VOLUME 1: APPLICATION AND COMPANY EVIDENCE

A. APPLICATION

B. COMPANY EVIDENCE

SECTION 1 INTRODUCTION

Page

SECTION 2 CUSTOMER OPERATIONS

SECTION 3 FINANCE

SECTION 3 FINANCE (Cont'd) **Page**

SECTION 4 CUSTOMER RATES & REGULATIONS **Page**

C. EXHIBITS

VOLUME 2: SUPPORTING MATERIALS

1. A Report on the Implementation of the ARBM
2. Cash Working Capital Lead/Lag Study
3. Actuarial Valuation of Defined Benefit Pension Plan
4. A Report on Employee Future Benefits
5. Actuarial Valuation of OPEBs
6. Weather Normalization Reserve
7. An Analysis of Current Supply Cost Dynamics
8. Customer, Energy and Demand Forecast
9. Description of Current Rate Structures
10. Cost of Service Study
11. 2006 Load Research Study
12. Marginal Cost Study
13. Rate Design Review

VOLUME 3: EXPERT EVIDENCE

1. McShane, Cost of Capital
2. Browne, Regulatory Accounting
3. 2006 Depreciation Study

A Report on the Implementation of the Asset Rate Base Method

May 2007

NEWFOUNDLAND POWER
A FORTIS COMPANY

Table of Contents

Page

1.0 BACKGROUND

In Order No. P.U. 19 (2003), the Board found that the Asset Rate Base Method (the "ARBM") should replace the invested capital method used to calculate rate base for Newfoundland Power (the "Company").[1]

Newfoundland Power's transition to the ARBM began with the inclusion of average deferred charges in its average rate base, as approved in Order No. P.U. 19 (2003). As a further step toward the implementation of the ARBM, the Board ordered Newfoundland Power to review the remaining reconciling items between its average invested capital and average rate base as identified by Grant Thornton (the "Reconciling Items").

In compliance with Order No. P.U. 19 (2003), the Company filed *A Report on the Asset Rate Base Methodology* ("the Report") with its 2006 Capital Budget Application. The Report provided a review of each of the remaining Reconciling Items and assessed the appropriateness of their inclusion in Newfoundland Power's rate base.

In its 2006 Accounting Policy Application, the Company filed the *Asset Rate Base Method Review* (the "Review").[2] It provided an update on the transition to the ARBM based on the recommendations of the Report. It also took into account the impact of Newfoundland Power's proposals with respect to (i) recognizing revenue on an accrual basis and (ii) discontinuing the use of regulated common equity in favour of book common equity in calculating the Company's return. The Board approved these proposals, effective January 1, 2006, in Order No. P.U. 40 (2005).

Newfoundland Power indicated in the Review that it would address the differences that will continue to exist with respect to the Reconciling Items in its next general rate application ("GRA"). This report addresses those differences and incorporates related matters arising from the Company's 2008 GRA.

2.0 RECONCILING ITEMS

2.1 Reconciliation of Average Invested Capital and Average Rate Base

The invested capital method and the ARBM should produce the same fair returns because the rate base should represent the invested capital necessary to finance the rate base. The rate base represents what has to be financed whereas invested capital represents the sources of financing.

Differences between rate base and invested capital can arise which are nevertheless consistent with the calculation of the return under both the ARBM and the invested capital method.

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1 Under the invested capital method, a utility's average invested capital (i.e., its sources of financing, such as debt and equity) is used directly in the computation of return. Newfoundland Power's return under the invested capital method would effectively be based on the sum of its approved interest expense, preferred share dividends and return on common equity. Under the ARBM, a utility's return is the product of (i) its average rate base (i.e., what is being financed rather than the sources of financing) and (ii) its weighted average cost of capital ("WACC").

2 See Exhibit NP-9 in Newfoundland Power's 2006 Accounting Policy Application.

For example, Newfoundland Power excludes assets from its rate base, such as construction work in progress ("CWIP"), if they are not yet used and useful in the provision of service. However, CWIP, because it exists, had to be financed and is therefore reflected in the Company's invested capital. Although rate base and invested capital would differ with respect to CWIP, the return should be the same under both the ARBM and invested capital method.

Differences between invested capital and rate base also arise due to differences in how rate base and invested capital items are calculated. These differences exist with respect to working capital and materials and supplies inventory.

Working capital and materials and supplies inventory are typically reflected in invested capital at the average of their opening and year-end amounts. However, working capital is usually included in rate base through a cash working capital allowance that reflects average daily working capital requirements. Materials and supplies inventory is usually included in rate base through a materials and supplies allowance that reflects monthly averages.

For Newfoundland Power, differences between average invested capital and average rate base related to CWIP, the cash working capital allowance and the materials and supplies allowance will continue to exist under the ARBM. The proposals in this report serve to update the calculations underlying these Reconciling Items.

Other differences between the Company's average invested capital and average rate base are related to other assets and liabilities, which are (i) customer finance program receivables, (ii) customer security deposits (iii) the accrued pension liability (iv) the accrued other post employment benefits ("OPEBs") liability and (v) the municipal tax liability. These differences exist because Newfoundland Power has not yet completed its transition to the ARBM. The proposals in this report serve to eliminate these Reconciling Items.

Table 1 is a *pro forma* reconciliation of Newfoundland Power's average invested capital and average rate base, for the 2008 test year, before and after the final implementation of the ARBM, including the effects of the proposals in the 2008 GRA.

Table 1
***Pro Forma* Reconciliation**
Average Invested Capital and Average Rate Base
(000s)

	2008 Test Year	
	Before ARBM Proposals	**After ARBM Proposals**
Average Invested Capital	$ 815,856	$ 812,488
Average Rate Base	819,071	809,291
Difference	$ 3,215	$ (3,197)
Reconciliation		
CWIP and Allowance for Funds Used During Construction ("AFUDC")[3]	$ (2,314)	$ (2,314)
Materials and Supplies Allowance	(957)	(1,023)
Cash Working Capital Allowance	(2,387)	140
Other Assets and Liabilities		
Customer Finance Programs Receivables	(1,728)	-
Customer Security Deposits	736	-
Accrued Pension Liability	3,003	-
Accrued OPEBs Liability[4]	3,183	-
Municipal Tax Liability[5]	3,679	-
	$ 3,215	$ (3,197)

A review of Newfoundland Power's treatment of the Reconciling Items follows.

2.2 CWIP and AFUDC

Although average CWIP is excluded from Newfoundland Power's average rate base under the ARBM, the Company must nevertheless finance its CWIP. The cost of financing CWIP together with CWIP itself represents the total cost of constructed plant that is eventually used to provide service to customers.

Under the cost of service standard, a regulated utility should be provided with a reasonable opportunity to recover its costs of providing service. To achieve this under the ARBM, the cost

3 This Reconciling Item was shown as "Plant (primarily construction in progress)" in the Review.
4 Proposals related to the adoption of the accrual method of accounting for OPEBs expense for regulatory purposes are set out in *Section 3.6 Employee Future Benefits*.
5 Proposals related to the Municipal Tax Liability are set out in *Section 3.7 Regulatory Deferrals and Reserves*.

of financing CWIP is capitalized[6] as an AFUDC and included in the average rate base along with CWIP once the related plant is placed into service.[7]

Newfoundland Power's current AFUDC rate was approved by the Board in Order No. P.U. 37 (1981), as follows:

> *For the purposes of calculating the rate to be used in determining Interest During Construction NLP will use the mid point of the rate of return on rate base on the percentage of funds used for net capital expenditures generated from operations and the prime bank rate on the balance of the funds used.*

To facilitate its transition to the ARBM, Newfoundland Power has reviewed its AFUDC methodology. The Company proposes that effective 2008 its AFUDC (i) be based on its WACC and (ii) include the cost of financing inventory used to expand the electricity system ("Expansion Inventory").[8]

These proposals, if approved by the Board, would align Newfoundland Power's AFUDC with the ARBM[9] and with mainstream utility practice in Canada. All 26 surveyed utilities that follow the ARBM, other than those regulated by the Ontario Energy Board, use the WACC to calculate the AFUDC, including Newfoundland and Labrador Hydro ("Hydro").

The estimated *pro forma* impact, for 2008, of the Company's AFUDC proposals is an increase in AFUDC of $138,000. This would reduce Newfoundland Power's revenue requirement in the 2008 test year.

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6 The cost of financing CWIP is effectively recorded as an increase in CWIP and a decrease in financing costs. CWIP inclusive of the AFUDC would be reclassified as plant in service once construction is complete and the plant actually placed into service. At that point the plant in service is included in the average rate base under the ARBM.

7 The AFUDC is depreciated in a manner consistent with that of the plant to which it relates. Through the inclusion of depreciation expense in revenue requirement, the utility is provided with a reasonable opportunity to recover the financing costs which are represented by the AFUDC over the period that the plant is used in the provision of service. Until the AFUDC is fully depreciated, the costs that it represents continue to be financed by the utility and are therefore included in the average rate base at their average undepreciated balance.

8 Conceptually, Expansion Inventory is a component of CWIP and should therefore be treated in the same manner as CWIP in the computation of the AFUDC under the ARBM. Average CWIP is removed directly from the average rate base under the ARBM. Average Expansion Inventory is removed from the average rate base through its exclusion from the Company's materials and supplies allowance. In order to provide Newfoundland Power with a reasonable opportunity to recover the cost of financing all of its CWIP, average Expansion Inventory should be included in the AFUDC calculation.

9 The removal of average CWIP, including average Expansion Inventory, from the average rate base reduces a utility's return by the product of (i) the WACC and (ii) average CWIP. This amount represents the cost of financing all CWIP in the period. Under the ARBM, this is the amount of financing costs that should be capitalized as an AFUDC.

In the determination of the average rate base under the ARBM, the AFUDC effectively shifts the costs of financing all CWIP to the years during which the related plant is used in the provision of service. Therefore, the increase in the AFUDC will not impact Newfoundland Power's 2008 rate base.

2.3 Materials and Supplies

Newfoundland Power maintains an inventory of materials and supplies that is used for the day-to-day operating and maintenance activities associated with providing service to customers. It also carries Expansion Inventory.

Mainstream utility practice in Canada is to include a materials and supplies allowance ("MS Allowance") in the average rate base. All 26 surveyed utilities that follow the ARBM include an MS Allowance in their rate base.

Newfoundland Power's MS Allowance is currently (i) the average of its 12 month-end materials and supplies balances for the year, less (ii) Expansion Inventory. Expansion Inventory is 18.3 percent (the "Expansion Factor") of the 12 month average. This method for calculating the MS Allowance was approved by the Board in Order No. P.U. 1 (1974).[10]

To facilitate its transition to the ARBM, Newfoundland Power has reviewed its MS Allowance. Pursuant to that review, Newfoundland Power's 2008 MS Allowance is (i) based on a 13 month average,[11] and (ii) incorporates an Expansion Factor of 19.4 percent.

Newfoundland Power's existing method of averaging, because it does not consider the inventory balance at the beginning of the year, captures only the changes in inventory levels for the months of February through December. A 13 month average captures the changes in inventory levels for all 12 months of the year and aligns Newfoundland Power's method of averaging with that of Hydro.

The increase in the Expansion Factor to 19.4 percent is based on an analysis of the materials and supplies used by the Company in 2005. The proposed change in the Expansion Factor serves to decrease Newfoundland Power's MS Allowance and, therefore, its rate base. The proposed Expansion Factor is not materially different from the existing Expansion Factor.

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10 The Company reports its MS Allowance to the Board annually in Return 7(A).

11 A 13 month average is calculated by adding together (i) the sum of the month-end inventory balances for the months of January through December, and (ii) the inventory balance at December 31 of the previous year, and dividing the result by thirteen.

The *pro forma* impacts, for 2008, of the Company's MS Allowance on its average rate base under the ARBM are set out in Table 2.

Table 2
MS Allowance Proposals
***Pro Forma* Impacts on Average Rate Base**
(000s)

	2008
MS Allowance, Existing	
Materials and Supplies, 12 Month Average	$ 5,500
Less: Expansion Inventory @ 18.3%	(1,007)
	$ 4,493
MS Allowance, Proposed	
Materials and Supplies, 13 Month Average	$ 5,492
Less: Expansion Inventory @ 19.4%	(1,065)
	$ 4,427
Decrease in MS Allowance and Average Rate Base	$ (66)

Table 2 indicates that the Company's MS Allowance reduces its 2008 average rate base by $66,000.

2.4 Cash Working Capital Allowance

Balance sheet working capital is merely a snapshot of working capital at the balance sheet date. It is not necessarily indicative of an entity's ongoing working capital requirements.

Mainstream utility practice in Canada is to include a cash working capital allowance ("CWC Allowance") in rate base. All 26 surveyed utilities that follow the ARBM include a CWC Allowance in their rate base.

A CWC Allowance is typically calculated via a lead/lag study that examines timing differences between when revenue is collected and when particular expenses are paid. The resultant CWC Allowance is indicative of a utility's daily working capital requirements.

Newfoundland Power's existing CWC Allowance was approved by the Board in Order No. P.U. 37 (1984) as 1.7 percent of the sum of (i) regulated operating expenses[12] and (ii) current income tax. The CWC Allowance was based on a lead/lag study approved by the Board in Order No. P.U. 21 (1980). That study was based on a detailed analysis of the Company's cash flows.

12 Includes purchased power expense. Excludes non-regulated expenses net of income tax.

To facilitate its transition to the ARBM, Newfoundland Power has reviewed its CWC Allowance and performed a lead/lag study.[13] The results of the lead/lag study indicate that an appropriate CWC allowance for 2008 is $9,340,000 or 2.1 percent of 2008 regulated operating expenses.

The *pro forma* impacts, for 2008, of the Company's CWC Allowance on its average rate base under the ARBM are set out in Table 3.

Table 3
CWC Allowance Proposal
***Pro Forma* Impacts on Average Rate Base**
(000s)

	2008
CWC Allowance, Existing	$ 6,813
CWC Allowance, Proposed	$ 9,340
Increase in Average Rate Base	$ 2,527

Table 3 shows that Newfoundland Power's 2008 CWC Allowance will increase the Company's average rate base for the 2008 test year by approximately $2.5 million.

The increase in the CWC Allowance is due primarily to the impact of the Harmonized Sales Tax and the change in the collection of municipal taxes from "in advance" to "in arrears" as ordered by the Board in Order No. P.U. 17 (1987).

2.5 Other Assets and Other Liabilities

Other assets and other liabilities include customer finance program receivables, customer security deposits, the accrued pension liability, and the municipal tax liability.[14] These are Reconciling Items because they are included in the average invested capital but not average rate base. If the proposals for OPEBs as set out in the 2008 GRA are approved, the accrued OPEBs liability would become a Reconciling Item unless it is included in the calculation of the Company's rate base.

In accordance with the principles underlying the determination of rate base under the ARBM, the remaining average customer finance program receivables should be added to Newfoundland Power's average rate base and the average customer security deposits, average accrued pension

13 The lead/lag study is found in *Volume 2: Supporting Materials, Tab 2*.

14 Customer finance program receivables represent amounts receivable from customers in connection with energy efficiency programs. Customer security deposits represent amounts received from customers, in accordance with the Company's *Schedule of Rates, Rules and Regulations*, as reasonable security for the payment of charges as may be required by the Company pursuant to its Board approved Customer Deposit Policy. The accrued pension liability represents the cumulative excess of pension expense over pension funding for the Company's pension uniformity plan and supplementary employee retirement plan. The Municipal Tax Liability is discussed under *Section 3.7.1 Regulatory Deferrals*.

liability, average accrued OPEBs liability and the Municipal Tax Liability should be subtracted from its average rate base.

The *pro forma* impacts, for 2008, of the treatment of these other assets and liabilities on the Company's average rate base under the ARBM are set out in Table 4.

Table 4
Other Assets and Liabilities
***Pro Forma* Impacts of Proposals on Average Rate Base**
(000s)

	2008
Customer Finance Program Receivables	$ 1,728
Customer Security Deposits	(736)
Accrued Pension Liability	(3,003)
Accrued OPEBs Liability	(3,183)
Municipal Tax Liability	(3,679)
Decrease in Average Rate Base	$ (8,873)

Table 4 shows that the treatment of these items reduce Newfoundland Power's 2008 average rate base by approximately $8.9 million.

2.6 Other Rate Base Matters

Newfoundland Power incurs various costs and fees in connection with issuing debt. In accordance with Canadian generally accepted accounting principles, Newfoundland Power records debt issue costs as deferred charges and amortizes[15] the deferred charges over the term of the related debt.

Average deferred debt issue costs are currently a component of the Company's average rate base. However, the associated amortization expense is a component of the Company's WACC. Effective 2008, average deferred debt issue costs should be excluded from the calculation of Newfoundland Power's average rate base and included in the calculation of its WACC.

Newfoundland Power's treatment is consistent with the determination of return under the ARBM.[16] The proposal places both the deferred debt issue costs and the amortization of those

[15] To "amortize" a deferred charge means to recognize it as an expense in the Company's statement of income. The amount amortized in each year is recorded as an increase in Finance Charges on the Company's statement of income and a decrease in Deferred and Other Charges on the Company's balance sheet.

[16] Under the ARBM, a utility's return is the product of (i) the WACC and (ii) the average rate base. The average deferred debt issue can therefore be treated as either an increase in average rate base or a decrease in average debt within the calculation of the WACC. However, if treated as a component of rate base, the associated amortization expense would typically be included directly in revenue requirement rather then being included through the WACC.

costs within the calculation of the WACC. This is also the approach followed by Hydro. The resultant WACC would then reflect all amounts that are related to the embedded cost of debt.

2.7 Concluding

The *pro forma* impacts of the Company's treatment of the remaining Reconciling Items as indicated in this Report on its average rate base for the 2008 test year are summarized in Table 5.

Table 5
Rate Base Proposals
***Pro Forma* Impacts on Average Rate Base**
(000s)

	2008 Test Year
Reconciling Items	
CWIP and AFUDC Proposals	$ -
MS Allowance Proposals	(66)
CWC Allowance Proposal	2,527
Other Assets and Liabilities (Table 4)	
Customer Finance Program Receivables	1,728
Customer Security Deposits	(736)
Accrued Pension Liability	(3,003)
Accrued OPEBs Liability	(3,183)
Municipal Tax Liability	(3,679)
Deferred Debt Issue Costs	(3,368)
Decrease in Average Rate Base	$ (9,780)

Table 5 shows that Newfoundland Power's treatment will reduce its average rate base for the 2008 test year by approximately $9.8 million.

This decline in average rate base reduces customer rates, from what they would otherwise be, by reducing Newfoundland Power's allowed return. The Company's approach is consistent with the principles underlying the determination of average rate base under the ARBM and their ultimate impact is to provide Newfoundland Power with a reasonable opportunity under the ARBM to recover its cost of providing service.

3.0 CONCLUSION

Newfoundland Power's treatment of the remaining Reconciling Items as indicated in this Report effectively conclude its transition from the invested capital method to the ARBM for rate base calculation in accordance with the direction of the Board in Order No. P.U. 19 (2003).

Cash Working Capital Lead/Lag Study

May 2007

NEWFOUNDLAND POWER
A FORTIS COMPANY

Table of Contents

1.0 INTRODUCTION

The inclusion of a cash working capital allowance ("CWC Allowance") in the rate base is an accepted practice for regulated utilities in Canada.[1]

Section 78(2) of the Public Utilities Act states:

> *In fixing a rate base the board may, in addition to the value of the property and assets as determined under section 64, include (a) an allowance for necessary working capital, …..*

The rate base, in its entirety, is intended to represent the amount of investor-supplied capital required to provide service. This is a cornerstone of the Asset Rate Base Method ("ARBM"). The CWC Allowance, together with a materials and supplies allowance, form the total allowance for necessary working capital that is included in the Company's rate base.

The CWC Allowance reflects the average amount of capital provided by investors above and beyond investments in plant and other separately identified rate base items that bridges the gap between the time expenditures are made to provide service and the time payment is received for that service.

To facilitate the completion of its transition to the ARBM, Newfoundland Power is proposing that its CWC Allowance be calculated in accordance with the Company's updated lead/lag study and be set at $9,340,000 for 2008. This is 2.1 percent of forecast 2008 regulated cash operating expenses.[2]

The proposed 2008 CWC Allowance, if approved by the Board, would not have a material impact on customers.

2.0 METHOD AND APPROACH

2.1 Method

Newfoundland Power has determined its proposed CWC Allowance through a lead/lag study.

Newfoundland Power's existing CWC Allowance is based on a lead/lag study that was approved by the Board in Order No. P.U. 21 (1980).

Mainstream regulatory practice by Canadian utilities, including Newfoundland and Labrador Hydro ("Hydro"), is to use a lead/lag study to calculate the CWC Allowance.[3]

[1] Of 29 surveyed Canadian utilities, all 26 utilities following the ARBM include a CWC Allowance in their rate base.

[2] Regulated cash operating expenses exclude all expenditures not recognized in the calculation of the Company's revenue requirements.

[3] Of the 26 surveyed Canadian utilities that follow the ARBM, 21 use a lead/lag study to calculate their CWC Allowance.

A lead/lag study recognizes that the utility renders service to customers prior to the receipt of payment for the service from customers. It also recognizes that there is generally a delay in payment by the utility for the goods and services it acquires.

A lead/lag study analyzes transactions over a period of time to determine (i) for each revenue stream, the average number of lag days between the provision of service to customers and the receipt of payment for that service from customers (the revenue lags), and (ii) for each expense, the average number of lag days between the provision of service to customers and the date that the utility pays for the goods and services that it acquires to provide service (the expense lags). The difference between these two lags is referred to as a net lag or net lead.

A net lag occurs when the payment of an expense precedes the collection of its related revenue stream. In this situation, the utility's investors must supply capital to finance the expense until receipt of the related revenues. A net lead position occurs in the opposite situation with the opposite impact.

Once the revenue lags and expense lags are determined, the calculation of the CWC Allowance involves the following steps:

1. Weight each revenue lag by its related revenue stream to calculate the total weighted average revenue lag.
2. Weight each expense lag by its related expense to calculate the total weighted average expense lag.
3. Subtract the weighted average expense lag from the weighted average revenue lag and divide the result by 365 days. This is the CWC factor.[4]
4. Multiply the CWC factor by the total expenses to calculate the average amount of working capital required to finance the expenses.
5. Add to the amount determined in step 4 the net impact of the collection and payment of the harmonized sales tax ("HST") on working capital. The result is the CWC Allowance.

The CWC Allowance determined via a lead/lag study is indicative of a utility's average daily working capital requirements.

2.2 Approach

Newfoundland Power's lead/lag study determines the amount of cash working capital required to finance regulated cash operating expenses. This is the approach traditionally used by Canadian utilities and is the approach used by Hydro.

Newfoundland Power's existing CWC Allowance, which is calculated using the same basic approach, was approved by the Board in Order No. P.U. 37 (1984) (the "1984 Order") as

[4] In a net lag situation, the CWC factor represents the percentage of expenses that has to be financed by the utility's investors during the year. Investor funding is necessitated by the fact that the cash outflows for expenses preceded the cash inflows for the related revenues. Under the ARBM, the CWC Allowance for a net lag is therefore added to the rate base in order to provide a utility with a reasonable opportunity to recover the cost of the related investor supplied funding. In a net lead situation, the opposite is true.

1.7 percent of the sum of (i) regulated operating expenses, including purchased power expense and (ii) current income tax. However, under the existing approach, the impact of the HST and the full impact of municipal tax is not included in the Company's CWC Allowance.

The impact of the HST is not included in the existing CWC Allowance because this tax was introduced subsequent to the 1984 Order.

The full impact of municipal tax is not included in the existing CWC Allowance because, subsequent to the 1984 Order, the Board approved a change in Newfoundland Power's accounting for municipal taxes from an expense method to a flow-through method.[5]

Under the expense method, municipal taxes were treated as an operating expense and were collected in advance. Under the flow-through method, municipal taxes are flowed through a balance sheet account called the Municipal Tax Account ("MTA") and are collected primarily in arrears. This change in accounting has two effects on the existing CWC Allowance.

First, the MTA is not included in regulated cash operating expenses because it is a balance sheet account. This effectively excludes municipal tax payments from the computation of the existing CWC Allowance.

Second, the existing CWC factor of 1.7 percent is too low. It effectively reflects a net lead for municipal taxes because these taxes were collected in advance when the CWC factor was calculated in 1984. It should reflect a net lag position because these taxes are now collected primarily in arrears.

The updated lead/lag study and the proposed 2008 CWC Allowance reflect the impact of the HST and the full impact of municipal taxes on the Company's cash working capital. These are the primary reasons why the Company's 2008 CWC Allowance would, if approved by the Board, increase from approximately $6.8 million based on the 1984 Order to approximately $9.3 million as proposed.

3.0 LEAD/LAG STUDY

Newfoundland Power's lead/lag study is based on 2005 actual data as it represents the most recent historical results available at the time the lead/lag study was performed. There have been no material changes to the Company's billing and collection procedures or to its payment procedures since 2005.[6] No material changes in this regard are forecast.

Through the lead/lag study, Newfoundland Power determined (i) its revenue lags, (ii) its expense lags and (iii) the leads/lags associated with HST. Together, these leads and lags form the basis for the CWC Allowance.

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5 The Company's treatment of municipal taxes is described in S*ection 3.4 Rate Base*.

6 In Order No. P.U. 40 (2005) the Board approved Newfoundland Power's adoption of the accrual method of revenue recognition. The Company's billing and collection procedures were not affected by this change in accounting policy.

The lead and lags so calculated have been applied to the Company's forecast 2008 test year data to calculate the proposed 2008 CWC Allowance. These calculations are summarized below.

3.1 Revenue Lag

The revenue lag was calculated by analyzing all of the Company's revenue streams and accounts receivable for 2005 to determine the average number of lag days between when service is provided to customers and when payment for the service is received from customers.

Newfoundland Power has two distinct revenue streams which can broadly be described as "consumer billings" and "other billings".

Consumer billings included in the calculation of the CWC Allowance are composed of (i) electricity billings and related municipal tax billings, (ii) forfeited discounts and interest earned on overdue accounts receivable, (iii) ancillary items such as connection/reconnection fees, and (iv) HST.

Other billings are composed primarily of pole rentals, and include various miscellaneous revenues and HST.

A separate revenue lag was calculated for consumer billings and other billings.

The calculated revenue lags for consumer billings and other billings were weighted, based on the percentage of the total forecast 2008 billings represented by each, to produce a total weighted average 2008 revenue lag for the Company of 39.34 days. This is set out in Schedule 1 of Appendix A.

3.2 Expense Lag

The expense lag was calculated by analyzing each of the Company's cash operating expenses for 2005 to determine the average number of lag days between when service is provided to customers and when payment is made for the goods and services that are acquired to provide service.

In calculating the expense lag, the Company performed a detailed analysis on approximately 94 percent of 2005 cash operating expenses.

The calculated expense lag for each cash operating expense was weighted based on the percentage of the total forecast 2008 cash operating expenses represented by each to produce a total weighted average 2008 expense lag for the Company of 31.61 days. This is set out in Schedule 2 of Appendix A.

3.3 HST Adjustment

HST is collected from customers on certain billed revenues and paid to suppliers on certain expenses and capitalized costs. The difference between HST collections and HST payments in each month is settled with government on the last day of the month that follows the month in which the HST was billed or, if that day is not a business day, on the first business day thereafter.

On average, HST on most of Newfoundland Power's billings is collected from customers before it is settled with government. The Company has use of these funds between the collection date and the settlement date. This serves to reduce the necessary CWC Allowance.

On average, HST billed by Newfoundland Power's suppliers is paid to those suppliers before it is settled with government. The Company has to finance the HST between the payment date and the settlement date. This serves to increase the necessary CWC Allowance.

Newfoundland Power's 2008 HST adjustment is set out in Schedule 3 of Appendix A. The net HST impact is a $780,000 increase in the Company's proposed 2008 test year CWC Allowance.

3.4 2008 Test Year CWC Allowance

Newfoundland Power's proposed 2008 test year CWC Allowance based on the calculated revenue lag, expense lag and HST adjustment is $9,340,000. This is set out in Schedule 4 of Appendix A.

The effect of the proposed 2008 CWC Allowance under the ARBM would be to provide Newfoundland Power with a reasonable opportunity to recover its cost of providing regulated service – no more, no less.

The proposed 2008 CWC Allowance, if approved by the Board, would not have a material impact on customers.

Because Newfoundland Power, on a test year basis, has followed the invested capital method its existing CWC Allowance was not used in the calculation of its test year return. Instead, its return in this regard was based on the simple average of its balance sheet working capital.[7]

The proposed 2008 CWC Allowance is approximately $140,000 higher than Newfoundland Power's forecast average balance sheet working capital for 2008.[8] The effect on Newfoundland Power's allowed return for 2008 would be approximately $12,300.[9]

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7 (Balance Sheet Working Capital, beginning of the year plus Balance Sheet Working Capital, end of the year) divided by 2. Balance sheet working capital is the difference between current assets and current liabilities at the balance sheet date.

8 See Table 1 in *A Report on the Implementation of the Asset Rate Base Method*.

9 $140,000 times weighted average cost of capital equals $140,000 times 8.82 percent equals $12,348.

4.0 CONCLUDING

Newfoundland Power has calculated its proposed 2008 CWC Allowance via a lead/lag study based on the traditional approach.

This methodology is consistent with mainstream utility practice in Canada, including that of Hydro.

Newfoundland Power’s 2008 test year CWC Allowance is $9,340,000.

The proposed CWC Allowance will not have a material impact on customers.

Newfoundland Power Inc.

2008 Revenue Lag

	Cash Inflows	2008 Forecast [1] ($000s)	Percent of Total	Net Lag Days	Weighted Average Lag Days
1	Consumer Billings	516,565	98.06%	38.30	37.55
2	Other Billings	10,219	1.94%	92.38	1.79
3	Total	526,784	100.00%		**39.34**
4					
5					
6					
7					
8					
9					
10					

11	[1] Reconciliation to Revenue Requirement ($000s) :	
12	Total Billings Above	526,784
13	Municipal Tax Billings	(12,499)
14	Billings Recorded as Revenue	514,285
15	Revenue excluded from CWC Allowance	
16	Amortization of 2005 Unbilled Revenue	5,363
17	Amortization of Municipal Tax Liability	817
	Interest on Rate Stabilization Account	20
18	Interest on Customer Finance Program Receivables	192
19	Total Revenue	520,677
20	Other Revenue	(12,011)
21	Revenue Requirement	508,666

Newfoundland Power Inc.

2008 Expense Lag

Line		2008 Forcast	Adjustments[1] ($000s)	Cash Operating Expenses	Percent of Total	(Lead) Lag Days	Weighted Average (Lead) Lag Days
	Operating Expenses						
1	Labour	28,671		28,671	7.03%	52.87	3.72
2	Vehicle Expenses	1,495		1,495	0.37%	45.21	0.17
3	Operating Materials	1,124		1,124	0.28%	45.21	0.12
4	Inter-Company Charges	568		568	0.14%	45.21	0.06
5	Plants,Subs,System Ops & Buildings	1,820		1,820	0.45%	45.21	0.20
6	Travel	987		987	0.24%	45.21	0.11
7	Tools and Clothing Allowance	836		836	0.21%	45.21	0.09
8	Miscellaneous	1,486		1,486	0.36%	45.21	0.16
9	Bank Service Charges & PUB Assessment	680		680	0.17%	229.51	0.38
10	Uncollectible Bills	1,050	1,050	0			
11	Insurance	1,775		1,775	0.44%	(167.50)	(0.73)
12	Pension & ERP Expense	3,348	216	3,132	0.77%	40.29	0.31
13	Retirement Allowances	175	175	0			
14	Education and Training	248		248	0.06%	45.21	0.03
15	Trustee & Directors' Fees	395		395	0.10%	42.28	0.04
16	Other Company Fees	1,835		1,835	0.45%	45.21	0.20
17	Stationery & Copying	372		372	0.09%	45.21	0.04
18	Equipment Rental & Maintenance	725		725	0.18%	45.21	0.08
19	Telecommunications	1,630		1,630	0.40%	45.21	0.18
20	Postage	1,571		1,571	0.39%	45.21	0.17
21	Advertising	371		371	0.09%	45.21	0.04
22	Vegetation Management	1,400		1,400	0.34%	45.21	0.16
23	Computer Equipment & Software	776		776	0.19%	45.21	0.09
24	Gross operating expenses	53,338		51,897			
25	Less: GEC	(2,100)		(2,100)	-0.52%	46.14	(0.24)
26	Net Operating Expenses	51,238		49,797			
27	Less: Non-Regulated Expenses	(1,500)		(1,500)	-0.37%	46.69	(0.17)
28	Regulated Operating Expenses	49,738		48,297			
29							
30							
31	**Purchased Power**	327,709	2,022	325,687	79.90%	35.62	28.46
32							
33							
34	**Current Income Tax**						
35	Total Tax	22,357	1,723	20,634			
36	Plus: Tax Effects of Non-Regulated Expenses	517		517			
37	Regulated Current Income Tax	22,874		21,151	5.19%	24.91	1.29
38							
39							
40	**Municipal Tax Paid**			12,499	3.07%	(109.71)	(3.36)
41							
42							
43	**Cash Operating Expenses in CWC Allowance**			407,634	100.00%		**31.61**
44							
45	**Costs Excluded from CWC Allowance**						
46	Return on Rate Base	71,370					
47	Depreciation Expense	40,207					
48	Accrued OPEBs Expense	6,370					
49	Amortization of Cost Recovery Deferrals	2,317					
50	Amort. Stock Costs & Interest on Security Deposits	92					
51		120,356					
52							
53	**Other Revenue**	(12,011)					
54							
55	**Revenue Requirement**	508,666					
56							

57 [1] Represents items that are not reoccurring cash operating expenses.

Newfoundland Power Inc.

2008 HST Adjustment

	HST ($000's)	Net (Lead) Lag Days	CWC Allowance [1] ($000's)
Consumer Billings	(71,569)	(22.54)	(4,437)
Other Billings	(1,410)	46.75	180
Purchased Power	45,596	40.43	5,035
Operating Expenses	2,247	0.42	2
			780

[1] (Lead) Lag Days / 365 * HST

Newfoundland Power Inc.

