF a
comprehensive proposal for the
2011 adoption of accrual accounting
for other post employment benefit costs
for Newfoundland Power Inc.
("Newfoundland Power")

AFFIDAVIT

I, Peter Alteen, of St. John's in the Province of Newfoundland and Labrador, make oath and say as follows:

1. That I am Vice President, Regulation and Planning, of Newfoundland Power Inc.

2. To the best of my knowledge, information and belief, all matters, facts and things set out in this Application are true.

SWORN to before me at St. John's
in the province of Newfoundland and
Labrador this 30th day of June, 2010

Barrister

Peter Alteen

Schedule A

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

IN THE MATTER OF a
comprehensive proposal for the
2011 adoption of accrual accounting
for other post employment benefit costs
for Newfoundland Power Inc.
("Newfoundland Power")

Report on Other Post Employment Benefits

June 30th, 2010

(filed in compliance with Order No. P.U. 43 (2009))

NEWFOUNDLAND POWER
A FORTIS COMPANY

Preliminary Note on Presentation

This report on other post employment benefits ("OPEBs") recommends changes to Newfoundland Power's regulatory accounting for, and recovery of, OPEBs costs commencing in 2011.

In 2007 and 2009, the Board considered Newfoundland Power's regulatory accounting within the framework of current Canadian generally accepted accounting principles ("GAAP"). For the purposes of continuity and comparability in the Board's considerations, the Company has used Canadian GAAP for the presentation of OPEBs costs and the evaluation of alternatives for recovery of the transitional balance, or regulatory asset, in this report. The Company has also used a 6.5% discount rate in the valuation of OPEBs obligations. This is the same discount rate used to value OPEBs obligations at the Company's most recent general rate application.

In 2011, Newfoundland Power will adopt International Financial Reporting Standards ("IFRS") which will change the financial reporting presentation of OPEBs costs. These changes have been taken into account in the Company's proposal and modestly impact proposed cost recovery in 2011. These changes will not, however, alter the total OPEBs costs to be recovered from customers in the long term. A description of the changes related to IFRS, together with a comparison to Canadian GAAP, is provided in the report to ensure reasonable transparency.

Finally, in preparation of this report Newfoundland Power consulted with Mr. John Browne, C.A., of JT Browne Consulting. Mr. Browne has provided overviews of (i) the regulatory principles and (ii) the relationship between regulatory accounting and GAAP, which are relevant to the matters considered in the report. These overviews are provided in appendices to the report.

Table of Contents

Page

1.0 EXECUTIVE SUMMARY

This report contains Newfoundland Power's comprehensive proposal for the adoption of the accrual method of accounting for other post employment benefits ("OPEBs") costs as of January 1, 2011.

Prior to preparing this proposal, Newfoundland Power reviewed and revised its OPEBs benefits plan. This revision reduced overall OPEBs costs to be recovered from customers.

The proposal addresses how the Company should (i) adopt accrual accounting for OPEBs costs on January 1, 2011 for regulatory purposes, (ii) recover the transitional balance, or regulatory asset, which arises from the adoption of accrual accounting for regulatory purposes, and (iii) deal with annual variances in OPEBs costs arising from changes in assumptions associated with valuation of OPEBs obligations.

Newfoundland Power recommends the adoption of accrual accounting for OPEBs costs on a tax-effected basis, on January 1, 2011. This is substantially similar to the Company's proposals for adoption of accrual accounting for OPEBs costs in its 2008 and 2010 general rate applications.

Newfoundland Power recommends that the transitional balance, or regulatory asset, arising from the adoption of accrual accounting for OPEBs costs be recovered over a 15-year term commencing January 1, 2011. The recommendation is based on economic analysis. It represents a balance of the increased costs related to recovery of this regulatory asset and the reduced finance costs related to adoption of accrual accounting for OPEBs costs. It results in a fair and equitable application of relevant regulatory principles.

Newfoundland Power recommends that annual variances in OPEBs costs arising from changes in assumptions used in valuation of OPEBs obligations be captured in a variance deferral account. This account is conceptually similar to that approved by the Board for annual pension expense.

In preparing this proposal, Newfoundland Power considered the current outlook for Canadian accounting standards, including its adoption of International Financial Reporting Standards ("IFRS") on January 1, 2011. The adoption of IFRS in 2011 will have a modest impact on the OPEBs costs proposed to be recovered commencing in 2011, but will not affect the total OPEBs costs required to be recovered by the Company in customer rates over the long term. IFRS will primarily affect the presentation of those costs for financial reporting purposes commencing in 2011.

The recommendations contained in this proposal, if approved by the Board, would result in a customer rate increase of approximately 1% effective January 1, 2011.

2.0 BACKGROUND

2.1 General

Newfoundland Power provides benefits for its employees upon retirement. These include retirement allowances for retiring employees as well as health, medical and life insurance for retirees and their dependents.

Newfoundland Power currently recognizes OPEBs costs on a cash basis for *regulatory purposes* (the "Cash Method"). This results in the Company's annual OPEBs expense being equal to the retirement allowances and insurance premiums actually paid in the year. On January 1, 2000, accrual accounting for OPEBs for *financial reporting purposes* was adopted by the Canadian Institute of Chartered Accountants (the "Accrual Method").

Differences between OPEBs costs calculated using the Cash Method for regulatory purposes and the Accrual Method for financial reporting purposes have been reflected in Newfoundland Power's financial statements as a regulatory asset.[1] This regulatory asset reflects a cost to be recovered in future customer rates.[2]

Differences in accounting methods for OPEBs do not impact the aggregate amount of OPEBs costs to be recognized or recovered by Newfoundland Power. Accordingly, the principal issue related to OPEBs accounting for the Company is the timing of recognition, and recovery from customers, of the OPEBs costs.

2.2 Regulatory Context

In its 2010 general rate application ("GRA"), Newfoundland Power proposed (i) to adopt the Accrual Method of recognizing OPEBs for regulatory purposes commencing in 2010 and (ii) to address in a later GRA disposition of the regulatory asset existing at year-end 2009.

In Order No. P.U. 43 (2009), the Board required Newfoundland Power to submit a comprehensive proposal for the 2011 adoption of the accrual method of accounting for OPEBs costs. The proposal was required to include recommendations and alternatives in relation to variances in OPEBs costs and recovery of the regulatory asset.

This report is filed in compliance with Order No. P.U. 43 (2009).

3.0 OPEBs COSTS

3.1 OPEBs Costs Overview

The accrued OPEBs obligation reflects the present value of Newfoundland Power's future obligations to employees and retirees under its OPEBs benefits plan (the "Plan").[3] The accrued OPEBs obligation represents the total OPEBs costs required to be recovered by the Company in customer rates over the long term. This obligation will change over time as a result of four principal factors.

First, as employees accumulate service with the Company each year, the present value of the obligation will increase. Second, the interest cost of the obligation existing in each year will tend to increase the obligation. Third, changes in actuarial assumptions or amendments to the Plan

1 The annual OPEBs cost recognized using the Cash Method are materially less than that using the Accrual Method. From 2000 to 2009, the regulatory asset arising from these differences totalled $46.7 million.

2 This regulatory asset is referred to as the *transitional balance* at page 36 of the Reasons for Decision for Order No. P.U. 43 (2009).

3 The value of the accrued OPEBs obligation and annual OPEBs costs are determined by the Company's actuary, Mercer (Canada) Limited. See Appendix A for the current OPEBs plan cost projection.

may increase or decrease the obligation. Finally, amounts paid in respect of benefits in each year will serve to reduce the obligation.

The first three of these factors are the primary *ongoing* components of the annual OPEBs costs calculated under the Accrual Method.

In addition to these ongoing components, annual OPEBs costs include amounts related to the transition to the Accrual Method.[4] The amounts related to this transition are exclusively costs related to past service of employees.

3.2 Recent Developments

Newfoundland Power is making a number of changes to the Plan effective 2011.[5]

Table 1 compares the existing and revised Plan in terms of (i) forecast accrued OPEBs obligations and (ii) annual OPEBs costs using the Accrual Method for 2011 through 2013.

Table 1
Forecast Impacts of OPEBs Plan Changes[6]
2011-2013
($millions)

	Accrued Obligation			**Annual Costs**		
	2011	**2012**	**2013**	**2011**	**2012**	**2013**
Existing Plan[7]	79.9	83.8	87.4	8.1	8.3	8.5
Revised Plan[8]	65.4	67.9	70.1	5.7	5.8	6.0
Difference	**(14.5)**	**(15.9)**	**(17.3)**	**(2.4)**	**(2.5)**	**(2.5)**

Changes to the Plan are forecast to reduce Newfoundland Power's accrued OPEBs obligation in the range of $15 to $17 million and reduce its annual OPEBs costs under the Accrual Method by approximately $2.5 million per year over the period 2011 to 2013.

4 Under current Canadian GAAP, such amounts would include (i) the OPEBs regulatory asset, which is forecast to be $52.4 million at December 31, 2010, and (ii) the unamortized portion of the transitional obligation created upon the adoption of accrual accounting for OPEBs for financial reporting purposes in 2000, which is forecast to be $9.4 million at December 31, 2010.

5 The most prominent changes to the Plan are the introduction of a 50% member-paid cost sharing arrangement for retirees over the age of 65, the removal of the current $5,000 annual benefit cap, and the introduction of drug dispensing fees. The plan changes will not impact existing retirees or employees eligible for full pension by December 31, 2012. Changes to the Plan have reduced Newfoundland Power's forecast accrued OPEBs obligation by almost 20%. The changes have reduced forecast accrual OPEBs costs by almost 30%.

6 Forecast OPEBs obligation and costs for 2011 to 2013 are based on a discount rate of 6.50% which is the same discount rate used in Newfoundland Power's amended 2010 general rate application. The actual discount rate is determined as of December 31st in each year and will vary over time.

7 See Appendix A, page 1 of 2.

8 See Appendix A, page 2 of 2.

3.3 Annual OPEBs Costs: Cash Method vs. Accrual Method

Table 2 shows Newfoundland Power's annual OPEBs costs currently reflected in customer rates, annual OPEBs costs associated with the revised Plan calculated under the Accrual Method, and annual differences for 2011 through 2013.

Table 2
Forecast Annual OPEBs Costs
Using the Accrual Method
2011-2013
($millions)

	2011	2012	2013
2010 Test Year OPEBs Costs[9]	1.7	1.7	1.7
Accrual OPEBs Costs[10]	5.7	5.8	6.0
Difference[11]	**4.0**	**4.1**	**4.3**

The forecast difference in annual OPEBs costs from that included in the 2010 test year ranges from $4.0 million in 2011 to $4.3 million in 2013.

3.4 The OPEBs Regulatory Asset

The OPEBs transitional balance referred to in Order No. P.U. 43 (2009) reflects the total accumulated difference between the Company's OPEBs costs under the Cash Method and the Accrual Method since 2000. This transitional balance is reflected in Newfoundland Power's financial statements as a regulatory asset.[12]

At year-end 2009, the value of this regulatory asset was $46.7 million. It is forecast to be approximately $52.4 million at the end of 2010.

Upon Newfoundland Power's adoption of the Accrual Method for OPEBs costs, the value of this regulatory asset would not change under current accounting standards.[13]

9 OPEBs costs in the 2010 test year, which is the basis for current customer rates, are based on the Cash Method for the existing Plan ($1.74 million in premiums and retirement allowances).

10 Accrual OPEBs costs for 2011 to 2013 are based on the Accrual Method under current Canadian GAAP and the revised Plan. See Section 5.3 *Accounting Standards* for a description of the anticipated changes in OPEBs costs as a result of IFRS adoption.

11 The difference in OPEBs costs is shown before capitalization effects.

12 See, for example, note 4 to Newfoundland Power's 2009 audited financial statements.

13 See Section 5.3 *Accounting Standards* for a description of the anticipated changes in the OPEBs regulatory asset as a result of IFRS adoption.