2008 Cash Working Capital Allowance

	CWC Factor	
1	Revenue Lag Days (Schedule 1)	39.34
2	Expense Lag Days (Schedule 2)	(31.61)
3	Net Lag Days	7.73
4		
5	CWC Factor (7.73 days divided by 365 days)	2.1%
6		
7		
8		
9		
10	**CWC Allowance**	
11		
12	Total Cash Operating Expenses (Schedule 2)	407,634
13	CWC Factor	2.1%
14		8,560
15	HST Adjustment (Schedule 3)	780
16	**CWC Allowance**	**9,340**

Actuarial Valuation of Defined Benefit Pension Plan at December 31, 2005

September 2006

Newfoundland Power Inc.
Retirement Income Plan

Report on the Actuarial Valuation for Funding Purposes as at December 31, 2005

MERCER
Human Resource Consulting

MMC Marsh & McLennan Companies

Contents

1

Summary of Results

Going-Concern Financial Position	**31.12.05**	**31.12.03**
Actuarial value of assets	$210,945,000	$176,473,000
Actuarial liability	($225,405,000)	($200,592,000)
Funding excess (unfunded liability)	($14,460,000)	($24,119,000)
Solvency and Wind-Up Financial Position	***31.12.05***	***31.12.03***
Market value of assets net of termination expenses	$223,170,000	$178,760,000
Solvency liability	($216,161,000)	($161,569,000)
Solvency excess (deficiency)	$7,009,000	$17,191,000
Solvency ratio	100%	100%
Funding Requirements (*annualised*)	***2006***	***2004***
Total current service cost	$4,636,000	$4,642,000
Estimated members' required contributions	($1,265,000)	($1,275,000)
Estimated employer's current service cost	$3,371,000	$3,367,000
Employer's current service cost as a percentage of members' pensionable earnings	10.44%	9.96%
Minimum special payments	$2,800,000	$2,800,000
Estimated minimum employer contribution for year	$6,171,000	$6,167,000
Estimated maximum employer contribution for year	$17,831,000	$27,486,000

2

Introduction

Report on the Actuarial Valuation as at December 31, 2005

To Newfoundland Power Inc.

At your request, we have conducted an actuarial valuation of the Newfoundland Power Inc. Retirement Income Plan as at December 31, 2005. We are pleased to present the results of the valuation.

The purpose of this valuation is to determine:

- the funded status of the plan as at December 31, 2005 on going-concern and solvency bases, and

- the minimum funding requirements from 2006.

The funded ratio, on a going concern basis, is 94% at December 31, 2005, as compared to 88% at December 31, 2003.

The next actuarial valuation of the plan will be required as at a date not later than December 31, 2008 or as at the date of an earlier amendment to the plan, in accordance with the minimum requirements of the *Pension Benefits Act (Newfoundland and Labrador)*.

There is an unfunded liability of $14,460,000, and a solvency ratio of 100% as at December 31, 2005. As such, in accordance with the minimum requirements of the *Pension Benefits Act (Newfoundland and Labrador)*, Newfoundland Power Inc. should make minimum annual contributions to the plan for 2006, as follows:

Annual Employer Contributions
For current service: 10.44% of members' pensionable earnings
Minimum special payments for unfunded liability: $2,800,000

On the basis of the members' estimated pensionable earnings, we have estimated the minimum total employer contribution for 2006 to be $6,171,000, or $514,250 per month. We have estimated the total members' contribution for 2006 to be $1,265,000.

This valuation reflects the provisions of the plan as at December 31, 2005.

Since the date of the previous valuation, the plan has been amended as follows:

- Effective May 1, 2004, the plan was amended to close the plan to new entrants and to improve death benefits available to surviving spouses. This amendment was reflected in the previous valuation as at December 31, 2003.

- Effective January 1, 2005, the plan was amended to provide special early retirement benefits to certain eligible employees.

A summary of the plan provisions is provided in Appendix D.

We have used the same going-concern valuation assumptions and methods as were used for the valuation as at December 31, 2003, except for the following assumptions which were adjusted to reflect changes in market conditions and legislation since the previous valuation:

	12.31.2005	**12.31.2003**
Increases in the YMPE	3.5% per year	4.0% per year
Increases in the Maximum Pension Permitted under the Income Tax Act	3.5% per year starting in 2010	4.0% per year starting in 2006

These changes have resulted in an increase of $2,194,000 in the actuarial liability and of $107,000 in the employer current service cost.

The assumptions used for the solvency and wind-up valuations have been updated to reflect market conditions at December 31, 2005.

A new Canadian Institute of Actuaries Standard of Practice For Determining Pension Commuted Values ("CIA Standard") became effective on February 1, 2005. The new CIA Standard has changed the assumptions to be used to value the solvency and wind-up liabilities for benefits assumed to be settled through a lump sum transfer. The financial impact of the new CIA Standard has been reflected in this actuarial valuation.

The assumptions used for purposes of this valuation are described in detail in Appendix B. All assumptions made for the purposes of the valuation were reasonable at the time the valuation was prepared.

Our valuation does not account for the impact of recent ad hoc pension increases provided to current pensioners who meet certain eligibility criteria. The impact of that program on the funding status, on going-concern and solvency bases, and on the minimum funding requirements, will be the subject of a separate report. After checking with representatives of Newfoundland Power, to the best of our knowledge, there have been no other events subsequent to the valuation date which, in our opinion, would have a material impact on the results of the valuation.

This report will be filed with the pension authorities in Newfoundland and Labrador and with the Canada Revenue Agency.

Respectfully submitted,

Scott Cushing

M. Scott Cushing
Fellow of the Society of Actuaries
Fellow of the Canadian Institute of Actuaries

Sept 27, 2006
Date

Anil Narale
Fellow of the Society of Actuaries
Fellow of the Canadian Institute of Actuaries

Sept 27, 2006
Date

Newfoundland Power Inc. Retirement Income Plan
Registration number in Newfoundland and Labrador: 75241
Registration number with the Canada Revenue Agency: 0486365

3

Financial Position of the Plan

Valuation Results — Going-Concern Basis

When conducting a valuation on a going-concern basis, we determine the relationship between the respective values of assets and accumulated benefits, assuming the plan will be maintained indefinitely.

Financial Position

The results of the valuation as at December 31, 2005, in comparison with those of the previous valuation as at December 31, 2003, are summarised as follows:

Financial Position — Going-Concern Basis

	31.12.05	**31.12.03**
Actuarial value of assets (adjusted market value)	$210,945,000	$176,473,000
Actuarial liability		
Present value of accrued benefits for:		
active and disabled members	$103,773,000	$101,001,000
pensioners and survivors	$121,345,000	$99,158,000
deferred pensioners	$287,000	$433,000
Total liability	$225,405,000	$200,592,000
Funding excess (unfunded liability)	($14,460,000)	($24,119,000)

Reconciliation of Financial Position

The plan's financial position, an unfunded liability of $14,460,000 as at December 31, 2005, is reconciled with its previous position, an unfunded liability of $24,119,000 as at December 31, 2003, as follows:

Reconciliation of Financial Position

Funding excess (unfunded liability) as at 31.12.03	($24,119,000)
Interest on funding excess (unfunded liability) at 6.00% per year to 31.12.05	($2,981,000)
Net experience gains (losses) over 2004-2005 *	$9,741,000
Employer's special payments to eliminate the unfunded liability	$14,417,000
Impact of changes in assumptions and methods	($2,194,000)
Impact of early retirement window (Amendment #12)	($9,065,000)
Net impact of other elements of gains and losses	($259,000)
Funding excess (unfunded liability) as at 31.12.05	($14,460,000)

* *Net experience gains (losses) are detailed below.*

Plan Experience

Actual experience has differed from that expected since the previous valuation as at December 31, 2003. The gains (losses) with respect to the main valuation assumptions are shown below:

Plan Experience

	Impact Gain (Loss)
Net Investment return	$12,932,000
Increases in pensionable earnings and YMPE	($3,409,000)
Retirements	($25,000)
Terminations of employment	$171,000
Mortality:	
pre-retirement	$100,000
post-retirement	($28,000)
Net experience gains (losses)	$9,741,000

Valuation Results — Solvency Basis

When conducting a solvency valuation, we determine the relationship between the respective values of the plan's assets and its liabilities on a solvency basis, determined in accordance with the *Pension Benefits Act (Newfoundland and Labrador)*. The values of the plan's assets and liabilities on a solvency basis are related to the corresponding values calculated as though the plan were wound up and settled on the valuation date. The circumstances in which the plan wind-up is assumed to have been taken place are as follows: total plan wind-up in conjunction with cessation of the plan sponsor's operations.

As at December 31, 2005, the solvency ratio of the plan, being the ratio of solvency assets to solvency liabilities, is 100%. The plan's solvency position as at December 31, 2005, in comparison with that of the previous valuation as at December 31, 2003, is determined as follows:

Solvency Position

	31.12.05	**31.12.03**
Market value of assets	$223,370,000	$178,960,000
Termination expenses	($200,000)	($200,000)
Net market value of assets	$223,170,000	$178,760,000
Actuarial liability		
Present value of accrued benefits for:		
Active and disabled members	$78,763,000	$59,578,000
pensioners and survivors	$137,038,000	$101,533,000
deferred pensioners	$360,000	$458,000
Solvency liabilities	$216,161,000	$161,569,000
Solvency excess (deficiency)	$7,009,000	$17,191,000
Solvency ratio	100%	100%

Impact of Plan Wind Up

In our opinion, the value of the plan's assets would be greater than its actuarial liabilities if the plan were to be wound up on the valuation date.

Specifically, assets would exceed the actuarial liabilities of the Plan by $7,009,000. This calculation includes a provision for termination expenses that might be payable from the pension fund.

4

Funding Requirements

Current Service Cost

The estimated value of the benefits that will accrue on behalf of the active members during 2006, in comparison with the corresponding value determined in the previous valuation as at December 31, 2003, is summarised below:

Employer's Current Service Cost

	2006	2004
Total current service cost	$4,636,000	$4,642,000
Estimated members' required contributions	($1,265,000)	($1,275,000)
Estimated employer's current service cost	$3,371,000	$3,367,000
Employer's current service cost expressed as a percentage of members' pensionable earnings	10.44%	9.96%

An analysis of the changes in the employer's current service cost follows:

Changes in Employer's Current Service Cost

Employer's current service cost as at 31.12.03	9.96%
Demographic changes	0.15%
Changes in assumptions	0.33%
Employer's current service cost as at 31.12.05	10.44%

Special Payments

Going-Concern Basis

As at the date of the previous valuation, December 31, 2003, the going concern unfunded liability was $24,119,000. In accordance with the *Pension Benefits Act (Newfoundland and Labrador)*, this unfunded liability must be amortized over a period not exceeding 15 years. The present value, as at December 31, 2005, of the remaining minimum annual special payments to amortize the going concern unfunded liability as at December 31, 2003, is as follows:

Present Value of Minimum Annual Special Payments

Type of Deficit	Effective Date	Annual Special Payment	Last Payment	Present Value Of Remaining Payments as At 31.12.05
Going concern unfunded liability	Dec. 31, 2000	$2,798,000	Dec. 31, 2015	$21,154,000
Going concern unfunded liability	Dec. 31, 2003	$2,000	Dec. 31, 2018	$18,000
Total		$2,800,000		$21,172,000

Due to the experience gain arising since the previous valuation, the unfunded liability as at December 31, 2005, $14,460,000, is now less than the present value of remaining minimum special payments.

In accordance with the *Pension Benefits Act (Newfoundland and Labrador)*, this gain must first be used to reduce any going-concern unfunded liability which may then be reamortised over the remainder of the original period or over a shorter period.

Accordingly, the recalculated minimum annual special payments, based on the assumptions described in Appendix B and with the older established going concern unfunded liability payments adjusted before later ones, are as follows:

Present Value of Minimum Annual Special Payments

Type of Deficit	Effective Date	Annual Special Payment	Last Payment	Present Value Of Remaining Payments as At 31.12.05
Going concern unfunded liability	Dec. 31, 2000	$2,798,000	Feb. 29, 2012	$14,442,000
Going concern unfunded liability	Dec. 31, 2003	$2,000	Dec. 31, 2018	$18,000
Total		$2,800,000		$14,460,000

The present value, as at December 31, 2005, of the current schedule of annual special payments, approved by the Board of Commissioners of Public Utilities, to amortize the going concern unfunded liability, is as follows:

Present Value of Annual Special Payments Approved by the Board of Commissioners of Public Utilities

Type of Deficit	Effective Date	Current Annual Special Payment	Last Payment	Present Value Of Remaining Payments as At 31.12.05
Initial Unfunded Liability	Apr. 1, 1984	$4,188,000	Jul. 31, 2008	$10,020,000
Data Correction/Experience Loss	Jan. 1, 1992	$256,000	Dec. 31, 2006	$248,000
Assumption Change/Experience Loss	Jan. 1, 1993	$158,000	Dec. 31, 2007	$298,000
Early Retirement Window	Jul. 1, 1997	$775,000	Jun. 30, 2007	$1,110,000
Early Retirement Window	Jan. 1, 1998	$258,000	Dec. 31, 2007	$486,000
Pensioner Upgrade	Jul. 1, 1998	$88,000	Jun. 30, 2008	$204,000
Early Retirement Program	Dec. 31, 1999	$521,000	Jul. 31, 2008	$1,246,000
Early Retirement Program	April 1, 2005	$1,147,000	Mar. 31, 2015	$8,182,000
Total		$7,391,000		$21,794,000

The unfunded liability as at December 31, 2005, $14,460,000, is now less than the present value of these special payments, $21,794,000.

The adjusted schedule of payments, with payments in the most distant future reduced first, such that the present value of remaining special payments equals the going concern unfunded liability, is as follows:

Type of Deficit	Effective Date	Current Special Payment	Last Payment	Present Value Of Remaining Payments as At 31.12.05
Initial Unfunded Liability	Apr. 1, 1984	$4,188,000	Mar. 31, 2008	$8,810,000
Data Correction/Experience Loss	Jan. 1, 1992	$256,000	Dec. 31, 2006	$248,000
Assumption Change/Experience Loss	Jan. 1, 1993	$158,000	Dec. 31, 2007	$298,000
Early Retirement Window	Jan. 1, 1997	$775,000	Jun. 30, 2007	$1,110,000
Early Retirement Window	Jan. 1, 1998	$258,000	Dec. 31, 2007	$486,000
Pensioner Upgrade	Jul. 1, 1998	$88,000	Jan. 31, 2008	$172,000
Early Retirement Program	Dec. 31, 1999	$521,000	Mar. 31, 2008	$1,096,000
Early Retirement Program	Apr. 1, 2005	$1,147,000	Jan. 31, 2008	$2,240,000
Total		$7,391,000		$14,460,000

Solvency Basis

No solvency special payments are required.

Total Special Payments

Since no solvency special payments are required, the total minimum special payments are those required to eliminate the unfunded liability. As such, the following minimum annual special payments, as previously determined, must be made within the periods prescribed by the *Pension Benefits Act (Newfoundland and Labrador)*.

Minimum Annual Special Payments

Type of Deficit	Effective Date	Annual Special Payment	Last Payment
Going concern unfunded liability	Dec. 31, 2000	$2,798,000	Feb. 29, 2012
Going concern unfunded liability	Dec. 31, 2003	$2,000	Dec. 31, 2018
Total		$2,800,000	

Since no solvency special payments are required, the total special payments are those required to eliminate the unfunded liability. The annual special payments approved by the Board of Commissions of Public Utilities, adjusted for gains and losses, is as follows:

Type of Deficit	Effective Date	Annual Special Payment	Last Payment
Initial Unfunded Liability	Apr. 1, 1984	$4,188,000	Mar. 31, 2008
Data Correction/Experience Loss	Jan. 1, 1992	$256,000	Dec. 31, 2006
Assumption Change/Experience Loss	Jan. 1, 1993	$158,000	Dec. 31, 2007
Early Retirement Window	Jan. 1, 1997	$775,000	Jun. 30, 2007
Early Retirement Window	Jan. 1, 1998	$258,000	Dec. 31, 2007
Pensioner Upgrade	Jul. 1, 1998	$88,000	Jan. 31, 2008
Early Retirement Program	Dec. 31, 1999	$521,000	Mar. 31, 2008
Early Retirement Program	Apr. 1, 2005	$1,147,000	Jan. 31, 2008
Total		$7,391,000	

Employer Contributions

There is an unfunded liability of $14,460,000, and a solvency ratio of 100% as at December 31, 2005. As such, based on the assumptions described in Appendix B and with actuarial gains used to adjust older established going concern unfunded liability payment before later ones, in accordance with the minimum requirements of the *Pension Benefits Act (Newfoundland and Labrador)*, Newfoundland Power Inc. must make minimum annual contributions to the plan for 2006, as follows:

Annual Employer Contributions

For current service: 10.44% of members' pensionable earnings
Minimum special payments for unfunded liability: $2,800,000

On the basis of the members' estimated pensionable earnings, we have estimated the minimum total employer contribution for 2006 to be $6,171,000, or $514,250 per month. We have estimated the total members' contributions for 2006 to be $1,265,000.

Estimated Minimum Employer's Contributions Until December 31, 2008

Year Ending	Current Service Cost	Minimum \Annual Special Payments	Minimum Employer's Contribution
2006	$3,371,000	$2,800,000	$6,171,000
2007	$3,506,000	$2,800,000	$6,306,000
2008	$3,646,000	$2,800,000	$6,446,000

Contributions for current service must be made within 30 days following the month to which they apply. Special payments to eliminate an unfunded liability or solvency deficiency must be made at least quarterly.

The estimated employer's contributions until December 31, 2008, based on the special payments approved by the Board of Commissioners of Public Utilities is as follows:

Year Ending	Current Service Cost	*Annual* Special Payments	Employer's Contribution
2006	$3,371,000	$7,391,000	$10,762,000
2007	$3,506,000	$6,747,000	$10,253,000
2008	$3,646,000	$1,280,000	$4,926,000

5

Actuarial Opinion

With respect to the Actuarial Valuation as at December 31, 2005
of the Newfoundland Power Inc. Retirement Income Plan
Newfoundland and Labrador Registration 75241
Canada Revenue Agency 0486365

Based on the results of this valuation, we hereby certify that, as at December 31, 2005,

- The employer's current service cost for 2006 and subsequent years, up to the next actuarial valuation should be calculated as 10.44% of members' pensionable earnings.
- The employer's current service cost for 2006 is estimated to be $3,371,000. Member required contributions for 2006 are estimated to be $1,265,000.
- The plan would be fully funded on a going-concern basis if its assets were augmented by $14,460,000. In order to comply with the provisions of the *Pension Benefits Act (Newfoundland and Labrador)*, the unfunded liability must be liquidated by annual special payments at least equal to the amounts indicated, and for the periods set forth, below:

Minimum Annual Special Payments

Type of Deficit	Effective Date	Annual Special Payment	Last Payment
Going concern unfunded liability	Dec. 31, 2000	$2,798,000	Feb. 29, 2012
Going concern unfunded liability	Dec. 31, 2003	$2,000	Dec. 31, 2018
Total		$2,800,000	

Unfunded liability special payments, as approved by the Board of Commissioners of Public Utilities, and adjusted for gains and losses by reducing the most distant future payments first, are as follows:

Type of Deficit	Effective Date	Current Annual Special Payment	Last Payment
Initial Unfunded Liability	Apr. 1, 1984	$4,188,000	Mar. 31, 2008
Data Correction/Experience Loss	Jan. 1, 1992	$256,000	Dec. 31, 2006
Assumption Change/Experience Loss	Jan. 1, 1993	$158,000	Dec. 31, 2007
Early Retirement Window	Jan. 1, 1997	$775,000	Jun. 30, 2007
Early Retirement Window	Jan. 1, 1998	$258,000	Dec. 31, 2007
Pensioner Upgrade	Jul. 1, 1998	$88,000	Jan. 31, 2008
Early Retirement Program	Dec. 31, 1999	$521,000	Mar. 31, 2008
Early Retirement Program	Apr. 1, 2005	$1,147,000	Jan. 31, 2008
Total		$7,391,000	

- The plan has a solvency excess of $7,009,000 as at December 31, 2005, before recognition of the present value of the next 5 years' special payments. No special payments are required for solvency purposes.
- The solvency liabilities used to determine the solvency status of the plan do not exclude any benefit provided under the plan.
- We have included in the solvency liabilities the value of all benefits that may be contingent upon the circumstances of the postulated plan wind up. The circumstance in which the plan wind-up is assumed to have taken place are as follows: plan wind-up in conjunction with cessation of plan sponsor's operations.

- The solvency ratio of the plan is 100%.
- In our opinion,
  - the data on which the valuation is based are sufficient and reliable for the purposes of the valuation,
  - the assumptions are, in aggregate, appropriate for the purposes of determining the funded status of the plan as at December 31, 2005 on going-concern and solvency bases, and determining the minimum funding requirements, and
  - the methods employed in the valuation are appropriate for the purposes of determining the funded status of the plan as at December 31, 2005 on going-concern and solvency bases, and determining the minimum funding requirements.
- This report has been prepared, and our opinions given, in accordance with accepted actuarial practice.
- All assumptions made for the purposes of the valuation were reasonable at the time the valuation was prepared.

M. Scott Cushing
Fellow of the Society of Actuaries
Fellow of the Canadian Institute of Actuaries

Sept 27, 2006
Date

Anil Narale
Fellow of the Society of Actuaries
Fellow of the Canadian Institute of Actuaries

Sept 27, 2006
Date

Appendix A

Plan Assets

Sources of Plan Asset Data

The pension fund is managed by Barclays Global Investors Canada Limited and by Northern Trust Global Advisors Inc. and held in trust with RBC Dexia Investor Services ("RBC Dexia").

We have relied upon fund statements prepared by RBC Dexia and data provided by Newfoundland Power Inc., for the period from December 31, 2003 to December 31, 2005.

Reconciliation of Plan Assets

The pension fund transactions for the period from December 31, 2003 to December 31, 2005 are summarised as follows:

Reconciliation of Plan Assets (Market Value)

	2004	2005
January 1	$178,960,000	$197,906,000
PLUS		
Members' contributions	$1,324,000	$1,221,000
Company's current service contributions	$3,427,000	$3,165,000
Company's past service contributions	$6,386,000	$7,411,000
Investment income	$18,099,000	$27,510,000
	$29,236,000	$39,307,000
LESS		
Pensions paid	$9,915,000	$11,473,000
Transfer to Fortis Inc. Retirement Income Plan	$0	$1,140,000
Lump-sum refunds	$0	$745,000
Administration and investment fees	$375,000	$485,000
	$10,290,000	$13,843,000
December 31	$197,906,000	$223,370,000

We have tested the pensions paid, the lump-sum refunds and the contributions for consistency with the membership data for the plan members who have received benefits or made contributions. The results of these tests were satisfactory.

Investment Policy

The plan administrator adopted a statement of investment policy and objectives effective October, 2003. This policy is intended to provide guidelines for the manager(s) as to the level of risk which is commensurate with the plan's investment objectives. A significant component of this investment policy is the asset mix.

The constraints on the asset mix are provided for information purposes:

Distribution of the Market Value of the Fund by Asset Class

	Investment Policy		
	Minimum	**Target**	**Maximum**
Canadian Equities	35%	40%	45%
U.S. Equities	10%	15%	20%
Non-North American Equities	0%	5%	10%
Fixed Income	35%	40%	45%
Cash and short term	0%	0%	5%
		100%	

Performance of Fund Assets

The average return on the adjusted market value, net of expenses, since the last valuation at December 31, 2003 was 9.39% per year. This rate is greater than the assumed investment return of 6.00% by 3.39% per year.

Appendix B

Actuarial Methods and Assumptions

Actuarial Valuations Methods — Going-Concern Basis

Valuation of Assets

For this valuation, we have continued to use an adjusted market value method to determine the actuarial value of plan assets. Under this method, investment gains (losses) arising during a given year are spread on a straight-line basis over three years. As a result, the asset value produced as at December 31, 2005 recognises the following percentages of the investment gains (losses) that arose during past years:

2003 and before:	100%
2004:	67%
2005:	33%

The asset values produced by this method are related to the market value of the assets, with the advantage that, over time, the market-related asset values will tend to be more stable than market values. To the extent that more investment gains than losses will arise over the long term, the actuarial value will tend to be lower than the market value.

The actuarial value of the assets, determined as at December 31, 2005 under the adjusted market value method, is $210,945,000.

This value was derived as follows:

Actuarial Value of Assets as at 31.12.05

Market value of assets		$223,370,000
LESS		
Unrecognised investment gains (losses)	2004: $6,950,000 x 33% =	$2,317,000
	2005: $15,163,000 x 67% =	$10,108,000
		$12,425,000
Actuarial value of assets		$210,945,000

Valuation of Actuarial Liabilities

Over time, the real cost to the employer of a pension plan is the excess of benefits and expenses over member contributions and investment earnings. The actuarial cost method allocates this cost to annual time periods.

For purposes of the going-concern valuation, we have continued to use the *projected unit credit actuarial cost method.* Under this method, we determine the actuarial present value of benefits accrued in respect of service prior to the valuation date, including ancillary benefits, based on projected final average earnings. This is referred to as the *actuarial liability.*

The *funding excess* or *unfunded liability,* as the case may be, is the difference between the actuarial value of assets and the actuarial liability. An unfunded liability will be amortised over no more than 15 years through special payments as required under the *Pension Benefits Act (Newfoundland and Labrador).* A funding excess may, from an actuarial standpoint, be applied immediately to reduce required employer current service contributions unless precluded by the terms of the plan or by legislation.

This actuarial funding method produces a reasonable matching of contributions with accruing benefits. Because benefits are recognised as they accrue, the actuarial funding method aims at keeping the plan fully funded at all times. This promotes benefit security, once any unfunded liabilities and solvency deficiencies have been funded.

Current Service Cost

The *current service cost* is the actuarial present value of projected benefits to be paid under the plan with respect to service during the year following the valuation date.

The employer's current service cost is the total current service cost reduced by the members' required contributions.

The employer's current service cost has been expressed as a percentage of the members' pensionable earnings to provide an automatic adjustment in the event of fluctuations in membership and/or pensionable earnings.

Under the projected unit credit actuarial cost method, the current service cost for an individual member will increase each year as the member approaches retirement. However, the current service cost of the entire group, expressed as a percentage of the members' pensionable earnings, can be expected to remain stable as long as the average age of the group remains constant.

Given that the Newfoundland Power Retirement Income Plan is closed to new entrants, the average age of the group is expected to increase in the future and therefore, the current service cost of the group, expressed as a percentage of the members' pensionable earnings, can be expected to increase as well.

Employer's Contribution

Accordingly, the employer's contributions for this purpose, to the extent allowed by the terms of the plan and applicable legislation, are determined as follows:

Employer's Contributions

With an unfunded liability	With a funding excess
Current service cost	Current service cost
PLUS	MINUS
Payments to amortise any unfunded liability	Any funding excess applied to cover the employer's current service cost

Actuarial Assumptions — Going-Concern Basis

The actuarial value of benefits is based on economic and demographic assumptions. At each valuation, we determine whether, in our opinion, the actuarial assumptions are still appropriate for the purposes of the valuation, and we revise them if necessary.

In this valuation, we have used the same assumptions as in the previous valuation except as noted. Emerging experience will result in gains or losses that will be revealed and considered in future actuarial valuations. For this valuation, we have used the following assumptions:

Economic Assumptions

Investment Return

We have assumed that the investment return on the actuarial value of the fund will average 6.0% per year over the long term. We have based this assumption on an expected long-term return on the pension fund less a margin (or adverse deviations). The expected long-term return on the pension fund was determined for the target asset mix specified in the plan's investment policy consistent with market conditions applicable on the valuation date.

Expenses

The assumed investment return reflects an implicit provision for expenses.

Increases in Pensionable Earnings

The benefits ultimately paid will depend on each member's final average earnings. To calculate the pension benefits payable upon retirement, death or termination of employment, we have taken salary rates at January 1, 2006 and assumed that such salaries will increase at 4.0% per year.

Increases in the YMPE

Since the benefits provided by the plan depend on the final average Year's Maximum Pensionable Earnings (YMPE) under the Canada Pension Plan, it is necessary to make an assumption about increases in the YMPE for this valuation. We have assumed that the YMPE will increase at the rate of 3.5% per year from its 2006 level of $42,100. An assumption of 4.0% per year was used in the previous valuation.

Increases in the Maximum Pension Permitted under the Income Tax Act

The *Income Tax Act* stipulates that the maximum pension that can be provided under a registered pension plan will be increased to specified amounts in 2006 through 2009, and automatically, starting in 2010, in accordance with general increases in the average wage. The scheduled limits, per year of service are as follows:

Year	2006	2007	2008	2009	2010 and later
Limit	$2,111	$2,222	$2,333	$2,444	Indexed

For this valuation, we have assumed that the maximum pension payable under the plan will increase as specified in the *Income Tax Act* in 2006 through 2009, and will increase starting in 2010 at the rate of 3.5% per year. An assumption of increases of 4.0% starting in 2006 was used in the previous valuation.

Indexation of Pensions in Payment

For this valuation, no assumptions have been made with respect to indexing pensions in payment.

Demographic Assumptions

Retirement Age

Because early retirement pensions are reduced in accordance with a formula, the retirement age of plan members has an impact on the cost of the plan. We have assumed that members will retire one year after the later of the date they would have attained age 60 and age plus service would total 95 (date at which the member is entitled to an unreduced early retirement) but not later than age 65.

Termination of Employment

We have made an allowance for projected benefits payable on the termination of employment before retirement for reasons other than death.

We have used termination rates that are based on 50% of the turnover rates under the Ontario Light termination table. We have not used rates of termination after age 39. Sample rates are shown in the following table:

Termination Rates

Age	Percentage
25	5.0%
30	2.8%
35	1.6%
39	1.2%
40 – 64	0.0%

Mortality

The actuarial value of the pension depends on the lifetime of the member. We have assumed mortality rates, both before and after retirement, in accordance with the projected Group Annuity Reserving (GAR) Table for 1994. According to this table, the life expectancy at age 65 is 19.8 years for males and 22.4 years for females.

Disability

We have not made an allowance for incidence of disability prior to retirement.

Family Composition

Benefits in case of death, before and after retirement, depend on the plan member's marital status.

For this valuation, we have assumed that 80% of plan members will have an eligible spouse on the earlier of death or retirement, and that the male partner will be three years older than the female partner.

Actuarial Valuation Methods and Assumptions — Solvency

We have used the market value of the plan's assets in our valuation of the plan for solvency purposes.

To determine the solvency actuarial liability, we have valued those benefits that would have been paid had the plan been wound up on the valuation date, with all members fully vested in their accrued benefits. The circumstances in which the plan wind-up is assumed to have taken place are as follows: total wind-up in conjunction with cessation of the plan sponsor's operations.

We have considered that members under 55 years of age on that date would be entitled to a deferred pension payable from age 65 or such earlier age for which plan eligibility requirements have been satisfied at December 31, 2005. Members aged 55 and over are considered to be entitled to an immediate pension, reduced in accordance with the plan rules. Benefits are assumed to be settled through a lump sum transfer for active and disabled members under 55 years of age at December 31, 2005. The value of the benefits accrued on December 31, 2005, for such members is based on the assumptions described in the Canadian Institute of Actuaries – Standard of Practice for Determining Pension Commuted Values applicable for December 31, 2005 for benefits expected to be settled through transfer in accordance with relevant portability requirements.

Benefits are assumed to be settled through the purchase of annuities for active and disabled members age 55 or older at December 31, 2005 as well as all deferred and current pensioners and beneficiaries. The value of the benefits accrued on December 31, 2005, for such members is based on an estimate of the cost of settlement through purchase of annuities. Assumptions are as follows:

Actuarial Assumptions

Mortality rates:	UP-1994 projected to 2015
Interest rates for benefits to be settled through lump sum transfer:	4.5% per year for the first 10 years following 31.12.05, 5.0% per year thereafter
Interest rates for benefits to be settled through annuity purchase:	4.50% per year
Final average earnings	Based on actual pensionable earnings over the averaging period
Family composition:	Same as for going-concern valuation
Maximum pension limit:	$2,000 per year of service
Termination expenses:	$200,000

In a solvency valuation, the accrued benefits are based on the member's final average earnings on the valuation date; therefore no salary projection is used. Also, the employment of each member is assumed to have terminated on the valuation date, therefore, no assumption is required for future rates of termination of employment.

Appendix C

Membership Data

Analysis of Membership Data

The actuarial valuation is based on membership data as at December 31, 2005, provided by Newfoundland Power Inc.

We have applied tests for internal consistency, as well as for consistency with the data used for the previous valuation. These tests were applied to membership reconciliation, basic information (date of birth, date of hire, date of membership, gender, etc.), pensionable earnings, credited service, contributions accumulated with interest and pensions to retirees and other members entitled to a deferred pension. Contributions, lump sum payments and pensions to retirees were compared with corresponding amounts reported in financial statements. The results of these tests were satisfactory.

Plan membership data are summarised below. For comparison, we have also summarised corresponding data from the previous valuation.

Membership Data

	31.12.05	31.12.03
Active Members		
▪ Number	538	623
▪ Average age	46.8	45.8
▪ Average years of pensionable service	21.4 years	20.6 years
▪ Total estimated pensionable earnings for following year	$32,294,554	$33,805,142
▪ Accumulated contributions with interest	$22,913,699	$23,726,434
Disabled Members		
▪ Number	19	26
▪ Average age	51.3	50.5
▪ Average years of pensionable service	22.6 years	22.6 years
▪ Total estimated pensionable earnings for following year	$758,994	$1,006,642
▪ Accumulated contributions with interest	$463,783	$677,521
Deferred Pensioners		
▪ Number	8	8
▪ Average age	49.3	48.7
▪ Total annual pension	$74,935	$61,747
Pensioners and Survivors		
▪ Number	673	613
▪ Average age	67.3	67.6
▪ Total annual lifetime pension	$8,551,945	$7,169,512
▪ Total annual bridge pension	$3,374,172	$2,866,416

The membership movement for all categories of membership since the previous actuarial valuation is as follows:

Reconciliation of Membership

	Actives	Disabled	Deferred Vested	Pensioners and Beneficiaries	Total
Total at 31.12.03	**623**	**26**	**8**	**613**	**1,270**
New entrants	1				1
Return from Disabled	4	(4)			
Return from Deferred	2		(2)		
To Disabled	(3)	3			
Deferred	(1)		1		
Terminations, transfers/refunds	(11)		2		(9)
Deaths, no benefits outstanding	(4)			(20)	(24)
Deaths with beneficiary				(19)	(19)
Beneficiaries				19	19
Retired	(73)	(6)	(1)	80	
Total at 31.12.05	**538**	**19**	**8**	**673**	**1,238**

The distribution of the active members by age and pensionable service as at December 31, 2005, is summarised as follows:

Distribution of Active Members by Age Group and Pensionable Service as at 31.12.05

	Years of Pensionable Service							
Age	**0-4**	**5-9**	**10-14**	**15-19**	**20-24**	**25-29**	**30+**	**Total**
Under 20								
20 - 24								
25 - 29	5	3						8
30 - 34	3	14						17
35 - 39	6	29	14	21	1			71
40 - 44	1	9	7	54	23	1		95
45 - 49	2	9	5	29	31	57	19	152
50 - 54		1	2	19	13	49	71	155
55 - 59		1		2	4	9	19	35
60 - 64		1		1		1	2	5
65 +								
Total	**17**	**67**	**28**	**126**	**72**	**117**	**111**	**538**

The distribution of the inactive members by age as at December 31, 2005, is summarised as follows:

Distribution of Inactive Members
By Age Group as at 31.12.05

	Deferred Pensioners		Pensioners and Survivors			
Age	**Number**	**Average Annual Pension**	**Number**	**Average Annual Lifetime Pension**	**Number**	**Average Annual Bridge Pension**
25 - 29	1	$1,760				
30 - 34						
35 - 39	1	$11,498				
40 - 44						
45 - 49	2	$11,615				
50 - 54	2	$13,123	46	$18,696	45	$13,947
55 - 59			127	$15,950	120	$12,386
60 - 64	2	$6,102	123	$13,411	108	$11,669
65 - 69			137	$11,412		
70 - 74			97	$11,296		
75 - 79			69	$9,791		
80 - 84			35	$11,314		
85 - 89			31	$7,564		
90 - 94			8	$6,432		
95 - 99						
100 +						
Total	8	$9,367	673	$12,707	273	$12,360

Appendix D

Summary of Plan Provisions

Introduction

The Newfoundland Power Inc. Retirement Income Plan became effective April 1, 1984.

This valuation is based on the plan provisions in effect on December 31, 2005. The following is a summary of the plan's main provisions in effect on December 31, 2005. It is not intended as a complete description of the plan.

Eligibility for Membership

Each employee hired before the effective date of this plan is eligible to participate. Each employee hired on or after the effective date shall become a member of the plan on the first day of employment.

Membership was optional for employees transferred from an affiliated company, for employees hired or designated as manager or executive, and for non-bargaining unit employees hired on or after August 1, 2003.

However, effective May 1, 2004, the plan was closed to new entrants.

Contributions

The members are contributing to the plan at the rate of 3 1/3% of their salary up to the Year's Maximum Pensionable Earnings (YMPE) and 5% of their salary in excess of the YMPE. For 1984, the members were contributing at the rate of 60% (2%/3%) of their full rate starting on April 1st.

No contributions shall be required to be made beyond 35 years of service. However, members may elect to make required contributions beyond completion of 35 years, up to the maximum of $1,000, in order to attain higher final average earnings.

Interest shall be credited on member contributions at a rate not less than the rate at issue of the last Canada Savings Bond issued prior to the start of the calendar year. Effective January 1, 1997, interest shall be credited based on the average of the yields on 5-year personal fixed term chartered bank deposits published in the Bank of Canada Review as CANSIM Series B14045, the averaging to be done over a reasonable recent period, not exceeding twelve months.

Additional voluntary contributions are not permitted after January 1, 1992.

The Company is contributing the remaining cost for current service and the cost for past service.

The YMPE, or Year's Maximum Pensionable Earnings, refers to the maximum annual amount of earnings upon which an employee and an employer contribute to the Canada/Québec Pension Plan (C/QPP).

Retirement Dates

Normal Retirement Date

The normal retirement date is the first day of the month coincident with or next following the member's 65th birthday.

Postponed Retirement

An active member may not postpone retirement beyond the normal retirement age of 65 years.

Retirement Benefits

Normal Retirement

Upon normal retirement a member is entitled to an annual pension equal to 1 1/3% of the average of his best 36 months of earnings during which contributions were made up to the final average YMPE plus 2% of such best average earnings in excess of the average of the final 36 months YMPE for each year of credited service (up to a maximum of 35 years).

Early Retirement Pension

An early retirement pension without reduction is payable if the member has both attained age 60 and has a combined total years of age plus service of 95.

An early retirement pension with a subsidized reduction is permissible if the member's age plus service is 85 or greater.

The amount of the reduction is:

1. if the member's total years of age plus service total 95 or more – 1/4% for each month before age 60, and.

2. if the member's total years of age plus service total less than 95 - 1/3% for each month before the earliest date at which the member could have elected unreduced retirement.

Early retirement is permitted after attaining age 55 with a pension that is actuarially reduced from age 65.

Maximum Pension

The total annual pension payable from the plan upon retirement, death or termination of employment cannot exceed the lesser of:

- 2% of the average of the best three consecutive years of total compensation paid to the member by the Company, multiplied by total credited service; and

- $2,000 or such other maximum permitted under the *Income Tax* Act, multiplied by the member's total credited service.

Survivor Benefits

Death Before Retirement

On death of a member before retirement, his/her surviving spouse shall be entitled to 55% of his/her accrued pension payable immediately for life.

If the surviving spouse is more than 15 years younger than the participant, the entitlement is reduced by 1.5% of each full year in excess of 15.

If there is no surviving spouse, the beneficiary shall receive a refund of the member's accumulated contributions with interest.

Notwithstanding the above, if a member or former member who has completed 2 years of membership in the plan dies after December 31, 1996, the surviving spouse or beneficiary is entitled to the minimum death benefit equal to the actuarial value of the vested pension benefits accrued after December 31, 1996.

Death After Retirement

The normal form of payment for a member with a spouse at retirement is a joint and survivor pension with 55% of the member's pension continuing to the surviving spouse. However, the member may elect to receive an optional form of pension on an actuarial equivalent basis.

The normal form of payment for a member without a spouse is pension payable for the member's lifetime. However, in no case shall the total of pension payments paid to the member prior to death be less than the member's accumulated contributions with interest at pension commencement.

Termination Benefits

Pension Benefit Accrued Prior to January 1, 1997

1. <u>Prior to Completion of 5 Years of Service</u>
   A member who terminates his/her employment after December 31, 1996 but prior to completing 5 years of service will receive a refund of his/her accumulated contributions made prior to January 1, 1997 with interest.

2. <u>After Completion of 5 Years of Service</u>
   A. A member who terminates his/her employment after December 31, 1996 and after completing 5 years of service will receive a termination benefit equal to the greater of:

      – 2 times his accumulated member's contributions made prior to January 1, 1997 with interest, or

      – the actuarial value of his vested pension accrued prior to January 1, 1997.

   B. For a member with age plus service totalling 45 or more, the member has the choice of receiving:

      – a deferred pension, or

      – a refund of his contributions and the balance of his/her termination benefit, as determined in section 2.A. above, transferred to a locked-in RRSP.

   C. Notwithstanding the above, a member who has attained age 45 and has 10 years or more of service is entitled to either a deferred pension or a transfer to a locked-in RRSP of the value of his termination benefits, as determined in section 2.A. above.

Pension Benefits Accrued After December 31, 1996

1. <u>Prior to Completion of 2 Years of Membership Service</u>
   A member who terminates his/her employment after December 31, 1996 before completing 2 years of membership service will receive a refund of his/her accumulated contributions made after December 31, 1996 with interest ("Post 96 Accumulated Member Contributions").

2. <u>Completion of 2 Years of Membership Service</u>
   A. A member terminates his/her employment after December 31, 1996 with 2 years of membership service will receive the termination benefit equal to the greater of:

      – 2 times his/her Post 96 Accumulated Member Contributions provided he/she has completed 5 years of service; and

      – the sum of:

        (1) the actuarial value of his pension benefit accrued after December 31, 1996.

        (2) the excess, if any, of the Post 96 Accumulated Member Contributions over 50% of the actuarial value of his/her pension benefit accrued after December 31, 1996 ("Excess Member Contribution").

   B. The Member has the choice of receiving:

      – a deferred pension with respect to his pension benefit accrued after December 31, 1996 plus a refund of his/her Excess Member Contribution; or

      – a refund of his/her Excess Member Contributions plus a transfer of the balance of the termination benefit, as determined under section 2.A. above, to a locked-in RRSP.

Disability Benefits

During a member's disability the earnings are deemed to be equal to the amount earned at the time of becoming disabled and the member continues to accrue service. A disabled member shall not be required to contribute to the plan. The Company contributes the entire cost of the benefits.

Appendix E

Employer Certification

With respect to the report on the actuarial valuation of the Newfoundland Power Inc. Retirement Income Plan, as at December 31, 2005, I hereby certify that, to the best of my knowledge and belief:

- a copy of the official plan documents and of all amendments made up to December 31, 2005, were provided to the actuary;
- the membership data provided to the actuary include a complete and accurate description of every person who is entitled to benefits under the terms of the plan for service up to December 31, 2005, and
- all events subsequent to December 31, 2005 that may have an impact on the results of the valuation have been communicated to the actuary.

September 14, 2006
Date

Signed

Robert G. Meyers, Treasurer
Name

A Report on Employee Future Benefits

(filed in compliance with Order No. P.U. 19 (2003))

May 2007

NEWFOUNDLAND POWER
A FORTIS COMPANY

Table of Contents

Page

1.0 INTRODUCTION

1.1 Background

Newfoundland Power provides defined benefit and defined contribution pension plans and other post employment benefits ("OPEBs") for its employees. Newfoundland Power's OPEBs are composed of retirement allowances for retiring employees as well as health, medical and life insurance for retirees and their dependents. Pensions and OPEBs together represent Newfoundland Power's total employee future benefits.

Newfoundland Power effectively recognizes OPEBs costs on a cash basis whereby the annual expense is equal to the related retirement allowances and insurance premiums actually paid in the year (the "Cash Method").[1] Newfoundland Power recognizes pension costs using the accrual method (the "Accrual Method").

In Order No. P.U. 19 (2003), the Board ordered the Company to file a report with its next general rate application ("GRA") addressing the use of the Accrual Method to recognize OPEBs expense.[2]

This report is filed in compliance with Order No. P.U. 19 (2003).

1.2 Regulatory Context

Newfoundland Power has assessed its OPEBs obligations, including the transitional obligations associated with moving to the Accrual Method and the rate implications of this change in accounting policy.

An actuarial valuation determined the present value of Newfoundland Power's total OPEBs obligation, as of January 1, 2006, to be approximately $69.8 million on an accrual basis.[3]

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1 The *Income Tax Act (Canada)* requires that the computation of current income tax reflect the Cash Method of accounting for OPEBs, i.e. only retirement allowances and insurance premiums actually paid are tax deductible.

2 At page 83 of Order No. P.U. 19 (2003), it stated: "The Board is concerned about the potential liability for employee future benefits and is of the view that NP should explore using the accrual method of accounting for these benefits. The Board recognizes that there are significant transitional obligations associated with this change in accounting policy but once the transitional obligation has been met these costs should decrease. NP should continue to monitor its obligations with respect to employee future benefits and corresponding regulatory practice. The Board will direct NP to propose a plan at its next general rate application for moving towards the accrual method of accounting for employee future benefits as recommended by CICA. The Board emphasizes such a plan should be presented to the Board as an alternative to the existing method and should address the transitional impact with a view to fulfilling NP's obligation to its employees while at the same time moderating its impact on rates. The Board will then be in a position to consider this alternative accrual method and its specific impacts at the next hearing."

3 The current actuarial valuation of the Company's OPEBs obligations on an accrual basis is found in *Volume 2: Supporting Materials, Tab 5*.

Table 1 shows the projected growth in Newfoundland Power's total OPEBs obligations over the period 2006 to 2010.

Table 1
Total OPEBs Obligation
Accrual Basis
As of December 31
($millions)

2006	2007	2008	2009	2010
69.8	73.4	77.0	80.7	84.5

As employees accumulate service with the Company, the value of Newfoundland Power's obligation to pay OPEBs will continue to increase.

There are significant transitional obligations associated with moving from the Cash Method to the Accrual Method (the "Transitional Obligation")[4].

Fully recognizing Newfoundland Power's total OPEBs obligations, including the Transitional Obligation, through adoption of the Accrual Method commencing in 2008 would result in an increase in 2008 revenue requirements of approximately 3 percent.

1.3 Newfoundland Power Proposal

Based on its assessment, the Company is proposing a measured transition to the Accrual Method. The proposal in the Application includes features that reasonably mitigate the impact on customer rates of the proposed change.

In this Application, Newfoundland Power proposes to:

1. adopt the Accrual Method of accounting for OPEBs costs for regulatory purposes commencing in 2008;
2. tax-effect all of its employee future benefits costs, represented by OPEBs expense and pension expense, for regulatory purposes commencing in 2008;[5] and
3. defer consideration of the Transitional Obligation of $34.1 million until its next general rate proceeding.[6]

The Company's proposals, if approved by the Board, will result in an increase in an increase in 2008 revenue requirements of approximately 1.5 percent.

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4 In accordance with GAAP requirements, Newfoundland Power recorded a regulatory asset of $27.8 million associated with the Transitional Obligation on its December 31, 2006 balance sheet. The Transitional Obligation represented by this regulatory asset is projected to grow to approximately $34.1 million by January 1, 2008.

5 Tax-effecting employee future benefits costs mitigates the impact on revenue requirement of adopting the Accrual Method of recognizing OPEBs costs for regulatory purposes.

6 If the Company adopts the accrual method of accounting for OPEBs in 2008 as proposed in the Application, the $34.1 million Transitional Obligation will not change.

2.0 OPEBs ACCOUNTING POLICY

2.1 The Accrual Method

Under the Accrual Method, OPEBs costs are recognized as an expense as employees earn the benefits that they will receive after retirement. Therefore, OPEBs costs are "accrued" rather than being recognized when benefits are paid.

Conceptually, OPEBs costs are no different than pension costs attributable to defined benefit pension plans. Both are costs of employee future benefits.

Newfoundland Power uses the Accrual Method to recognize pension expense attributable to its defined benefit pension plans for both financial reporting and regulatory purposes. Pension expense is actuarially determined and reflects management's best estimates with respect to matters such as the expected performance of pension plan assets, future salary escalation and the retirement ages of employees. Under the Accrual Method, OPEBs expense would be calculated in a similar manner.

Newfoundland Power proposes to adopt the Accrual Method of accounting for OPEBs costs for regulatory purposes in 2008.

2.2 Canadian Standards and Practice

2.2.1 Financial Reporting Standards

Canadian generally accepted accounting principles ("GAAP") with respect to the recognition of both defined benefit pension costs and OPEBs costs for financial reporting purposes are set out in section 3461 of the Canadian Institute of Chartered Accountants ("CICA") Handbook.

Pursuant to section 3461, defined benefit pension costs and OPEBs costs would normally be recognized under the Accrual Method for financial reporting purposes.[7]

However, the CICA Handbook effectively permits rate-regulated entities such as Newfoundland Power to recognize costs under methods other than the Accrual Method. For this reason, Newfoundland Power's use of the Cash Method to recognize OPEBs costs is currently in compliance with GAAP.

CICA accounting guideline AcG-19[8] titled *disclosures by entities subject to rate regulation* effectively requires rate-regulated entities like Newfoundland Power to record regulatory assets and regulatory liabilities on their balance sheets.[9]

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[7] For Newfoundland Power, section 3461 of the CICA Handbook became effective on January 1, 2000.

[8] CICA accounting guidelines are a component of the CICA Handbook and are therefore a source of GAAP. AcG-19 is effective for fiscal years ending on or after December 31, 2005.

[9] Regulatory assets and liabilities are created when revenues and/or expenses are recognized for rate-setting purposes in a manner other than that which would be required for entities not subject to rate regulation. Regulatory assets represent future revenues associated with certain costs, incurred in the current or prior periods, which will be recovered from customers in future periods through the rate-setting process. Regulatory liabilities represent future revenue reductions or limitations of increases in future revenues, associated with amounts that are expected to be refunded to customers.

In compliance with AcG-19, Newfoundland Power reported a regulatory asset (the "Transitional Obligation") and a GAAP liability of $27.8 million with respect to its OPEBs on its December 31, 2006 balance sheet.[10] This actuarially determined amount[11] represents the amount of Newfoundland Power's accumulated benefit obligation for OPEBs that would have been recorded as both an expense and a liability by December 31, 2006 pursuant to section 3461 of the CICA Handbook.

The accumulated OPEBs expense of $27.8 million has been recorded as a regulatory asset because Newfoundland Power's OPEBs expense is effectively recognized under the Cash Method. This Transitional Obligation represents the amount of incurred OPEBs expense for which recognition, and recovery from customers, has effectively been deferred until future periods.

The Transitional Obligation is forecast to increase to approximately $34.1 million by December 31, 2007.[12]

GAAP effectively provides that the Transitional Obligation would be recognized as OPEBs expense for financial reporting purposes during the periods in which these costs are recovered from customers.

2.2.2 Financial Reporting and Regulatory Practice

The Company surveyed 24 regulated Canadian utilities with respect to their OPEBs accounting policy for financial reporting and regulatory purposes. A list of the utilities surveyed is provided in Appendix A.

Table 2 summarizes the survey results.

Table 2
Survey Results
OPEBs Accounting Policy
Financial Reporting and Regulatory Purposes

	Number of Regulatory Jurisdictions	Number of Utilities
Accrual Method	10	18[13]
Cash Method	4	6
		24

Table 2 shows that the Accrual Method is the mainstream accounting policy for regulated Canadian utilities.

10 See Return 1 of Newfoundland Power's 2006 Annual Report to the Board.
11 The effective date of the actuarial valuation (the "OPEBs Actuarial Valuation") is December 31, 2006. The OPEBs Actuarial Valuation reflects the impacts of Newfoundland Power's 2005 early retirement program.
12 Per the OPEBs Actuarial Valuation.
13 Includes Newfoundland and Labrador Hydro ("Hydro").

2.3 Impact of Adopting the Accrual Method

2.3.1 Impact of Accrual Method on Net OPEBs Expense

The forecast impact of the Accrual Method on Newfoundland Power's net OPEBs expense[14] for 2008 is summarized in Table 3.

Table 3
OPEBs Accrual Method
Forecast Impact on Net OPEBs Expense
($millions)

	2008
Cash Method	1.1
Accrual Method	7.5
Increase	6.4

Table 3 shows that in 2008 net OPEBs expense under the Accrual Method would be approximately $6.4 million higher than that calculated under the Cash Method.

2.3.2 Impact of Accrual Method on Rate Base

Actual OPEBs payments made by Newfoundland Power in any period is the total of the insurance premiums and retirement allowances paid in the period.

Under the Accrual Method, the excess of OPEBs expense recognized in any period over OPEBs payments made in the period would, in accordance with GAAP, be recorded as a net liability on Newfoundland Power's balance sheet. This net liability (the "Accrued OPEBs Liability") represents, at any date, the amount by which cumulative OPEBs expense recognized to that date has exceeded cumulative OPEBs payments to that date.[15]

Because OPEBs expense under the Cash Method is equal to OPEBs payments, the Accrued OPEBs Liability is also equal to the cumulative difference between (i) OPEBs expense under the Cash Method and (ii) OPEBs expense under the Accrual Method.

Under the asset rate base method ("ARBM"), the Accrued OPEBs Liability serves to decrease Newfoundland Power's rate base. In order to facilitate its transition to the ARBM[16],

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[14] The *forecast* amounts in Table 2 are based on the OPEB Actuarial Valuation and, in the case of the Accrual Method, GAAP as set out in section 3461 of the CICA Handbook. The calculation of net OPEBs expense under the Accrual Method is consistent with the calculation of net pension expense for the Company's defined benefit pension plans.

[15] The recognition of OPEBs expense increases the Accrued OPEBs Liability. OPEBs payments decreases the Accrued OPEBs Liability.

[16] In Order No. P.U. 19 (2003), the Board found that the ARBM should replace the invested capital method in determining the rate base for Newfoundland Power.

Newfoundland Power proposes that the Accrued OPEBs Liability be deducted from its rate base commencing in 2008 upon the adoption of the Accrual Method of accounting for OPEBs.[17]

Essentially, the Accrued OPEBs Liability is identical to the Company's future income tax liability. Both represent expenses recognized in the current period or in prior periods for which payment will not occur until future periods, i.e. both are deferred liabilities. Newfoundland Power's future income tax liability is subtracted from its rate base.[18]

The forecast impact of the adoption of the Accrual Method on Newfoundland Power's average rate base for 2008 is set out in Table 4.

Table 4
OPEBs Accrual Method
Forecast Impact on Average Rate Base
($millions)

	2008
Accrued OPEBs Liability, Beginning of the Year	-
Net OPEBs Expense, Accrual Method[19]	7.5
Net OPEBs Expense, Cash Method[20]	(1.1)
Accrued OPEBs Liability, End of the Year	6.4
Reduction in Average Rate Base[21]	3.2

The reduction in average rate base shown in Table 4 will reduce Newfoundland Power's permitted return and revenue requirement. In this way, the cash flow benefits associated with the increased net OPEBs expense under the Accrual Method are passed on to customers.

The OPEBs driven reduction in rate base tends to offset the growth in rate base attributable to increases in Newfoundland Power's deferred pension asset. The growth in the deferred pension asset reflects the fact that, under the Accrual Method, pension funding for defined benefit plans tends to exceed pension expense.[22] The excess is recorded as a deferred asset until it is recognized as pension expense in future periods.

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17 The treatment of Newfoundland Power's Accrued OPEBs Liability as a reduction in rate base would be consistent with the treatment of the deferred pension asset relating to its defined benefits pension plans. The inclusion of Newfoundland Power's deferred pension asset in its rate base was approved by the Board in Order No. P.U. 19 (2003).

18 See Return 3 in Newfoundland Power's Annual Reports to the Board.

19 Per Table 3.

20 OPEBs payments related to insurance premiums and retirement allowances.

21 (Accrued OPEBs Liability, Beginning of the Year plus Accrued OPEBs Liability, End of the Year) divided by 2.

22 Pension funding is actuarially determined. Pension expense is determined in accordance with GAAP and reflects both the actuary's calculations and management's best estimates. As actuarial assumptions tend to be more conservative than management's best estimates, pension funding tends to exceed pension expense.

Under the Accrual Method, the opposite is true for OPEBs. The resultant Accrued OPEBs Liability is recorded as a deferred liability until it is extinguished through the payment of OPEBs costs in future periods.

These underlying and offsetting dynamics serve to limit the rate base impacts of the Company's employee future benefits programs when the Accrual Method is used to account for both its OPEBs and its defined benefit pension plans.

2.3.3 Impact of Accrual Method on Revenue Requirement

Table 5 sets out, on a forecast basis for 2008, the impact of the Accrual Method on the revenue requirement attributable to OPEBs.

Table 5
OPEBs Accrual Method
Forecast Impact on Revenue Requirement
($millions)

	2008
Operating Expenses	
Increase in Net OPEBs Expense[23]	6.4
Tax Effects[24]	3.4
Increase in Revenue Requirement	9.8
Return on Rate Base	
Rate Base Effects[25]	(0.3)
Tax Effects	(0.1)
Decrease in Revenue Requirement	(0.4)
Increase in Revenue Requirement	9.4

Table 5 shows that the forecast impact of the Accrual Method on revenue requirement in 2008 is $9.4 million.

2.4 Transitional Obligation

Newfoundland Power proposes that the Transitional Obligation, shown as a regulatory asset on its December 31, 2006 balance sheet, be addressed at its next general rate proceeding.

The Transitional Obligation is the actuarially determined difference between (i) the total OPEBs expense that would have been recognized by the Company pursuant to the Accrual Method since

[23] Per Table 3.
[24] Based on Newfoundland Power's marginal income tax rate of 34.5 percent for 2008.
[25] (Reduction in Rate Base as per Table 4) times (Return on Rate Base) or ($3.2 million times 8.82 percent).

January 1, 2000,[26] and (ii) the total OPEBs expense recognized since that date under the Cash Method. It represents legacy OPEBs costs that have not yet been recovered from customers.

As at the proposed January 1, 2008 adoption date for the Accrual Method of accounting for OPEBs, the forecast Transitional Obligation is approximately $34.1 million.

The manner in which the Transitional Obligation is recognized as an expense for regulatory purposes is to be determined by the Board. GAAP effectively requires the treatment for financial reporting purposes match the regulatory treatment.

Given the impact on revenue requirement of Newfoundland Power's proposal to adopt the Accrual Method of accounting for OPEBs costs, the Company proposes that the disposition of the Transitional Obligation be addressed at the Company's next general rate proceeding.

Newfoundland Power's proposals would effectively result in a two stage approach to addressing the Company's OPEBs accounting policy. The first stage would be the adoption of the Accrual Method of accounting commencing January 1, 2008. The second stage would be addressing, at a later date, the legacy OPEBs costs represented by the Transitional Obligation.

A two stage approach benefits customers by reducing the immediate impacts on revenue requirement and customer rates that would otherwise be associated with the adoption of the Accrual Method of accounting for OPEBs costs for regulatory purposes.

3.0 TAX-EFFECTING EMPLOYEE FUTURE BENEFITS EXPENSE

Newfoundland Power proposes to tax-effect employee future benefits expense through the adoption of the asset and liability method of income tax accounting for regulatory purposes[27] commencing in 2008.

3.1 Tax-Effecting Generally

The timing of the recognition of an expense for income tax purposes is determined by federal and provincial tax laws. The timing of the recognition of an expense for financial reporting and regulatory purposes is determined by GAAP or the regulator.

The period in which an expense is recognized for income tax purposes may, therefore, differ from the period in which it is recognized for financial reporting and regulatory purposes. When this happens, the income tax effects of an expense and the expense itself are not recognized in the same period.

To "tax-effect" an expense means to recognize the income tax effects of the expense in the period 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.

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[26] This is the effective date for Newfoundland Power of the Accrual Method of accounting for OPEBs for financial reporting purposes pursuant to section 3461 of the CICA Handbook.

[27] The treatment for regulatory purposes will effectively result in an identical treatment for financial reporting purposes.

3.2 Current and Future Income Tax

Current income tax expense (recovery)[28] is the amount of income tax actually paid (recovered) in the current period, i.e., "cash taxes".

Future income tax expense is the reduction in cash taxes in the current period that is attributable to expenses that will be recognized in future periods for financial reporting and regulatory purposes.

Future income tax recovery is the reduction in cash taxes that is expected to occur in future periods that is attributable to expenses recognized in the current period for financial reporting and regulatory purposes.

When an entity's accounting policy for financial reporting and regulatory purposes is to recognize only current income taxes, it is said to follow the "Flow-through Method".

When an entity's accounting policy for financial reporting and regulatory purposes is to recognize both current and future tax, it is said to use the "Asset and Liability Method". In order to tax-effect OPEBs expense and pension expense an entity would follow the Asset and Liability Method with respect to that expense.

Newfoundland Power's income tax accounting policy for financial reporting and regulatory purposes is a hybrid of these two methods. The Company recognizes future income tax liabilities in connection with temporary timing differences between depreciation expense and capital cost allowance. It also tax-effects its regulatory reserves, such as the weather normalization reserve. Otherwise, it follows the Flow-through Method.

3.3 Regulatory Standards

Tax-effecting employee future benefits partially mitigates the impacts of adopting the Accrual Method of accounting for OPEBs.

The excess of OPEBs expense determined using the Accrual Method over that determined using the Cash Method is not deductible in determining current income tax expense for the period. Rather, this additional amount of OPEBs expense becomes tax deductible in future years when the insurance premiums and retiring allowances that it represents are actually paid.

Similarly, the reduction in income tax expense associated with pension expense is not matched with pension expense. Rather, it is matched to pension funding. This is because under the Flow-Through Method, only current income taxes, driven by pension funding rather than pension expense, are recognized.

By tax-effecting employee future benefits, these future income tax impacts are recognized in the same period as the employee future benefit expense. This is consistent with the principle of intergenerational equity. To do otherwise would result in one generation of customers bearing the cost and another generation receiving the tax benefits.

[28] An income tax recovery is effectively a reduction in income tax expense.

Tax-effecting employee future benefits expense is accomplished by recognizing a net future income tax recovery and a net future income tax asset in an amount equal to the net reduction in cash taxes that is expected to occur in future periods when the expense effectively becomes tax deductible. This serves to offset the additional OPEBs expense recognized under the Accrual Method of accounting, thereby reducing revenue requirement.

The immediate result of tax-effecting is a reduction in the impact on customers of a switch from the Cash Method to the Accrual Method of accounting for OPEBs. The long-term impact is to smooth fluctuations in net OPEBs expense and the resultant revenue requirement.

3.4 Financial Reporting and Regulatory Practice

The Company surveyed 22 taxable Canadian utilities regarding their income tax accounting policy for financial reporting and regulatory purposes.[29]

The survey results are summarized in Table 6.

Table 6
Survey Results
Income Tax Accounting Policy
Financial Reporting and Regulatory Purposes

	Number of Utilities
Flow-Through Method	10
Asset and Liability Method	5 [30]
Other	7 [31]
Total	**22**

Table 6 shows that although the most common income tax accounting policy is the Flow-through Method, a variety of practices do exist.

29 Excludes Hydro as it is not subject to income tax.

30 The regulator of one of these utilities has determined that although the utility effectively uses the Asset and Liability Method to account for its payments-in-lieu of income tax for financial reporting and regulatory purposes, the legislation governing the utility effectively requires that it uses the Flow-through Method. In its 2006 decision with respect to the utility's most recent GRA, the regulator effectively permitted the utility to continue to set rates using the Asset and Liability Method. The regulator also ordered the utility to "formulate a strategy" to address the matter.

31 These utilities use a hybrid income tax accounting methodology. Altalink L.P., Atco Electric Ltd. and Yukon Electric use the Asset and Liability Method to calculate federal tax and the Flow-Through Method to calculate provincial tax. Atco Gas and Pipelines Ltd., FortisBC, Pacific Northern Gas Ltd. and Union Gas Limited account for specific items using the Asset and Liability Method and use the Flow-Through Method for remaining items.

3.5 Impact of Tax-Effecting on Revenue Requirement

Table 7 sets out, on a forecast basis for 2008, the impacts that tax-effecting OPEBs and pension would have on Newfoundland Power's future income tax recoveries, future income tax asset and rate base.

Table 7
Tax-Effecting Employee Future Benefits
2008 Forecast Future Income Tax and Rate Base Impacts
(millions)

	OPEBs	Pension	Total
Future Income Tax Asset, Beginning of the Year	$ -	$ -	$ -
Future Income Tax Recovery[32]	2.0	(0.5)	1.5
Future Income Tax Asset, End of the Year[33]	$ 2.0	$ (0.5)	$ 1.5
Increase in Rate Base (Average Future Income Tax Asset)[34]	$ 1.0	$ (0.3)	$ 0.7

The future income tax recovery shown in Table 7 decreases revenue requirement. The increase in rate base shown in Table 6 increases revenue requirement. The net impact is a reduction in revenue requirement.

32 Represents the reduction in income tax expense that would be shown on Newfoundland Power's statement of income.
33 Represents the future income tax asset that would be shown on Newfoundland Power's balance sheet.
34 (Future Income Tax Asset, Beginning of the Year plus Future Income Tax Asset, End of the Year) divided by 2. Newfoundland Power's future income tax liabilities are subtracted from its existing rate base. Conversely, future income tax assets would be added to rate base. Both of these treatments are consistent with the determination of rate base under the ARBM.

Table 8 shows the 2008 forecast impact on revenue requirement.

Table 8
Tax-Effecting Employee Future Benefits
2008 Forecast Impact on Revenue Requirement
($millions)

	OPEBs	Pension	Total
Income Tax Recovery			
Future Income Tax Recovery	(2.0)	0.5	(1.5)
Tax Effects	(1.1)	0.3	(0.8)
Change in Revenue Requirement	(3.1)	0.8	(2.3)
Return on Rate Base			
Rate Base Effects	0.1	-	0.1
Tax Effects	-	-	-
Change in Revenue Requirement	0.1	-	0.1
Change in Revenue Requirement	(3.0)	0.8	(2.2)

Table 8 shows, on a forecast basis, that tax-effecting OPEBs and pension expense would reduce the impact on customers of the proposed adoption of the Accrual Method of accounting for OPEBs.

4.0 CONCLUSION

The impacts, on a forecast basis for 2008, of Newfoundland Power's proposals on revenue requirement are shown in Table 9.

Table 9
Forecast Impacts of Proposals
2008 Test Year Revenue Requirement
($millions)

OPEBs Accrual Method[35]		9.4
Tax-Effecting		
OPEBs	(3.0)	
Pensions	0.8	
		(2.2)
Increase in Revenue Requirement		7.2

[35] Net OPEBs costs including income tax effects and excluding the Transitional Obligation.

Table 9 shows that Newfoundland Power's proposals would serve to increase 2008 test year revenue requirement by approximately $7.2 million.

The adoption of the Accrual Method of accounting for OPEBs expense will bring Newfoundland Power's OPEBs accounting policy into the mainstream of Canadian regulated utility practice commencing in 2008. It will also align the accounting for OPEBs with that of the Company's defined benefit pension plans and with the practice followed by Hydro. The Accrual Method is consistent with GAAP, the cost of service standard and the principle of intergenerational equity.

Addressing the disposition of the Transitional Obligation of $34.1 million at the Company's next general rate proceeding reduces the impact on customer rates that would otherwise be associated with the adoption of the Accrual Method.

Tax-effecting OPEBs expense and pension expense is consistent with the principles of intergenerational equity and rate stability. As well, tax-effecting OPEBs expense reduces the impact on customers of the proposed adoption of the Accrual Method of accounting for OPEBs costs.