4.0 COST RECOVERY ALTERNATIVES

4.1 General Observations

The Board has recognized that Newfoundland Power should move to the Accrual Method for OPEBs costs for regulatory purposes.[14] This is consistent with current Canadian regulatory practice.[15]

The Board has also recognized that recovery of the regulatory asset associated with the transition to the Accrual Method for OPEBs raises challenges of balancing the fair application of the cost of service standard, and the principles of customer rate stability and intergenerational equity.[16] The balancing of these competing principles has been a central consideration in Newfoundland Power's development of a comprehensive proposal in respect of future OPEBs cost recovery.[17]

Adoption of the Accrual Method for OPEBs will result in Newfoundland Power's annual OPEBs costs recovered in customer rates exceeding its annual cash cost of OPEBs for the foreseeable future. This excess will reduce Newfoundland Power's rate base, which will, in turn, reduce the Company's financing requirements. The customer benefits of these reduced financing requirements, or Rate Base Effects, are cumulative – they will increase over time.[18]

This cost relationship was recognized by the Company in its development of a balanced approach to recovery of the regulatory asset.

4.2 Amortization Methods

Alternatives and Methodology

Newfoundland Power used economic analyses to assess alternative methods for amortization and recovery of the OPEBS costs reflected in the regulatory asset. This is consistent with the practical application of regulatory principles. It is also consistent with the economic approach used by actuaries in their determination of accrued OPEBs obligations.

Two alternative methods were considered for the amortization of the regulatory asset. The first was amortization on a simple straight-line basis (the "Straight-Line Method"). This method amortizes the regulatory asset in equal amounts in each year. This, in effect, stabilizes recovery of the *regulatory asset* over time.

The second was amortization on a basis that offsets recovery of the regulatory asset with Rate Base Effects associated with adoption of the Accrual Method for OPEBs costs (the "Mortgage Method"). This method amortizes the regulatory asset by a varying amount in each year to achieve consistency in the annual recovery of costs related to past service. This, in effect, stabilizes recovery of *net OPEBs costs* over time.

---

14 See page 35, Reasons for Decision for Order No. P.U. 43 (2009).

15 See, for example, the survey contained in the Report on Other Post Employment Benefits filed in support of Newfoundland Power's 2010 general rate application, Volume 2: Supporting Materials, Tab 4.

16 See page 35, Reasons for Decision for Order No. P.U. 43 (2009).

17 See Appendix B for a description of the primary regulatory principles considered.

18 See Appendix C for an explanation of Rate Base Effects.

The essential cost dynamics of each of these methods do not vary with changes in amortization term. These dynamics are illustrated using a 15-year amortization term. Use of current Canadian GAAP or IFRS to determine the costs would also not vary these dynamics.

Straight-Line Method
Table 3 provides a forecast of the Company's accrual OPEBs costs, amortization of the OPEBs regulatory asset using the Straight-Line Method over 15 years, and Rate Base Effects for 2011 through 2014 and 2025.

Table 3
Pro Forma OPEBs Costs
Straight-Line Method, 15 Year
($millions)

	2011	**2012**	**2013**	**2014**	**2025**
Accrual OPEBs Costs[19]	5.7	5.8	6.0	6.1	6.9
Amortization of Regulatory Asset[20]	3.5	3.5	3.5	3.5	3.5
Rate Base Effects[21]	(0.2)	(0.7)	(1.2)	(1.6)	(5.1)
Net OPEBs Cost	**9.0**	**8.6**	**8.3**	**8.0**	**5.3**

Using the Straight-Line Method, the *net impact* of OPEBs cost recovery declines over the 15-year period. This essentially reflects the cumulative impact of Rate Base Effects which reduce net impacts.

Appendix D shows the detailed calculation of use of the Straight-Line Method with a 15-year amortization.

Mortgage Method
Table 4 provides a forecast of the Company's accrual OPEBs costs, amortization of the OPEBs regulatory asset using the Mortgage Method over 15 years, and Rate Base Effects for 2011 through 2014 and 2025.

Table 4
Pro Forma OPEBs Costs
Mortgage Method, 15 Year
($millions)

	2011	**2012**	**2013**	**2014**	**2025**
Accrual OPEBs Costs[22]	5.7	5.8	6.0	6.1	6.9
Amortization of Regulatory Asset[23]	1.2	1.4	1.6	1.8	5.5
Rate Base Effects[21]	(0.2)	(0.5)	(0.8)	(1.1)	(5.0)
Net OPEBs Cost[24]	**6.7**	**6.7**	**6.8**	**6.8**	**7.4**

---

19 Appendix D, line 6.
20 Appendix D, line 7.
21 Rate Base Effects include the impact of reduced financing requirements on return on rate base and associated income tax effects.
22 Appendix E, line 6.
23 Appendix E, line 7.
24 Recovery of OPEBs costs related to past service together with Rate Base Effects are uniformly spread through the 15-year period.

Under the Mortgage Method, the *net impact* of OPEBs cost recovery is relatively constant over the 15-year period. This reflects the fact that, over time, increases in the amortization amounts tend to offset increases in Rate Base Effects.

Appendix E shows the detailed calculation associated with use of the Mortgage Method with a 15-year amortization.

4.3 Amortization Term

Alternatives Considered

Three alternative periods were considered for the term of amortization of the regulatory asset: 10, 15 and 20 years.

A 10-year period was considered a practical minimum amortization term due to the magnitude of the regulatory asset and associated customer rate impacts. A 20-year period was considered a practical maximum term. A 15-year period roughly corresponds to the estimated average remaining service life ("EARSL") for Newfoundland Power employees who are members in the Plan.[25]

The essential cost dynamics of the Straight-Line and Mortgage Methods do not vary with changes in amortization term. The differing amortization terms have been compared based on pro forma rate impacts.

Rate Impact Comparisons

Table 5 shows a comparison of the pro forma 2011 rate impacts of (i) adoption of the Accrual Method for OPEBs costs in 2011 and (ii) amortization of the regulatory asset commencing in 2011, using the Straight-Line Method and the Mortgage Method over 10, 15 and 20-year terms.

Table 5
Pro Forma 2011 Rate Impacts[26]
OPEBs Regulatory Asset Amortization Alternatives
(%)

	10-Year	15-Year	20-Year
Straight-Line Method	1.75	1.43	1.26
Mortgage Method	1.33	0.99	0.84

The pro forma 2011 rate impacts using the Straight-Line Method range from 1.26% to 1.75%. The pro forma 2011 rate impacts using the Mortgage Method range from 0.84% to1.33%.

These pro forma 2011 rate impacts do not reflect expected future net OPEBs costs variations due to the amortization method chosen. Net OPEBs cost impacts can be expected to decrease over time with amortization of the regulatory asset using the Straight-Line Method. Net OPEBs cost

25 EARSL is widely used by both actuaries and accountants in the valuation of, and accounting for, employee future benefits. For example, current Canadian GAAP accounting standards indicate that actuarial gains and losses in employee future benefit plans should be amortized over EARSL. Similar amortization is required for plan amendment impacts.

26 See Appendix F for detailed calculation of pro forma base rate impacts.

impacts can be expected to be relatively constant over time with amortization of the regulatory asset using the Mortgage Method.

4.4 Cost Recovery Comparison

Table 6 shows a comparison of the portion of Newfoundland Power's accrued OPEBs obligation recovered by the Company under the Straight-Line and Mortgage Methods over a 15-year amortization term.

Table 6
Comparative OPEBs Obligation Recovery
15-Year Amortization
($millions)

	Straight-Line	**Mortgage**
2011 Unrecovered OPEBs Obligation[27]	62.7	62.7
2025 Unrecovered Balance[28]	9.6	9.6
OPEBs Obligation Recovery	**53.1**	**53.1**

Both the Straight-Line and Mortgage Methods achieve the same level of OPEBs obligation recovery over the 15-year amortization term. The OPEBs obligation recovery under each of these methods remains comparable with changes in amortization term.

The cumulative cost impact of OPEBs recovery from customers over time is higher under the Mortgage Method than that under the Straight-Line Method. This reflects the fact that slower recovery of the regulatory asset results in increased finance costs.[29]

4.5 Assessment

Amortization Methods

Cost of Service Standard: Both the Straight-Line Method and Mortgage Method meet the cost of service standard. They permit Newfoundland Power the opportunity to recover its costs.

[27] The 2011 OPEBs obligation includes the opening 2011 balance of $62.3 million plus plan amendment costs of $0.4 million which vest at January 1, 2011.

[28] The 2025 unrecovered balance arises as a result of the Canadian GAAP requirement that actuarial gains and losses be recognized when they exceed 10% of the OPEBs plan obligations. Currently, the Company has actuarial losses which exceed 10% of its plan obligations. The portion of these losses in excess of the 10% corridor is recognized for the purposes of determining annual OPEBs expense. The portion of these losses which is less than the 10% corridor is not recognized for the purpose of determining annual OPEBs expense, and is not recovered in customer rates. The full amount of any actuarial gains and losses is recognized for the purpose of determining OPEBs plan obligations.

[29] Forecast net OPEBs cost recovery from 2011 through 2025 is approximately $104.9 million under the Mortgage Method, and approximately $98.0 million under the Straight-Line Method. See Appendices D and E for further details.

Intergenerational Equity: Newfoundland Power's OPEBs regulatory asset relates exclusively to past service. In the circumstances, intergenerational equity is best met by recovering the OPEBs costs related to past service fairly over a number of years.[30]

Both the Straight-Line Method and Mortgage Method recover the costs over a number of years. The Straight-Line Method amortizes only the regulatory asset evenly over the term. The Mortgage Method amortizes the regulatory asset in a way that results in overall OPEBs cost recovery (including past service cost recovery) being evenly spread over the amortization term. In this overall context, the Mortgage Method is more fair.

Rate Stability: The Mortgage Method results in more stable annual recovery of net OPEBs costs, so would tend to provide better rate stability.

Amortization Term

Cost of Service Standard: Each amortization term meets the cost of service standard. They permit Newfoundland Power the opportunity to recover its costs.

Intergenerational Equity: A shorter amortization term will result in a higher impact on customers in 2011, but the impact will be of shorter duration. A longer amortization term will result in a lower impact on customers in 2011, but the impact will be of a longer duration. A 15-year amortization is a reasonable balance of these considerations.

Rate Stability: A longer amortization term will result in a lower impact on customer rates in 2011. Extension of the amortization term has diminishing impacts.[31]

Recommendation

Newfoundland Power recommends use of the Mortgage Method over a 15-year term. This will provide a fair and equitable basis of recovering Newfoundland Power's regulatory asset associated with the transition to the Accrual Method for OPEBs costs for regulatory purposes.

5.0 ACCOUNTING MATTERS

5.1 General Observations

In developing a comprehensive proposal in respect of future OPEBs cost recovery, Newfoundland Power considered several accounting matters. These include the appropriate method of accounting for tax and the impact of evolving financial accounting standards, particularly the adoption of IFRS in 2011.

[30] Typically, intergenerational equity would require that these costs be recovered as quickly as practical, so that those who benefitted from the service pay the related costs. Many of these costs, including those comprising the regulatory asset, relate to service provided to customers years ago, as opposed to the Company's customers today. Accordingly, the application of this principle has practical limitations.

[31] See Table 5, Section 4.3 *Amortization Term*. For example, the reduction in 2011 rate impacts from a 10-year to a 15-year amortization term using the Mortgage Method is 0.34%. The reduction in 2011 rate impacts from a 15-year to a 20-year amortization term using the Mortgage Method is 0.15%, or less than half as much.

The Company's recommendation for the appropriate method of accounting for tax associated with OPEBs is consistent with that proposed in 2007 and 2009.[32]

The adoption of IFRS will affect the Company's accounting for OPEBs costs for *financial reporting purposes*. The adoption of IFRS will not affect the total amount of OPEBs costs to be recovered for *regulatory purposes* over the long term. However, use of IFRS to determine annual costs may reduce regulatory complexity in the future. The differences between regulatory accounting policies and financial accounting principles are described generally in Appendix G.

5.2 Accounting for Tax

Newfoundland Power's proposals include tax-effecting of OPEBs expense through adoption of the accrual method of income tax accounting for regulatory purposes commencing in 2011.[33] This is consistent with financial accounting standards.[34]

The OPEBs costs recovered using the Accrual Method in excess of that using the Cash Method are not deductible for tax purposes. This excess becomes tax deductible in future years when the insurance premiums and retiring allowances that it represents are actually paid.

By tax-effecting OPEBs costs, future income tax impacts are recognized for regulatory and financial reporting purposes in the same year as the associated expense. This is consistent with the principle of intergenerational equity. It effectively ensures that the group of customers bearing the cost also receive the tax benefits.

The immediate result of tax-effecting is a reduction in the costs to be recovered from customers for adoption of the Accrual Method for OPEBs. In 2011, this reduction is approximately $1.3 million.[35] The longer-term impact is to smooth fluctuations in customer rates.

5.3 Accounting Standards

Current Canadian GAAP

Current Canadian GAAP effectively permit regulated utilities to record as regulatory assets differences in OPEBs costs calculated under the Accrual Method and OPEBs costs recovered in

---

[32] See the Report on Other Post Employment Benefits filed in support of Newfoundland Power's 2008 general rate application, Volume 2: Supporting Materials, Tab 4, and the Report on Other Post Employment Benefits filed in support of Newfoundland Power's 2010 general rate application, Volume 2: Supporting Materials, Tab 4.

[33] The year in which an expense is recognized for income tax purposes may differ from the year in which it is recognized for financial reporting and regulatory purposes. When such a timing difference occurs, the income tax effects of an expense and the expense itself would not be recognized in the same year. To "tax-effect" an expense means to recognize the income tax effects of the expense in the year in which the expense itself is recognized for financial reporting and regulatory purposes. This is accomplished through the recognition of *future income tax* for financial reporting and regulatory purposes.
The Company currently recognizes future income tax liabilities in connection with: (i) timing differences between depreciation expense and capital cost allowance; and (ii) timing differences between pension funding and expense. It also tax-effects its regulatory reserves, such as the weather normalization reserve.

[34] This includes current Canadian GAAP and IFRS.

[35] $1.3 million represents the effective reduction in 2011 income tax expense due to tax-effecting OPEBs costs. Equals the difference between accrual OPEBs costs recovered in customer rates and the cash cost of OPEBs times the future tax rate, or (($6.8 million - $2.2 million) x 29%).

customer rates.[36] Conceptually, a regulatory asset represents revenues that are expected to be recovered from customers in future years.

Current Canadian GAAP also permits actuarial gains and losses associated with OPEBs plans to be amortized over EARSL. Such gains or losses are required to be recognized only when they exceed 10% of the OPEBs plan obligations.[37] Costs associated with OPEBs plan amendments are also permitted to be amortized over EARSL.[38]

Newfoundland Power accounts for its OPEBs costs in accordance with current Canadian GAAP.

International Financial Reporting Standards ("IFRS")

Effective January 1, 2011, all publicly accountable enterprises in Canada, including Newfoundland Power, will be required to comply with IFRS for financial reporting purposes.

For regulated utilities, the preeminent outstanding issue related to the transition to IFRS is the future accounting treatment of regulatory assets and liabilities. IFRS currently contain no specific guidance which would permit the recognition of regulatory assets and liabilities for financial reporting purposes. In December 2008, the International Accounting Standards Board ("IASB"), which oversees IFRS, initiated a project on rate-regulated activities. This project will determine the standards, if any, concerning recognition, measurement and reporting of regulatory assets and liabilities within IFRS. Uncertainty with respect to accounting for rate-regulated activities under IFRS will continue until the IASB issues guidance on this matter.[39]

It is possible that adoption of IFRS could result in regulatory assets and liabilities no longer being recognized for *financial reporting purposes*. Such a development would not affect the continued recognition of regulatory assets and liabilities for *regulatory purposes*.

The adoption of IFRS, including future treatment of regulatory assets and liabilities, will affect a number of aspects of financial reporting for Canadian regulated utilities. One aspect is accounting for OPEBs costs.

OPEBs Under IFRS

IFRS 1 *First Time Adoption of International Financial Reporting Standards* governs the adoption of IFRS for all affected entities, including Newfoundland Power. IFRS 1 will effectively require Newfoundland Power to recognize vested past service OPEBs costs for

---

[36] Prior to 2009, Canadian GAAP contained guidance that effectively permitted the recognition of regulatory assets and liabilities. Effective 2009, the Canadian Accounting Standards Board removed from Canadian GAAP the guidance that permitted recognition of regulatory assets and liabilities. For 2009 and 2010, Canadian regulated utilities effectively rely on U.S. GAAP (particularly, Statement of Financial Accounting Standards No. 71 *Accounting for the Effects of Certain Types of Regulation*) which permits recognition of regulatory assets and liabilities on a conceptually similar basis to that allowed under Canadian GAAP prior to 2009.

[37] See CICA Handbook, Section 3461.087 *et seq.* Newfoundland Power currently amortizes actuarial gains and losses in excess of the 10% corridor over EARSL.

[38] See CICA Handbook, Section 3461.083 *et seq.* Where amendments reduce plan obligations, the reduction is required to be first applied against any unamortized past service costs, with the excess amortized over EARSL.

[39] In February 2010, the IASB directed further analysis as part of its project on rate-regulated activities. It was expected that this analysis would take several months to complete, though no firm timelines were established.

financial reporting purposes immediately upon adoption of IFRS.[40] IFRS 1 will affect both Newfoundland Power's OPEBs regulatory asset and its annual accrual OPEBs costs. It will not, however, affect the total OPEBs obligations that the Company must recover over the long term.

On an ongoing basis, IAS 19 *Employee Benefits* is the standard which primarily governs accounting for OPEBs under IFRS.[41] IAS 19 currently permits actuarial gains and losses associated with OPEBs plans to be amortized over EARSL, in a manner similar to current Canadian GAAP. It also currently requires such gains or losses to be recognized only when they exceed 10% of the OPEBs plan obligations. Costs associated with OPEBs plan amendments are also treated similarly to current Canadian GAAP.

Appendix H provides an actuarial forecast of OPEBs costs calculated in accordance with IFRS.

Table 7 compares Newfoundland Power's OPEBs regulatory asset as at January 1, 2011, calculated in accordance with current Canadian GAAP and IFRS.

Table 7
Forecast 2011 OPEBs Regulatory Asset
Under Current Canadian GAAP and IFRS
($millions)

	Current Canadian GAAP	**IFRS**
2011 OPEBs Obligation[42]	62.7	62.7
Unamortized Balances		
2000 Transitional Obligation[43]	(9.4)	-
Past Service Costs[44]	12.0	8.0
Actuarial Gain (Loss)[45]	(12.9)	(2.1)
Total Unamortized Balances	(10.3)	5.9
Regulatory Asset	**52.4**	**68.6**

[40] Vested past service costs relate to benefits for which employees are fully eligible. By contrast, unvested past service costs relate to benefits for which employees are not fully eligible, but are expected to be fully eligible in the normal course (i.e. with continuing service.)

[41] IAS 19 is currently under review. In April 2010, the IASB issued an exposure draft proposing amendments to IAS 19. The IASB plans to accept comments on this exposure draft until September 2010, and to finalize amendments to IAS 19 in mid-2011. Changes to IAS 19 are not expected to take effect prior to 2012. The details of any actual changes are currently uncertain.

[42] The 2011 OPEBs obligation includes the opening 2011 balance of $62.3 million plus plan amendment costs of $0.4 million which vest at January 1, 2011.

[43] IFRS 1 will effectively require Newfoundland Power to recognize to equity for financial reporting purposes the unamortized balance of OPEBs past service costs which arose at December 31, 1999, upon adoption of CICA Handbook Section 3461.

[44] This is the 2011 unamortized balance associated with plan amendments. Under current Canadian GAAP, this equals the December 31, 2010 balance of $12.4 million, plus the ($0.4) million plan amendment costs which vest at January 1, 2011. IFRS 1 will effectively require Newfoundland Power to recognize to equity for financial reporting purposes the vested portion of any unamortized balance of OPEBs past service costs associated with plan amendments, or approximately $4 million (Appendix H).

[45] This is the unamortized balance associated with past actuarial losses and gains as at December 31, 2010. IFRS 1 will effectively require Newfoundland Power to recognize to equity for financial reporting purposes the unamortized balance of actuarial losses and gains as at December 31, 2009. The $2.1 million IFRS balance (Appendix H) reflects the actuarial loss associated with the use of a 6.5% discount rate for evaluation purposes as compared to the 6.7% discount rate actually used for 2010 OPEBs expense purposes.

Upon adoption of IFRS in 2011, the Company's OPEBs regulatory asset will increase by approximately $16.2 million, whether or not that asset is recognized for financial reporting purposes.[46]

Table 8 compares Newfoundland Power's forecast 2011 OPEBs costs under the Accrual Method as calculated in accordance with current Canadian GAAP and IFRS.

Table 8
Accrual 2011 OPEBs Costs
Under Current Canadian GAAP and IFRS
($millions)

	Current Canadian GAAP	**IFRS**
Accrual OPEBs Costs	5.7	4.3

Newfoundland Power's accrual 2011 OPEBs costs are forecast to be $1.4 million less as a result of the adoption of IFRS.

The principal impacts of Newfoundland Power's adoption of IFRS in 2011 will be to (i) increase the OPEBs regulatory asset by $16.2 million, and (ii) reduce its annual OPEBs costs under the Accrual Method by $1.4 million for financial reporting purposes. These impacts will not, however, affect the total OPEBs obligations that the Company must recover over the long term.

6.0 OPEBs COST RECOVERY

6.1 General

To establish the appropriate level of increased OPEBs cost recovery for regulatory purposes in 2011, the Company (i) based its recovery of annual OPEBs costs on IFRS, and (ii) adopted the Mortgage Method over a 15-year term to recover the OPEBs regulatory asset associated with the transition to the Accrual Method for OPEBs costs.

Effective January 1, 2011, Newfoundland Power will be required to comply with IFRS for financial reporting purposes. While this does not necessarily require the use of IFRS to determine OPEBs cost recovery for regulatory purposes, use of IFRS-based costs should reduce regulatory complexity in the future.[47] In addition, the effective date of the comprehensive proposal ordered by the Board was indicated to be January 1, 2011. Finally, the differences in OPEBs costs under current Canadian GAAP and IFRS are essentially related to timing of cost recognition. Newfoundland Power's OPEBs obligations under current Canadian GAAP and IFRS are equal.

The use of the Mortgage Method over a 15-year term strikes a reasonable balance of the regulatory principles which apply to the recovery of the OPEBs regulatory asset. Appendix I

---

[46] The amount of the OPEBs liability reflected in Newfoundland Power's financial statements will increase by approximately $16.2 million.

[47] Following IFRS adoption, continued use of current Canadian GAAP for the purposes of determining regulatory recovery of OPEBs costs will tend to increase regulatory complexity.

shows the forecast of OPEBs costs based on IFRS through 2025. It includes amortization of the OPEBs regulatory asset existing on January 1, 2011, using the Mortgage Method with a 15-year term.

6.2 Revenue Requirement Impacts

Newfoundland Power's customer rates currently recover approximately $1.2 million in operating costs related to OPEBs.[48] To commence recovery of the additional costs associated with (i) adoption of the Accrual Method for OPEBs costs in 2011 and (ii) amortization of the regulatory asset commencing in 2011, will require an increase in customer rates in 2011.

Table 9 shows the pro forma revenue requirement increase and associated customer rate impact for 2011 to permit recovery of these additional costs based upon amortization of the regulatory asset using the Mortgage Method over a 15-year term, calculated under current Canadian GAAP and IFRS.