The Surveyed Utilities

Utility	Regulatory Jurisdiction
Altalink	Alberta
Atco Electric	Alberta
Atco Gas	Alberta
B.C. Hydro	British Columbia
Enbridge Gas	Ontario
Enersource Hydro	Ontario
FortisAlberta	Alberta
FortisBC	British Columbia
FortisOntario	Ontario
Gaz Metro	Quebec
Hydro One	Ontario
Hydro Ottawa	Ontario
Hydro Quebec	Quebec
Manitoba Hydro	Manitoba
Maritime Electric	Prince Edward Island
New Brunswick Power	New Brunswick
Newfoundland & Labrador Hydro	Newfoundland
Northwest Territories Power Corp.	Northwest Territories
Nova Scotia Power	Nova Scotia
Ontario Power Generation	Ontario
Pacific Northern Gas	British Columbia
Saskatchewan Power	Saskatchewan
Terasen	British Columbia
Toronto Hydro	Ontario
Union Gas	Ontario
Yukon Electrical Company	Yukon
Total Utilities 26	**Total Regulatory Jurisdictions 12**

Actuarial Valuation of OPEBs
at December 31, 2006

17 January 2007

Newfoundland Power Inc.

Report on Non-Pension Post Retirement Benefit Expense for the Fiscal Year Ending December 31, 2006 Under CICA Section 3461

MERCER
Human Resource Consulting

Contents

Report Highlights

This report has been prepared by Mercer Human Resource Consulting at the request of Newfoundland Power Inc. This report provides non-pension post retirement expense reporting for financial statements and interested parties pursuant to Section 3461 of the Canadian Institute of Chartered Accountants Handbook ("CICA 3461"), relating to the Non-Pension Post Retirement Benefit Plan.

The Non-Pension Post Retirement Benefit Plan is a defined benefit plan funded on a cash basis by contributions from Newfoundland Power Inc.

Fiscal Year Ending December 31, 2006

The net period benefit cost calculated in accordance with CICA 3461 for the fiscal year ending December 31, 2006, is a charge of $7,643,000.

The employer-paid benefit payments during the fiscal year ending December 31, 2006 were $2,837,000 which includes an adjustment to recognize early retirement allowances that were paid in 2005 but were not reflected in the 2005 expense.

The accrued benefit liability as of December 31, 2006 is $27,782,000.

Principal Expense Information

A summary of principal expense information, as required for disclosure purposes pursuant to CICA 3461, from the current fiscal year follows.

Components of Net Periodic Benefit Cost[1]	**Fiscal Year Ending December 31, 2006**	**Fiscal Year Ending December 31, 2005**
Current service cost	$1,350,000	$1,066,000
Interest cost	3,518,000	3,347,000
Actual return on plan assets	0	0
Actuarial loss (gain)	1,376,000	7,928,000
Costs arising in the period	**$6,244,000**	**$12,341,000**
Differences between costs arising in the period and costs recognized in the period in respect of:		
▪ Return on plan assets	0	0
▪ Actuarial loss (gain)	(29,000)	(6,972,000)
▪ Transitional obligation (asset)	1,428,000	1,428,000
Net periodic benefit cost recognized	**$7,643,000**	**$6,797,000**

[1] CICA 3461 requires an analysis of the components of net periodic benefit cost showing separately amounts arising from events in the period, the difference between actual return on plan assets and the expected return on plan assets, other adjustments for deferrals and amortizations of amounts previously deferred, and the change in the valuation allowance if applicable. The actual derivation of the net period benefit cost is set out in the Supplemental Information – Development of Costs section of this report.

Principal Expense Information *(continued)*

Weighted-Average Assumptions for Expense	Fiscal Year Ending December 31, 2006	Fiscal Year Ending December 31, 2005
Discount rate	5.25%	6.00%
Expected long-term rate of return on plan assets	N/A	N/A
Rate of compensation increase	4.00%	4.00%
Initial prescription drug trend rate	7.50%	8.00%
Ultimate prescription drug trend rate	4.50%	4.50%
Year ultimate rate reached	2012	2012
Initial semi-private hospital and other medical cost trend rate	4.50%	4.50%
Ultimate semi-private hospital and other medical cost trend rate	4.50%	4.50%
Year ultimate rate reached	N/A	N/A
Initial weighted average health care trend rate	6.87%	7.26%
Ultimate weighted average health care trend rate	4.50%	4.50%
Year ultimate rate reached	2012	2012

Weighted-Average Assumptions for Disclosure	Fiscal Year Ending December 31, 2006	Fiscal Year Ending December 31, 2005
Discount rate	5.25%	5.25%
Expected long-term rate of return on plan assets	N/A	N/A
Rate of compensation increase	4.00%	4.00%
Initial prescription drug trend rate	7.00%	7.50%
Ultimate prescription drug trend rate	4.50%	4.50%
Year ultimate rate reached	2012	2012
Initial semi-private hospital and other medical cost trend rate	4.50%	4.50%
Ultimate semi-private hospital and other medical cost trend rate	4.50%	4.50%
Year ultimate rate reached	N/A	N/A
Initial weighted average health care trend rate	6.46%	6.87%
Ultimate weighted average health care trend rate	4.50%	4.50%
Year ultimate rate reached	2012	2012

Principal Expense Information *(continued)*

Change in Accrued Benefit Obligation	Fiscal Year Ending December 31, 2006	Fiscal Year Ending December 31, 2005
Accrued benefit obligation at end of prior year	**$66,397,000**	**$55,373,000**
Current service cost	1,350,000	1,066,000
Interest cost	3,518,000	3,347,000
Employees' contributions	0	0
Estimated benefits paid	(2,837,000)	(1,317,000)
Actuarial loss (gain)	1,376,000	7,928,000
Accrued benefit obligation at end of year	**$69,804,000**	**$66,397,000**

Change in Plan Assets	Fiscal Year Ending December 31, 2006	Fiscal Year Ending December 31, 2005
Fair value of plan assets at end of prior year	**$0**	**$0**
Estimated employer contributions	2,837,000	1,317,000
Employees' contributions	0	0
Estimated benefits paid	(2,837,000)	(1,317,000)
Fair value of plan assets at end of year	**$0**	**$0**

Reconciliation of Funded Status to Accrued Benefit Asset (Liability)	Fiscal Year Ending December 31, 2006	Fiscal Year Ending December 31, 2005
Surplus (Deficit) at end of year	**$69,804,000**	**$66,397,000**
Employer contributions during period from measurement date to fiscal year end	0	0
Unamortized transitional obligation (asset)	15,141,000	16,569,000
Unamortized past service costs	0	0
Unamortized net actuarial loss (gain)	26,881,000	26,852,000
Accrued benefit asset (liability)	**($27,782,000)**	**($22,976,000)**

Certification

We have prepared an actuarial valuation of Newfoundland Power Inc.'s benefit obligations for accounting purposes as at January 1, 2005 and extrapolated those results to December 31, 2005. In accordance with our mandate, the purpose of this valuation and extrapolation is to account for the costs of the plan for the fiscal year beginning January 1, 2006 and ending December 31, 2006 in accordance with Section 3461 of the Canadian Institute of Chartered Accountants Handbook ("CICA 3461").

In addition, we have extrapolated the results of the valuation of Newfoundland Power Inc's benefit obligations for accounting purposes as at January 1, 2005 to December 31, 2006. In accordance with our mandate, the purpose of this valuation and extrapolation is to enable the Company to satisfy the disclosure requirements under CICA 3461.

Plan Provisions

The results of the valuations set forth in this report reflect the provisions of the plan as of the date of the valuations as reported to us by Management.

A summary of the plan provisions and the plan amendments are provided in Section 4 of this report.

Data

The valuation is based on membership data as at January 1, 2005 provided by Newfoundland Power Inc. The membership data is summarized in Section 2 of this report.

Subsequent Events

After checking with representatives of Newfoundland Power Inc., to our knowledge there have been no events subsequent to January 1, 2005 the valuation date which, in our opinion, would have a material impact on the results of the valuations and extrapolations.

Methods and Assumptions

The actuarial valuation methods, and Management accounting policies and assumptions in the valuations and determination of net periodic benefit cost are summarized in Section 3 of this report.

Emerging experience, differing from the assumptions, will result in gains or losses that will be revealed in future valuations and will affect future net periodic benefit cost.

Actuarial computations under CICA 3461 are for purposes of fulfilling employer accounting requirements. Determination for purposes other than meeting employer financial accounting requirements may be significantly different from the results reported herein. Accordingly, additional determinations are needed for other purposes such as adequacy of funding for the ongoing plan or purchase price calculations or plan design costings.

Statement of Opinion

The methods used in the valuations of benefit obligations and determination of plan costs were selected by Management in accordance with the requirements of Section 3461 of the CICA Handbook.

The preparers of the financial statements have selected the assumptions used in the valuations of the plan obligations and determination of plan costs. They are Management's best-estimate assumptions, selected for accounting purposes, in accordance with CICA 3461. These assumptions are in accordance with accepted actuarial practice.

In our opinion,

- The data on which the valuations are based are sufficient and reliable for the purposes of the valuations, and
- The calculations have been made in accordance with the requirements of Section 3461 of the CICA Handbook

This report has been prepared and my opinion given, in accordance with accepted actuarial practice.

Respectfully submitted,

Kerry Worgan
Fellow of ~~Society~~ of Actuaries
Fellow of Canadian Institute of Actuaries

January 17, 2007
Date

Supplemental Information

The remainder of the report includes information supporting the results presented in the previous sections.

1. **Development of Costs** shows the financial position of the plan and the calculation of the various components of plan costs.

2. **Membership Data** presents and describes the membership data used in the valuations and the validation checks made on the data.

3. **Valuation Methods and Assumptions** describes the methods and assumptions used to value the plan as well as accounting policies used to calculate the net periodic benefit cost.

4. **Summary of Plan Provisions** provides a summary of the benefits, which have been valued for this report.

5. **Employer Certification**

1. Development of Costs

A. Financial Position of the Plan

		January 1, 2006	January 1, 2005
1.	Accrued benefit obligation		
	a. Retirees and survivors	($36,789,000)	($31,880,000)
	b. Active fully eligible members	(4,231,000)	(3,516,000)
	c. Active not fully eligible members	(25,377,000)	(19,977,000)
	d. Total (a. + b. + c.)	**($66,397,000)**	**($55,373,000)**
2.	Fair value of plan assets	0	0
3.	**Surplus (Deficit) (1(d) + 2.)**	**($66,397,000)**	**($55,373,000)**
4.	Employer contributions after measurement date	0	0
5.	Unamortized transitional obligation (asset)	16,569,000	17,997,000
6.	Unamortized past service costs	0	0
7.	Unamortized net actuarial loss (gain)	26,852,000	19,881,000
8.	**Accrued benefit asset (liability) (3.+4.+5.+6.+7.)**	**($22,976,000)**	**($17,495,000)**

1. Development of Costs *(continued)*

B. Net Periodic Benefit Cost

		Fiscal Year Ending December 31, 2006	Fiscal Year Ending December 31, 2005
1.	Current service cost	$1,350,000	$1,066,000
2.	Interest cost	3,518,000	3,347,000
3.	Expected return on plan assets	0	0
4.	Amortizations		
	a. Transitional obligation (asset)	1,428,000	1,428,000
	b. Past service costs	0	0
	c. Net actuarial loss (gain)	1,347,000	956,000
5.	**Net periodic benefit cost**	**$7,643,000**	**$6,797,000**

Components of these calculations are developed on the following pages.

1. Development of Costs *(continued)*

C. Interest Cost

		Fiscal Year Ending December 31, 2006	Fiscal Year Ending December 31, 2005
1.	Accrued benefit obligation	$66,397,000	$55,373,000
2.	a. Current Service Cost	1,350,000	1,066,000
	b. Weighted for timing	1,350,000	1,066,000
3.	a. Plan amendment	0	0
	b. Weighted for timing	0	0
4.	a. Expected distributions	(1,461,000)	(1,317,000)
	b. Weighted for timing	(731,000)	(659,000)
5.	Average accrued benefit obligation (1. + 2(b) + 3(b) – 4(b))	$67,016,000	$55,780,000
6.	Discount rate	5.25%	6.00%
7.	**Interest cost (5. x 6.)**	**$3,518,000**	**$3,347,000**

1. Development of Costs *(continued)*

D. Amortization Amounts

	January 1, 2006	January 1, 2005
1. Transitional Obligation (Asset)		
a.) Unamortized transitional obligation (asset) as of beginning of year	$16,569,000	$17,997,000
b.) Years Remaining	11.6	12.6
c.) Amortization amount	**$1,428,000**	**$1,428,000**
2. Past Service Costs		
a.) Unamortized past service costs as of beginning of year	$0	$0
b.) Years Remaining	n/a	n/a
c.) Amortization amount	**$0**	**$0**
3. Unamortized (gain)/loss subject to amortization as of beginning of year		
a.) Unamortized net actuarial loss (gain) [from A.7]	$26,852,000	$20,479,000
b.) Accrued benefit obligation [from A.1(d)]	66,397,000	$55,373,000
c.) 10% of accrued benefit obligation b.	6,640,000	$5,537,000
d.) Unamortized net actuarial loss (gain) subject to amortization [excess of a. over c., if any]	20,212,000	$14,340,000
e.) Expected average remaining service	15	15
f.) Amortization amount (d. ÷ e.)	**$1,347,000**	**$956,000**

1. Development of Costs *(continued)*

E. Sensitivity to Change in Health Care Cost Trend Rates

	Medical	Accrued Benefit Obligation as of December 31, 2006	Service Cost for 2006	Interest Cost for 2006	Aggregate of Service Cost and Interest Cost for 2006
1.	Valuation trend	$69,802,000	$1,350,000	$3,518,000	$4,868,000
2.	Valuation trend + 1%	82,098,000	1,678,000	4,132,000	5,810,000
3.	**Difference (2. – 1.)**	**$12,296,000**	**$328,000**	**$614,000**	**$942,000**
4.	Valuation trend – 1%	60,250,000	1,114,000	3,042,000	4,156,000
5.	**Difference (4. – 1.)**	**($9,552,000)**	**($236,000)**	**($476,000)**	**($712,000)**

1. Development of Costs *(continued)*

F. Analysis of Other Liability Loss (Gain)

Gains and Losses Due to:		Due to Remeasurement as of December 31, 2006
1.	Actual 2006 benefit payments differing from expected	$1,376,000
2.	**Total**	**$1,376,000**

2. Membership Data

The actuarial valuation is based on membership data as at January 1, 2005, provided by Newfoundland Power Inc.

We have applied tests for internal consistency, as well as for consistency with the data used for the previous valuation. These tests were applied to membership reconciliation, basic information (date of birth, date of hire, date of membership, gender, etc.), earnings, and service. The results of these tests were satisfactory. Our testing did not include verifying the data to member source records.

Plan membership data are summarized below. For comparison, we have also summarized corresponding data from the previous valuation.

A. Membership Data

Active Employees	January 1, 2005	June 1, 1999
Executive		
Number	5	6
Average earnings	$207,200	$175,167
Average years of service	10.6 years	13.0 years
Average age	43.5	46.2
Management		
Number	236	311
Average earnings	$66,820	$53,564
Average years of service	19.8 years	17.5 years
Average age	44.9	42.3
Union		
Number	336	440
Average earnings	$48,539	
Average years of service	19.4 years	17,9 years
Average age	45.9	43.9
Total		
Number	577	757
Average earnings	$57,391	$46,439
Average years of service	19.5 years	17.7 years
Average age	45.5	43.3

2. Membership Data (continued)

A. Membership Data

	January 1, 2005	June 1, 1999
Retirees		
Number	540	427
Average age	64.9	64.6
Spouses		
Number	464	375
Average age	61.6	61.4
Widows		
Number	113	94
Average age	73.3	72.3

2. Membership Data *(continued)*

The membership movement for all categories of membership since the previous actuarial valuation is as follows:

B. Reconciliation of Membership

	Executive	Management	Union	Retirees and Surviving Spouses	Total
Total at June 1, 1999	**6**	**311**	**440**	**521**	**1278**
Adjustments	3	6	(9)		0
New entrants	1	23	37	171	232
Terminations	(4)	(43)	(23)		(70)
Deaths				(82)	(82)
Retirements	(1)	(61)	(109)		(171)
Surviving spouses				43	43
Total at January 1, 2005	**5**	**236**	**336**	**653**	**1230**

2. Membership Data *(continued)*

The distribution of the active members by age and completed years of service as at January 1, 2005 is summarized as follows:

Distribution of Active Members

By Age Group and Completed Years of Service as at Jan 1, 2005

	Years of Completed Service							
Age	**0-4**	**5-9**	**10-14**	**15-19**	**20-24**	**25-29**	**30+**	**Total**
Under 20								0
20 - 24	4							4
25 - 29	7	1						8
30 - 34	15	10	2					27
35 - 39	22	22	11	26	2			83
40 - 44	7	11	7	54	22	2		103
45 - 49	4	7	9	21	35	64	25	165
50 - 54	3	2	3	19	9	55	57	148
55 - 59	1	1	1	4	3	7	17	34
60 - 64		2		1		1	1	5
65+								0
Total	**63**	**56**	**33**	**125**	**71**	**129**	**100**	**577**

2. Membership Data *(continued)*

The distribution of the retirees and surviving spouses by age as at January 1, 2005 is summarized as follows:

Distribution of Retirees and Surviving Spouses By Age Group as at Jan 1, 2005

Age	Retirees	Spouses	Widows	Total
35 - 39		1		1
40 - 44		1		1
45 - 49		23	2	25
50 - 54	51	78	5	134
55 - 59	128	111	4	243
60 - 64	103	99	5	207
65 - 69	106	74	22	202
70 - 74	69	39	20	128
75 - 79	42	21	25	88
80 - 84	23	11	13	47
85 - 89	14	3	10	27
90 - 94	3	3	6	12
95 - 99				
100+	1		1	2
Total	**540**	**464**	**113**	**1,117**

3. Valuation Methods and Assumptions

A. Cost Method

Accrued benefit obligations shown in this report are computed using the Projected Benefit Method Pro Rated on Service, as defined in CICA 3461. The objective under this method is to expense each member's benefits under the plan taking into consideration projections of benefit costs to and during retirement. Under the Projected Benefit Method Pro Rated on Services, an equal portion of the total estimated future benefit is attributed to each year of service.

For retirees, spouses and surviving spouses, the accrued benefit obligation (ABO) is the present value of all future projected benefits as at the beginning of the fiscal year.

For each active member, a "full eligibility" date is determined as the first date the member has or will have met the age and service requirements to qualify for all benefits after retirement.

Full eligibility is the earlier of age 55 with 2 years of service or age plus service of 85 points

For active members who have reached "full eligibility", the ABO is the present value of all future projected benefits as at the beginning of the fiscal year. For these members, the service cost is zero.

For active members who have not yet reached "full eligibility", the ABO is the present value of all future projected benefits as at the beginning of the fiscal year, multiplied by the ratio of service at the valuation date to projected service at "full eligibility". For these members, the current service cost is the present value of benefits deemed to accrue in the fiscal year, and is determined as the present value of all future projected benefits divided by the projected service at "full eligibility".

The accrued benefit obligation is the actuarial present value of the accrued benefit for valuation purposes at the beginning of the fiscal year and the current service cost is the actuarial present value of the benefit deemed to accrue in the fiscal year.

The plan's **current service cost** is the sum of the individual current service costs, and the plan's **accrued benefit obligation** is the sum of the individual accrued benefit obligations for all members under the plan.

3. Valuation Methods and Assumptions *(continued)*

B. Funding Policy

The non-pension post retirement benefits are funded on a pay-as-you-go basis. The company funds on a cash basis as benefits are paid. No assets have been segregated and restricted to provide the non-pension post retirement benefits.

3. Valuation Methods and Assumptions *(continued)*

C. Accounting Policies

Management applied the Recommendations of Section 3461 of the CICA Handbook prospectively and elected to amortize the transitional (asset)/obligation on a linear basis from January 1, 2005 over the average remaining service period of active members expected to receive benefits under the plan 15.0 years.

Obligations are attributed to the period beginning on the member's date of hire and ending on the date of reaching first full eligibility for benefits.

3. Valuation Methods and Assumptions *(continued)*

D. Summary of Assumptions

The following assumptions were used in valuing the benefit obligations under the plan.

Measurement date	January 1	
Discount rate	▪ 5.25% per annum for the December 31, 2005 funded status and Fiscal 2006 net periodic benefit cost determination ▪ 5.25% per annum for the December 31, 2006 funded status and Fiscal 2007 net periodic benefit cost determination	
Salary increases	4.00% per annum	
Health care cost trend rates	Semi-private Hospital	4.50% per annum
	Prescription drugs	8.00% per annum in 2005 grading down to 4.50% per annum in and after 2012
	Other medical	4.50% per annum
	Vision care	0.00% per annum
	Health premium	4.50% per annum
Life Premium Increases	None	
Mortality	Static 1994 Group Annuity Table Rates at sample ages are shown below (per 1000 members):	

Age	Male	Female
20	0.51	0.28
30	0.80	0.35
40	1.07	0.71
50	2.58	1.43
60	7.98	4.44
70	23.73	13.73
80	62.03	39.40
90	152.93	116.27

Withdrawal

50% of Ontario Light to Age 39

Rates at sample ages are shown below:

Age	Male	Female
20	9.0%	9.0%
25	5.0%	5.0%
30	2.8%	2.8%
35	1.6%	1.6%
39+	0.0%	0.0%

No withdrawal assumed after attainment of eligibility for retirement.

3. Valuation Methods and Assumptions *(continued)*

D. Summary of Assumptions *(continued)*

Retirement Age	One year after the later of the date of attainment of age 60 and completion of age plus service of 95 points, but not later than age 65.			
Marital status	For active members, 80% are assumed to be married at retirement with males assumed to be 3 years older than their female spouses.			
2005 per covered member claim costs (at age 65) with administration and taxes			Pre 65	Post 65
	Semi-private hospital		$22.93	$17.47
	Prescription drugs		$1,081.08	$1,055.96
	Vision care		$56.78	$30.58
	Other medical		$267.54	$56.78
	Total		$1,429.33	$1,160.80
Employee Cost Sharing of Premium	Under 65 – 50%			
	Over 65 – 0%			
2005 Employee Annual Premium			Single	Family
	Health		$654.72	$2,261.52
	Group life (per $1,000)		$2.52	N/A
	Dependent life (per $1,000)		$15.96	N/A
Increases in utilization by age	**Attained Age**	**Semi-Private Hospital**	**Prescription Drug**	**Other Medical**
	55 – 59	6.1%	4.3%	6.2%
	60 – 67	8.0%	3.5%	9.2%
	68 – 76	7.8%	1.9%	8.7%
	77 – 86	4.5%	0%	7.6%
	Over 87	3.0%	0%	5.0%
Administrative expenses as a percentage of paid claims	Medical	5.00%		
	Life insurance	5.00%		
Taxes	4.00% of claims and administrative expenses for all medical and life benefits.			
Participation	100% of members are assumed to participate in the retiree health plan.			

3. Valuation Methods and Assumptions *(continued)*

E. Claims Cost Development

The per covered member claim costs used in the January 1, 2005 valuation and extrapolated for purposes of determining the liabilities as at December 31, 2006 were based on the actual retiree and dependent claims information for the 3 year period, January 1, 2002 to December 31, 2004, increased with assumed inflation to 2005. This claims experience was collected and analysed separately for Hospital, Prescription Drug, Vision Care, and Other Medical benefits.

A description of the process used to set the "2005 Per Covered Person Claim Costs (at age 65) with Administration and Taxes" shown in Section 3 D) is as follows:

- For each calendar year of claims, a cost per covered member was developed by dividing the total annual claims by the total number of eligible retirees, and dependents covered during the year.
- This cost per person has been adjusted to the cost per covered member at age 65 based on the actual individual ages of the covered members using the "Increases in Utilization by Age" assumptions shown in Section 3 D).
- These costs have been increased to include the cost of insurance company administrative expenses and provincial taxes charged on the claims.
- The costs are then trended forward from the claims experience year to the midpoint of the valuation year of July 1, 2005.
- As indicated, this analysis was performed for each calendar year 2002, 2003 and 2004. The assumed cost per covered member for the January 1, 2005 valuation was based on a weighted average of the costs for the three years, as follows:

Percentage Contribution to Valuation Assumed 2005 Claim Cost	
2002 claims experience	33.3%
2003 claims experience	33.3%
2004 claims experience	33.3%
Total	**100.0%**

3. Valuation Methods and Assumptions *(continued)*

E. Claims Cost Development (continued)

Pre 65 Retirees	2004 Total	2003 Total	2002 Total
Actual Newfoundland Power - Pre 65 retirees' paid claims (before administration costs and taxes)			
Hospital	$9,030	$4,185	$4,730
Other	$76,709	$63,765	$59,075
Drug	$328,430	$353,306	$336,662
Vision	$22,390	$22,206	$29,524
Total	**$436,559**	**$443,462**	**$429,991**
Number of Newfoundland Power - retirees and spouses			
▪ Eligible for medical benefits	445	474	508
Per covered member costs			
Hospital	$20.29	$8.83	$9.31
Other	172.38	134.53	116.29
Drug	738.04	745.37	662.72
Vision	50.31	46.85	58.12
Total	**$981.03**	**$935.57**	**$846.44**
Trend to July 01, 2004			
Hospital	1.00	1.045	1.092
Other	1.00	1.045	1.092
Drug	1.00	1.045	1.092
Vision	1.00	1.000	1.000
2004 per covered member costs			
Hospital	$20.29	$9.23	$10.17
Other	172.38	140.58	126.99
Drug	738.04	778.91	723.71
Vision	50.31	46.85	58.12
Total	**$981.03**	**$975.57**	**$918.98**
Weighting	**33.3%**	**33.3%**	**33.3%**
Trend to July 01, 2005			
Hospital	1.045		
Other	1.045		
Drug	1.045		
Vision	1.000		
2005 per covered member costs			
Hospital	$13.82		
Other	153.25		
Drug	780.50		
Vision	51.76		
Total	**$999.33**		

3. Valuation Methods and Assumptions *(continued)*

E. Claims Cost Development (continued)

Adjustment factors to convert 2005 per covered member costs into age 65 per covered member costs		
Hospital	1.5191	
Other	1.5987	
Drug	1.2684	
Vision	1.0046	
Drug offset assumption at age 65	**0%**	
Per covered member age 65 claims costs		
Hospital	$21.00	
Other	245.00	
Drug - incorporating 0% drug offset	990.00	
Vision	52.00	
Total	**$1,308.00**	
Administration costs and taxes		
▪ Administration costs for medical	5.00%	of claims
▪ Premium and sales taxes	4.00%	of claims
Total administration costs and taxes	**9.20%**	**of claims**
Per covered member age 65 claims costs with administration costs and taxes		
Hospital	$22.93	
Other	267.54	
Drug - incorporating 0% drug offset	1,081.08	
Vision	56.78	
Total	**$1,428.34**	

3. Valuation Methods and Assumptions *(continued)*

E. Claims Cost Development (continued)

Post 65 Retirees	2004 Total	2003 Total	2002 Total
Actual Newfoundland Power - Post 65 retirees' paid claims (before administration costs and taxes)			
Hospital	$9,750	$19,451	$8,440
Other	$60,856	$50,366	$36,177
Drug	$562,739	$486,686	$439,303
Vision	$14,220	$12,243	$14,981
Total	**$647,565**	**$568,746**	**$498,901**
Number of Newfoundland Power - retirees, spouses and surviving spouses			
▪ Eligible for medical benefits	540	486	443
Per covered member costs			
Hospital	$18.06	$40.02	$19.05
Other	112.70	103.63	81.66
Drug	1,042.11	1,001.41	991.65
Vision	26.33	25.19	33.82
Total	**$1,199.19**	**$1,170.26**	**$1,126.19**
Trend to July 01, 2004			
Hospital	1.00	1.045	1.092
Other	1.00	1.045	1.092
Drug	1.00	1.045	1.092
Vision	1.00	1.000	1.000
2004 per covered member costs			
Hospital	$18.06	$41.82	$20.81
Other	112.70	108.30	89.18
Drug	1,042.11	1,046.48	1,082.91
Vision	26.33	25.19	33.82
Total	**$1,199.19**	**$1,221.79**	**$1,226.71**
Weighting	**33.3%**	**33.3%**	**33.3%**
Trend to July 01, 2005			
Hospital	1.045		
Other	1.045		
Drug	1.045		
Vision	1.000		
2005 per covered member costs			
Hospital	$28.11		
Other	108.04		
Drug	1,104.74		
Vision	28.45		
Total	**$1,269.33**		

3. Valuation Methods and Assumptions *(continued)*

E. Claims Cost Development (continued)

Adjustment factors to convert 2005 per covered member costs into age 65 per covered member costs		
Hospital	0.5693	
Other	0.4813	
Drug	0.8753	
Vision	0.9843	
Drug offset assumption at age 65	**0%**	
Per covered member age 65 claims costs		
Hospital	$16.00	
Other	52.00	
Drug - incorporating 0% drug offset	967.00	
Vision	28.00	
Total	**$1,063.00**	
Administration costs and taxes		
• Administration costs for medical	5.00%	of claims
• Premium and sales taxes	4.00%	of claims
Total administration costs and taxes	**9.20%**	**of claims**
Per covered member age 65 claims costs with administration costs and taxes		
Hospital	$17.47	
Other	56.78	
Drug - incorporating 0% drug offset	1,055.96	
Vision	30.58	
Total	**$1,160.80**	

4. Summary of Plan Provisions

Life Insurance

Executives	4 times salary, maximum of $2,000,000, reduction to 25% at age 65, with $10,000 maximum.
Management & Union	3 times salary, maximum of $750,000, reduction to 25% at age 65, with $10,000 maximum.
Basic AD&D	Matches life benefit, terminates at age 65.
Dependent Life	$10,000/spouse and $5,000/dependent child.

Medical Benefits

Medical benefits are subject to an overall plan maximum of $5,000 per year after age 65.

	Retiree < Age 65	**Retiree Age 65 and >**
Available Coverage	Single or family	Single or family
Hospital	Semi-private	Semi-private
	100%	80%
	Unlimited days	Unlimited days
	No deductible	No deductible
Drugs	Prescription drugs (generic basis)	Prescription drugs (generic basis)
	80%	80%
	No per prescription deductible	No per prescription deductible
	No dispensing fee cap	No dispensing fee cap
	Managed Care Formulary	Managed Care Formulary
	Coverage for life	Coverage for life
Vision	100%	100%
	$150/24 months	$150/36 months
Major Medical	100% supplies and appliances	80% supplies and appliances
Hearing Aids	$600/ear/3 years	$600/ear/3 years
Private Duty Nursing	100%	80%
	$10,000/year	$5,000/illness
Paramedical	100%	80%
	$250 max per benefit, except physiotherapy $500/year	$250 max per benefit, except physiotherapy $500/year
Out-of-Canada	100%	100%
	Limited to overall plan maximum	Limited to overall plan maximum

4. Summary of Plan Provisions *(continued)*

Retirement Allowance

Upon retirement, employees with 10 or more years of service receive an allowance of:

- (2 x Basic Weekly Pay) x number of years employed; plus

Provincial Programs

The government of Newfoundland covers all residents aged 65 or older who receive the Guaranteed Income Supplement under the Senior Citizen's Drug subsidy plan. We have assumed that all retirees and future retirees of Newfoundland will be ineligible for the GIS supplement and hence no retiree will be covered by the provincial program.

5. Employer Certification

With respect to the Report on Non-Pension Post Retirement Benefit Expense for the Fiscal Year Ending December 31, 2006 Under CICA Section 3461 of the Newfoundland Power Inc.'s non-pension post retirement benefit plan, I hereby certify that, to the best of my knowledge and belief:

- The membership data supplied to the actuary provides a complete and accurate description of all persons who are entitled to benefits under the terms of the plans for service up to the date of the valuation
- A copy of the plan documents and of all amendments made up to January 1, 2005 were supplied to the actuary;
- All substantive commitments (as defined under CICA 3461) have been communicated to the actuary;
- Accounting policies as adopted by the Company are those described in this report;
- The actuarial methods, amortization method and amortization periods to be used for the purposes of the valuation are those described in this report;
- The Management's best-estimate assumptions for purposes of the valuations of the plan and the extrapolation of the financial position of the plan as of the fiscal year end December 31, 2006 are those described in this report; and
- All events subsequent to the valuation that may have an impact on the results of the valuation or a future valuation have been communicated to the actuary.

May 3, 2007
Date

Jocelyn Perry
Signed

Jocelyn Perry
Name

VP Finance, CFO
Title

Weather Normalization Reserve Balance Review

May 2007

NEWFOUNDLAND POWER
A FORTIS COMPANY

Table of Contents

1.0 BACKGROUND

1.1 General

The Weather Normalization Reserve acts to stabilize electricity rates to customers by removing the volatility in the Company's sales and power supply cost related to weather and hydrology.

The Company's Weather Normalization Reserve (the "Reserve") consists of two components:

1. the Hydro Production Equalization Reserve (the "Hydro Component") which normalizes Newfoundland Power's annual supply costs for variations in the Company's hydroelectric production due to abnormal precipitation levels;[1] and,
2. the Degree Day Normalization Reserve (the "Degree Day Component") which normalizes the Company's revenue and energy supply costs for the effects of abnormal weather conditions.[2]

A detailed explanation of the Reserve components is provided in Appendix A.

In theory, balances in each component are expected to average to zero over time. Consequently, there is no automatic adjustment mechanism to deal with reserve balances. However, recent experience has demonstrated that balances can become large due to either (i) extended trends in abnormal weather or precipitation levels, or (ii) changes in the rates that convert the kWh adjustments to dollar values.

In Order No. P.U. 19 (2003) (the "2003 GRO"), the Board accepted the Company's proposal to recover $5.6 million of the $9.4 million balance in the Hydro Component, as at December 31st 2001, through customer rates over a 5 year period. The $5.6 million reflected an amount that was not expected to reverse due to changes over time in the wholesale purchased power rate and the income tax rate.

1.2 Regulatory Compliance

In the 2003 GRO, the Board directed the Company to review the balance in the Hydro Component and to apply to the Board for an order as to the disposition of outstanding balances, positive or negative, as part of its next general rate application.