Table 9
Pro Forma Revenue Requirement and Customer Rate Impacts
Mortgage Method, 15-Year
($000s)

	2010 Test Year[48]	**Canadian GAAP 2011 Forecast**	**IFRS 2011 Forecast[49]**
OPEBs Accrual Expense	1,196	5,340[50]	3,947
Amortization of Regulatory Asset	-	1,152	2,838
Rate Base Effects[51]	-	(165)	(176)
Future Tax Effects[52]		100	106
Forecast Revenue Requirement	1,196	6,427	6,715
Increase in Revenue Requirement[53]		5,231	5,519
Pro Forma Base Rate Impact (%)[54]		**0.99**	**1.04**
Pro Forma Customer Rate Impact (%)[55]		**0.97**	**1.02**

48 For 2010 Test Year OPEBs operating costs calculated using the Cash Method, see Exhibit 7 (1st Revision) to Company evidence filed in support of Newfoundland Power's 2010 general rate application.

49 Under IFRS, the approximately $1.4 million lower OPEBs accrual expense will be substantially offset by the increased amortization of the regulatory asset of approximately $1.7 million in 2011(see Appendix I).

50 $5.3 million is the operating cost portion of $5.7 million in 2011 OPEBs costs under the Accrual Method. The $0.4 million difference represents the 42% of OPEBs current service costs capitalized as overhead associated with the Company's capital program. This equals 42% of OPEBs current service costs, or (42% x $0.7 million).

51 See Appendix C for details regarding the method for calculation of Rate Base Effects.

52 Future Tax Effects includes tax associated with differences in current and future tax rates. Equals the difference between accrual OPEBs costs recovered in customer rates and the cash cost of OPEBs times the difference between current and future tax rates, plus related income tax effects. Under current Canadian GAAP, equals (($6.8 million - $2.2 million) x (30.5% - 29.0%) / (1 – 30.5%)). Under IFRS, equals (($7.1 million - $2.2 million) x (30.5% - 29.0%) / (1 – 30.5%)).

53 This is the forecast increase in revenue requirement from the 2010 Test Year cost recovery.

54 Based on 2010 Test Year base rate revenue of $528,783,000.

55 Based on the proposed effect of operation of the Rate Stabilization Account and Municipal Tax Adjustment for July 1, 2010. Under current Canadian GAAP equals $5,231,000 x 1.025 (2.5% MTA adjustment factor) / $554,339,000, or 0.97. Under IFRS equals $5,519,000 x 1.025 (2.5% MTA adjustment factor) / $554,339,000, or 1.02.

The pro forma customer rate impact of recovery of the additional costs related to OPEBs in 2011 is approximately 1%. The rate impact does not materially change whether OPEBs costs are calculated under IFRS or current Canadian GAAP.

Table 10 shows a comparison of the portion of Newfoundland Power's accrued OPEBs obligation recovered by the Company under current Canadian GAAP and IFRS, using the Mortgage Method over a 15-year amortization term.

Table 10
Comparative OPEBs Obligation Recovery
Current Canadian GAAP and IFRS
2011 - 2025
($millions)

	Current Canadian GAAP	**IFRS**
2011 Unrecovered OPEBs Obligation	62.7	62.7
2025 Unrecovered Balance	9.6	2.1
OPEBs Obligation Recovery	**53.1**	**60.6**

OPEBs obligation recovery during the 15-year term under IFRS is approximately $7.5 million higher than that under current Canadian GAAP. This reflects a timing difference in the recovery of OPEBs costs that are forecast to arise over the 15-year amortization term. Over the longer term the total OPEBs costs to be recovered are the same under current Canadian GAAP or IFRS. The timing difference is reflected in the differences in the forecast 2025 unrecovered balance under current Canadian GAAP and IFRS.[56] It is the reason why the pro forma revenue requirement and customer rate impacts under IFRS are modestly higher than those under current Canadian GAAP.

Appendix J shows the revisions to Newfoundland Power's 2010 test year revenue requirements to support recovery of the additional costs related to OPEBs in 2011 as calculated under IFRS.

6.3 Future Cost Variation

The accrued benefits obligation and annual expense related to OPEBs are subject to year-to-year variability due to changes in the discount rate and other assumptions. For example, the discount rate used to value the OPEBs obligation, and thus determine annual OPEBs costs, is established at December 31st of the preceding year, and is not reasonably predictable.[57]

[56] See footnote 28 for an explanation of the $9.6 million 2025 unrecovered balance which arises under current Canadian GAAP. The $2.1 million 2025 unrecovered balance under IFRS is the result of the combined effect of IFRS 1 and IAS 19. The application of IFRS 1 will effectively require Newfoundland Power to recognize to equity for financial reporting purposes actuarial losses arising before December 31, 2009 (see Table 7). The $2.1 million IFRS balance arises from an actuarial loss in 2010 (see footnote 45). This is within the corridor of 10% of the OPEBs obligation which is not required to be recognized for the purpose of determining annual OPEBs expense under IAS 19. Failing a change in accounting standards or further actuarial losses or gains, the $2.1 million will remain unamortized through 2025.

[57] Other assumptions used to determine annual OPEBs costs are also subject to change in future. These include assumptions related to health care cost trends and mortality rates for members in the Plan. Plan amendments, such as the 2011 benefit provision changes, may also impact the value of the OPEBs obligation and annual OPEBs costs. However, Plan amendments would not be subject to the unpredictability associated with changes in assumptions.

Newfoundland Power recommends the creation of an OPEBs Cost Variance Deferral Account to capture future changes in OPEBs costs from that included in rates. The regulatory mechanism recommended is similar to that approved for pension expense.[58] Similarity in the treatment of future variances in annual employee future benefit costs would reduce regulatory complexity.

Cost variances captured by the OPEBs Cost Variance Deferral Account would reflect changes in OPEBs expense, the amortization of the OPEBs regulatory asset, and associated rate base effects, from those included in the Company's most recent test year used to set customer rates.

The proposed OPEBs Cost Variance Deferral Account is provided in Appendix K.

A sample calculation of operation of the proposed OPEBs Cost Variance Deferral Account is provided in Appendix L.

7.0 RECOMMENDATIONS

Effective January 1, 2011, Newfoundland Power recommends that it:

1. adopt, for regulatory purposes, the Accrual Method for OPEBs costs and for income tax related to OPEBs under IFRS;
2. recover the OPEBs regulatory asset under IFRS on the basis of the Mortgage Method and a 15-year amortization term; and
3. adopt an OPEBs Cost Variance Deferral Account to capture differences in OPEBs costs arising from changes in assumptions associated with the valuation of OPEBs obligations.

Implementation of these recommendations would require an increase in Newfoundland Power's customer rates of approximately 1% effective January 1, 2011.

If approved by the Board, these recommendations would deal comprehensively with the issues arising on the Company's adoption of the accrual method of accounting for OPEBs for regulatory purposes as of January 1, 2011. These recommendations would provide for recovery of the transitional balance, or regulatory asset, arising from the adoption of accrual accounting for OPEBs for regulatory purposes.

[58] The Pension Expense Variance Deferral Account was approved by the Board in Order No. P.U. 43 (2009).

Newfoundland Power Inc.
5 Year Projection @ 6.50% - Base

Period	Actual	Projected	Projected	Projected	Projected	Projected
Year	2009	2010	2011	2012	2013	2014
From	1/1/2009	1/1/2010	1/1/2011	1/1/2012	1/1/2013	1/1/2014
To	12/31/2009	12/31/2010	12/31/2011	12/31/2012	12/31/2013	12/31/2014
Change in benefit obligation						
Benefit obligation - end of prior period	59,636,000	69,667,000	75,600,000	79,926,000	83,753,000	87,406,000
Current service cost (employer)	1,008,000	1,032,000	1,140,000	1,188,000	1,238,000	1,290,000
Interest cost	4,485,000	4,673,000	4,945,000	5,190,000	5,427,000	5,662,000
Employee contributions	0	0	0	0	0	0
Plan amendments	1,004,000	0	432,000	0	0	0
Benefits paid	-1,304,000	-1,891,000	-2,191,000	-2,551,000	-3,012,000	-3,173,000
Net transfer in (out)	0	0	0	0	0	0
Acquisitions (divestitures)	0	0	0	0	0	0
Increase (decrease) in obligation due to curtailment	0	0	0	0	0	0
Obligation being settled	0	0	0	0	0	0
Special termination benefits	0	0	0	0	0	0
Actuarial loss (gain)	4,838,000	2,119,000	0	0	0	0
Benefit obligation - end	69,667,000	75,600,000	79,926,000	83,753,000	87,406,000	91,185,000
Change in plan assets						
Market value of plan assets - end of prior period	0	0	0	0	0	0
Actual return on plan assets	0	0	0	0	0	0
Employer contributions	1,304,000	1,891,000	2,191,000	2,551,000	3,012,000	3,173,000
Employee contributions	0	0	0	0	0	0
Benefits paid	-1,304,000	-1,891,000	-2,191,000	-2,551,000	-3,012,000	-3,173,000
Surplus paid out to employer	0	0	0	0	0	0
Settlement payments	0	0	0	0	0	0
Net transfer in (out)	0	0	0	0	0	0
Acquisitions (divestitures)	0	0	0	0	0	0
Actual plan expenses	0	0	0	0	0	0
Market value of plan assets - end	0	0	0	0	0	0
Reconciliation of funded status						
Benefit obligation - end	69,667,000	75,600,000	79,926,000	83,753,000	87,406,000	91,185,000
Market value of plan assets - end	0	0	0	0	0	0
Funded status - surplus (deficit)	-69,667,000	-75,600,000	-79,926,000	-83,753,000	-87,406,000	-91,185,000
Employer contributions after measurement date	0	0	0	0	0	0
Unamortized transitional obligation (asset)	10,857,000	9,429,000	8,001,000	6,573,000	5,145,000	3,717,000
Unamortized past service costs	1,004,000	890,000	1,159,000	996,000	833,000	670,000
Unamortized net actuarial loss (gain)	11,093,000	12,917,000	12,537,000	12,212,000	11,938,000	11,710,000
Accrued benefit asset (liability)	-46,713,000	-52,364,000	-58,229,000	-63,972,000	-69,490,000	-75,088,000
Unamortized transitional increase (decrease) in valuation allowance	0	0	0	0	0	0
Valuation allowance	0	0	0	0	0	0
Accrued benefit asset (liability), net of valuation allowance	-46,713,000	-52,364,000	-58,229,000	-63,972,000	-69,490,000	-75,088,000
Components of expense						
Current service cost (including provision for plan expenses)	1,008,000	1,032,000	1,140,000	1,188,000	1,238,000	1,290,000
Interest cost	4,485,000	4,673,000	4,945,000	5,190,000	5,427,000	5,662,000
Expected return on plan assets	0	0	0	0	0	0
Amortization of transitional obligation (asset)	1,428,000	1,428,000	1,428,000	1,428,000	1,428,000	1,428,000
Amortization of past service costs	0	114,000	163,000	163,000	163,000	163,000
Amortization of net actuarial loss (gain)	22,000	295,000	380,000	325,000	274,000	228,000
Curtailment loss (gain)	0	0	0	0	0	0
Settlement loss (gain)	0	0	0	0	0	0
Amortization of transitional increase (decrease) in VA	0	0	0	0	0	0
Increase (decrease) in valuation allowance	0	0	0	0	0	0
Special termination benefits	0	0	0	0	0	0
Net expense (income)	6,943,000	7,542,000	8,056,000	8,294,000	8,530,000	8,771,000
Assumptions						
At beginning of period						
Discount rate	7.50%	6.70%	6.50%	6.50%	6.50%	6.50%
Rate of compensation increase	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%
Health care inflation - Select	9.33%	8.09%	7.98%	7.90%	7.77%	7.62%
Health care inflation - Ultimate	4.50%	4.55%	4.55%	4.55%	4.55%	4.55%
Expected rate of return on plan assets	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
At end of period						
Discount rate	6.70%	6.50%	6.50%	6.50%	6.50%	6.50%
Rate of compensation increase	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%
Health care inflation - Select	8.09%	7.98%	7.90%	7.77%	7.62%	7.45%
Health care inflation - Ultimate	4.55%	4.55%	4.55%	4.55%	4.55%	4.55%