Reserve balances are filed with the Board for approval on an annual basis. In its consideration of Newfoundland Power's application for approval of the 2005 year-end balance in the Reserve, the Board inquired whether the Company intended to take any steps to address the increasing balance in the Degree Day Component. The Company informed the Board that it would review the matter and make such proposals as may appear necessary as part of its next general rate application. This report provides the results of the review.

1 The Hydro Production Equalization reserve was approved Order No. P.U. 32 (1968).
2 The Degree Day Normalization Reserve was approved in Order No. P.U. 1 (1974).

2.0 RESERVE BALANCE

A comparison of the year-end negative balances in the Reserve in 2001 and 2006 is set out in Table 1.[3]

Table 1
Weather Normalization Reserve
Year-end Balances
($millions)

	2001	**2006**
Hydro Component	9.4	5.0
Degree Day Component	0.5	6.8
Total	**9.9**	**11.8**

From an overall perspective, the balance in the Reserve to be recovered from customers has continued to increase. However, the proportion of the balance contributed by each component has changed materially. The following sections provide a review of the balances for each component of the Reserve.

3.0 HYDRO COMPONENT

The Hydro Component effectively smoothes the effects of abnormal stream-flows on energy supply costs. The balance in the Hydro Component represents the cumulative change in energy supply costs resulting from stream-flows differing from normal, stated on an after-tax basis. On a conceptual basis, a balance owing from customers indicates that stream-flows have been below normal on a cumulative basis, requiring additional purchases from Newfoundland and Labrador Hydro ("Hydro").

In theory, the balance should tend to zero over time. However, changes to the wholesale rate and the income tax rate have altered the relationship between the stream-flow variances and the value of the reserve transfers.

The balance in the Hydro Component declined from $9.4 million at year-end 2001 to $5.0 million at year-end 2006. This reduction primarily reflects the annual credit of $1.12 million per year for four years ($4.5 million in total) related to the 5-year recovery approved in the 2003 GRO. An additional $1.12 million will be credited to the Hydro component in 2007, further reducing the balance.

Assuming normal stream-flows this year, the projected 2007 year-end balance in the Hydro Component will be approximately $3.9 million to be recovered from customers.

[3] Negative balances represent amounts to be recovered from customers.

3.1 Variance in Stream-flows

In 2000, the Company revised its normal production to reflect the recommendations of the Acres Water Management Study (the "Water Management Study"). Newfoundland Power's estimate of normal production for its hydroelectric generating facilities is adjusted annually, as necessary, to reflect physical plant changes and scheduled plant availability.

In 2000, the Company also implemented the practice of adjusting normal production on an annual basis and reviewing the normal every 5 years. These changes should allow the transfers to and from the Hydro Component to more closely track the effects of stream flows over time. Over the long term, this should help ensure the balance in the Hydro Component tends to zero.

In 2005, the Company requested that Acres update the Water Management Study to incorporate new data available from the preceding 5-year period.[4] The Water Management Study update is the basis for the normal values used in computing transfers to the Hydro Component since January 1, 2006.

Since 2001 the cumulative balance in the Hydro Component has not been materially affected by variances in stream-flows. Actual stream-flows for the 5-year period from 2002 to 2006 inclusive averaged 421.7 GWh. Compared to an average normal of 423.2 GWh for the same period, this is a difference of only 0.4 percent. The combined effect of the stream-flow variances, mill rate changes and tax rate variations was to increase the Hydro Component balance by approximately $0.1 million.[5]

3.2 Change in Rates

Effective January 1, 2007, the wholesale rate used in calculating the Hydro Component transfers increased to 88.05 mills (8.805¢ per kWh). The increase in the mill rate will increase the magnitude of the transfers to the Hydro Component which, in turn, will increase the potential for larger positive and negative balances.

3.3 Hydro Component Summary

The Hydro Component balance has reduced from $9.4 million to a projected $3.9 million at year-end 2007 due to the recovery in rates of the $5.6 million non-reversing balance. The projected 2007 year-end balance in the Hydro Component of $3.9 million reflects lower than normal stream-flows on a cumulative basis.[6] This amount is expected to diminish over time if

4 The Water Management Study update was filed with the Board in January 2006.

5 The average mill rate and the average tax rate in place used in calculating transfers to the reserve over 2002 to 2006 were 47.635 mills and 36.2%, respectively. Average mill rate based on: 45.31 for Jan. 1, 2002 to Aug. 31, 2002; 47.89 for Sept. 1, 2002 to Jun. 30, 2004; 52.34 for July 1, 2004 to Dec. 31, 2004; and a 2nd block energy rate of 47.00 mills for the period Jan. 1, 2005 to Dec. 31, 2006.

6 The $3.9 million projected balance is based on the 2006 year-end balance of $5.0 million less the $1.1 million 2007 amortization.

normal stream-flow variations continue. Based on the current mill rate, the $3.9 million reflects approximately 68 GWh or 16 percent of annual inflows.[7]

No action is required with respect to the existing balance in the Hydro Component. The Company will continue to monitor the balance.

4.0 DEGREE DAY COMPONENT

The Degree Day Component effectively smoothes the effects of abnormal weather (i.e., temperature and wind speed) on revenue from rates and energy supply costs. Conceptually, the balance in the Degree Day Component represents the cumulative change in contribution from sales resulting from abnormal weather (i.e., variances from normal temperature and normal wind speed), stated on an after-tax basis.[8] The current negative balance indicates that weather has been warmer than normal on a cumulative basis.

4.1 Variance in Weather

The balance in the Degree Day Component has increased from $0.5 million at year-end 2001 to $6.8 million at year-end 2006. The Company has reviewed the methodology used to compute the adjustments, and has concluded that the normalization method continues to provide a reasonable estimate of the impact of abnormal weather on energy usage. The increase in the Degree Day Component balance is directly related to warmer than normal weather conditions experienced in the Company's service area over the past 5 years.

An analysis of actual and normal heating degree days[9] and average wind speed over the Company's service area for the 2002 to 2006 period shows that on average both heating degree days and wind speed have been lower than normal.[10]

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[7] The $3.9 million represents $6 million in purchased power expense which is equivalent to 68 GWh at 8.805¢ per kWh.

[8] Contribution equals revenue from additional kWh sales minus the cost of purchasing additional kWh sales.

[9] The number of degree days in a day is set to equal 18° C. minus the mean temperature. At temperatures below 18° C., heating load is assumed to be required. The normal degree days are based on a rolling 30 year average and are updated annually.

[10] From 2002 to 2006, actual heating degree days were on average 5.4 percent warmer than normal in St. John's, 6.2 percent warmer than normal in Gander, 5.4 percent warmer than normal in Corner Brook and 4.9 percent warmer than normal in Stephenville. During the same period, average wind speed was lower than normal by 8.6 percent in St. John's, 5.4 percent in both Gander and Corner Brook and by 5.5 percent in Stephenville.

Table 3 provides actual annual electricity usage and normal annual electricity usage of Domestic customers that heat with electricity for the period 2002 to 2006.[11]

Table 3
Domestic All-Electric Average Use

Year	Actual	Normal	Change
2002	19,897	20,081	(0.9%)
2003	19,588	20,110	(2.6%)
2004	19,157	20,057	(4.5%)
2005	18,729	19,690	(4.9%)
2006	17,713	19,204	(7.8%)
Average	**19,017**	**19,828**	**(4.1%)**

The average use in each of the years that were warmer than normal, especially the 3 years from 2004, 2005 and 2006, was materially lower than normal. This reduction in average use demonstrates the effects weather has on Domestic customers' heating requirements.

4.2 Change in Rates

The relationship of abnormal weather to contribution transfers to/from the Degree Day Component was reversed upon implementation of the flow-through of the January 1, 2007 Hydro rate change. This has implications for the recovery of the balance in the Degree Day Component.

Transfers to and from the Degree Day Component are based on the difference between the marginal revenue and marginal purchased power cost ("Contribution Transfer Rate").
The Contribution Transfer Rate has historically been positive because marginal revenues from customers have exceeded the marginal cost of purchases.

Under Hydro's wholesale rate that became effective January 1, 2007, Newfoundland Power's energy supply costs related to changes in energy sales are actually higher than associated retail rate revenue. Under the new pricing relationship, the Contribution Transfer Rate to the reserve is now negative. This change in the energy pricing relationship has created recovery implications for the balance in the Degree Day Component.

[11] This data is based on information from the Company's Customer Service System.

4.2.1 Wholesale Rate

The wholesale rate is comprised of a demand charge and a two block energy charge. The energy charges are as follows:

1st Block**:** First 250,000,000 kWh per month.............................3.246¢/kWh
2nd Block: All usage over 250,000,000 kWh ....8.805¢/kWh

The 2nd block wholesale rate increased from 4.7¢ per kWh in 2006 to 8.805¢ per kWh as a result of the test year fuel price increasing from approximately $29 per barrel to approximately $55 per barrel.

Newfoundland Power's purchases from Hydro exceed 250,000,000 kWh during all months of the year. Therefore, the energy charge of 8.805¢ per kWh is the marginal cost of purchases for all months of the year. The marginal cost of purchases cost is further increased by 5.7 percent to reflect the cost of energy losses; this produces a 9.3¢ per kWh marginal cost to supply energy sales.

4.2.2 Retail Rates

Revised retail rates were implemented January 1st 2007 to recover the increased cost of energy supply from Hydro.[12] The increase in base rates (i.e., before RSA and MTA adjustments)[13] was approximately 1.3¢ per kWh.[14] The increase in base rates was materially lower than the 4.1¢ per kWh increase in the 2nd block of the wholesale rate.[15] This is because the increased cost related to fuel is applied to all kWh in retail rates but only applies to usage in excess of 250,000,000 kWh per month in the wholesale rate.

The effect of the January 1st rate changes is that revenue from changes in energy sales related to weather is now lower than the cost of supplying the change in energy sales related to weather.[16]

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12 The 2007 wholesale rate from Hydro reflected an approximate 24% increase primarily as a result of the increased test year cost of fuel. However, customer rates were not materially impacted by higher fuel costs as the higher fuel costs were already reflected in the RSA factor in customer rates.

13 Base rates are used to determine the transfers to and from the Reserve because it is the base rate revenue and base rate purchased power expense that impact earnings from sales.

14 Hydro's 2007 test year forecast includes 2.54 million barrels of No. 6 fuel. The price increase of $26 per barrel applied to 2.54 million barrels increased fuel costs by approximately $66 million. The 1.3¢ per kWh increase in base rate energy charges is calculated by dividing the $66 million increased fuel costs by Newfoundland Power's 2007 forecast sales of approximately 5,052.3 GWh.

15 4.1¢ equals 8.805¢ minus 4.70¢.

16 For all classes except Rate 2.1

The effect of this change is demonstrated in Table 4 which provides a comparison of the Contribution Transfer Rates for 2006 and 2007.[17]

Table 4
Comparison of Average Contribution Transfer Rates
(¢ per kWh)

	2006 Transfer Rate	**2007 Transfer Rate**
kWh Sales[18]	6.545	7.702
kWh Purchases[19]	4.968	9.307
Net Contribution	**1.577**	**(1.605)**

Under the 2007 wholesale and retail rates, the overall Contribution Transfer Rate to the Degree Day Component has effectively reversed.

Now, if weather is colder than normal, the reduction in contribution related to the abnormal weather is recovered or debited to the Degree Day Component. Conversely, if weather is warmer than normal, the increased contribution related to the abnormal weather is credited to the Degree Day Component.

The current negative balance has accumulated as a result of the weather being warmer than normal. With the reversal in the contribution transfer rate for 2007, the $6.8 million balance in the Degree Day Component will only decline if weather remains warmer than normal for an extended period. The balance will increase in years when the weather is colder than normal.

4.3 Degree Day Component Summary

The increased negative balance in the Degree Day Component is directly related to warmer than normal weather conditions experienced in the Company's service area over the past 5 years. However, due to recent changes in wholesale and retail rates that have implications for the operation of the Degree Day Component, the current negative balance is not expected to reverse unless weather continues to be warmer than normal over an extended period.

Due to the expectation that over the long term the warmer than normal periods will be offset by colder than normal periods, the Reserve has no established recovery mechanism. However, if colder than normal weather offsets the warmer than normal weather experienced over the past 5 years, the balance in the Degree-Day Component will continue to increase. As a result, there is uncertainty as to whether the current $6.8 million negative balance in the Degree Day

[17] The overall sales rate is lower than the Domestic rate as the General Service 2.2, 2.3, and 2.4 end block rates are approximately 3¢ per kWh lower than the Domestic rate.
[18] Computed based on the average of 2006 kWh weather adjustments applied to 2006 and 2007 base rates.
[19] kWh purchases cost equal 2nd block purchased power energy rate increased by 5.7 percent for losses.

Component will average to zero over time.[20] From a conceptual perspective, the $6.8 million balance in the Degree Day component can be considered non-reversing.

5.0 CUSTOMER RATES

Customer rates currently reflect a $1.12 million annual amortization of the balance in the Hydro Component. This amortization concludes at the end of 2007. On a go forward basis, the balance in the Hydro Component should be monitored to determine if further action on balance disposition is warranted.

Recovering the current balance of approximately $6.8 million in the Degree Day Component through rates over a 5-year period would require an annual amortization of $1.36 million through rates.[21] The associated revenue requirement, after accounting for income taxes, is approximately $2.1 million. This is approximately $0.4 million greater than the $1.7 million currently included in customer rates (slightly less than 0.1 percent of revenue from rates).

6.0 CONCLUSION

No action is required with respect to the existing balance in the Hydro Component. The Company will continue to monitor the balance in the Hydro Component.

From a conceptual perspective, the $6.8 million balance in the Degree Day Component can be considered non-reversing. Replacing the current amortization of the balance in the Hydro Component that concludes in 2007 with a 5-year amortization of the balance in the Degree Day Component will permit the recovery of the balance in the Degree Day Component and result in a minimal change in customer rates (an increase of slightly less than 0.1 percent).

[20] The $6.8 million represents power supply costs not yet recovered from customers as at December 31, 2006.
[21] The 5-year amortization approach was considered reasonable from an intergenerational equity perspective and was approved by the Board at the 2003 GRA for the Hydro Component

Weather Normalization Method

1.0 BACKGROUND

Newfoundland Power's Weather Normalization Reserve consists of the following two components:

i) the Hydro Production Equalization Reserve (the "Hydro Component") which normalizes Newfoundland Power's annual supply costs for variations in the Company's hydroelectric production due to abnormal precipitation levels;[1] and,

ii) the Degree Day Normalization Reserve (the "Degree Day Component") which normalizes the Company's revenue and energy supply costs for the effects of abnormal weather conditions.[2]

The purpose of the Weather Normalization Reserve is to stabilize rates for customers. Newfoundland Power's annual revenue and purchased power expense on its financial statements are reflective of normal weather and normal stream-flows to its hydro plants.

The calculations supporting transfers to, or from, the Weather Normalization Reserve are reviewed annually by the Board. The Board has issued orders approving the balance in the reserve for each year from 1974 to present.

A summary of the mechanics to determine the monthly adjustment for each reserve component follows:

1.1 Mechanics of the Hydro Component

The Hydro Component enables Newfoundland Power to normalize its energy supply costs for annual variations in normal stream-flows to its hydro plants. If cumulative stream-flows are below normal for the year, the Reserve is debited in an amount equal to the cost of increased purchases from Hydro. Conversely, if cumulative stream-flows are above normal for the year, the Reserve is credited with an amount equal to the savings from reduced purchases from Hydro.

[1] The Hydro Production Equalization reserve was approved in Order No. P.U. 32 (1968).
[2] The Degree Day Normalization Reserve was approved in Order No. P.U. 1 (1974).

The calculation for the 2005 year-end adjustment to the Hydro Component is provided below:

Calculation of 2005 Hydro Component Transfer

Average Natural Flow (GWh)		426.1
Less: Actual Natural Flow (GWh)		449.1
Equals: Gross Variation (GWh)		(23.0)
Times the End block Purchased Power Rate (in mills)	x 47.00	
Equals: Variation in Purchased Power Expense		$1,079,000
Less: Income Tax @ 35%		$ 377,650
Net Transfer (To) From Reserve		($ 701,350)

Because stream-flows were 23.0 GWh above normal in 2005, Newfoundland Power purchased 23.0 GWh less from Hydro. To offset the resulting impact on earnings, the after-tax effect of the reduced purchased power expense was credited to the Hydro Component.

1.2 Mechanics of Degree Day Component

The Degree Day Component enables Newfoundland Power to normalize its sales and purchases for annual variations in weather, specifically temperature and wind.

Econometric modelling is used to determine the change in customers' usage resulting from a unit variation in normal monthly weather.[3] The factors derived for each rate class are referred to as normalization coefficients.

The equations below provide a summary of the calculations used in determining the monthly adjustments for each rate class:

Monthly Sales Adjustment (MWh) equals (Normal Weather minus Actual Weather) times Sales Normalization Coefficient

Monthly Purchases Adjustment (MWh) equals (Normal Weather minus Actual Weather) times Purchases Normalization Coefficient

The derived monthly kWh adjustments are used to determine weather normalized sales and purchases.

Weather Normalized Sales equals Actual Sales plus Monthly Sales Adjustment

Weather Normalized Purchases equals Actual Purchases plus Monthly Purchases Adjustment

[3] The Company uses a degree-day variable to measure temperature and average daily wind speed to measure wind speed.

The monthly kWh adjustments are also used to determine the transfers to the Degree Day Component.

Monthly Revenue Adjustment equals Monthly Sales Adjustment (MWh) times Marginal Revenue

Monthly Purchased Power Cost Adjustment equals Monthly Purchases Adjustment (MWh) times Marginal Purchased Power Cost

Net Contribution Adjustment equals Monthly Revenue Adjustment minus Monthly Purchased Power Cost Adjustment

Degree Day Component Transfer equals Net Contribution Adjustment times (1 minus Income Tax Rate)

The Board approved an updated Degree Day Normalization methodology in 1995. The coefficients used in calculating adjustments are adjusted annually and provided to the Board in January of each year.

An Analysis of Current Supply Cost Dynamics

May 2007

Table of Contents

1.0 GENERAL

The principal driver of electricity price increases over the past 5 years for Newfoundland Power's customers has been the price of No. 6 fuel burned by Newfoundland and Labrador Hydro ("Hydro") at the Holyrood Thermal Generating Station ("Holyrood"). Currently, Hydro's 2007 fuel forecast for Holyrood determines the marginal energy price in the wholesale rate design under which Newfoundland Power purchases its electricity supply from Hydro.[1]

Approximately 69 percent[2] of Newfoundland Power's retail rate revenue is associated with the recovery of the cost of electricity supply from Hydro. The remaining 31 percent is associated with the recovery of the costs related to Newfoundland Power's ownership and operation of its portion of the Island interconnected grid.

The direct consequences of the increased price of Holyrood fuel recognized in 2007 wholesale rates is that (i) the marginal cost of Newfoundland Power's electricity supply has increased dramatically but is reflective of Hydro's forecast 2007 marginal production costs, and (ii) the difference between the marginal cost of Newfoundland Power's electricity supply and average cost of power supply has increased dramatically.[3]

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1 The cost to Newfoundland Power of a change in wholesale energy purchases (marginal energy supply costs) is determined by the 2nd block energy price of the wholesale rate. The 2nd block price is set at the test year production cost at Holyrood.

2 Based upon forecast results for 2007.

3 The marginal cost reflected in rates is the marginal cost as forecast in the test year. The extent to which actual marginal costs vary from test year is not reflected in the rate design. The impact of this variance on Hydro's revenue is dealt with through Hydro's Rate Stabilization Plan and flowed through to Newfoundland Power's customers without impacting the price signal to Newfoundland Power.

The implication of current supply cost dynamics is that Newfoundland Power's contribution[4] from electricity sales will be eroded as a result of even modest increased customer load requirements. This, in turn, will impair Newfoundland Power's ability to recover its cost of providing service to its customers without seeking rate relief.

2.0 CURRENT MARGINAL SUPPLY COST DYNAMICS

The marginal cost of Newfoundland Power's electricity supply from Hydro ("Marginal Supply Cost") is the total of the marginal energy supply cost and the marginal demand supply cost.

Table 1 shows Newfoundland Power's Marginal Supply Costs from 2004 to 2008F.

Table 1
Marginal Supply Cost[5]
2004 to 2008F
(¢/kWh purchased)

	2004	**2005**	**2006**	**2007**	**2008**
Marginal Energy Supply Cost	4.789	4.700	4.700	8.805	8.805
Marginal Demand Supply Cost[6]	-	1.274	1.545	1.096	1.096
Marginal Supply Cost	4.789	5.974	6.245	9.901	9.901

The increase in the Marginal Supply Cost from 2006 to 2008F shows the effect of the increased cost of Holyrood fuel reflected in Hydro's wholesale rate in 2007. The 2007 Marginal Energy Supply Cost of 8.805¢ per kWh is approximately 87 percent higher than the 2006 Marginal Energy Supply Cost of 4.7¢ per kWh. The 2007 Marginal Supply Cost of approximately 9.9¢

4 Contribution is the net amount of electricity revenue after deducting the cost of electricity supply payable to Hydro. Contribution, in effect, is the net amount of electricity revenue available to Newfoundland Power in any year to cover its cost of service, other than electricity supply costs.

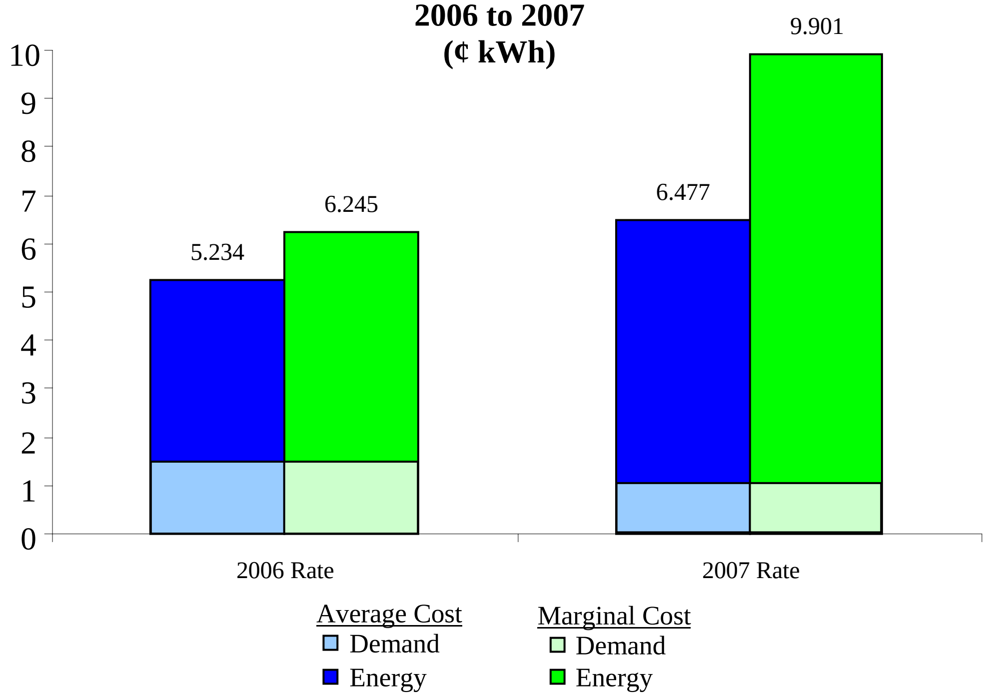
5 Based on January prices.

6 Cost per kW of native peak demand converted to cents/kWh based on a NP's load factor of 50 percent. This assumes the additional kWh was purchased over 12 months with a load profile equivalent to NP overall load curve.

per kWh is approximately 59 percent higher than the 2006 Marginal Supply Cost of approximately 6.2¢ per kWh.

It is the average test year cost of supply that is included in setting retail rates to Newfoundland Power's customers ("Average Supply Cost").[7] Chart 1 shows a comparison on a kWh basis of the Average Supply Cost and the Marginal Supply Cost reflected in Hydro's wholesale rate for 2006 and 2007.

Chart 1
Average and Marginal Supply Costs
2006 to 2007
(¢ kWh)



The Marginal Supply Cost is higher than the Average Supply Cost included in customer rates for both 2006 and 2007. The difference creates a systemic shortfall in supply cost recovery on a

[7] Average Supply Cost equals test year purchased power cost divided by test year purchases.

marginal basis.[8] However, because the difference between Marginal Supply Cost and the Average Supply Cost has more than tripled from 2006 to 2007 (i.e., from 1¢ per kWh to 3.4¢ per kWh), this systemic shortfall is much higher under the current wholesale rate than under the 2006 wholesale rate.

Retail rates were revised on January 1, 2007 to recover the increased 2007 forecast supply costs. Therefore, there is no shortfall associated with the increased purchased power expense in 2007.[9] However, load requirements on the system increase annually, principally as a result of the addition of new customers. This increase in load requirements increases supply costs from Hydro based on the Marginal Supply Cost to provide the additional load.

Forecast Average Supply Cost for 2008 is 6.534¢ per kWh.[10] The difference between the 2008 Average Supply Cost and the 2007 test year Average Supply Cost of 6.477¢ per kWh increases Newfoundland Power's supply costs by approximately $2.9 million.[11] This is reflected in the Company's 2008 proposed revenue requirement as described in this Application.

The implication of current supply cost dynamics is that Newfoundland Power's contribution from electricity sales will be eroded as a result of even modest increased customer load requirements.

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8 The shortfall results from the inverted structure of the energy charge portion of the wholesale rate. Chart 1 shows that there is no material difference between the average demand supply cost included in rates (¢/kWh) and the marginal demand supply cost (¢/kWh) at a 50 percent load factor (the Company's forecast load factor). While variances between actual and forecast demand costs may result in differences between actual demand supply costs and that recovered from rates, demand cost effects are not considered a systemic cost recovery issue.

9 In Order No. P.U. 42 (2006), the Board approved a year end adjustment to the Rate Stabilization Account to true up any mismatch in 2007 between the increased purchased power expense and increased revenue related to the Hydro rate change.

10 2008 forecast purchased power costs under existing rates divided by forecast purchases.

11 By comparison, Newfoundland Power's proposed 18 basis point range in return on rate base is equivalent to approximately $2.3 million in 2008 electricity supply costs. Further, the $2.9 million due to the systemic shortfall does not include any variance from forecast sales that may actually occur.

Table 2 shows Newfoundland Power's marginal contribution per kWh of sales from 2004 to 2008F.

Table 2
Marginal Contribution[12]
2004 to 2008F
(¢/kWh sold)

	2004	**2005**	**2006**	**2007**	**2008F**
Marginal Revenue[13]	7.9	8.1	8.2	9.3	9.8
Marginal Supply Cost of Sales[14]	5.1	6.3	6.6	10.5	10.5
Marginal Contribution	**2.8**	**1.8**	**1.6**	**(1.2)**	**(0.7)**

A negative unit contribution currently exists and is forecast to continue into 2008. This negative contribution demonstrates a systemic shortfall in marginal supply cost recovery related to increases in customer load. This shortfall impairs Newfoundland Power's ability to recover not only its supply costs from Hydro but also its own costs of providing service.

For years beyond 2008, the supply cost recovery shortfall which currently exists can be expected to continue for so long as the Marginal Supply Cost remains materially higher than the Average Supply Cost included in rates. To permit reasonable recovery of supply costs for periods beyond 2008, this situation can be expected to result in an increased frequency in rate cases for Newfoundland Power.

12 Based on January prices and sales to new customers.

13 This is the marginal revenue from new customers. Marginal revenue expressed in cents/kWh includes increased revenue that will occur from basic customer charges, energy charges and demand charges. The marginal revenue also assumes the usage patterns of new customers are the same as those of existing customers. The revenue excludes RSA and MTA impacts as these are flow-through items that do not affect revenue. 2008 forecast marginal revenue includes the effect of a 5.3 percent increase in customer rates.

14 Includes energy losses. Due to energy losses within the distribution system, in order to sell 1 kWh of energy to customers, Newfoundland Power must purchase approximately 1.057 kWh of energy from Hydro.

3.0 ADDRESSING SUPPLY COST DYNAMICS

A number of practical considerations must be taken into account in considering the appropriate regulatory response to the current supply cost dynamics.

One consideration is that existing regulatory mechanisms provide that (i) Hydro, which incurs the cost of fuel at Holyrood, has a reasonable opportunity to recover prudently incurred fuel costs, and (ii) Newfoundland Power's customers, whose load requirements largely require Holyrood fuel to be consumed, ultimately pay their appropriate share of Hydro's prudently incurred fuel costs.[15]

Another consideration is the practical limitations of retail rate design. While Newfoundland Power's retail rate designs do include marginal cost elements, there are limitations in the ability of retail rates to fully reflect marginal production costs.[16]

In addition, the principal cause of load growth is new customer connections and there are obvious limitations in charging new customers materially different rates than existing customers.[17]

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15 Hydro's Rate Stabilization Plan provides for transfers of substantially all variances from test year in the total cost of fuel burned at Holyrood. A portion of these transfers are passed on to Newfoundland Power's customers through the Company's RSA mechanism. The remaining portion is passed on to Hydro's Industrial Customers. A portion of Holyrood fuel cost variances related to Hydro's rural customers and variances in Holyrood's efficiency are absorbed by Hydro.

16 If retail prices were modified to fully recover the Marginal Supply Cost, Newfoundland Power's revenues would materially exceed the Company's revenue requirement. Newfoundland Power, therefore, cannot price all sales at the Marginal Supply Cost. Similar limitations have been recognized in the pricing of Hydro's sales to Newfoundland Power. To allow Hydro's test year revenues to match test year revenue requirement, and to provide a marginal cost based pricing signal, it was necessary to design an inverted rate structure with a lower priced 1st block and a higher priced 2nd block.

17 In order to obtain revenue from new customers that fully recover the marginal cost of supplying them, the rates charged to new customers would have to be set at marginal costs. These rates would be higher than the rates charged to existing customers. This would require pricing new customers contrary to Section 73 of the *Public Utilities Act*.

A third consideration is regulatory efficiency. An available option to address current supply cost dynamics is for Newfoundland Power to file annual rate cases. However, considerations of regulatory efficiency may not support such a proposition where Newfoundland Power's other costs are reasonably stable on a year-to-year basis.

Newfoundland Power Inc.
Customer, Energy and Demand Forecast
2007 - 2008

May 2007

Table of Contents

1.0 INTRODUCTION

The Customer, Energy and Demand forecast, which is prepared annually, forms the foundation of Newfoundland Power's planning process. The forecast is a key input in developing estimates of capital expenditures required to ensure the electrical system can meet the increasing demands associated with both customer and energy sales growth. The forecast also directly impacts the forecast of both revenue from electrical sales and the Company's single largest expenditure, purchased power. These items are key components of the Company's financial planning process.

2.0 FORECAST METHODOLOGY

Newfoundland Power provides electrical service to three distinct categories of customers: domestic; general service; and, street and area lighting. In 2006, domestic accounted for 60 percent of total energy sales while general service and street and area lighting represent 39 percent and 1 percent, respectively.

The domestic category, Rate # 1.1, primarily refers to residential dwellings such as single detached homes, single attached homes, apartments and mobile homes. The category also includes non-residential services such as cottages, personal use garages and other meter services that qualify for the domestic rate category. Residential customers use electricity primarily for space and water heating, and the operation of miscellaneous appliances and lighting. In this category a customer/average use methodology is employed where customer growth is primarily based on the housing starts while average use is forecast using an end-use/econometric model that includes the market share for electric space heating, personal disposable income and the marginal price of electricity in the current and previous year.

The general service category primarily refers to commercial, institutional and industrial customers. Unlike the domestic category which represents a homogenous group of customers, the general service category represents a very diverse group whose activities include, trade, finance, real estate, public administration, health, education, commercial services, transportation, manufacturing, mining, fishing, forestry and construction. These customers provide goods and services to the local market as well as for export. In 2006, approximately 85 percent of energy sales in this category were to customers in the service producing sector of the economy while only 15 percent were in the goods producing sector.

From a forecasting perspective the general service category is divided into small general service which includes Rate # 2.1 0 - 10 kW and Rate # 2.2 10 – 100 kW (110 kVA) and large general service which includes Rate # 2.3 110 kVA (100 kW) – 1000 kVA and Rate # 2.4 1000 kVA and Over. In the small general service category a customer/average use methodology is employed where the number of customers is primarily based on the number of domestic customers while average use is forecast using an econometric model that includes the Gross Domestic Product for the service sector per small general service customers and the average price of electricity in the current year.

In the large general service category, given the relatively small number of customers in this group, an informed opinion methodology is employed and energy sales are forecast on an individual customer basis.

Street and area lighting energy sales are directly related to the number of fixtures required to meet the lighting needs of both municipalities and unincorporated communities. At the end of 2006 approximately 55,700 fixtures were installed with high pressure sodium fixtures accounting for 85 percent of these fixtures and mercury vapour accounting for the remainder. Given the nature of this category an end use forecasting methodology is employed. The street and area lighting sales forecast is determined by multiplying the forecast quantity of fixtures by the amount of electricity consumed for each fixture type and wattage.

Total energy sales are calculated by adding domestic, general service, and street and area lighting sales. Company use, system losses and wheeled are then added to total energy sales to obtain total produced, purchased and wheeled. Company use includes all electricity consumed in facilities owned by Newfoundland Power and used in the delivery of service to customers. System losses refer to energy that is lost during the transmission and distribution of energy between the source of supply and delivery to customers. Wheeled information is provided by Newfoundland and Labrador Hydro.

Purchased energy is calculated by subtracting normal hydraulic production from the forecast of total produced and purchased. Each year normal production is adjusted to reflect plant availability and any modifications to plants that may impact production. Purchased power demand is calculated by subtracting the hydraulic generation credit from native peak.

Newfoundland Power's native peak is determined using a load factor based methodology. The load factor used in the calculation is the average of 15 years of normalized annual load factors. Native peak is calculated by applying the average load factor to total produced and purchased power. This peak is adjusted to reflect the impact of load curtailment by Newfoundland Power customers and at company owned facilities.

3.0 KEY FORECAST ASSUMPTIONS

The forecasting process relies on a wide range of information related to the economy, energy prices and other resource based developments within Newfoundland Power's Service territory.

3.1 Economic Outlook

While the Company monitors forecasts from various banks and financial institutions the Conference Board of Canada is the Company's primary provider of economic information. The economic assumptions used in preparing the customer and energy sales forecasts are based on the Conference Board of Canada, *Provincial Outlook 2007, Long-Term Economic Forecast*, dated December 19, 2006. A table summarizing the key economic indicators contained in this forecast
for 2007 and 2008 is shown in Appendix A. A copy of the Conference Board of Canada's long-term economic forecast is enclosed as Attachment A.

Since 1996, the Newfoundland and Labrador economy has been primarily driven by the mining sector. Large resource based projects such as Hibernia, Terra Nova, White Rose and Voisey's Bay have resulted in the mining sector experiencing average annual growth in excess of 20 percent per year during this period. As a result Newfoundland and Labrador has lead the country in economic growth in 5 of the past 10 years. The fishing sector has also contributed with increased landings of both crab and shrimp. These developments have positively impacted other key economic indicators such as personal income, unemployment rates and service sector growth.

As in recent years economic performance will continue to be driven by large resource based projects. In 2006 economic growth was negatively impacted by a two-month strike at Voisey's Bay and lost production due to a six-month shutdown at the Terra Nova offshore oil field. With both projects fully operational, real GDP growth is forecast to jump from 2.9 percent in 2006 to a country leading 5.7 percent in 2007. In 2008, with lower production at the Hibernia offshore oil field, real GDP growth is forecast to drop to 0.2 percent, the lowest in the country. Even with the strong growth in real GDP, the underlying domestic economy remains weak with declining population, weak consumer spending, low employment growth, high unemployment and low growth in real personal disposable income and service sector GDP growth.

Given Newfoundland Power's customer base, energy sales growth is primarily influenced by the domestic economy. More specifically, growth in the service sector, changes in employment levels, personal income, energy prices and population demographics in the Company's service territory are more determinative of sales growth than resource industry production levels.

Economic growth will not be uniform across Newfoundland Power's service territory. In the Northeast Avalon, growth will continue to be strong principally due to activities related to the offshore oil industry. In contrast much of rural Newfoundland and Labrador is expected to continue the trend of economic stagnation.

3.2 Energy Prices Outlook

Changes in energy prices have a direct impact on energy sales growth through the inclusion of price elasticity effects in the various models. Overall, analysis of customer response to changes in the price of electricity is relatively inelastic. That is to say a 1 percent change in the price of electricity will result in a change in energy sales of less than 1 percent. The current model indicated that a 1 percent increase in the price of electricity will result in a 0.25 percent decrease in energy sales. The model also indicates the response will vary depending on the time frame and rate category. In addition, changes in oil prices can impact the market share of electricity in the competitive space heating market.

The energy sales forecast is impacted by changes in the price of electricity during the past two years as well forecast changes in the price of electricity. Electricity prices forecasts are developed based on information available internally and provided by Newfoundland and Labrador Hydro. The annual review of the rate stabilization mechanism resulted in increases in the price of electricity of 5.2 percent on July 1, 2005 and 4.8 percent on July 1, 2006. Electricity prices also increased by approximately 0.1 percent on January 1, 2007 as a result of a combination of higher purchased power cost from Newfoundland and Labrador Hydro and a reduction in Newfoundland Power's rate of return. The forecast assumes no changes in the price of electricity on July 1, 2007 as a result of the rate stabilization mechanism. The forecast includes an electricity rate decrease of 2.1 percent on July 1, 2008. This reduction reflects the net impact of an expected base increase in rates by Newfoundland and Labrador Hydro and a reduction related to the full recovery of the December 2003 outstanding balance in Newfoundland and Labrador Hydro's Rate Stabilization Plan. As proposed in Newfoundland Power's application, a 5.3 percent increase in current customer rates effective January 1, 2008 has been included in the energy sales forecast under proposed rates.

Furnace oil prices are expected to remain at the 2006 level in 2007 and decline slightly in 2008. This projection is consistent with the forecast of No. 6 fuel forecast used in the calculation of the Rate Stabilization Plan adjustments.

3.3 Other Inputs

Information from a number of other sources is used in preparing the forecast. Each year Newfoundland Power surveys approximately 150 customers representing approximately 600 accounts requesting information with respect to future load requirements. This information along with information gathered from Newfoundland Power regional operations, the St. John's Board of Trade, various other trade organizations, and the provincial and federal government is also incorporated into the large general service forecast. In addition, information from Canada Mortgage and Housing with respect to housing starts is combined with information received from the Conference Board of Canada in preparing the domestic customer forecast.

4.0 CUSTOMER AND ENERGY FORECAST

Appendix B shows the customer and energy forecasts for the 2007 - 2008 period under both existing and proposed rates. Under both scenarios the total number of customers is forecast to increase by 1.0 percent in 2007 and 0.9 percent in 2008. Energy sales under existing rates are forecast to increase by 1.2 percent in 2007 and 2.0 percent in 2008. Energy sales under proposed rates are forecast to increase by 1.2 percent in 2007 and 1.3 percent in 2008. Under both forecasts energy sales in 2008 are higher by 0.3 percent due to an additional day of sales resulting from 2008 being a leap year.

Domestic customer growth is largely a result of housing starts. The Conference Board of Canada forecasts housing starts of 1,701 units in 2007 and 1,405 in 2008 while Canada Mortgage and Housing is projecting 2,150 units in 2007 and 2,050 units in 2008. Using an average of these forecasts the number of domestic customers is forecast to grow by 1.0 percent in 2007 and 0.9 percent in 2008.

Domestic electricity consumption is a function of the major end uses in the home, such as space heating, water heating, lighting, and major appliances. In addition, changes in energy prices and income have an impact on electricity consumption. Using proposed rates the average use of energy is forecast to increase slightly in 2007 and by 0.2 percent in 2008.

The combined impact of increased numbers of customers and changes in average use will result in growth in domestic energy sales under proposed rates of 1.1 percent in 2007 and 1.2 percent in 2008.

In the small general service rate classes 2.1 and 2.2, customer and energy sales growth are dependent on growth in the service-producing sector of the GDP and changes in the price of electricity. In the large general service rate classes 2.3 and 2.4, energy sales are also influenced by changes in the service-producing sector of the GDP. However, in the large general service category, energy sales are mainly determined by changes in the load of larger customers in the goods-producing sector. Information obtained from specific customers is incorporated into forecasts for rate classes 2.3 and 2.4.

Overall, the number of General Service customers is forecast to grow by 0.6 percent in 2007 and 0.5 percent in 2008. Under proposed rates the volume of General Service energy sales is forecast to grow by 1.3 percent in 2007 and 1.6 percent in 2008.

In the street and area lighting class the number of customers is forecast to grow on average by 0.5 percent during the 2007 – 2008 period while the volume of energy sales is forecast to grow on average by 0.6 percent. The volume of street and area lighting energy sales continues to be impacted by the conversion of mercury vapour lights to the energy efficient high pressure sodium fixtures.

Produced and purchased is the sum of total energy sales, company use and system losses. The forecast of company use is based on historical energy usage and information gathered from each of Newfoundland Power's operating areas with respect to the operation of these facilities. System losses are based on historical information and are forecast to be approximately 5.4 percent of total produced and purchased.

5.0 PURCHASED ENERGY AND DEMAND FORECAST

Purchased energy is calculated by subtracting Newfoundland Power's normal hydraulic production from produced and purchased. Newfoundland Power's normal hydraulic production is based on the Water Management Study – Hydrology Update prepared by SGE Acres Limited in 2005. This study recommended a normal production of 419.6 GWh. Each year, normal production is adjusted to reflect plant availability and any modifications to plants that may impact production. In 2007 the refurbishment of Rattling Brook Hydro plant will result in lost production of 38.2 GWh. In 2008 the normal hydro production has been increased by 6.2 GWh to reflect increased production resulting from the modifications to the Rattling Brook Hydro plant.

Newfoundland Power's forecast of native peak demand is determined by applying the average weather adjusted load factor to the forecast of produced and purchased energy. The peak demand is then adjusted to reflect the impact of load curtailment by Newfoundland Power customers and company owned facilities. Newfoundland Power's purchased demand is then derived by subtracting the generation credit approved by the Public Utilities Board.

A copy of the Energy Purchased and Demand forecast is contained in Appendix C.

6.0 FORECAST ACCURACY

The energy sales forecasts and actual weather adjusted energy sales for the past 10 years are shown in Appendix D. During this period, differences from forecast have ranged from a high of 2.7 percent to a low of 0.1 percent with differences being 1 percent or less in 7 of the past 10 years. Further, the analysis of differences indicates that 50 percent of the time the actual was higher than forecast and vice versa.

Newfoundland Power Inc.

Key Economic Indicators[1]
2006 - 2008F

(millions of dollars)

Indicator	2005	2006 (Forecast)	Change From 2005	2007 (Forecast)	Change From 2006	2008 (Forecast)	Change From 2007
Gross Domestic Product ($ 1997)							
Goods Producing Industries	5,000	5,076	1.5%	5,672	11.7%	5,567	-1.8%
Service Producing Industries	8,283	8,598	3.8%	8,811	2.5%	8,950	1.6%
Total of All Industries	13,630	14,019	2.9%	14,824	5.7%	14,858	0.2%
Consumer Price Index (1992=100)	126.1	128.9	2.2%	130.9	1.5%	133.3	1.8%
Personal Disposable Income ($ 1992)	8,334	8,501	2.0%	8,571	0.8%	8,708	1.6%
Unemployment Rate (%)	15.2%	15.0%		14.6%		14.0%	
Housing Starts - Units	2,498	2,202	-11.8%	1,701	-22.8%	1,405	-17.4%
Canadian GDP Deflator (1997=100)	119.1	121.2	1.8%	122.8	1.3%	125.1	1.9%
Canada Mortgage and Housing Corporation[2]							
Housing Starts - Units	2,498	2,215	-11.3%	2,150	-2.9%	2,050	-4.7%

[1] Conference Board of Canada, Provincial Outlook 2007, Long-Term Economic Forecast, Dated: December 19, 2006.
[2] Canada Mortgage and Housing Corporation, Housing Market Outlook, Fourth Quarter, 2006.

Newfoundland Power Inc.

Customer & Energy Forecast[1]
2007 - 2008F

		Actual			Existing				Proposed			
		2005	2006	Percentage Change	2007	Percentage Change	2008	Percentage Change	2007	Percentage Change	2008	Percentage Change
Customers												
Domestic	1.1	196,412	198,568	1.1%	200,609	1.0%	202,453	0.9%	200,609	1.0%	202,453	0.9%
General Service												
0-10 kW	2.1	12,046	11,915	-1.1%	11,911	0.0%	11,901	-0.1%	11,911	0.0%	11,901	-0.1%
10-100 kW (110 kVA)	2.2	8,114	8,261	1.8%	8,376	1.4%	8,486	1.3%	8,376	1.4%	8,486	1.3%
110 kVA (100 kW) - 1000 kVA	2.3	1031	1,031	0.0%	1,038	0.7%	1,047	0.9%	1,038	0.7%	1,047	0.9%
1000 kVA and Over	2.4	61	61	0.0%	63	3.3%	63	0.0%	63	3.3%	63	0.0%
Total General Service		21,252	21,268	0.1%	21,388	0.6%	21,497	0.5%	21,388	0.6%	21,497	0.5%
Street and Area Lighting	4.1	9,637	9,664	0.3%	9,718	0.6%	9,764	0.5%	9,718	0.6%	9,764	0.5%
Total Customers		227,301	229,500	1.0%	231,715	1.0%	233,714	0.9%	231,715	1.0%	233,714	0.9%
Energy Sales (GWh)												
Domestic	1.1	2,988.6	2,981.1	-0.3%	3,013.0	1.1%	3,076.5	2.1%	3,013.0	1.1%	3,048.5	1.2%
General Service												
0-10 kW	2.1	96.7	94.0	-2.8%	93.8	-0.2%	95.2	1.5%	93.8	-0.2%	94.6	0.9%
10-100 kW (110 kVA)	2.2	611.4	616.4	0.8%	626.4	1.6%	641.0	2.3%	626.4	1.6%	636.7	1.6%
110 kVA (100 kW) - 1000 kVA	2.3	862.7	854.0	-1.0%	867.8	1.6%	879.7	1.4%	867.8	1.6%	879.7	1.4%
1000 kVA and Over	2.4	411.4	413.7	0.6%	416.7	0.7%	425.0	2.0%	416.7	0.7%	425.0	2.0%
Total General Service		1,982.2	1,978.1	-0.2%	2,004.7	1.3%	2,040.9	1.8%	2,004.7	1.3%	2,036.0	1.6%
Street and Area Lighting	4.1	36.1	35.9	-0.6%	36.3	1.1%	36.3	0.0%	36.3	1.1%	36.3	0.0%
Total Energy Sales		5,006.9	4,995.1	-0.2%	5,054.0	1.2%	5,153.7	2.0%	5,054.0	1.2%	5,120.8	1.3%
Company Use		12.0	11.7	-2.5%	11.4	-2.6%	11.4	0.0%	11.4	-2.6%	11.4	0.0%
Losses		279.9	285.9	2.1%	286.1	0.1%	292.7	2.3%	286.1	0.1%	290.4	1.5%
Produced & Purchased		5,298.8	5,292.7	-0.1%	5,351.5	1.1%	5,457.8	2.0%	5,351.5	1.1%	5,422.6	1.3%
Wheeled		62.1	61.7	-0.6%	68.4	10.9%	69.0	0.9%	68.4	10.9%	69.0	0.9%
Total System Energy		5,360.9	5,354.4	-0.1%	5,419.9	1.2%	5,526.8	2.0%	5,419.9	1.2%	5,491.6	1.3%

Note:
[1] All amounts are reported on an accrued basis.

Newfoundland Power Inc.

Purchased Energy & Demand Forecast
2007 - 2008F

	Produced Purchased & Wheeled	Total Wheeled Energy	Total Curtailed Demand	Total Produced & Purchased (NP Native Peak)			NP Produced		Total Purchased	
	(1)		(2)			(3)	(4)	(5)		
Year	GWH	GWH	MW	GWH	MW	Load Factor	GWH	Credit MW	GWH	MW
Existing										
2007	5,419.9	68.4	10.0	5,351.5	1,211.32	50.02%	381.4	117.93	4,970.1	1,093.39
2008	5,526.8	69.0	10.0	5,457.8	1,232.17	50.02%	425.8	117.93	5,032.0	1,114.24
Proposed										
2007	5,419.9	68.4	10.0	5,351.5	1,211.32	50.02%	381.4	117.93	4,970.1	1,093.39
2008	5,491.6	69.0	10.0	5,422.6	1,224.16	50.02%	425.8	117.93	4,996.8	1,106.23

Notes:

1. Energy for 2008 is based upon a leap year (8,784 hours).
2. Based on historical performance of participants plus curtailment of company owned facilities.
3. Load Factor is based on an average of 15 year historical (normalized) load factors.
4. Average water year for the forecast period is 419.6 GWh adjusted for plant availability and efficiency improvements.
5. Assumes a generation credit of 117.93 MW.

Newfoundland Power Inc.

Comparison of Forecast Energy Sales
To Weather Adjusted Actual Sales[1]

	Forecast Sales[2] (GWh)	Weather Adjusted Actual Sales (GWh)	Difference (GWh)	Difference (%)
1997	4,400.5	4,438.0	37.5	0.9
1998	4,443.7	4,439.6	-4.1	-0.1
1999	4,516.4	4,499.7	-16.7	-0.4
2000	4,558.5	4,554.8	-3.7	-0.1
2001	4,592.3	4,666.7	74.4	1.6
2002	4,652.0	4,764.9	112.9	2.4
2003	4,852.2	4,882.0	29.8	0.6
2004	4,927.0	4,978.6	51.6	1.0
2005	5,010.1	5,004.0	-6.1	-0.1
2006	5,130.6	4,991.2	-139.4	-2.7

Notes:

[1] All amounts are reported on a billed basis.

[2] The forecast sales figures are from the annual forecasts prepared in the previous year and were part of the Capital Budget presentations made to the Board in those years. The 1997, 1999, 2003 and 2004 forecasts were the basis for the revenue requirement determinations presented as part of the Company's rate applications in 1996, 1998 and 2003, respectively.

Conference Board of Canada
Provincial Outlook 2007
Long-Term Economic Forecast
Dated: December 19, 2006

The Conference Board of Canada
Insights You Can Count On

Provincial Outlook 2007

Long-Term Economic Forecast

ECONOMIC PERFORMANCE AND TRENDS

The Conference Board of Canada
Insights You Can Count On

Provincial Outlook Long-Term Economic Forecast 2007
by *The Conference Board of Canada*

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Preface

The *Provincial Outlook Long-Term Economic Forecast 2007* was prepared by Marie-Christine Bernard, Associate Director, under the general direction of Paul Darby, Deputy Chief Economist.

The report examines the long-term economic outlook for the provinces, including gross domestic product (GDP), output by industry and labour market conditions. At the end of the report, there is a forecast for Canadian economic indicators and a comparison of GDP by province and industry.

The Provincial Outlook Long-Term Forecast is updated annually using the Conference Board's large econometric model of the provincial economies.

The publication can be accessed on-line at www.e-library.ca and for clients subscribing to e-Data at www.conferenceboard.ca/edata.htm. For more information, please contact our information specialist at 613-526-3280 or 1-866-711-2262 or e-mail contactcboc@conferenceboard.ca.

Contents

Marie-Christine Bernard

Demographic Changes Take a Toll on Potential Growth

NATIONAL OVERVIEW

A short-lived hiccup in U.S. economic growth in 2007 underlies an excellent forecast for Canada going forward. Elevated commodity prices, a relatively good fiscal stance, low inflation and the lift to purchasing power resulting from a strong currency have benefited many sectors in the economy. Consumer spending and business investment in particular have surged over the past three years, allowing real gross domestic product (GDP) to advance at a healthy clip despite the significant drag caused by a deteriorating trade balance. Total government spending has posted steady and strong gains recently, as federal transfers to the provinces have seen generous increases, helping cover the quickly expanding costs of health care. Better-than-expected government revenues, through tax cuts and transfers, are being passed back to the consumer. Residential investment too has added fuel to the fire, although this boom is expected to come to an end soon as home construction realigns with demographic demand. Over the next five years (2006–10), the Canadian economy is expected to advance by an average growth pace of 3 per cent, slower than the 3.3 per cent growth attained between 1995 and 2005. Demographic factors suggest that economic growth will advance more and more slowly over the long term, averaging 2.6 per cent over 2011 to 2020. The economy is expected to manage growth of 2.1 per cent per year over the last 10 years of the forecast, still not a bad result considering weak population growth and the effects of a much older society.

Although the forecast is promising, we need to be aware of a number of potential snags that could significantly alter the near-term growth path. Of most concern is the question of whether the United States will manage to smoothly navigate the large imbalances that plague its economy. The presence of a hefty federal government deficit is overshadowed by the global imbalance evidenced by a huge current account deficit. Assuming that the U.S. and world economies do steer their way through the troubles ahead, Canada's outlook is positive. The Canadian economy has survived numerous structural adjustments on the domestic and international stage, including fiscal reform, the high-tech wreck, the development of multinational trading blocs, corporate malfeasance and globalization. More recently, Canadian manufacturers have been scrambling to adjust to what amounted to a reduction in sales prices of more than 30 per cent, the result of the rapid acceleration in the value of our currency. While adjustments are not complete, the manufacturing sector has done surprisingly well over the transition, undergoing heavy retooling and layoffs that finally produced excellent growth in labour productivity.

Demographic factors suggest that economic growth will advance more slowly over the long term.

And while there has been poor growth in manufacturing employment recently, Canada has not been lacking in new jobs. This is especially true in Alberta, where high energy prices have led to frenzied investment and construction activity in the oil patch. Elevated commodity prices have resulted in increased economic activity for many resource sectors, while British Columbia is undergoing a construction boom, in part due to preparation for the 2010 Olympics and infrastructure upgrades. The situation has resulted in low unemployment, higher wages and changing migration flows as central and eastern Canadians massively migrate west, especially to Alberta, looking for better job opportunities.

Energy and commodity prices are assumed to have peaked, but they are forecast to remain strong, partly because of the steady growth in demand from China and other developing nations. Elevated oil prices will support ongoing development of Canada's massive oil sands reserves; other resource sectors, with some notable exceptions, will also benefit from the profitable situation brought about by high world prices. Central Canada too will face better prospects as the Canadian dollar stabilizes and eases modestly in the near term. This will provide a break for the manufacturing sector, which must remain lean and innovative to compete in the global environment. More balanced regional performances in 2008 will help lift real GDP growth by 3.3 per cent, while growth will remain strong at about 3 per cent over the remainder of the near term as the economy reaches its full potential.

Beyond 2010 the Canadian economy will experience a deceleration in growth that is expected to continue through the remainder of the forecast horizon. Slower population growth and the effects of an aging population will restrain labour force growth and heavily influence income and spending patterns. With the first members of the large baby-boom cohort reaching sixty, the labour market is on the verge of a massive wave of retirement that will only accelerate over the next 20 years. Even with optimistic immigration assumptions, this will result in a sharp slowing in the labour force that will weaken growth in GDP. However, economic growth can be rescued by heavy investment in machinery and equipment and technology, and by utilizing more highly skilled workers and using more innovative production processes. To some extent, all of these things are already happening and the pace of productivity growth has been improving. Over the long term, strong labour productivity—getting more output per worker—is a key assumption behind our long-term forecast.

The most striking development over the long term will be the aging of the Canadian population. The post-war baby boom came to an end in the mid 1960s, and the fertility rate has been much lower since then. Consequently, the age distribution of the population will change considerably as the baby-boom generation progresses up the population pyramid. This will be particularly noticeable beyond 2010, when the share of the population over 65 climbs steeply. The assumption is made that a strong and growing level of immigration will shore up overall population growth. International immigration is expected to rise from about 213,000 in recent years to an annual average of about 300,000 from 2019 to 2030. Thanks to strong net immigration, Canadian population growth will be sustained over the long term, with growth easing modestly from its current pace of 0.9 per cent to an average just above 0.7 per cent over 2026–30.

Financial markets will come under pressure as baby boomers become low-saving senior citizens.

Higher immigration will not suffice to offset the dominant aging of the baby boom, with the most important implication arising as a growing constraint on labour force growth. The pressure is not immediate, as a strong economic performance in recent years has enticed people to reenter the job market. In particular, relief came as the result of an extraordinary jump in the participation of women in the 55–59 age cohort. This change was brought about by the aging of women who through their working lives have exhibited higher labour force participation than have earlier generations. These developments provide temporary relief to the effects of the aging population on the labour force, but the overall participation rate will start to ease in the next decade as baby boomers begin to leave the labour force. This will lead to a dramatic slowing in overall labour force growth and will result in a shortage of workers, in particular skilled workers, to replace the increasing number of retirees.

Several changes will occur in the marketplace to address the rising pressures. The tightening labour market is assumed to produce high real wage growth, which in turn will lead firms to substitute capital for labour wherever feasible. Therefore, although growth in investment will slow as the technology sector matures, it will still remain robust over the next 25 years, and labour productivity will improve dramatically. Moreover, some workers eligible to retire will remain in the workforce to take advantage of higher real wages. The net result will be an unemployment rate that shrinks steadily, averaging just below 5.4 per cent over the last five years of the forecast, and labour productivity that reaches growth of just shy of 2 per cent annually beyond 2010.

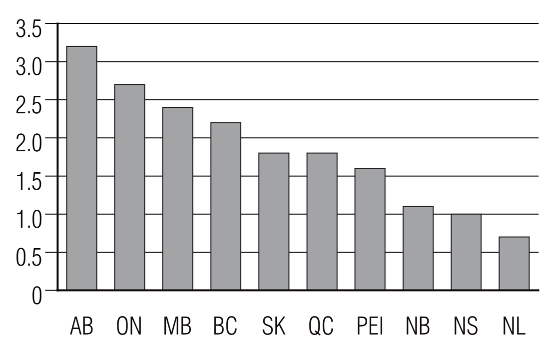
The aging population will bring many more challenges and changes to the long-term outlook. One of the more significant challenges will be the additional burden on the health-care system and thus on public finances. Particular pressure will be added in the latter years of the forecast as costs rise significantly for the 75+ age group. In addition, the changing age structure will shrink the market for single-detached family dwellings through the entire forecast period. Conditions will change somewhat with a recovery in the number of people aged 0–14 beginning around 2012, as the grandchildren of the baby boom arrive in heavy numbers. Provincial governments will once again feel the pressure of a surge in elementary school enrolment in the later years of the long-term forecast.

Other important structural changes over the long term include an ever-shrinking role for producers of raw materials but a real increase in the prices of certain raw materials, including crude oil and forest products, as they become scarce. Financial markets will come under pressure as baby boomers move from the high-saving pre-retirement years to become low-saving senior citizens. Consumption of durable items such as autos and household furnishings will slow, while consumption of services will continue to expand, especially after 2020. For further details on the challenges that the Canadian economy will face over the next 25 years, see the full edition of *Canadian Outlook: Long-Term Forecast, 2007 Edition.*

PROVINCIAL OVERVIEW

Ontario, Alberta, Manitoba and British Columbia will post the strongest economic growth over the long term, while real GDP in the remainder of the country will average just 1.7 per cent, compounded annually, from 2006 to 2030. In the top two spots, Alberta and Ontario are expected to do particularly well. While Ontario is going through a difficult time restructuring its export-oriented manufacturing sector, the long-term potential of the province is bright. Robust international migration will benefit the province, especially the service sector. The Alberta economy is firing on all cylinders, easily surpassing all other provinces, and total GDP growth is expected to hit 7 per cent in 2006. The economic outlook for 2007 remains healthy, with 5 per cent growth anticipated. The energy sector will remain one of the main driving forces in Alberta over the forecast as the province benefits from rising oil prices, several multibillion-dollar investment projects, an immense non-conventional oil supply and better extraction technology. Alberta's oil sands are expected to generate close to $100 billion in investment by 2030. Over the longer term, with a significant number of Canada's aging citizens expected to move to British Columbia and Prince Edward Island, population and service sector output will grow in these provinces. Thanks to oil projects and development at Voisey's Bay, Newfoundland and Labrador will post the strongest real GDP growth in 2007. Nonetheless, continued population decline and the depletion of oil reserves will severely slow growth in the province's overall economy in the last 15 years of the forecast, enough to leave the average growth rate much weaker than in any other province over the entire forecast. At first glance, the wedge of 2.6 percentage points separating the fastest and slowest growing provinces may not seem significant, but it becomes quite large when compounded over more than 25 years.

Chart 1
Long-Term Growth Rankings
(GDP, annual average growth)



Sources: The Conference Board of Canada; Statistics Canada.

The key factors influencing the long-term performance of an economy are population growth, labour force productivity and investment patterns. Population growth will vary considerably from province to province, though all provinces will be dealing with a declining natural rate of increase. Moreover, although significant advances in communication technology have lessened the importance of location for many industries, the movement of population within and between provinces is expected to continue to be from smaller to larger centres, and net international migration will favour the larger provinces. These trends will lead to declining population in three provinces—Newfoundland and Labrador, Nova Scotia, and New Brunswick—over most of the forecast period. The sluggish population prospects will lead to a faster aging of the population in these Atlantic provinces. This profound demographic change will result in fewer people of working age and therefore to weaker economic growth. But even if firmer productivity gains will mitigate the demographic effects on real GDP growth, real economic growth will be roughly two-thirds less over 2011–30 than in this decade in all Atlantic provinces except Prince Edward Island. However, with productivity gains, real GDP per capita will continue to make advances, albeit at a slower pace, over the next 25 years.

An aging population will dampen growth in the labour force considerably in the last decade of the forecast.

Estimates of potential output have been generated for all provinces by taking into account growth in potential employment, the capital stock and total factor productivity. Detailed demographic analysis, an essential determinant of potential output, has been conducted for each province, taking into account the unique population characteristics of each over the long term. One clear result emerges from these estimates of potential output: potential output growth will decelerate in every province over the next 25 years. This general finding is attributable mainly to an aging population, which will dampen growth in the labour force considerably in the last decade of the forecast.

AGRICULTURE

Canada's agriculture industry has been adapting to ongoing structural changes. Lower transportation subsidies have changed the cost structure for grain farmers in the Prairies since the mid 1990s, resulting in greater concentration of ownership, changes to the crop mix and higher value-added products at home. As livestock producers take advantage of economies of scale, production in this industry too has become increasingly concentrated. At the same time, the international agriculture subsidy war is forcing lower subsidy jurisdictions to be more efficient. A gradual global movement away from protectionism in agriculture markets is expected to further enhance Canada's export potential. As a relatively low cost producer, Canada is generally on a sound footing heading into the future.

Agricultural output will be shaped over the long term by developments in global demand and supply. The key factor determining demand will be population growth. The United Nations expects world population to grow from 6.5 billion in 2005 to 8.2 billion by 2030; over that span, Canadian exports are expected to shift to non-traditional, high population-growth markets. Moreover, upward pressure on agricultural commodity prices is expected to come from constraints on food supply and, by extension, on the supply of global arable land. In addition, growing interest in grain-based alternative fuels will add to the upward pressure on grain prices. This in turn is expected to spur productivity-enhancing research and development, including a greater reliance on genetically modified food. In addition, a growing Mexican middle class, combined with greater Canadian access to the Mexican market under the North American Free Trade Agreement, will result in increased pork exports. China represents another potentially strong export market for Canadian producers, especially in light of China's recent acceptance into the World Trade Organization and its emerging status as an economic superpower. Consequently, growth in Canadian agricultural output is expected to exceed global population growth, with average annual compound growth of 1.9 per cent over 2006–30.

FISHING

Fisheries on the east and west coasts are expected to face supply constraints over the long term. Mollusks and crustaceans have dominated the east coast industry in recent years; but, while these species are more profitable than groundfish, on balance they generate fewer jobs. The east coast groundfish industry has shown few signs of improvement and appears to be far from a measurable recovery. Recent studies by the federal government indicate that cod stocks have not recovered since the moratorium on cod fishing was imposed in 1992 and that the fish are scrawnier than before, likely due to adaptations in breeding. The drop in sea temperature in the Scotian Shelf has increased the population of pelagics such as herrings, which eat cod eggs, making the recovery difficult. The recovery of groundfish species like haddock and cod is also related to environmental factors and difficult to predict. Though the cod moratorium has been lifted, it is unlikely that cod stocks will be returning to their levels of the late 1980s.

The slump in the groundfish industry forced fishermen to turn to crustaceans, such as crab, lobster and shrimp. The stocks of these species are also dwindling. Total allowable catch for crab was reduced in recent years by the Department of Fisheries. Lobster landings also declined, continuing to follow a downward trend over time. An expected drop in the sea temperature will limit growth in east coast fishery over the forecast period. Meanwhile, the traditional west coast fishery is battling lower stocks, although it is unclear whether this phenomenon is temporary or permanent. As well, the Canadian fishing industry is combating public stigma toward new technological developments in aquaculture (fish farms), especially with respect to farmed salmon.

Continued growth of the aquaculture industry (which is classified under agriculture) is expected to buttress long-term job creation, but Canadian producers will face stiff competition from warm water aquaculture producers, particularly in South America. In the near term, the aquaculture industry must contend with studies that criticize the way it operates and which adversely compare the quality of its products to those of wild fish. A U.S. study concluded that farm-raised Atlantic salmon contain pollutants and toxins and that their consumption should be limited. The near-term outlook is not all grim for aquaculture in Atlantic Canada. Cooke Aquaculture Inc. will open nine new fish farms over 2007–09, tripling the production of farmed salmon in Newfoundland and Labrador.

The east coast groundfish industry appears to be far from a measurable recovery.

The medium-term outlook for fishing shows modest opportunities, with average growth of 1.4 per cent per year expected between 2006 and 2015. Over the remainder of the forecast, growth will be quite limited. Years of struggle have caused young Canadians to shy away from the profession, and newer technology requires fewer human resources. Although the restraint shown by the federal government in applying catch restrictions is expected to bear fruit over the long term, there is too much uncertainty surrounding the industry to predict a dramatic recovery. All told, average annual compound growth of –0.2 per cent per year is anticipated over the last 15 years of the forecast.

FORESTRY

The forestry sector in Canada will face serious supply and demand constraints in the long term, causing the industry to experience slow growth over the forecast. The industry, which accounted for approximately 2.3 per cent of total real output in the goods sector in 2005, will account for a mere 1 per cent by 2030. Overall, the sector is forecast to make slight gains in the short run, growing at an average annual compound rate of 0.9 per cent from 2006 to 2011, before contracting by an annual compound average of 1.1 per cent from 2012 to 2030.

The mountain pine beetle has destroyed some $40 billion worth of British Columbia's most valuable timber since the late 1990s.

The settlement of the softwood lumber agreement between Canada and the United States will provide Canadian exporters with some stability and will return US$4.4 billion in duties to Canadian companies. However, at the crux of the agreement is a sliding export tax that will be collected by the Canadian government. On the west coast, the industry continues to face a natural disaster in slow motion as the mountain pine beetle continues its infestation, which has already destroyed some $40 billion worth of the province's most commercially valuable timber since the late 1990s. It is estimated that by 2013 the insect will have killed 80 per cent of the province's mature lodgepole pine, which accounts for nearly 30 per cent of British Columbia's timber supply. The province has been responding to the infestation by increasing the allowable annual cut (AAC) in regions where the destruction has been rampant. However, with supply limited, near-term increases will need to be offset with decreases in the long term. In 2005, Quebec initiated sustainable forest management by implementing a reduction of 20 per cent in the province's AAC; this has taken a major toll on the province's forest industry.

Demand-side issues will also affect the sector in the long term. The aging Canadian population will result in a deceleration in household formation rates; this, coupled with decelerating population growth, will dampen the outlook for housing in Canada and the United States. Declining housing starts will in turn lead to weak lumber demand. Struggles in the pulp and paper industry will also inhibit growth in the industry. The sector, however, will receive some benefit from China's growing population. China has become the largest consumer of wood products in the world, as well as the largest importer of wood and wood fiber. The industry is also faced with the challenge of attracting labour as skill shortages become more acute within Canada; this will permeate every aspect of mill operations.