Mercer Pension and Benefits Expensing Software (PBES)
Version 1.2

Newfoundland Power Inc. Non-Pension Post Retirement Benefit Costing
5 Year Projection @ 6.50% - After Plan Changes

Year From To	Actual 2009 1/1/2009 12/31/2009	*Projected* 2010 1/1/2010 12/31/2010	*Projected* 2011 1/1/2011 12/31/2011	*Projected* 2012 1/1/2012 12/31/2012	*Projected* 2013 1/1/2013 12/31/2013	*Projected* 2014 1/1/2014 12/31/2014
Change in benefit obligation						
Benefit obligation - end of prior period	59,636,000	69,667,000	62,334,000	65,408,000	67,903,000	70,140,000
Current service cost (employer)	1,008,000	1,032,000	746,000	788,000	831,000	876,000
Interest cost	4,485,000	4,673,000	4,058,000	4,221,000	4,371,000	4,515,000
Employee contributions	0	0	0	0	0	0
Plan amendments	1,004,000	-13,266,000	432,000	0	0	0
Benefits paid	-1,304,000	-1,891,000	-2,162,000	-2,514,000	-2,965,000	-3,110,000
Net transfer in (out)	0	0	0	0	0	0
Acquisitions (divestitures)	0	0	0	0	0	0
Increase (decrease) in obligation due to curtailment	0	0	0	0	0	0
Obligation being settled	0	0	0	0	0	0
Special termination benefits	0	0	0	0	0	0
Actuarial loss (gain)	4,838,000	2,119,000	0	0	0	0
Benefit obligation - end	69,667,000	62,334,000	65,408,000	67,903,000	70,140,000	72,421,000
Change in plan assets						
Market value of plan assets - end of prior period	0	0	0	0	0	0
Actual return on plan assets	0	0	0	0	0	0
Employer contributions	1,304,000	1,891,000	2,162,000	2,514,000	2,965,000	3,110,000
Employee contributions	0	0	0	0	0	0
Benefits paid	-1,304,000	-1,891,000	-2,162,000	-2,514,000	-2,965,000	-3,110,000
Surplus paid out to employer	0	0	0	0	0	0
Settlement payments	0	0	0	0	0	0
Net transfer in (out)	0	0	0	0	0	0
Acquisitions (divestitures)	0	0	0	0	0	0
Actual plan expenses	0	0	0	0	0	0
Market value of plan assets - end	0	0	0	0	0	0
Reconciliation of funded status						
Benefit obligation - end	69,667,000	62,334,000	65,408,000	67,903,000	70,140,000	72,421,000
Market value of plan assets - end	0	0	0	0	0	0
Funded status - surplus (deficit)	-69,667,000	-62,334,000	-65,408,000	-67,903,000	-70,140,000	-72,421,000
Employer contributions after measurement date	0	0	0	0	0	0
Unamortized transitional obligation (asset)	10,857,000	9,429,000	8,001,000	6,573,000	5,145,000	3,717,000
Unamortized past service costs	1,004,000	-12,376,000	-10,942,000	-9,940,000	-8,939,000	-7,936,000
Unamortized net actuarial loss (gain)	11,093,000	12,917,000	12,494,000	12,115,000	11,776,000	11,473,000
Accrued benefit asset (liability)	-46,713,000	-52,364,000	-55,855,000	-59,155,000	-62,158,000	-65,167,000
Unamortized transitional increase (decrease) in valuation allowance	0	0	0	0	0	0
Valuation allowance	0	0	0	0	0	0
Accrued benefit asset (liability), net of valuation allowance	-46,713,000	-52,364,000	-55,855,000	-59,155,000	-62,158,000	-65,167,000
Components of expense						
Current service cost (including provision for plan expenses)	1,008,000	1,032,000	746,000	788,000	831,000	876,000
Interest cost	4,485,000	4,673,000	4,058,000	4,221,000	4,371,000	4,515,000
Expected return on plan assets	0	0	0	0	0	0
Amortization of transitional obligation (asset)	1,428,000	1,428,000	1,428,000	1,428,000	1,428,000	1,428,000
Amortization of past service costs	0	114,000	-1,002,000	-1,002,000	-1,001,000	-1,003,000
Amortization of net actuarial loss (gain)	22,000	295,000	423,000	379,000	339,000	303,000
Curtailment loss (gain)	0	0	0	0	0	0
Settlement loss (gain)	0	0	0	0	0	0
Amortization of transitional increase (decrease) in VA	0	0	0	0	0	0
Increase (decrease) in valuation allowance	0	0	0	0	0	0
Special termination benefits	0	0	0	0	0	0
Net expense (income)	6,943,000	7,542,000	5,653,000	5,814,000	5,968,000	6,119,000
Assumptions						
At beginning of period						
Discount rate	7.50%	6.70%	6.50%	6.50%	6.50%	6.50%
Rate of compensation increase	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%
Health care inflation - Select	9.33%	8.09%	7.98%	7.90%	7.77%	7.62%
Health care inflation - Ultimate	4.50%	4.55%	4.55%	4.55%	4.55%	4.55%
Expected rate of return on plan assets	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
At end of period						
Discount rate	6.70%	6.50%	6.50%	6.50%	6.50%	6.50%
Rate of compensation increase	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%
Health care inflation - Select	8.09%	7.98%	7.90%	7.77%	7.62%	7.45%
Health care inflation - Ultimate	4.55%	4.55%	4.55%	4.55%	4.55%	4.55%

n:\nfld_pwr\opeb\year2010\costing\apr 2010\accounting\option 2 - 50% ee\nfdpower_dca.xls 1 of 1 4/12/2010 3:05:19 PM

REGULATORY PRINCIPLES

In the context of Newfoundland Power's development of a comprehensive proposal for its future OPEBs cost recovery, the following regulatory principles are relevant: just and reasonable rates, cost of service standard, intergenerational equity, and rate stability and predictability.

Just & Reasonable Rates

The primary regulatory principle, and the one most likely to be incorporated into regulatory legislation, is that rates should be just and reasonable. "Just and reasonable" applies to both customers and regulated entities. It requires a weighting of the legitimate interests of both parties. Unfortunately, "just and reasonable" is a vague and subjective concept. It provides an overall direction to regulators but little specific guidance.

This principle is consistent with the declared policy of the Province of Newfoundland and Labrador. For example, paragraph 3 of the "Electric Power Control Act, 1994" states that it is the declared policy of the province that the rates to be charged, either generally or under specific contracts, for the supply of power within the province should be reasonable and not unjustly discriminatory.

Cost of Service Standard

At the heart of rate regulation is the cost of service standard, sometimes referred to as the revenue requirement standard.

Under this standard, a regulated entity is permitted to set rates that allow it the opportunity to recover its costs for regulated operations, including a fair rate of return on its investment devoted to regulated operations – no more, no less.

It's important to note that this standard only gives the entity the opportunity to earn a fair return; it does not guarantee it. In most cases, rates are set prospectively, based on anticipated future costs. If the entity over-recovers, it keeps the excess. If it under-recovers, it bears the deficiency.

This standard reflects fairness and the necessity to offer adequate incentives for providing regulated services.

- In fairness, an entity's investors should have the opportunity to recover their costs, including a fair return, just as they would if they were to invest in a non-regulated entity of similar risk. However, customers should not have to provide investors with the opportunity to earn more than they could expect from investing in non-regulated operations.

- From an incentive viewpoint, unless investors have a reasonable opportunity to recover their costs, including a fair return, it will be difficult to attract the investment necessary to provide regulated operations. However, the opportunity to recover these costs should provide an adequate incentive to attract those funds.

The cost of service standard is applicable to all regulatory methodologies, including performance-based methods such as price cap regulation. A regulated utility may earn more or less than a fair return, and performance based methods increase the possibility of realized earnings deviating from a fair return. However, the issue is that a regulated entity should have a reasonable opportunity to earn a fair return, which implies that the possibility of under and over earning is offsetting[1].

The cost of service standard is consistent with what is expected to occur in a competitive market, where the price of services tends towards the cost of providing them, including a fair return.

The principle is also consistent with the Newfoundland and Labrador Public Utilities Act. For example, paragraph 80 states:

> *(1) 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 …*
>
> *(2) The return shall be in addition to those expenses that the board may allow as reasonable and prudent and properly chargeable to operating account, and to all just allowances made by the board according to this Act and the rules and regulations of the board.*
>
> *(3) Reasonable payments each year to former employees of a public utility who have retired and are receiving payments of supplemental income from the public utility are expenses that the board may allow as reasonable and prudent and properly chargeable to the operating account of the public utility. …*

Intergenerational Equity

Under this principle, customers in a given period should pay only the costs necessary to provide them with service in that period. They should not have to pay for any costs incurred to provide service to customers in another period. This principle is consistent with setting just and reasonable rates within each period.

For example, a regulated entity is usually not allowed to earn a return on projects under construction. It's incurring this cost to provide service to future customers, not customers in the current period. Instead, the return is capitalized and recovered through depreciation over the period in which the assets are used to provide service.

Combined with the cost of service standard, the principle of intergenerational equity requires that rates within a period should cover the costs of providing service in that period.

This principle's importance depends on the periods involved. Customers in one year tend to be the same as those in the next and an individual's usage generally doesn't vary that much from one year to the next. Having customers in one year pay more as a result of costs incurred to provide service in the previous year would not be as serious a breach of this principle as it would

---

[1] The expected rate of return should equal a fair rate of return where the expected rate of return is equal to the average of the possible rates of return weighted by the probability of their occurrence.

be if they had to pay more because of service provided to customers 10 years earlier. If costs can't be recovered in the period for which they were incurred, it's generally best to recover them in a period as close as possible to the one for which they were incurred.

Under the principle of intergenerational equity, costs that might be expensed in one period under normal accounting principles could be deferred for regulatory purposes and recovered from customers in a future period.

Situations may arise where unrecovered costs relate to periods far in the past. In such a case, many current and future customers may not have benefited from the costs not being recovered in the periods to which they relate. In such a case, spreading the recovery of the past costs over a number of periods, so as to reduce the impact in any one year, may provide greater equity between periods.

Rate Stability and Predictability

This principle requires rates to remain stable and predictable – at least to the extent practical. It may, therefore, justify smoothing out changes in rates to avoid sharp rate climbs or temporary fluctuations.

The principle's intent is to establish only when costs are recovered, not the amount actually recovered. In practice, it does affect the amounts recovered because the timing of cost recovery affects financing costs. Where costs are deferred, the deferred amount must be financed, and regulated entities are entitled to recover the additional financing costs under the cost of service standard.

The principle of rate stability and predictability may require costs to be collected from customers in periods other than those for which they were incurred. Therefore, it is inconsistent with the principle of intergenerational equity. Despite that, it is justified because it recognizes the adverse impact where customers must adjust to significant rate increases or short-term rate fluctuations.

As time passes, the makeup and usage of a customer group changes. Therefore, the longer the period that costs are deferred, the more serious the breach of the intergenerational equity principle. As a result, when the principle of rate stability and predictability is applied, cost deficiencies should be recovered over as short a period as is reasonable, so the customer group that eventually pays for the costs is similar to the one benefiting from the costs. Similarly, if, to avoid a sharp rate increase, costs are recovered before a period for which they will be incurred, the intervening period should also be as short as reasonably possible.

Newfoundland Power Inc.

An Explanation of Rate Base Effects

A. Introduction

As well as physical assets, Newfoundland Power's rate base includes a number of additions and deductions due to regulatory accounting.[1] These additions and deductions typically represent timing differences between the payment of costs and the receipt of revenue in respect of those costs.