MINING

The mining sector is expected to post robust growth over the long term, growing beyond the national average GDP for the period. Growth will vary among the four industry sub-groupings: metals, non-metallic minerals, mineral fuels and services incidental to mining. The sector, however, will be propelled by strength in mineral-fuel mining. Overall, the mining sector will grow at an average annual compound rate of 2.7 per cent from 2006 to 2030.

Over the first part of the forecast, the metal mining sector will continue to benefit from elevated metal prices, driven in part by seemingly insatiable demand from China. High prices are driving a flurry of exploration activity across the country and resulting in the reopening of operations once mothballed. Growth in metal mining will also be stimulated by the opening of several new mines in Canada. Worldwide depletion of uranium stocks and improving prospects for growth in the nuclear electricity-generation sector will translate into improved growth for uranium production. Over 2006–15, metal mining is expected to grow by 1.8 per cent, compounded annually. Tighter global environmental restrictions on new mine development and the discovery of more cost-effective mines in other parts of the world, however, will limit real mining growth to a mere 0.3 per cent, compounded annually, from 2016 to 2030.

Driven primarily by the development of diamond mines in the Northwest Territories and in Nunavut, non-metal mining will grow by 2.4 per cent, compounded annually, from 2006 to 2030. Canada is expected to become the third largest diamond producer in the world. Snap Lake is scheduled to begin production in 2007, and the Victor project in northern Ontario is slated to open in 2008. Further, production at the Gahcho Kue diamond mine in Canada's Northwest Territories—the largest new diamond mine now under development anywhere in the world—is assumed to commence in 2010.

Long-term prospects for potash demand are also good, as the gradual erosion of soil nutrients will result in more intensive use of fertilizers. Potash Corporation of Saskatchewan holds a large proportion of the world's potash supply, so increased demand for fertilizer, in an industry already operating at close to capacity, is a boon for that province's non-metal mining industry.

Global spare capacity for crude oil continues to be worryingly tight, and this is reflected in energy prices.

On the energy front, events during the past couple of years have shown how a tight supply–demand situation for key commodities can quickly send prices skyward and governments scrambling to secure reliable sources. Global spare capacity for crude oil continues to be worryingly tight, and this is reflected in energy prices. The billions of dollars of investment slated to increase capacity in Canada's oil sands will be but a drop in the bucket in light of the rate at which developing economies, such as China and India, are expected to consume oil. Even for industrialized economies like the United States, oil and natural gas demand are set to continue at an unwavering pace unless significant steps are put in place to curb demand. Just to satisfy expected global demand, there will be a need for billions of dollars to be poured into oil exploration and development by member states in the Organization of the Petroleum Exporting Countries (OPEC) and in the Caspian region.

The small cushion of spare production capacity, currently estimated at 1 to 2 million barrels per day, will remain constant over the medium term, as will the risk to oil exports from geopolitically sensitive regions such as the Middle East. The Conference Board expects world oil prices to reflect the tight global supply–demand situation and associated geopolitical risks in the near and medium terms, but these should dissipate in the long term. Crude oil demand growth is forecast to be especially strong in developing countries, whose share of world oil consumption will increase from the current 40 per cent to 50 per cent by 2030. The West Texas Intermediate (WTI) price of crude oil will lose some steam over the medium term to reach US$42 (2005 dollars) by 2012 and will then resume climbing as new sources become more difficult to discover and exploit. By 2030, the WTI will reach an equilibrium price of US$55 per barrel.

Canadian energy investment will be dominated over the medium and long terms by the development of Alberta's vast oil sands. Recent announcements of expansions to existing projects and some new projects indicate that capital spending on plant, machinery, equipment and labour will surpass $100 billion over 2006–15. Approximately $30 billion has already been spent in the sector since 2000, and more than 60 projects have been announced since 1996. Technical improvements to the extraction process have made this development profitable at projected world oil prices. The outlook is somewhat at risk as both skilled labour and building materials are in high demand and low supply. Significant funds will also be committed to exploration and development of offshore resources on Canada's east coast, especially offshore Newfoundland. An upside risk to the forecast is presented by the prospect—currently remote and speculative—of west coast exploration projects.

The decline in the conventional oil supply will continue but will be offset by oil sands development in the west as well as offshore production in Newfoundland. Bad luck encountered by some energy companies in offshore Nova Scotia in recent years will dampen the investment outlook in that province. Quebec will lead the nation in hydroelectric development, with some major projects already under construction or about to begin, and some longer term projects planned after 2010.

Natural gas spot prices are affected more significantly than oil by supply and demand fundamentals in North America. The tight natural gas situation will not reverse itself in the short or medium term. On an energy-content basis, oil and natural gas prices should converge over time, as a greater portion of industrial users in the United States can switch between the fuels. In Canada, conventional production is forecast to continue declining over the medium and long terms, especially in Alberta, with the maturing of the Western Canadian Sedimentary Basin. Gas extracted through unconventional methods is not expected to make up the loss from conventional production in the near or medium term.

While the number of natural gas wells being drilled remained high in 2006, production is forecast to remain stable in the very near term but to decline over the medium and long terms, particularly in Alberta. Most new wells are shallow and are being depleted faster than new reserves can be found, and Alberta's natural gas fields, the source of 75 per cent of Canada's natural gas supply, no longer have the huge reserves needed to meet growing North American demand.

Manufacturing will post the highest average growth among Canada's major industry groupings.

Finally, pipeline projects will form a significant part of the energy investment outlook as new production capacity coming out of the oil sands will need to be transported to new and existing markets. In fact, over $25 billion will be invested in pipeline extensions between now and 2015 to provide capacity increases to meet export demand for mineral fuels. This includes the $7-billion pipeline in the Mackenzie Valley that will transport Mackenzie and Beaufort gas south to Alberta and the U.S. market, and the expansion of the Trans Mountain pipeline in 2007.

MANUFACTURING

Canadian manufacturers, especially those located in Central and Eastern Canada, have been suffering for the past few years. Higher energy and raw material prices have raised costs while the stronger Canadian dollar has lowered the prices many manufacturers receive. Furthermore, intensified competition from low-wage countries such as China and India has put downward pressure on product prices globally. In an effort to increase cash flow and invest strategically in this new industrial era, manufacturers will focus on reducing operating costs over the forecast period. Western Canada's manufacturing industry, greatly benefiting from the exceptional economic development in Alberta and stellar construction activity in British Columbia over the past few years, has outperformed the overall national average.

These recent developments combined to restrain growth in manufacturing activity to a paltry 0.8 per cent in 2006. Manufacturing output is expected to accelerate gradually over the medium term as manufacturers adapt and become more efficient. As such, manufacturing output is forecast to increase by an average compound growth rate of 3.3 per cent from 2006 to 2010. Over the longer term, the manufacturing sector will post the highest average growth rate among Canada's major industry groupings, growing by an annual average compound rate of 3.1 per cent from 2006 to 2030. The strongest performers will be manufacturers of transportation equipment (aerospace and motor vehicles), furniture, primary metals, electrical, machinery, petroleum and coal, and chemicals.

CONSTRUCTION

Canada's non-residential real estate market is tighter, especially in Western Canada and Ontario. Vacancy rates have been coming down since 2003. Strong economic activity has helped lower vacancy rates for commercial, industrial and office space, especially in key urban centres. Consequently, growth in non-residential investment is recovering outside the energy sector, with growth expected to average 4.3 per cent over 2006–10. A decline in the pace of overall GDP growth will also ease the pace at which capital outlays are made over the long term. Growth in non-energy, non-residential construction will average 2.2 per cent annually from 2011 to 2030.

Growing energy needs have prompted Canadian utilities to consider medium-term investment projects. There will be numerous power projects in Quebec over the forecast period. Hydro-Québec remains committed to heavy investment in new and existing hydroelectric projects. The company has moved ahead with the 480MW, $2-million Eastmain-1 generating station, which has been under way since 2002 and should be completed by 2008. The $1-billion, 450MW Peribonka project, under construction since 2004, will also be in operation by 2008; and more than $5 billion will be spent between 2007 and 2012 on the construction of the Eastmain and La Sarcelle hydroelectric generating stations and the partial diversion of the Rupert River for hydroelectric purposes. Hydro-Québec will also purchase 3000 MW of wind power from companies throughout the province between 2005 and 2012. This $3-billion investment in new wind-power capacity will be made by individual companies. On a more speculative note, a liquid natural gas terminal in the eastern part of the province may also be constructed before the end of the decade at a cost of $700 million.

Over the longer term, about 4700 MW of new capacity will be added if the Petite Mecatine and Grand-Baleine hydroelectric projects go ahead, at a combined cost of $15 billion. As a result, the outlook includes additional spending of between $10 billion and $15 billion by Hydro-Québec on these new projects, in addition to a $4-billion facility on the Churchill River in Labrador. Ontario will also invest heavily in the energy sector over the next several years to refurbish nuclear reactors, develop new natural-gas-fired generating plants, and generate power from wind.

Pipelines will also account for significant construction investment. Some $25 billion will be invested in pipeline extensions between now and 2015 to provide capacity increases to meet export demand for mineral fuels. Kinder Morgan is expected to begin expanding the capacity of its Trans Mountain pipeline in 2007. In addition, two competing projects to build a pipeline to deliver up to 400,000 barrels of crude per day from Fort McMurray or Edmonton to Kitimat, British Columbia, have been proposed by Kinder Morgan and Enbridge. This so-called Gateway pipeline carries a price tag of $4 billion. TransCanada Pipelines also wants to get into the business of transporting oil from the oil sands by way of the proposed Keystone Pipeline, which would be capable of moving 400,000 barrels per day of heavy oil from Hardisty, Alberta, to Wood River, Illinois, as early as 2009. This would be done through the conversion of a natural gas pipeline in Canada and the construction of a new pipeline from the Canada–U.S. border to Wood River. Plans are also on the table to build pipelines to transport imported diluents and condensates to the oil sands. Investment in pipeline infrastructure has gained renewed interest, as it will be necessary to deliver an additional 2 million barrels of crude per day by 2015 from the oil sands to new markets, mainly in the United States.

The utility projects, plus significant oil sands and offshore oil and gas investment over the forecast period, play a noticeable part in the long-term construction and investment profile.

When structural changes in the economy suppressed employment and income growth during the 1990s, housing markets experienced paltry growth. Building activity was well below household formation levels as would-be market entrants doubled up, remained in family homes longer or sought cheaper rent in subdivided existing housing units. A combination of pent-up demand, strong employment growth and low borrowing costs has sparked a housing boom over recent years that far exceeded the most optimistic expectations. Housing starts have exceeded the 200,000 mark for years running, at levels significantly above demographic requirements. While the frenzied activity is continuing, there are growing signs that the market is getting saturated. Still-low financing rates are expected to allow home construction to ease to levels more in line with demographic requirements. From a peak of close to 220,000 units expected in 2006, starts are forecast to slide to about 166,000 units in 2030. As a result of stronger immigration assumptions, anticipated new housing requirements are higher than in last year's long-term outlook.

Some $25 billion will be invested in pipeline extensions between now and 2015 to provide capacity increases to meet export demand for mineral fuels.

SERVICE SECTOR

The shift in the age structure of the population is expected to boost domestic demand for services over the long term. With continued improvement in global communication technology, a significant portion of these services will be imported. Consequently, total imports of services are expected to outpace service exports, increasing the services trade deficit substantially.

However, domestic service industries will also benefit from increased demand in the long term. Manufacturing is expected to drive growth in the transportation, wholesale trade and business services industries. The trend toward outsourcing of key business processes will continue, ensuring steady growth in consulting services. The financial services industry is expected to post strong growth over the forecast, as a growing number of senior citizens will require wealth management services. At the same time, demand for housing will wane, so the real estate sector is expected to suffer lower demand for services. Overall, service sector output is forecast to increase by 2.3 per cent over 2006–30, compounded annually.

The public sector is expected to contribute to growth over the medium term as all provinces except Ontario and Prince Edward Island are out of deficit. Ontario is expected to achieve a budgetary surplus in 2009–10. Better income tax returns have boosted fiscal revenues and brightened the regional budgetary situation. Growth in public output is expected to rise by an annual average of 2.8 per cent from 2006 to 2010. After 2010, public sector output will continue to expand at a slow pace, averaging 2.2 per cent at compound annual rates from 2011 to 2030.

NEWFOUNDLAND AND LABRADOR

Newfoundland and Labrador is expected to lag behind all other provinces in real GDP growth over the long term, advancing at an average annual compound growth rate of 0.7 per cent from 2006 to 2030. A declining population is the key driver underlying this weak outlook. Steady net out-migration, combined with a low and declining natural rate of population increase, will perpetuate the population decline that began in 1994. Further, the national trend of an aging population will be amplified in Newfoundland and Labrador, constraining labour force growth and putting pressure on provincial government spending.

During the last 10 years, the province's economy has been stimulated and shielded by several factors. These include major natural-resource-driven business investment and construction, production start-ups, public spending and tax cuts, high commodity prices, and strong global demand. However, some of these factors will soon cease and others will ease, resulting in a possible slowdown in economic growth beyond 2007. Furthermore, high energy prices and a strong Canadian dollar will continue to challenge the province's struggling manufacturing sector. At the same time, the provincial government will face significant pressure to refrain from running fiscal deficits, with much greater effort needed to reduce its massive debt-to-GDP ratio—the largest in the country.

PRINCE EDWARD ISLAND

Prince Edward Island will experience reasonable long-term growth, thanks to a positive demographic outlook. The Island will lead the Atlantic provinces in GDP growth, averaging 1.6 per cent, compounded annually, over 2006 to 2030. The goods-producing sector will get a boost from manufacturing, which is forecast to grow at an average annual compound rate of 1.8 per cent. Solid gains in aerospace, food-processing, and the engine, turbine and power transmission equipment industries will help stimulate manufacturing over the long term. The utility sector will also energize the goods-producing sector, advancing by an average annual compound rate of 2.1 per cent over the forecast period.

The public sector is expected to contribute to growth over the medium term.

Population growth will benefit from positive net interprovincial migration, reinforcing the province's image as a retirement haven for Atlantic Canadians. Prince Edward Island will post the highest average population growth rate in the Atlantic region, a demographic trend that will help sustain consumption growth in the long term. Growth in the consumption of services will be particularly strong, as an aging population tends to purchase relatively more services, such as health care and travel.

Overall, compounded real economic growth will advance by a healthy annual average of 2.1 per cent per year in the medium term (2006 to 2011), but weakening demographic fundamentals will help limit growth to 1.4 per cent over the long term (2012 to 2030).

NOVA SCOTIA

The Nova Scotia economy is anticipated to advance by an average of 1 per cent annually from 2006 to 2030, ranking it ninth among the 10 provinces. Growth in most of the domestic industries is expected to soften during the forecast period. In particular, the production of mineral fuels will drop by an average of 1.2 per cent annually as exploration activities lose momentum, with attention shifted from the Scotian Shelf to Western Canada and the Territories. The reduction of exploration activities will slow growth in mining services to an average of 1.9 per cent over the forecast, compared with 15.3 per cent between 1994 and 2005. ExxonMobil, one of the biggest petroleum players in Nova Scotia, abandoned half of its exploration licenses in 2004 as more holes turned up dry. This created anxiety among other offshore explorers and led to a loss of over $650 million in exploration commitments at the end of 2006. The uninspiring finding rate could lead to further evaporation of the $917 million in exploratory licenses the province is counting on between now and 2012. This could kill prospects on the Scotian Shelf. Owners of the Sable Island natural gas project have also scaled back reserve estimates in the field, effectively reducing the life of the project by 10 years. The loss in momentum in offshore oil and gas activities does not bode well for the construction industry. Anadarko Petroleum has cancelled the $650-million liquefied natural gas plant it was proposing to build in the Cape Breton area because it could not secure a supply of natural gas for the project. This has dashed the hopes of construction workers counting on the project to compensate for the end of the housing boom.

Nova Scotia will face a number of fundamental demographic challenges over the forecast period. First, the average age of the population will gradually increase as the baby boomers inch closer to retirement. The aging of the baby boomers will put enormous strain on the province's fiscal prospects. While more spending on facilities and services will be required for health and long-term care for the baby boomers, the aging of the population will slow economic growth and thus the government's revenue-generating capacity. A compositional shift in consumer spending will also result as people buy fewer durable goods and consume more services. Second, low fertility rates and negative interprovincial migration will slow population growth in the province.

Weak demographic fundamentals are expected to dominate the population outlook, exerting a profound impact on the province's labour market and the economy. Overall, economic growth is projected to reach an average of 1.9 per cent over 2006–10 and to decelerate to 1.1 per cent over the next decade. The consequences of the demographic change will further slow the economy in the last decade of the forecast. Growth in GDP is expected to average 0.5 per cent from 2021 to 2030.

NEW BRUNSWICK

Real GDP in New Brunswick is projected to grow at a relatively slow average rate of 1.1 per cent from 2006 to 2030, for eighth rank among the 10 provinces. Weaknesses in the construction and transportation sectors will limit overall economic growth as the province grapples with the completion of megaprojects. Forestry will also add to the slow pace of economic growth as the annual allowable cut continues to decline and structural changes in market conditions stifle demand for pulp and paper. Metal mining is the only industry expected to grow by more than 2 per cent over the entire forecast. A recent rally in metal prices has engendered exploration and drilling activities that are likely to yield better results. Two mines that were shut down in 1998 have now reopened, softening the blow of the impending shutdown of the Brunswick mines in 2008.

New Brunswick's total population is projected to shrink every year over the forecast.

In the medium term, however, the construction industry will be propped up by energy investments, as well as by capital spending on health-care facilities and municipal infrastructure. Work is underway on Irving Oil's $750-million liquefied natural gas project at the Canaport terminal near Saint John, a project expected to engage more than 500 construction workers for nearly three years. The provincial government is also going ahead with the multimillion-dollar refurbishment of the Point Lepreau nuclear plant. In another large venture, Irving Oil is planning to build a second refinery in New Brunswick that could cost as much as $5 billion.

Weak demographic dynamics will dominate the outlook over the long term. One notable factor will be a rise in the average age of the population. As the proportion of those older than 65 increases, consumption patterns will change for both government and consumers. Spending on health care will have to rise significantly to meet the changing needs of the aging population. In addition, rising net international immigration will be largely offset by a net outflow of people to other parts of Canada. Finally, New Brunswick's fertility rate, one of the lowest in the country, will be a drag on population growth. Total population is projected to shrink every year over the forecast.

The weakening population outlook will have significant consequences for the province's labour market and overall economic growth. The Conference Board expects growth in real GDP to decelerate from an annual average of 2.3 per cent in the first five years of the forecast to 1.1 per cent over 2011–20 and still further to 0.6 per cent from 2021 to 2030.

QUEBEC

With favourable financing conditions whipping up consumer expenditures over the last two years, the Quebec economy was relatively successful in overcoming the dampening effects of an appreciating Canadian dollar. Even as the export-sensitive manufacturing sector shed jobs, overall provincial real GDP growth at market prices averaged close to 2 per cent over 2005–06. Quebec's real GDP at market prices is expected to progress by an average of 2.4 per cent from 2006 to 2010 and by a moderate 1.7 per cent compound annual rate over the last 20 years of the outlook, in line with potential growth, as demographic changes weigh on economic prospects.

With the auto industry restructuring dramatically in response to dwindling U.S. vehicle sales, prospects are modest for manufacturers.

Economic growth will slow over the long term as the aging of baby boomers and a low fertility rate weaken population growth to a compound annual rate of only 0.5 per cent between 2016 and 2030, reducing consumer expenditures and housing demand. The proportion of people aged 65 and older will increase substantially over the entire forecast period, by more than 10 percentage points to 24.5 per cent, while the number of young people under the age of 20 will shrink from 1,711,849 in 2006 to 1,640,283 in 2030. Housing starts will fall steadily from 44,017 units in 2006 to about 18,687 units in 2030 as demographic factors weaken the number of new households and the need for new housing. Real export growth, the pillar of robust economic activity in the late 1990s, will gradually decelerate over the long term because of slowing U.S. growth and a Canadian currency averaging around US$0.84. The telecommunications, transportation equipment, biotechnology, and metal sectors are expected to be some of the contributors to the trade outlook over the next 25 years.

ONTARIO

The economic outlook for Ontario will remain tempered over the near term. Real GDP at market prices is expected to advance by 1.7 per cent in 2006 and by 2.4 per cent in 2007. The manufacturing industry is bracing for additional challenges, as weakening consumer demand south of the border will certainly not pull it out of the abyss. Manufacturing output defied the appreciation of the Canadian dollar over the past few years by making gains, but a sharp slowdown in the auto sector is expected to contract real manufacturing output in 2006. With the auto industry restructuring dramatically in response to dwindling U.S. vehicle sales, prospects are modest for manufacturers. Nevertheless, a solid performance by a number of industries—chemical, electrical equipment, machinery and equipment, and refined petroleum and coal products—should enable real total exports to post a better performance in 2007 than in 2006.

The trade sector will continue to weigh on economic growth as imports continue to grow firmly to satisfy the sturdy demand for machinery and equipment and consumer goods. The declining trade balance will chop 2 percentage points from GDP growth in 2006 and 0.6 percentage points in 2007. Stabilizing in 2008, the trade balance should make a small, positive contribution to the economy.

Strong domestic demand will continue to bolster economic activity. Business investment and consumer spending are expected to remain robust. Limited spare capacity in the commercial and industrial markets combined with moderate financing rates will continue to encourage investment in non-residential sectors. Furthermore, public spending commitments to upgrade energy and transportation infrastructure will support the near-term investment forecast.

Between 2008 and 2011, as prospects improve south of the border and the Canadian currency stabilizes to an average of US$0.854, Ontario should fare much better, with real GDP growth rebounding to 3.4 per cent. The Ontario economy will be among the strongest in Canada over the long term, trailing only Alberta and expanding by a compound annual rate of 2.7 per cent over 2006–30.

Potential output growth is estimated to grow by 2.9 per cent per year on average from 2006 to 2015 and 2.6 per cent over 2016 to 2030. Two key factors will reduce the economy's capacity to expand. First, the proportion of retirees in the population will rise considerably, constraining long-term potential labour force growth. Second, the growth of total factor productivity is expected to slow as the forecast wears on, as it is assumed that the current pace of technological change will ease.

MANITOBA

Manitoba is expected to enjoy a relatively healthy economy over the next 25 years, in good part thanks to a diversifying and expanding manufacturing sector, solid employment growth, and strong government spending. The economy is expected to grow by an average annual compound growth rate of 2.4 per cent over 2006–30.

Manitoba's long-term economic health will slow interprovincial out-migration and strengthen immigration.

Manitoba's long-term economic health will slow interprovincial out-migration and strengthen immigration. With both of these factors helping to offset a declining natural rate of population increase, the population growth rate will hold steady over the forecast period. However, the low fertility rate of baby boomers will result in an aging population plus a sharp deceleration in labour force growth. The aging of the population will further strain an already overburdened health-care sector, forcing the government to devote a greater share of its spending to this area.

Manufacturing will remain the strongest component of output over 2006–30, with growth of 3.2 per cent, compounded annually. Even with some short-term challenges in the cattle industry, Manitoba's agriculture outlook remains healthy over the period, with an annual compound growth rate of 2.4 per cent.

SASKATCHEWAN

Saskatchewan's economic growth is expected to be strong for the remainder of this decade, but it will cool off in the long term as demographic changes take hold.

The province's real GDP is forecast to grow at 2 per cent annually between 2006 and 2015, and by 1.7 per cent per year between 2016 and 2030. Taken together, this yields average growth of 1.8 per cent per year over the entire forecast period, ranking Saskatchewan fifth among Canada's provinces but well below the national average of 2.4 per cent.

Saskatchewan will face a number of fundamental changes over the next 25 years. First, the average age of the population will gradually increase. This will put an enormous strain on the province's health-care sector and force the government to increase spending to rebuild and maintain health-care resources. Second, the aging of the population will result in a structural change in consumption, as an older population is expected to spend less on durable goods and more on services, especially in the last five to ten years of the outlook. Third, a relatively high fertility rate will be more than offset by steady interprovincial out-migration, resulting in moderate population growth.

Manufacturing will remain the strongest component of output over 2006–30, with growth of 3.3 per cent, compounded annually. Saskatchewan's agricultural outlook remains relatively healthy, with an annual compound growth rate of 1.7 per cent expected between 2006 and 2015 and 1.4 per cent between 2016 and 2030. Finally, mining promises to post solid growth for the remainder of this decade, with average annual growth of 1.4 per cent over the entire forecast period.

ALBERTA

The Alberta economy will advance solidly over 2006 to 2030, expanding by a compound average annual rate of 3.2 per cent, and the energy sector will remain a driving force. Sustained high oil prices, an immense non-conventional oil supply and continually improving extraction technology have shifted the focus of the energy market to oil sands production. Long-term prospects for the non-conventional oil industry in Alberta are very favourable. About $67 billion in activities related to the oil sands has already been proposed by several major energy players for 2006–20, while an additional $27 billion in oil sands-related development is slated for the remainder of the outlook. About $28 billion has been spent in the sector since 1995.

Natural gas spot prices are affected by supply and demand fundamentals in North America. The tight natural gas situation will not reverse itself in the short or medium term. Although the number of wells being drilled for natural gas is being kept elevated by drilling for coal bed methane, production of natural gas is expected to decline over the forecast, especially in Alberta, with the maturing of the Western Canadian Sedimentary Basin (WCSB). Most wells being drilled are shallow and are depleted faster than new reserves can be found. Gas extracted through unconventional methods is not expected to make up the loss from conventional production in the near or medium term.

Production of natural gas is expected to decline over the forecast, especially in Alberta.

While the long-term forecast for the province is favourable, an aging population will take its toll on output. Total population growth is projected to weaken, dampening demand for consumer goods and housing. However, record resource revenues and the positive job market will continue to attract businesses and job seekers, boosting Alberta's population growth beyond that of other provinces. Overall, economic growth is expected to reach an average annual compound rate of 4.1 per cent during the first decade of this century before weaker demographic conditions slow the economy to average annual growth of 2.9 per cent over 2011 to 2030, in line with underlying potential output growth.

BRITISH COLUMBIA

Real GDP in British Columbia is forecast to grow at a compound annual rate of 2.2 per cent over 2006–30. After rebounding strongly from 2004 to 2006, the economy is expected to maintain a healthy pace over the medium term, expanding by a healthy compounded average of 3.1 per cent from 2006 to 2011. The export sector will be stimulated by stronger global demand, especially from the United States and Asia, and the domestic sector will continue to build momentum with increased interprovincial migration. Large-scale infrastructure investment and a host of projects in preparation for the 2010 Olympics will keep activity healthy in the province's construction sector over the medium term. Government coffers are benefiting from the strong economic performance, and a budget surplus of around $2.15 billion is expected in the 2006–07 fiscal year. The provincial government is forecasting further budget surpluses over the medium term and should therefore become a positive force in the economy after a few years of tepid growth.

Demographic changes will moderate economic growth in British Columbia over the long term. Population growth will slow over the forecast period, even with positive net interprovincial migration, as the aging of the baby boomers dramatically changes the province's age profile. This shift will also slow growth in domestic demand, with consumer spending patterns and housing activity undergoing the most pronounced changes. While sluggish, population growth will be higher than in most other provinces, with a compound annual rate of 1.1 per cent from 2006 to 2030.

Over the near term, the outlook is quite positive for forestry, the province's key resource sector, as the sector is benefiting from expedited lumber harvests to combat the mountain pine beetle infestation and reductions in Quebec's annual allowable cut. However, the long-term outlook is not quite as upbeat, as the forecast incorporates a decline in real forestry output following the peak of the pine beetle epidemic. Further, the reduction in housing demand likely to result from an aging North American population will lead to a corresponding drop in demand for wood products. Although worldwide demand for wood is expected to pick up gradually over the forecast period, the challenge for British Columbia will be to respond to the increased demand in the face of a shrinking timber supply.

CHAPTER 1

Alan Chaffe

Newfoundland and Labrador

Newfoundland and Labrador is expected to lag behind all other provinces in real gross domestic product (GDP) growth over the long term, advancing at an average annual compound growth rate of 0.7 per cent from 2006 to 2030. A declining population is the key driver underlying this weak outlook. Steady net out-migration, combined with a low and declining natural rate of population increase, will perpetuate the population decline that began in 1994. Further, the national trend of an aging population will be amplified in Newfoundland and Labrador, constraining labour force growth and putting pressure on provincial government spending.

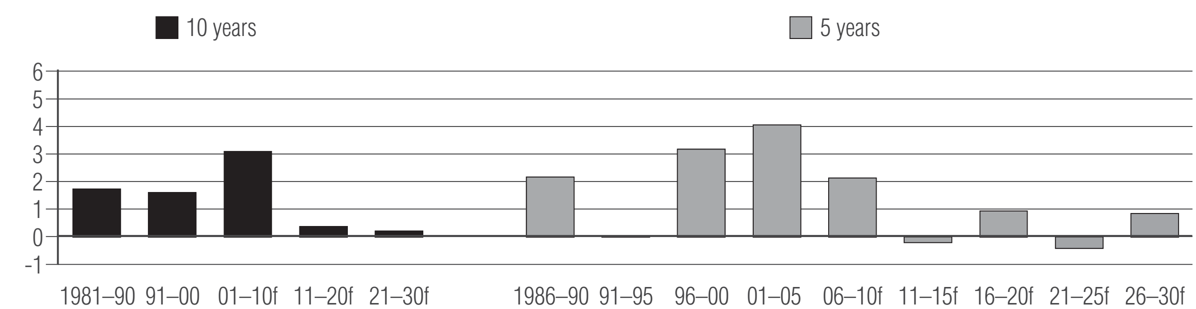
During the last 10 years, the province's economy has been stimulated and shielded by several factors. These include major natural-resource-driven business investment and construction, production start-ups, public spending and tax cuts, high commodity prices, and strong global demand. However, some of these factors will soon cease and others will ease, resulting in a possible slowdown in economic growth beyond 2007. (See Chart 1.) Furthermore, high energy prices and a strong Canadian dollar will continue to challenge the province's struggling manufacturing sector. At the same time, the provincial government will face significant pressure to refrain from running fiscal deficits, with much greater effort needed to reduce its massive debt-to-GDP ratio—the largest in the country.

DEMOGRAPHIC PATTERNS

As population trends are a key determinant of consumer spending and potential output growth, demographic projections play an important part in long-term economic forecasting. The province faces a difficult demographic scenario: a falling natural rate of increase, high levels of out-migration and a rising average age will cause the population to decrease at an average annual compound growth rate of 0.3 per cent from 2006 to 2030. Total population is expected to fall from 510,413 in 2006 to 472,439 in 2030.

Between 1994 and 1998, on average, the province lost 7,000 more people to other provinces per year than it received. After reaching a record –8,522 in 1997, net interprovincial migration averaged –4,005 from 1998 to 2005. The reduced loss is attributed to the construction of oil megaprojects and the development of the Voisey's Bay mine, which continue to bring jobs to rural areas of the province as well as to St. John's. Negative net interprovincial migration is expected to continue over the forecast period, averaging about –1,656 annually over the medium term (2007 to 2011) and –599 annually over the long term (2012 to 2030). Unlike the slowdown in the late 1990s, however, this easing of net interprovincial losses will occur because of a reduced population base rather than as a result of positive economic factors.

Chart 1
Real GDP at Basic Prices
(average annual compound growth rate)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Table 1
Key Demographic Assumptions

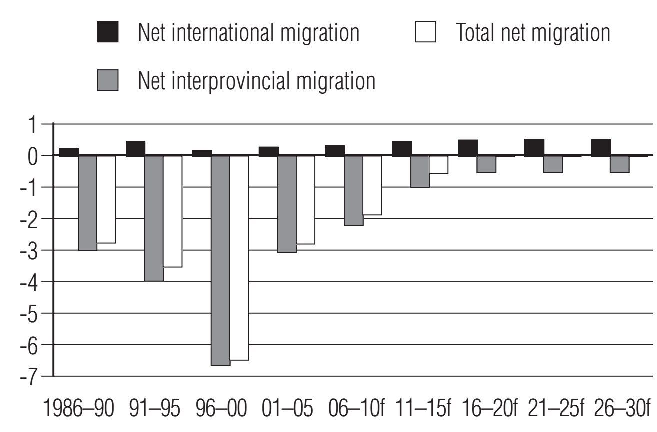
Components	Assumptions
Population declining	Newfoundland and Labrador's population is expected to decline by an average rate of 0.3 per cent over 2006 to 2030.
Provincial out-migration continues	Newfoundland and Labrador's will continue to lose people to other provinces; net interprovincial migration will remain negative, averaging 946 people per year over the forecast period.
International migration stable	Net international migration will remain steady, averaging 464 people per year over the forecast period.
Fertility rate	The fertility rate in Newfoundland and Labrador is 1.32, well below the replacement rate of 2.1.
Natural rate reduces population	The natural rate of increase is expected to draw down on population over the forecast period, as the rate of deaths increases and the rate of births decreases.

Sources: The Conference Board of Canada; Statistics Canada.

A steady increase in international migration from 296 people in 2006 to 521 in 2030 will help to replenish the declining population. (See Chart 2.)

The steady net out-migration is especially troubling since it is primarily young, well-educated residents who leave in search of improved employment opportunities in other provinces. This tendency will lead to an unfavourable shift in the age distribution of the province's population. The 25-to-34 age group, which makes up 12.3 per cent of the population in 2006, will account for only 10.1 per cent of the population by 2030. This is particularly distressing, as this is the age cohort most likely to have children. Their departure will result in a decline in the birth rate. Newfoundland's low fertility rate of 1.32 children born to each woman of childbearing age (compared with 1.51 for Canada as a whole) puts even more downward pressure on the natural rate of increase. The number of deaths in the province has already begun to exceed the number of births—a development that will turn into a trend over the forecast period.