Additions to rate base typically reflect cash outlays by the Company in providing a regulated service which have not yet been recovered in customer rates. For example, deferred charges, which are added to the Company's rate base, include funding for the Company's defined benefit pension plan which has not yet been reflected as an expense for the purposes of calculating customer rates. Deductions from rate base typically reflect cash amounts received by the Company in providing a regulated service which have not yet resulted in a cash outlay. For example, the municipal tax liability, which is deducted from the Company's rate base, reflects an amount received by the Company in revenue in advance of its payment to municipalities.

These rate base additions and deductions impact the amount which the Company is required to finance as part of its ongoing provision of service to customers. They are approved by the Board. This is a common current regulatory practice in Canada.

In this appendix, the Company has used current Canadian GAAP in determining the OPEB's costs to illustrate the rate base effects.

B. OPEBs Rate Base Effects

General

The adoption of the Accrual Method for OPEBs costs will increase Newfoundland Power's annual recognition of OPEBs costs for regulatory purposes. This increase in OPEBs costs recovery and the related income tax effects will both impact Newfoundland Power's rate base.

First, OPEBs costs recognized for regulatory purposes will exceed cash costs. This will tend to *reduce* the Company's financing requirements. This reflects the fact that the Company will receive cash revenue in excess of the cash costs it incurs.

Second, by tax-effecting OPEBs costs under the Accrual Method, the Company will effectively credit customers with the effect of income tax deductions before they are actually available.[2]

---

1 See, for example, Return 3 of Newfoundland Power's 2009 Annual Report to the Board which indicates the computation of average rate base for 2009.

2 This is the result of the *Income Tax Act (Canada)* permitting tax deductibility for only cash outlays made in respect of OPEBs. Newfoundland Power proposes to tax-effect its OPEBs expense to match the increased costs of OPEBs with the associated future tax deductions. See *Section 5.2 Accounting for Tax.*

The Company will, however, pay increased annual cash taxes.[3] This will tend to *increase* the Company's financing requirements. This reflects the fact that the Company will pay cash taxes in excess of the tax amounts recovered in revenue.

Accrual Accounting

Table 1 illustrates the impact on 2011 average rate base resulting from the increased OPEBs expense under the Accrual Method.[4]

Table 1
OPEBs Accrual Method
Illustrative Impact on 2011 Average Rate Base
($000s)

OPEBs Liability, Beginning of the Year	-
OPEBs Costs, Accrual Method	5,653
Amortization of OPEBs Regulatory Asset	1,152
OPEBs Costs, Cash Method	(2,162)
OPEBs Liability, End of the Year	4,643
Reduction in Average Rate Base[5]	2,322

The reduction in average rate base shown in Table 1 would reduce Newfoundland Power's financing requirements in 2011. This is a cash flow benefit associated with the increased OPEBs expense under the Accrual Method.

[3] This is the result of increased revenue associated with recovery of increased OPEBs costs under the Accrual Method.

[4] All costs calculated in accordance with current Canadian GAAP.

[5] Equals ((Accrued OPEBs Liability, Beginning of the Year + Accrued OPEBs Liability, End of the Year) / 2).

Income Tax
Table 2 illustrates the impact on 2011 average rate base resulting from tax-effecting OPEBs expense under the Accrual Method.

Table 2
Tax-Effecting OPEBs
Illustrative Impact on 2011 Average Rate Base
($000s)

Future Income Tax Asset, Beginning of the Year	-
Future Income Tax Recovery[6]	1,346
Future Income Tax Asset, End of the Year[7]	1,346
Increase in Average Rate Base[8]	673

The future income tax asset of $1.3 million shown in Table 2 effectively represents tax deductions credited to customers in advance of the deduction being available to the Company. The increase in average rate base of $0.7 million shown in Table 2 would increase Newfoundland Power's financing requirements in 2011.

Summary of Rate Base Effects
Table 3 illustrates the 2011 aggregate impact on average rate base associated with the adoption of the Accrual Method for OPEBs costs on a tax-effected basis in 2011.

Table 3
OPEBs Accrual Method
Summary of 2011 Average Rate Base Effects
($000s)

Adoption of Accrual Method	(2,322)
Tax-Effecting	673
Net Change in Average Rate Base	(1,649)

For 2011, Newfoundland Power's average rate base would be reduced by approximately $1.6 million as a result of the adoption of the Accrual Method for OPEBs costs on a tax-effected basis.

6 Represents the effective reduction in income tax expense due to tax-effecting OPEBs costs. Equals annual change in Accrued OPEBs Liability (from Table 1) x the future tax rate, or ($4.643 million x 29%).
7 Represents the future income tax asset that would be included in Newfoundland Power's balance sheet.
8 Equals ((Future Income Tax Asset, Beginning of the Year + Future Income Tax Asset, End of the Year) / 2).

Rate Base Effects represent the reduction in the Company's financing requirements due to this reduction in average rate base. For 2011, these Rate Base Effects would be a reduction of approximately $0.2 million.[9]

C. Implications

In Newfoundland Power's development of a comprehensive proposal in respect of OPEBs cost recovery, Rate Base Effects have two primary implications. The first relates to the choice of amortization method for the regulatory asset. The consideration of Rate Base Effects practically permits the use of a mortgage-type amortization as proposed, which smoothes costs over the amortization period and thus tends to increase customer rate stability. The second implication relates to the operation of the proposed variance deferral account. Any such mechanism must reasonably account for cumulative Rate Base Effects in periods between general rate applications.

[9] Equals (Net Change in Rate Base, as per Table 3) x (pre-tax return on rate base), or ($1.649 million x 10.03%). Pre-tax return on rate base is the Company's approved return on rate base adjusted for income taxes related to the equity component of return, as follows:

	Weighted Allowed Return	**Income Tax Effect (30.5%)**	**Pre-Tax Return**
Debt	4.15%	-	4.15%
Preferred Equity	0.06%	0.03%	0.09%
Common Equity	4.02%	1.77%	5.79%
Total	**8.23%**	**1.80%**	**10.03%**

Newfoundland Power
OPEBs Costs[1]
Amortization of the OPEBs Regulatory Asset Using the Straight-Line Method
15-Year Amortization Period
2011-2025
($000s)

		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
1	Current Service Cost	746	788	831	876	924	973	1,024	1,077	1,132	1,189	1,248	1,310	1,375	1,443	1,512	16,448
2	Interest Cost	4,058	4,221	4,371	4,515	4,645	4,748	4,830	4,897	4,955	5,031	5,106	5,145	5,197	5,269	5,335	72,323
3	Amortization of Actuarial Loss	423	379	339	303	269	241	217	195	177	160	141	126	116	101	88	3,275
4	Amortization of Transitional Obligation	1,428	1,428	1,428	1,428	1,428	1,428	861	-	-	-	-	-	-	-	-	9,429
5	Amortization of Past Service Costs	(1,002)	(1,002)	(1,001)	(1,003)	(1,001)	(1,003)	(1,001)	(1,025)	(1,115)	(1,117)	(1,115)	(559)	-	-	-	(11,944)
6	OPEBs Expense for Financial Reporting	5,653	5,814	5,968	6,119	6,265	6,387	5,931	5,144	5,149	5,263	5,380	6,022	6,688	6,813	6,935	89,531
7	Amortization of Regulatory Asset	3,491	3,491	3,491	3,491	3,491	3,491	3,491	3,491	3,491	3,491	3,491	3,491	3,491	3,491	3,490	52,363
8	OPEBs Expense for Regulatory Purposes	9,144	9,305	9,459	9,610	9,756	9,878	9,422	8,635	8,640	8,754	8,871	9,513	10,179	10,304	10,425	141,894
9	Rate Base Effects	(248)	(729)	(1,196)	(1,652)	(2,092)	(2,497)	(2,859)	(3,151)	(3,397)	(3,658)	(3,917)	(4,154)	(4,444)	(4,775)	(5,098)	(43,867)
10	Net OPEBs Cost	8,896	8,576	8,263	7,958	7,664	7,381	6,563	5,484	5,243	5,096	4,954	5,359	5,735	5,529	5,327	98,027

Reconciliation of Current and Past Service Costs

		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
11	Net OPEBs Cost (Line 10)	8,896	8,576	8,263	7,958	7,664	7,381	6,563	5,484	5,243	5,096	4,954	5,359	5,735	5,529	5,327	98,027
12	Less Current Service Cost (Line 1)	746	788	831	876	924	973	1,024	1,077	1,132	1,189	1,248	1,310	1,375	1,443	1,512	16,448
13	Past Service Cost Recovery	8,150	7,788	7,432	7,082	6,740	6,408	5,539	4,407	4,111	3,907	3,706	4,049	4,360	4,086	3,815	81,579

[1] All costs calculated in accordance with current Canadian GAAP.

Newfoundland Power
OPEBs Costs[1]
Amortization of the OPEBs Regulatory Asset Using the Mortgage Method
15-Year Amortization Period
2011-2025
($000s)

		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
1	Current Service Cost	746	788	831	876	924	973	1,024	1,077	1,132	1,189	1,248	1,310	1,375	1,443	1,512	16,448
2	Interest Cost	4,058	4,221	4,371	4,515	4,645	4,748	4,830	4,897	4,955	5,031	5,106	5,145	5,197	5,269	5,335	72,323
3	Amortization of Actuarial Loss	423	379	339	303	269	241	217	195	177	160	141	126	116	101	88	3,275
4	Amortization of Transitional Obligation	1,428	1,428	1,428	1,428	1,428	1,428	861	-	-	-	-	-	-	-	-	9,429
5	Amortization of Past Service Costs	(1,002)	(1,002)	(1,001)	(1,003)	(1,001)	(1,003)	(1,001)	(1,025)	(1,115)	(1,117)	(1,115)	(559)	-	-	-	(11,944)
6	OPEBs Expense for Financial Reporting	5,653	5,814	5,968	6,119	6,265	6,387	5,931	5,144	5,149	5,263	5,380	6,022	6,688	6,813	6,935	89,531
7	Amortization of Regulatory Asset	1,152	1,358	1,571	1,795	2,025	2,264	3,074	4,217	4,577	4,868	5,178	4,945	4,729	5,103	5,502	52,359
8	OPEBs Expense for Regulatory Purposes	6,805	7,172	7,539	7,914	8,290	8,651	9,005	9,361	9,726	10,131	10,558	10,967	11,417	11,916	12,437	141,890
9	Rate Base Effects	(165)	(490)	(815)	(1,144)	(1,473)	(1,784)	(2,088)	(2,391)	(2,701)	(3,049)	(3,416)	(3,763)	(4,148)	(4,580)	(5,030)	(37,039)
10	Net OPEBs Cost	6,640	6,682	6,724	6,770	6,817	6,867	6,917	6,970	7,025	7,082	7,142	7,204	7,269	7,336	7,407	104,848

Reconciliation of Current and Past Service Costs

		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
11	Net OPEBs Cost (Line 10)	6,640	6,682	6,724	6,770	6,817	6,867	6,917	6,970	7,025	7,082	7,142	7,204	7,269	7,336	7,407	104,848
12	Less Current Service Cost (Line 1)	746	788	831	876	924	973	1,024	1,077	1,132	1,189	1,248	1,310	1,375	1,443	1,512	16,448
13	Past Service Cost Recovery	5,894	5,894	5,893	5,894	5,892	5,893	5,893	5,893	5,892	5,893	5,894	5,894	5,894	5,892	5,895	88,400

[1] All costs calculated in accordance with current Canadian GAAP.

Newfoundland Power Inc.

Pro Forma 2011 Revenue Requirement and Base Rate Impact[1]
Straight-Line Method
($000s)

	10-Year Amortization	15-Year Amortization	20-Year Amortization
OPEBs Accrual Expense	5,340	5,340	5,340
Amortization of Regulatory Asset	5,236	3,491	2,618
Rate Base Effects[2]	(310)	(248)	(217)
Future Tax Effects[3]	188	151	132
Forecast Revenue Requirement	10,454	8,734	7,873
Increase in Revenue Requirement[4]	**9,258**	**7,538**	**6,677**
Pro Forma Base Rate Impact (%)[5]	**1.75**	**1.43**	**1.26**

[1] All costs calculated in accordance with current Canadian GAAP.
[2] Rate Base Effects include the impact of reduced financing requirements on return on rate base and associated income tax effects.
[3] Future Tax Effects includes tax associated with differences in current and future tax rates.
[4] This is the forecast increase in 2011 revenue requirement from the 2010 Test Year cost recovery of $1.2 million.
[5] Based on 2010 Test Year base rate revenue of $528,783,000.

Newfoundland Power Inc.

Pro Forma 2011 Revenue Requirement and Base Rate Impact[6]
Mortgage Method
($000s)

	10-Year Amortization	15-Year Amortization	20-Year Amortization
OPEBs Accrual Expense	5,340	5,340	5,340
Amortization of Regulatory Asset	2,970	1,152	336
Rate Base Effects[7]	(230)	(165)	(136)
Future Tax Effects[8]	139	100	(82)
Forecast Revenue Requirement	8,219	6,427	5,622
Increase in Revenue Requirement[9]	**7,023**	**5,231**	**4,426**
Pro Forma Base Rate Impact (%)[10]	**1.33**	**0.99**	**0.84**

6 All costs calculated in accordance with current Canadian GAAP.
7 Rate Base Effects include the impact of reduced financing requirements on return on rate base and associated income tax effects.
8 Future Tax Effects includes tax associated with differences in current and future tax rates.
9 This is the forecast increase in 2011 revenue requirement from the 2010 Test Year cost recovery of $1.2 million.
10 Based on 2010 Test Year base rate revenue of $528,783,000.

Regulatory Accounting Policies vs. Financial Accounting Principles

There is a great deal of similarity between regulatory accounting policies ("RAP") and accounting principles employed for financial reporting purposes. Still, there are differences, and these differences usually result from differences in objectives.

OBJECTIVES

Both regulators and financial accountants require accounting policies to establish a utility's costs.

Regulators normally set rates on a basis that reflects the costs of providing regulated service, where costs include a fair return. With return on rate base regulation, such as that used in regulating Newfoundland Power, there is a very tight relationship between costs and rates. With many of the incentive / performance based methodologies, the link may not be as direct, but is usually still there. This creates the need to establish regulatory accounting policies to determine the costs to be recovered through the rates in each period.

In preparing the financial statements for a utility, financial accountants must also establish the costs of each period (i.e., expenses). Up until now, they have followed Canadian generally accepted accounting principles ("GAAP"). The primary source of Canadian GAAP is the CICA Handbook – Accounting which is maintained by the Accounting Standards Board of the Canadian Institute of Chartered Accountants ("CICA").

Starting January 1, 2011, International Financial Reporting Standards ("IFRS") will replace Canadian GAAP for all Canadian publically accountable enterprises, including Newfoundland Power. These entities will have to follow IFRS for financial reporting purposes. IFRS are established by the International Accounting Standards Board ("IASB").

Although regulators and financial accountants are both attempting to establish a utility's costs, they have different objectives which are reflected in their accounting policies and principles:

- Regulators are attempting to set just and reasonable rates. They expect to have a direct impact on the economic results of a utility.
- Financial accountants are attempting to report on the economic position of the reporting entity and the change in its economic position.[1] They do not intend to have a direct impact on the economic results of a utility. They are attempting only to report those economic results.

The difference in objectives can result in differences between RAP and GAAP/IFRS.

The focus on just and reasonable rates can even result in differences in RAP between regulatory jurisdictions, or even between utilities within the same regulatory jurisdiction. Different

[1] See CICA Handbook; Section 1000 - Financial Statement Concepts; para. 1000.15.

circumstances may require different regulatory accounting policies to produce “just and reasonable” rates.

IMPACT OF GAAP/IFRS ON RAP

GAAP (and IFRS in the future) has a major influence on the RAP established by each regulator and is usually the starting point for RAP:

- Both GAAP and IFRS are a widely accepted set of principles and rules for determining the costs of a period.
- Both GAAP and IFRS normally result in costs being expensed in the period that they contribute to the provision of goods or services. Regulators normally seek such a matching since it is in accordance with the principle of intergenerational equity.

Although regulators generally refer to GAAP (and IFRS in the future) in setting their RAP, they are usually not required to do so and there are a number of examples where regulators have deviated from GAAP. For example:

- Regulators recognize the cost of equity as a cost to be recovered through rates even though it is not a cost recognized by GAAP or IFRS.
- Regulators often allow utilities to defer and recover in future periods significant costs that were not considered in setting current rates, even though GAAP and IFRS would normally require that they be expensed in the period the costs were incurred.

Presumably, regulators deviate from GAAP/IFRS because they believe that it results in rates that are more just and reasonable. For example:

- Regulators allow a return on equity because it is generally considered just and reasonable for equity investors to receive a fair return on their investment. More importantly, if utilities were not able to recover the cost of equity, they would not be able to attract the capital necessary to provide regulated service.
- Regulators may allow the future recovery of costs not covered by existing rates so as to provide a utility with a reasonable opportunity to recover its costs in accordance with the cost of service standard.

REGULATORY ASSETS & LIABILITIES

Differences between RAP and GAAP/IFRS can be categorized as either permanent or timing differences. The recognition of the cost of equity represents a permanent difference. Financial accounting will never recognize the cost of equity. Cost deferrals represent a timing difference. The costs will be recognized for both financial reporting and regulatory purposes, but will be recognized in different periods.

Timing differences give rise to regulatory assets and liabilities. Essentially, regulatory assets represent costs that would normally have been expensed for financial reporting purposes but which are expected to be recognized for regulatory purposes, and recovered in rates, in a future period[2]. Essentially regulatory liabilities represent amounts that a utility has recovered in rates to cover costs that will not be recognized for financial reporting purposes until a future period[3].

Up until now, Canadian utilities have generally recognized their regulatory assets and liabilities in their financial statements[4] with a corresponding impact on their reported income. For example, since it uses the cash method for recovering its OPEB costs, Newfoundland Power recognizes a regulatory asset in its financial statements equal to the cumulative differences between its OPEBs expense for financial reporting purposes and the cash amounts that it has been allowed to collect in rates. The regulatory asset essentially represents the amount of past OPEBs expense that it will be allowed to collect from customers in the future. The recognition of this regulatory asset affects the calculation of Newfoundland Power's reported net income since the recognition of the increases to its OPEB regulatory asset offsets the amount of its OPEB expense in excess of the amount it is allowed to collect in rates.

However, there is a question as to whether Canadian utilities will be allowed to continue recognizing regulatory assets and liabilities for financial reporting purposes under IFRS. The IASB is currently considering this issue.

Whether or not utilities can recognize regulatory assets and liabilities for financial reporting purposes will have implications that regulators may want to consider. However, regulators will remain free to set whatever regulatory accounting policies best produce "just and reasonable" rates. Also, even though regulatory assets and liabilities may not be recognized for financial reporting purposes, they could still be recognized for regulatory purposes.

CONCLUSION

RAP is designed to meet regulatory requirements.

Accounting principles employed for financial reporting purposes (either GAAP or IFRS) have a major influence on RAP and are usually the starting point for establishing RAP. However, regulators are usually not required to follow GAAP/IFRS. Since the objectives for RAP are different from those for GAAP/IFRS, it is not surprising that there are differences between RAP and GAAP/IFRS.

---

2 A regulatory asset represents the right to increase rates from what would otherwise be allowed and this right is expected to produce additional revenue and cash flow approximately equal to the amount of the regulatory asset.

3 A regulatory liability represents an obligation to reduce rates from what would otherwise be allowed and this obligation is expected to result in a reduction in revenue and cash flow approximately equal to the amount of the regulatory liability.

4 Certain conditions must be met before a utility can recognize a regulatory asset or liability.

Essentially, regulatory asset and liabilities represent the timing differences between RAP and GAAP/IFRS: amounts that would normally have been expensed for financial reporting purposes but which are expected to be recognized for regulatory purposes, and recovered in rates, in a future period; or amounts that a utility has recovered in rates to cover costs that will not be recognized for financial reporting purposes until a future period.

Traditionally, Canadian utilities have recognized regulatory assets and liabilities in their financial statements. With the adoption of IFRS, there is a question as to whether utilities will be able to do so in the future. However, regardless of whether they are recognized for financial reporting purposes, regulatory assets and liabilities could continue to be recognized for regulatory purposes.

Newfoundland Power Inc. Non-Pension Post Retirement Benefit Costing

IFRS - 5 Year Projection @ 6.50% - After Plan Changes

	CICA Actual	IFRS *Opening Balance*	IFRS *Projected*	IFRS *Projected*	IFRS *Projected*	IFRS *Projected*	IFRS *Projected*
Year	2009	12/31/2009	2010	2011	2012	2013	2014
From	1/1/2009		1/1/2010	1/1/2011	1/1/2012	1/1/2013	1/1/2014
To	12/31/2009		12/31/2010	12/31/2011	12/31/2012	12/31/2013	12/31/2014
Change in benefit obligation							
Benefit obligation - end of prior period	59,636,000		69,667,000	62,334,000	65,408,000	67,903,000	70,140,000
Current service cost (employer)	1,008,000		1,032,000	746,000	788,000	831,000	876,000
Interest cost	4,485,000		4,673,000	4,058,000	4,221,000	4,371,000	4,515,000
Employee contributions	0		0	0	0	0	0
Plan amendments	1,004,000		-13,266,000	432,000	0	0	0
Benefits paid	-1,304,000		-1,891,000	-2,162,000	-2,514,000	-2,965,000	-3,110,000
Net transfer in (out)	0		0	0	0	0	0
Acquisitions (divestitures)	0		0	0	0	0	0
Increase (decrease) in obligation due to curtailment	0		0	0	0	0	0
Obligation being settled	0		0	0	0	0	0
Special termination benefits	0		0	0	0	0	0
Actuarial loss (gain)	4,838,000		2,119,000	0	0	0	0
Benefit obligation - end	69,667,000	69,667,000	62,334,000	65,408,000	67,903,000	70,140,000	72,421,000
Change in plan assets							
Market value of plan assets - end of prior period	0		0	0	0	0	0
Actual return on plan assets	0		0	0	0	0	0
Employer contributions	1,304,000		1,891,000	2,162,000	2,514,000	2,965,000	3,110,000
Employee contributions	0		0	0	0	0	0
Benefits paid	-1,304,000		-1,891,000	-2,162,000	-2,514,000	-2,965,000	-3,110,000
Surplus paid out to employer	0		0	0	0	0	0
Settlement payments	0		0	0	0	0	0
Net transfer in (out)	0		0	0	0	0	0
Acquisitions (divestitures)	0		0	0	0	0	0
Actual plan expenses	0		0	0	0	0	0
Market value of plan assets - end	0	0	0	0	0	0	0
Reconciliation of funded status							
Benefit obligation - end	69,667,000	69,667,000	62,334,000	65,408,000	67,903,000	70,140,000	72,421,000
Market value of plan assets - end	0	0	0	0	0	0	0
Funded status - surplus (deficit)	-69,667,000	-69,667,000	-62,334,000	-65,408,000	-67,903,000	-70,140,000	-72,421,000
Employer contributions after measurement date	0		0	0	0	0	0
Unamortized transitional obligation (asset)	10,857,000	0	0	0	0	0	0
Unamortized past service costs	1,004,000	680,000	-8,419,000	-7,445,000	-6,763,000	-6,081,000	-5,399,000
Unamortized net actuarial loss (gain)	11,093,000	0	2,119,000	2,119,000	2,119,000	2,119,000	2,119,000
Accrued benefit asset (liability)	-46,713,000	-68,987,000	-68,634,000	-70,734,000	-72,547,000	-74,102,000	-75,701,000
Unamortized transitional increase (decrease) in valuation allowance	0	0	0	0	0	0	0
Valuation allowance	0	0	0	0	0	0	0
Accrued benefit asset (liability), net of valuation allowance	-46,713,000	-68,987,000	-68,634,000	-70,734,000	-72,547,000	-74,102,000	-75,701,000
Components of expense							
Current service cost (including provision for plan expenses)	1,008,000		1,032,000	746,000	788,000	831,000	876,000
Interest cost	4,485,000		4,673,000	4,058,000	4,221,000	4,371,000	4,515,000
Expected return on plan assets	0		0	0	0	0	0
Amortization of transitional obligation (asset)	1,428,000		0	0	0	0	0
Amortization of past service costs	0		77,000	-682,000	-682,000	-682,000	-682,000
Amortization of net actuarial loss (gain)	22,000		0	0	0	0	0
Curtailment loss (gain)	0		0	0	0	0	0
Settlement loss (gain)	0		0	0	0	0	0
Amortization of transitional increase (decrease) in VA	0		0	0	0	0	0
Increase (decrease) in valuation allowance	0		0	0	0	0	0
Special termination benefits	0		0	0	0	0	0
Immediate recognition of vested past service costs	0		-4,245,000	138,000	0	0	0
Net expense (income)	6,943,000		1,537,000	4,260,000	4,327,000	4,520,000	4,709,000
Assumptions							
At beginning of period							
Discount rate	7.50%		6.70%	6.50%	6.50%	6.50%	6.50%
Rate of compensation increase	4.00%		4.00%	4.00%	4.00%	4.00%	4.00%
Health care inflation - Select	9.33%		8.09%	7.98%	7.90%	7.77%	7.62%
Health care inflation - Ultimate	4.50%		4.55%	4.55%	4.55%	4.55%	4.55%
Expected rate of return on plan assets	0.00%		0.00%	0.00%	0.00%	0.00%	0.00%
At end of period							
Discount rate	6.70%		6.50%	6.50%	6.50%	6.50%	6.50%
Rate of compensation increase	4.00%		4.00%	4.00%	4.00%	4.00%	4.00%
Health care inflation - Select	8.09%		7.98%	7.90%	7.77%	7.62%	7.45%
Health care inflation - Ultimate	4.55%		4.55%	4.55%	4.55%	4.55%	4.55%

Newfoundland Power
OPEBs Costs[1]
Amortization of the OPEBs Regulatory Asset Using the Mortgage Method
15-Year Amortization Period
2011-2025
($000s)

		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
1	Current Service Cost	746	788	831	876	924	973	1,024	1,077	1,132	1,189	1,248	1,310	1,375	1,443	1,512	16,448
2	Interest Cost	4,058	4,221	4,371	4,515	4,645	4,748	4,830	4,897	4,955	5,031	5,106	5,145	5,197	5,269	5,335	72,323
3	Amortization of Past Service Costs	(682)	(682)	(682)	(682)	(682)	(682)	(682)	(698)	(759)	(759)	(759)	(377)	-	-	-	(8,126)
4	Vested Past Service Costs	138	-	-	-	-	-	-	-	-	-	-	-	-	-	-	138
5	OPEBs Expense for Financial Reporting	4,260	4,327	4,520	4,709	4,887	5,039	5,172	5,276	5,328	5,461	5,595	6,078	6,572	6,712	6,847	80,783
6	Amortization of Regulatory Asset	2,838	3,159	3,357	3,567	3,792	4,028	4,280	4,564	4,912	5,222	5,554	5,524	5,526	5,934	6,373	68,630
7	OPEBs Expense for Regulatory Purposes	7,098	7,486	7,877	8,276	8,679	9,067	9,452	9,840	10,240	10,683	11,149	11,602	12,098	12,647	13,220	149,413
8	Rate Base Effects	(176)	(522)	(869)	(1,224)	(1,578)	(1,918)	(2,252)	(2,588)	(2,933)	(3,318)	(3,725)	(4,115)	(4,547)	(5,028)	(5,532)	(40,325)
9	Net OPEBs Cost	6,922	6,964	7,008	7,052	7,101	7,149	7,200	7,252	7,307	7,365	7,424	7,487	7,551	7,618	7,688	109,088

Reconciliation of Current and Post Service Costs

		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
11	Net OPEBs Cost (Line 9)	6,922	6,964	7,008	7,052	7,101	7,149	7,200	7,252	7,307	7,365	7,424	7,487	7,551	7,618	7,688	109,088
12	Less Current Service Cost (Line 1)	746	788	831	876	924	973	1,024	1,077	1,132	1,189	1,248	1,310	1,375	1,443	1,512	16,448
13	Past Service Cost Recovery	6,176	6,176	6,177	6,176	6,176	6,175	6,176	6,175	6,174	6,176	6,176	6,177	6,176	6,174	6,176	92,640

[1] All costs calculated in accordance with IFRS.

Newfoundland Power Inc.

Revised 2010 Test Year Revenue Requirements
Assuming Accrual Method for OPEBs Costs
($000s)

	Current[1]	Changes	Revised[2]
Return on Rate Base	71,750	(144) [4]	71,606
Other Costs			
Power Supply Cost	351,034	-	351,034
Operating Costs[1]	50,493	-	50,493
Pension	8,196	-	8,196
OPEBs Expense[1]	1,196	5,589 [5]	6,785
Amortization of Depreciation Cost Recovery Deferral	3,861	-	3,861
Depreciation	43,378	-	43,378
Income Taxes	17,098	74 [6]	17,172
	475,256	5,663	480,919
2010 Revenue Requirement	547,006	5,519 [7]	552,525
Deductions			
Other Revenue	(13,692)	-	(13,692)
2005 Unbilled Revenue	(4,618)	-	(4,618)
Other Adjustments[3]	87	-	87
	(18,223)	-	(18,223)
2010 Revenue Requirement from Rates	528,783	5,519	534,302
Required rate increase on January 1, 2011		**1.044%** [8]	

[1] Pursuant to Order No. P.U. 43 (2009). For comparative purposes, OPEBs expense is shown separately from operating costs. OPEBs costs also include the amortization of the regulatory asset.

[2] 2010 Test Year revenue requirement adjusted for OPEBs costs based on IFRS.

[3] Includes $37,000 related to the amortization of capital stock issue expenses and $50,000 related to customer security deposits.

[4] The rate base effects reflect that OPEBs costs are collected in advance of the required premium payments. Excludes associated reduction in income tax of $32,000.

[5] The forecast increase in OPEBs operating costs due to the adoption of the accrual method of accounting under IFRS effective January 1, 2011.

[6] Assumes that OPEBs costs will be tax effected and includes the reduction in income tax of $32,000 associated with the reduction in return on rate base.

[7] The total increase in the 2010 revenue requirement as a result of the adoption of accrual accounting for OPEBs costs beginning January 1, 2011 and a 15-year amortization of the transitional balance using the Mortgage Method.

[8] Calculated as $5,519,000 divided by $528,783,000.

Newfoundland Power Inc.

OPEBs Cost Variance Deferral Account

Proposed Definition

OPEBs Cost Variance Deferral Account

This account shall be charged or credited with the amount by which the *net OPEBs cost* for any year differs from that approved for the establishment of revenue requirement from rates.

Net OPEBs cost for the year is the total of (i) the OPEBs expense for regulatory purposes for the year, (ii) the amortization of OPEBs regulatory asset for the year, and (iii) the rate base effects associated with OPEBs for the year.

Disposition of any Balance in this Account
Newfoundland Power shall charge or credit any amount in this account to the Rate Stabilization Account as of the 31st day of March in the year in which the difference arises.

If there is an application before the Board for rates based on a new test year that is anticipated to be outstanding as of the 31st day of March in a year in which the new rates are expected to become effective, then Newfoundland Power shall apply to the Board for determination of the amount to be charged or credited to the account for that year and the timing thereof.

Power Inc.

OPEBs Cost Variance Deferral Account
Sample Calculation Based on 1% Decrease in Discount Rate

Table 1
2011 Pro forma Net OPEBs Cost Variance
Assuming a Discount Rate of 5.5%
($000)

2011 Actual Net OPEBs Cost[1]		
OPEB Operating Expense[2]	A	4,189
Amortization of OPEBs Regulatory Asset[3]	B	2,838
OPEBs Rate Base Effects[4]	C	(187)
Total	**D = A + B + C**	**6,840**
Revised 2010 Test Year Net OPEBs Cost[5]		
OPEBs Operating Expense	E	3,947
Amortization of OPEBs Regulatory Asset	F	2,838
OPEBs Rate Base Effects	G	(176)
Total	**H = E + F + G**	**6,609**
2011 Variance from Revised 2010 Test Year	**I = D - H**	**231**
2011 Transfer To (From) Deferral Account	**J = I**	**231**

1 As defined within the OPEBs Cost Variance Deferral Account definition.
2 From Table 2.
3 This equals the amortization of the OPEBs Regulatory Asset as of January 1, 2011 based on the 15 year Mortgage Method.
4 From Table 3.
5 See Table 9 of *Schedule A*.

Table 2
2011 Pro forma OPEBs Regulated Operating Expense
Assuming a Discount Rate of 5.5%
($000s)

2011 OPEBs Accrual Expense[6]	A		4,578
Capitalized OPEBs Expense			
2011 Current Service Cost[6]	B	927	
Portion Capitalized[7]	C	42.0%	
2011 OPEBs Costs Capitalized	D = B x C	389	389
2011 OPEBs Operating Expense	**E = A – D**		**4,189**

6 Provided by Actuary.
7 Based on a 3-year average of the percentage of total labour related to capital.

Table 3
2011 Pro forma Rate Base Effects Related to OPEBs
Assuming a Discount Rate of 5.5%
($000s)

2011 Rate Base Related to OPEBs			
OPEB Liability - December 31, 2010[8]	A		-
Add: 2011 Total OPEB Accrual Expense[9]	B		4,578
Add: 2011 Amortization of OPEB Regulatory Asset[10]	C		2,838
Less: 2011 Forecast OPEB Benefit Payments[11]	D		(2,163)
OPEB Liability - December 31, 2011	E = A + B + C + D		5,253
Future Tax Asset - December 31, 2010	F		-
Add: 2011 Total OPEB Accrual Expense	G	4,578	
Add: 2011 Amortization of OPEB Regulatory Asset	H	2,838	
Less: 2011 Forecast OPEB Benefit Payments	I	(2,163)	
Timing Difference	J = G + H + I	5,253	
Future Income Tax Rate	K	29.0%	
2011 Future Tax Amount	L = J x K	1,523	1,523
Future Tax Asset - December 31, 2011	M = F + L		1,523
Total OPEB Related Rate Base			
Balance on January 1, 2011	N = F – A		-
Balance on December 31, 2011	O = M – E		(3,730)
2011 Average Rate Base Related to OPEBs	**P = (N + O) / 2**		**(1,865)**
2011 Rate Base Effects Related to OPEBs			
2011 Average Rate Base Related to OPEBs[12]	Q		(1,865)
Pre Tax Rate of Return on Rate Base[13]	R		10.03%
Required Pre-Tax Return Rate Base	**S = Q x R**		**(187)**

8 Beyond 2011, this will be provided in the Company's Annual Report to the PUB.
9 From Table 2.
10 From Table 1.
11 Forecast provided by Actuary in for purposes of determining variance by March 31 of current year. Actual benefits costs will only be known at year end of current year.
12 See Table 3.
13 Pre-tax return on rate base is the Company's approved return on rate base adjusted for income taxes related to the equity component of return, as follows:

	Weighted Allowed Return	Income Tax Effect (30.5%)	Pre-Tax Return
Debt	4.15%	-	4.15%
Preferred Equity	0.06%	0.03%	0.09%
Common Equity	4.02%	1.77%	5.79%
Total	**8.23%**	**1.80%**	**10.03%**