Chart 2
Immigration
(thousands of persons)



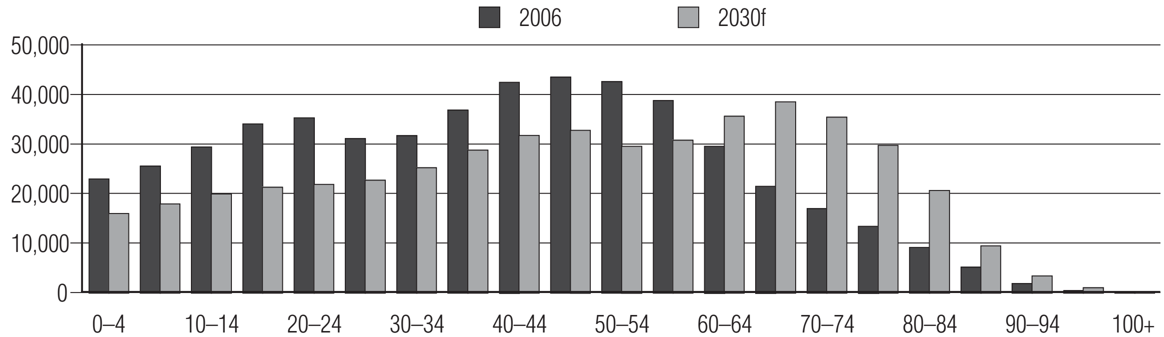
f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

A steady increase in international migration will help to replenish the declining population.

Another important factor affecting Newfoundland's long-term demographic outlook is the impending retirement of the baby-boom generation. This is a problem facing all of Canada, but the falling birth rate and high rate of out-migration of young people will exacerbate the situation in Newfoundland. The change in the age distribution of the population over 2006–30 will be quite remarkable as the bulge representing baby boomers moves toward the tail end of the population distribution. (See Chart 3.) The baby boomers will be retiring in force from 2011 to 2015. By the end of the forecast period, with a significant proportion of this cohort gone from the labour force, Newfoundland's working-age population will be much lower. Specifically, the number of people aged 15 to 64 represents 71.4 per cent of the population in 2006; this number will shrink to 59.3 per cent by 2030. At the same time, the proportion of the population 65 years of age and older will increase from 13.4 per cent in 2006 to 29.3 per cent in 2030—well above the national share of 22.2 per cent.

Strong natural resource development over the last ten years has lifted the province's labour force participation rate substantially, from 52.5 in 1997 to 59 in 2006. The participation rate is expected to peak at 59.1 around 2007 and then gradually to decline over the remainder of the forecast. Consequently, the labour force is expected to remain largely unchanged in 2006 and 2007. Thereafter, the completion of various megaproject developments will lead to a decline in the participation rate at around the same time as the demographic

Chart 3
Population Increases in Older Age Cohorts
(number of people)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

situation becomes acute. As a result of these factors, the labour force will deteriorate more quickly, shrinking at a compound rate of 0.9 per cent over the remainder of the forecast.

PRODUCTIVITY AND POTENTIAL OUTPUT

This long-term economic forecast is guided by the concept of potential output, which is the highest level of economic activity an economy can attain without surpassing its capacity limits and igniting inflation. Potential output is not directly measured and, as such, the Conference Board uses a structural production function to obtain an estimate of potential. We assume that the production function takes a Cobb-Douglas form, in which the mix of labour, capital and technical efficiency are modelled to produce potential output. With this assumption, our estimate of potential output depends on potential employment, capital and trend total factor productivity (TFP).

Potential employment measures the contribution of labour to potential output by estimating the available workforce when the economy is operating at capacity. Under these conditions, the labour force participation rate is at its structural peak and unemployment is at its "natural rate." Therefore, movements in the structural participation rate and the natural rate of unemployment are the two main factors driving changes in labour's contribution to output over the long term.

The natural rate of unemployment defines a minimum level of unemployment that would remain because some people are in transition between jobs and others prefer not to work at the current wage. Unemployment resulting from workers in transition is expected to decline over the forecast. This will occur because the average age of the labour force will increase, and older workers are not as likely to quit their jobs to look for other work. Thus, the natural rate of unemployment is expected to trend slowly downward over the forecast period, positively contributing to labour potential.

The overall participation rate is expected to decline sharply over the next 25 years.

On the other hand, the aging labour force will detrimentally affect labour potential through the labour force participation rate. As workers move into older age cohorts, their aggregate labour force participation generally declines as a result of health problems and early retirement. Consequently, the overall participation rate is expected to decline sharply over the next 25 years as a significant share of baby boomers move into their retirement years. On balance, the negative effects of declining participation rates will largely outweigh the benefit derived from a lower natural rate of unemployment. Therefore, labour's contribution to potential output will decline over the long term. Overall, labour will depress potential output by an average of 0.1 percentage points from 2006 to 2011 and is projected to slide back even further over the remainder of the forecast.

The value of productive capital is the second factor of production required to calculate potential output. Instead of relying on a measure of potential or optimal capital stock, the Conference Board assumes that productive capital is accurately measured and that the level of capital in the economy at any time is all that is available. Total public and private capital, excluding residential assets, contributes to the level of productive capital. Over the forecast period, the net capital stock is assumed to increase each year by the amount of new investment, net of depreciation and discarded capital. The contribution of capital to potential output growth will average about 1.2 percentage points per year over the medium term and 0.6 percentage points per year over the remainder of the long term.

Economic growth is expected to weaken over the remainder of the forecast.

The technical efficiency in which capital and labour are utilized to produce output is measured by TFP. Over history, TFP is calculated residually, using the logarithmic form of the Cobb-Douglas production function, so that changes in output not explained by labour or capital are attributed to changes in technical efficiency. It should be noted that, for purposes of this calculation, total output is defined as real output at basic prices for all industries, excluding paid and imputed rent. Paid and imputed rent is excluded because the Board's estimates of the capital stock do not take into account residential assets, since these do not contribute to the productive capacity of the economy.

TFP fluctuates considerably over the business cycle. The reasons for this are wide-ranging but include changes in the mix between capital and labour, relative shifts in the types of capital purchased, shifts in labour productivity as labour force skills evolve, and tax changes. In order to remove the effects of volatile short-term movements, potential output is calculated with trend TFP, which is our residual measure smoothed with a Hodrick-Prescott filter. Over the long term, trend TFP growth is expected to be robust. With the growth in the number of workers dwindling, to maintain growth in TFP, firms will need to continually invest in productivity-enhancing technology and the skills development of their workforce. The contribution of TFP to growth in potential will remain in line with recent historical performance, contributing roughly 0.4 percentage points to growth annually over the forecast horizon.

When actual real GDP diverges from potential output, an economy is said to have an output gap. Prior to 1998, Newfoundland and Labrador's economy performed almost consistently under potential, resulting in a sizable output gap. Thanks in large part to Hibernia oil production and construction relating to the Terra Nova offshore oil project, the province's economy grew much faster than potential between 1998 and 2000. From 2002 to 2007, oil, hydro and mining development boosted economic growth above potential growth for the most part. (See Chart 4.) These major investment projects will boost real GDP to an average annual compound growth rate of 4.3 per cent from 2006 to 2007 and will push the output gap into positive territory in 2007. Economic growth is expected to weaken over the remainder of the forecast, advancing by a mere 0.4 per cent, compounded annually. In fact, real GDP will contract between 2014–15 and 2021–25. In 2010, weak economic growth will push the gap back into the negative, and the gap will continue to widen over time. As a result, inflationary pressures are forecast to remain relatively subdued over the forecast horizon. The Consumer Price Index is projected to average 1.9 per cent from 2006 to 2011 and 1.8 per cent from 2012 to 2030.

AGGREGATE DEMAND

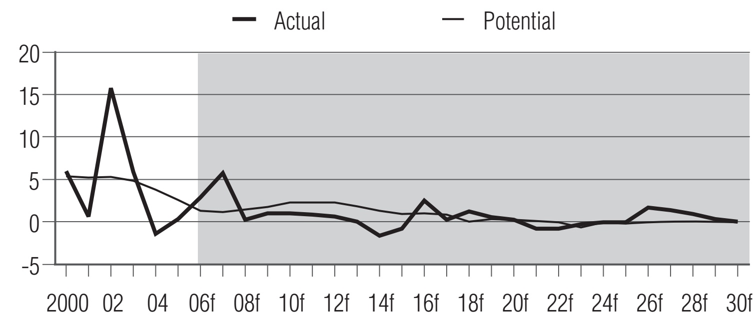
CONSUMPTION

The demographic shifts expected over the long term will also be felt in the province's household sector. The unfolding of this process will change not just the pace of growth of consumption expenditures but also the type of spending that occurs. Equally important, demographic change is expected to significantly affect the trend in savings. The life cycle theory of consumption predicts that since households either save less or draw down their savings during the retirement phase of life, population aging will cause a decline in the savings rate.

While demographic change will maintain the goods–services balance in total consumption spending, it is expected to contribute to a deceleration in the pace of growth in consumption outlays. Declining population combined with a quickly growing elderly segment will reduce the pace of expansion in consumption spending. As such, the average annual compound rate of nominal consumer spending growth is forecast to ease from 3.2 per cent over 2006–11 to 2.5 per cent from 2012 to 2030. The savings rate will be an astonishing 11.7 per cent in

2006 before sliding back to a more normal 1.5 per cent in 2007. The surge in personal savings in 2006 was caused by a one-time payment by the government to reduce the actuarial deficit of a pension plan sponsored by the government. Despite this anomaly, the average annual savings rate will be 1.2 per cent in the medium term before easing gradually over the forecast period, reaching a negative rate of 0.3 in 2030.

Chart 4
Actual versus Potential GDP Growth
(percentage change)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

EMPLOYMENT AND INCOME

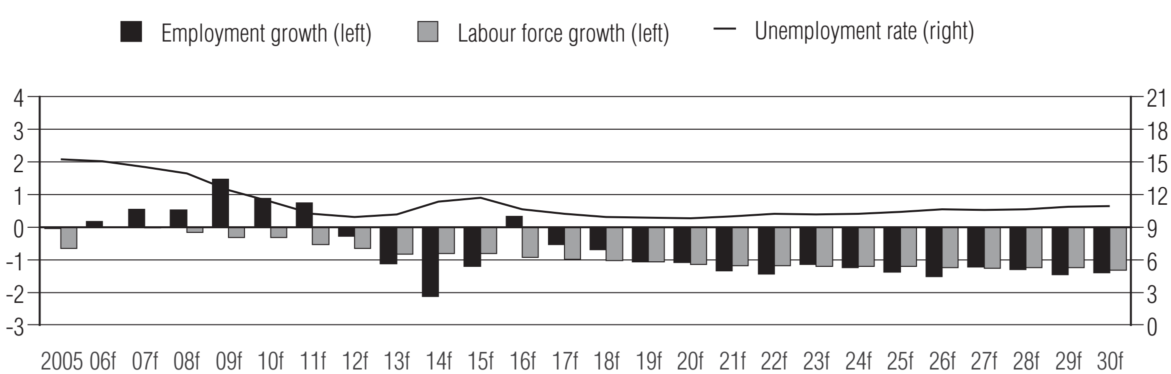
With the construction of megaprojects like White Rose and Voisey's Bay, there will be average annual compound employment growth of 0.7 per cent from 2006 to 2011. Afterward, however, the winding down of construction at these large projects will mean a drop in employment growth. In 2006, the unemployment rate in Newfoundland stood at 15 per cent, the highest in the country. This rate should decline fairly steadily over the forecast period, reaching 10.9 per cent in 2030. The unemployment rate will drop because of the shrinking labour force, not because of employment growth. (See Chart 5.)

Fuelled by employment gains over the medium term, nominal personal disposable income will advance by an average annual compound growth rate of 3.4 per cent from 2006 to 2011. In 2006, the pension payment made by the government is expected to help personal disposable income surge by 22.6 per cent. As a result of falling employment, disposable income will continue to post weak growth over the remainder of the forecast, averaging 2.5 per cent, compounded annually. With the weak employment outlook during this period, labour income growth will be poor. However, given the rising number of elderly people, disposable income growth will get some support from an increase in transfer payments and pension income.

INVESTMENT

The investment profile in Newfoundland and Labrador has been driven by large natural resource projects, with offshore oil projects a big source of investment. Construction of the White Rose offshore oil project is now complete and production underway. The Hebron offshore

Chart 5
Employment and Labour Force Growth and the Unemployment Rate
(percentage)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

oil project has been delayed, although our forecast assumes that construction could begin in 2012 with production commencing in 2016. The offshore Newfoundland region has received quite a bit of attention recently, as a number of energy companies have bought up land leases and exploration rights in various basins, so another offshore oil project could begin in the next 25 years.

Several scenarios have been proposed over the last four years to develop the hydroelectric capacity of the Lower Churchill River in Labrador. First, preliminary negotiations with Hydro-Québec from 1998 to 2000 for a $12-billion development came up empty. In the spring of 2006, the government of Newfoundland and Labrador decided that it would lead the development of the project along with Newfoundland and Labrador Hydro. The major components of the project are the development of the Gull Island and Muskrat Falls sites and new transmission lines in Labrador and Quebec. Construction on the Gull Island site is anticipated to commence in 2009 and run until 2014, with construction at Muskrat Falls to follow. The project has the potential to supply electricity for 1.4 million homes annually after production begins in 2015. Overall, the total value of the projected is estimated to be $6 billion.

The construction of the Voisey's Bay mine and mill concentrator is now complete, with shipments of ore underway. This project has provided a big boost to non-residential non-energy investment spending in the last few years. At the end of this decade, the construction of the Voisey's Bay hydromet processing facility in southern Newfoundland at Long Harbour should begin, at a cost of $800 million.

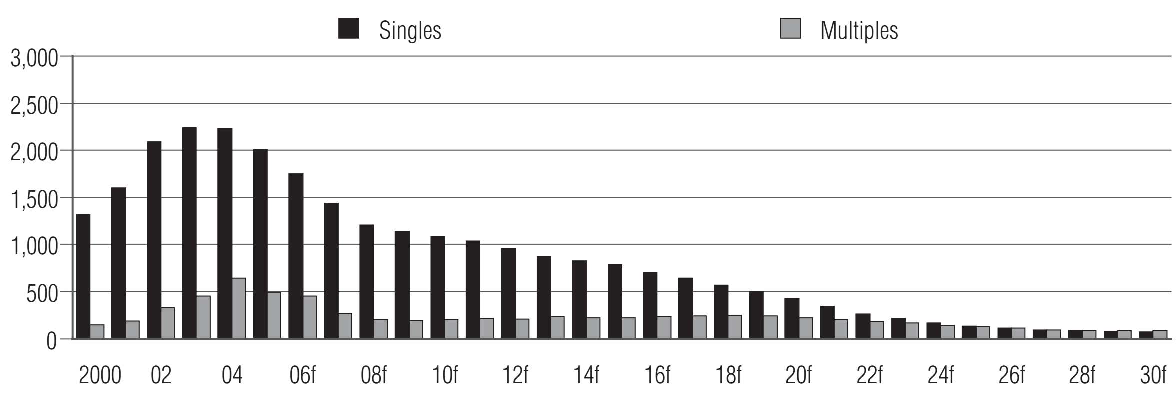
With construction investment tapering off at the major project sites, non-residential investment spending is forecast to decrease by 12.5 per cent in 2006 and to contract even further, by 3.2 per cent, in 2007. However, non-residential investment will rebound in the near term, growing at a compounded annual rate of 10.3 per cent from 2006 to 2011. With few new large projects on the horizon after 2011, non-residential investment is expected to grow at an annual compound rate of 1.3 per cent over the remainder of the forecast.

On the residential front, an aging population will severely limit new housing demand. As a result, housing starts are expected to decline by a compound annual average of 10.4 per cent from 2006 to 2030. (See Chart 6.) This trend will dominate residential investment spending over the long term, falling by an average compound growth rate of 2.4 per cent from 2006 to 2030.

GOVERNMENT

The provincial government of Newfoundland and Labrador faces a serious financial imbalance and the challenge of major financial restoration. However, several positive developments offer a measure of comfort. Chief among these is the new Atlantic Accord reached between the province and the federal government, which will allow

Chart 6
Total Housing Starts
(units)



f = forecast
Sources: The Conference Board of Canada; Canada Mortgage and Housing Corporation.

petroleum revenues to be retained by the province without reduction in equalization payments over the next eight years. In addition, a new equalization and health-care agreement has secured additional transfer payments. Together these developments have given a much needed lift to the fiscal prospects of the province.

Overall, revenues are not expected to post any growth in fiscal year 2006–07.

Stronger-than-anticipated revenues, mainly from oil, helped the government record a $76.5-million surplus for fiscal year 2005–06, a considerably healthier outlook than the projected deficit of $493 million. After initially expecting a surplus of $6.2 million for the fiscal year 2006–07, the province has revised its estimate downward to a $39.8-million deficit. Unforeseen delays in production at the Terra Nova and Hibernia offshore oil fields and the Voisey's Bay nickel mine resulted in significantly lower revenues than originally forecast. Overall, revenues are not expected to post any growth in fiscal year 2006–07. The biggest surprise is on the spending side, with total program expenditures projected to increase by 11.3 per cent.

Unsurprisingly, health care and education will receive the biggest boosts. While the accrual deficit appears to be on a downward path over the medium term, the province's net debt as a share of GDP is staggering—just over 55 per cent in 2005–06. With net debt totalling $11.9 billion dollars, the province's debt-to-GDP ratio remains the highest in the country. Consequently, the province's fiscal situation remains a serious problem and challenge going forward. With these factors in mind, nominal government spending on goods and services is forecast to grow by an average compound growth rate of 3.6 per cent from 2006 to 2030.

INDUSTRY ANALYSIS

The goods sector of the provincial economy is not expected to grow on average from 2006 to 2030. Among the primary sectors, metal mining will provide the lion's share of stimulus to total mining output in the near term. The depletion of reserves will be a major factor in the decline of mineral fuels output over the forecast. Overall, the mining sector will weigh down overall growth in the goods sector; it is not expected to see any growth on an average annual compound basis over the entire forecast period.

Oil from Hibernia helped Newfoundland's economy grow phenomenally from the start of production in late 1997 through 2000. Although offshore oil development failed to make much headway in 2001, mineral fuel expansion grew by leaps and bounds in 2002. Growth continued in 2003, albeit at a much more muted pace, when Hibernia and Terra Nova obtained approval to increase their maximum daily production. Delays in production at the Terra Nova and Hibernia offshore oil fields dampened growth in mineral fuels output for 2006. With production at both sites expected to return to normal levels in 2007, mineral fuels output will surge ahead by 25.9 per cent. The production of first oil from White Rose will boost mineral fuels output in the short term, but this new output will not be enough to keep total output from falling at an annual compound rate of 0.8 per cent from 2006 to 2011. In the longer term, the depletion of reserves by 2015 will cause some operations to wind down. Thus, compound annual mineral fuels output from 2012 to 2030 will fall by 5.1 per cent.

Real metal mining output is forecast to grow by an annual average of 8.1 per cent from 2006 to 2011.

Total real mining output will be boosted by production at the Voisey's Bay nickel-copper-cobalt deposit. Construction of the open pit mine and mill/concentrator processing plant at the site is now complete, with production underway. Fuelled by this project and strong global demand, real metal mining output is forecast to grow by an annual average of 8.1 per cent from 2006 to 2011 before contracting by an annual compounded rate of 0.8 per cent from 2012 to 2030.

The fishing industry in Newfoundland and Labrador has rebounded since the collapse of the cod fishery in the early 1990s. The recovery has been bolstered by diversification into shellfish, specifically crab and shrimp. The cod industry, however, received another damaging blow in 2003, when Ottawa closed much of the cod fishery around Newfoundland. This affected some

4,000 Atlantic fishermen, about 900 of whom depended heavily on the cod fishery. The fishing industry is expected to expand overall at an annual compound rate of 0.4 per cent over the forecast period. Decisions being made by the provincial government about restructuring the bruised fishing industry could result in serious consequences for the industry; they constitute a downside risk.

Over the long term, falling population will constrain growth in the services sector to an average annual compound rate of 1 per cent. With the increased retirement of baby boomers during the second half of the forecast, public administration spending will reflect demand for non-commercial services, including health care and social services. However, growth in non-commercial services output will be somewhat tempered by the shrinking population. Overall, non-commercial services will grow by an average of 1.4 per cent from 2006 to 2030. Natural resource production will be the principal driver behind wholesale trade growth, which is expected to average 2.6 per cent per year from 2006 to 2011 before slowing to an annual compound pace of 0.6 per cent over the remainder of the forecast.

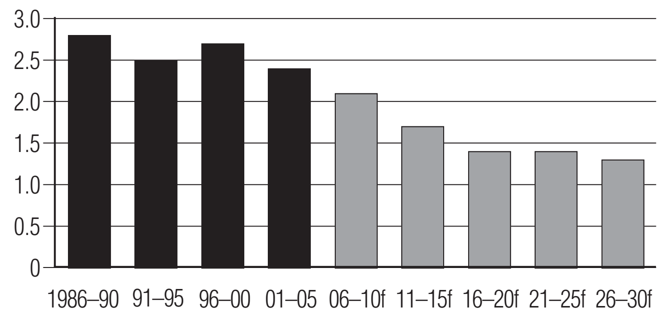
Alan Chaffe

Prince Edward Island

OVERVIEW

Prince Edward Island will experience reasonable long-term growth, thanks to a positive demographic outlook. The Island will lead the Atlantic provinces in gross domestic product (GDP) growth, averaging 1.6 per cent, compounded annually, over 2006 to 2030. The goods-producing sector will get a boost from manufacturing, which is forecast to grow at an average annual compound rate of 1.8 per cent. Solid gains in aerospace, food-processing, and the engine, turbine and power transmission equipment industries will help stimulate manufacturing over the long term. The utility sector will also energize the goods-producing sector, advancing by an average annual compound rate of 2.1 per cent over the forecast period.

Chart 1
Real GDP at Basic Prices
(average annual compound growth rate)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Population growth will benefit from positive net interprovincial migration, reinforcing the province's image as a retirement haven for Atlantic Canadians. Prince Edward Island will post the highest average population growth rate in the Atlantic region, a demographic trend that will help sustain consumption growth in the long term. Growth in the consumption of services will be particularly strong, as an aging population tends to purchase relatively more services, such as health care and travel.

Overall, compounded real economic growth will advance by a healthy annual average of 2.1 per cent per year in the medium term (2006 to 2011), but weakening demographic fundamentals will help limit growth to 1.4 per cent over the long term (2012 to 2030). (See Chart 1.)

DEMOGRAPHIC PATTERNS

Population on the Island is projected to rise from 138,388 in 2006 to 160,849 in 2030, for an average annual compound growth rate of 0.6 per cent. The province will post modest population gains over the medium term, with an average compound growth rate of 0.5 per cent expected from 2006 to 2011. Population growth is expected to gain momentum over the longer term as baby boomers begin to retire on the Island, especially those from Atlantic Canada. Additionally, good employment prospects and quality-of-life considerations should provide incentives for younger residents to remain in the province. Overall, these two factors are expected to result in compounded annual population growth of 0.7 per cent from 2012 to 2030.

Prince Edward Island will post the highest average population growth rate in the Atlantic region.

The main driver behind the Island's upbeat population forecast is interprovincial migration. (See Chart 2.) Net interprovincial migration, 205 in 2006, is expected to make steady gains, reaching 688 people a year in 2030. Over the forecast period, net interprovincial migration will add a total of 13,540 people to the Island's population, an average of 542 people per year. All other Atlantic provinces are expected to experience interprovincial emigration over the forecast period.

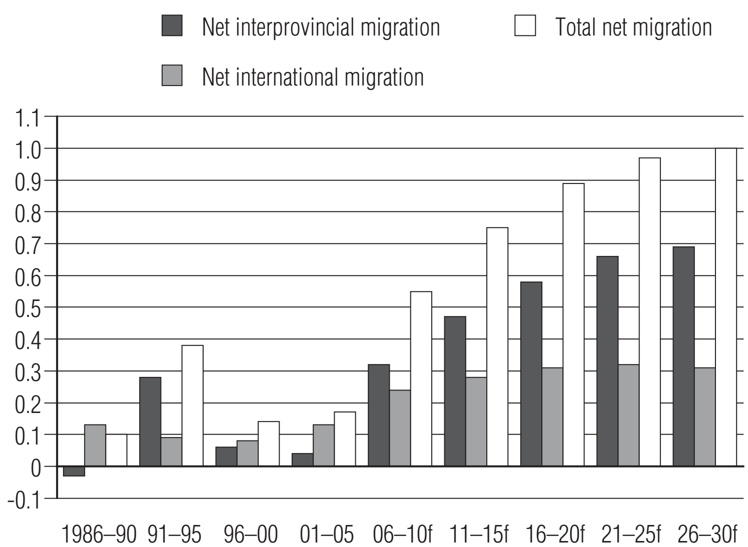
Also helping to brighten the demographic outlook is an expected boost from international migration. Net international immigration will number 250 people in 2006, and will increase to approximately 311 people per year by

Table 1
Key Demographic Assumptions

Components	Assumptions
Population maintains growth	Prince Edward Island's population is expected to grow at an annual average rate of 0.6 per cent over 2006 to 2030, but the average age of the population will steadily increase.
Provincial migration ramps up	After a poor showing in the last few years, Prince Edward Island's net interprovincial migration will gain momentum, averaging 542 people per year over the forecast period.
International migration stabilizes	After contributing 250 people in 2006, net international migration will grow to 311 people in 2030, averaging 291 people per year.
Fertility rate too low	The fertility rate in Prince Edward Island is 1.53, well below the replacement rate of 2.1.
Natural rate reduces gains	The natural rate of increase is expected to draw down population growth as the number of deaths will begin outpacing the number of births in 2024.

Sources: The Conference Board of Canada; Statistics Canada.

Chart 2
Prince Edward Island's Migration Profile
(thousands of persons)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

2030. Overall, net international immigration is expected to boost the population of the Island by 7,273 people over the forecast period.

Dampening the demographic projection for the province is the declining number of women of prime childbearing age over the forecast period. Compounding this problem, the Island's fertility rate is only 1.53, well below the standard replacement rate of 2.1. The decline in women of childbearing age and the relatively low fertility rate will make it impossible to sustain current population through natural increase (births minus deaths) in the long term.

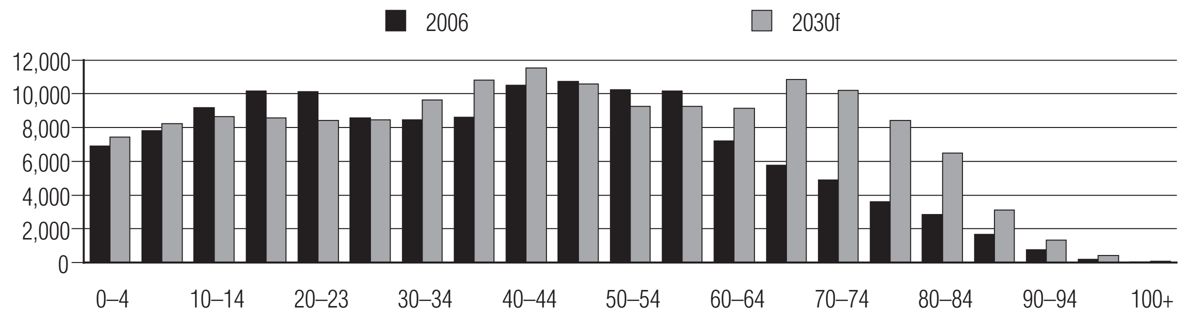
The decline in women of childbearing age and the relatively low fertility rate will make it impossible to sustain current population through natural increase.

Another pronounced trend in the Island's demographic situation is the rising number of seniors. The proportion of those aged 65 and over is expected to increase from 14.3 per cent in 2006 to 25.4 per cent by 2030. (See Chart 3.) Despite advances in medical technology that have increased life expectancy, an older population inevitably implies an increase in the death rate. An increasing death rate can be expected to suppress total population growth.

Annual growth in the labour force on the Island will outpace population growth from 2006 to 2011. However, with the average age of the population rising over time, growth in the labour force will fall below total population growth beginning in 2012. Even with labour force growth expected to slow to an annual compound rate of 0.2 per cent from 2012 to 2030, the Island will outpace the other Atlantic provinces, which are anticipating negative compounded labour force growth.

Helping slow labour force growth is the downward trend in the participation rate. However, as the aging workforce retires and more Atlantic Canadians choose the

Chart 3
Population Increases in Older Age Cohorts
(number of people)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Island as a retirement destination, the participation rate is expected to decline, reaching 62.1 by the end of the forecast.

POTENTIAL OUTPUT AND PRODUCTIVITY

This long-term economic forecast is guided by the concept of potential output, which is the highest level of economic activity an economy can attain without surpassing its capacity limits and igniting inflation. Potential output cannot be directly measured; as such, the Conference Board uses a structural production function to obtain an estimate of potential. We assume that the production function takes a Cobb-Douglas form, in which the mix of labour, capital and technical efficiency are modelled to produce potential output. With this assumption, our estimate of potential output is dependent on potential employment, capital and trend total factor productivity (TFP).

Potential employment measures the contribution of labour to potential output by estimating the available workforce when the economy is operating at capacity. Under these conditions, the labour force participation rate is at its structural peak and unemployment is at its “natural rate.” Therefore, movements in the structural participation rate and the natural rate of unemployment are the two main factors driving changes in labour’s contribution to output over the long term.

The natural rate of unemployment defines a minimum level of unemployment that would persist with some people in transition between jobs and others preferring not to work at the current wage. Unemployment resulting from workers in transition is expected to decline over the forecast. This will occur because there will be an increase in the average age of the labour force, and older workers are not as likely to quit their jobs to look for other work. Thus, the natural rate of unemployment is expected to trend slowly downward over the forecast period, positively contributing to labour potential.

On the other hand, the aging labour force will detrimentally affect labour potential through the labour force participation rate. As workers move into older age cohorts, their aggregate labour force participation generally declines as a result of health problems or early retirement. Consequently, the overall participation rate is expected to decline sharply over the next 25 years as a significant

Table 2
Key Determinants of Long Term Growth

Components	Assumptions
Labour force restrains potential	An aging population means that participation rates will fall, limiting labour’s average annual contribution to potential output from 0.5 percentage points over the medium term to 0.1 percentage points over the long term.
Investment is important	Dwindling labour supplies will lead firms to invest in capital to remain competitive. The capital stock will contribute, on average, 0.6 percentage points to potential output.
Productivity slows	Productivity growth will slow as the share of the service sector increases. Productivity will contribute an average of 0.8 percentage points to potential output over the forecast.

Sources: The Conference Board of Canada; Statistics Canada.

share of baby boomers move into their retirement years. On balance, the negative effects of declining participation rates will outweigh the benefit derived from a lower natural rate of unemployment. Therefore, labour's contribution to potential output will decline steadily over the long term. Overall, labour's annual contribution to potential output growth will average 0.5 percentage points over 2006 to 2011 and will then decline to an average of 0.1 percentage points over the remainder of the forecast.

The value of Prince Edward Island's productive capital is the second factor of production required to calculate potential output. The Conference Board of Canada does not rely on a measure of potential or optimal capital stock; instead, we assume that productive capital is accurately measured and that the level of capital available in the economy at any moment is all that is available to contribute to potential output. Total public and private capital, excluding residential assets, contributes to the level of productive capital. Over the forecast period, the net capital stock is assumed to increase each year by the amount of new investment, net of depreciation and discarded capital. The contribution of capital to potential output growth will average about 0.6 percentage points per year over 2006–30.

Overall, labour's annual contribution to potential output growth will average 0.5 percentage points over 2006 to 2011 and will then decline.

The technical efficiency with which capital and labour are utilized to produce output is measured by TFP. Over history, TFP is calculated residually, using the logarithmic form of the Cobb-Douglas production function, so that changes in output not explained by labour or capital are attributed to changes in technical efficiency. It should be noted that, for purposes of this calculation, total output is defined as real output at basic prices for all industries, excluding paid and imputed rent. Paid and imputed rent is excluded because the Board's estimates of the capital stock do not take into account residential assets, since these do not contribute to the productive capacity of the economy.

TFP fluctuates considerably over the business cycle. The reasons for this are wide-ranging but include changes in the mix between capital and labour, relative shifts in the types of capital purchased, shifts in labour productivity as labour force skills evolve, and tax changes. In order to remove the effects of volatile short-term movements, potential output is calculated with trend TFP, which is our residual measure smoothed with a Hodrick-Prescott filter. Over the long term, trend TFP growth is expected to be robust. With the growth in the number of workers dwindling, to maintain growth in TFP, firms will need to continually invest in productivity-enhancing technology and the skills development of their workforce. The contribution of TFP to growth in potential will remain in line with recent historical performance, contributing roughly 0.8 percentage points to growth annually over the forecast horizon.

In the long run, the economy is expected to perform at close to its potential.

When actual real GDP diverges from potential output, an economy is said to have an output gap. Over the medium term, average real GDP growth of 2.1 per cent will result in a significant narrowing of the output gap that opened earlier in the decade, with closure expected in around 2010. In the long run, the economy is expected to perform at close to its potential and thus alleviate concerns for inflationary pressures. (See Chart 4.) The Consumer Price Index is expected to remain within the Bank of Canada's target range, averaging 1.9 per cent over the forecast horizon.

EMPLOYMENT AND INCOME

Given the stable long-term economic outlook for the Island, employment will continue to make yearly gains, but the momentum is expected to soften. Employment will post average robust growth of 0.8 per cent over the medium term before sliding back to average annual growth of 0.2 per cent from 2012 to 2030. Driven by increased demands brought about by the aging population, the service sector will account for nearly 63 per cent of all employment gains over the forecast period.

These moderate gains in employment, together with a relatively stable labour force, imply a tightening in labour market conditions as the reduction in the growth of labour supply aligns more closely with demand. This tightening will cause the unemployment rate to fall marginally throughout the forecast. The Island's unemployment rate was a relatively low 11 per cent in 2006; it is expected to decline only marginally to 10.5 per cent by 2030, remaining the second highest provincial rate in the country. (See Chart 5.)

Two important factors are expected to boost personal disposable income growth over the forecast. First, investment in education and innovation is expected to lead to productivity gains. This will boost gains in wages and salaries per employee. Second, with the population aging, non-salary income, such as pension payments, will rise over the final years of the forecast, boosting household income. Consequently, personal disposable income is expected to rise at a compounded annual average of 3.7 per cent over the forecast period.

AGGREGATE DEMAND

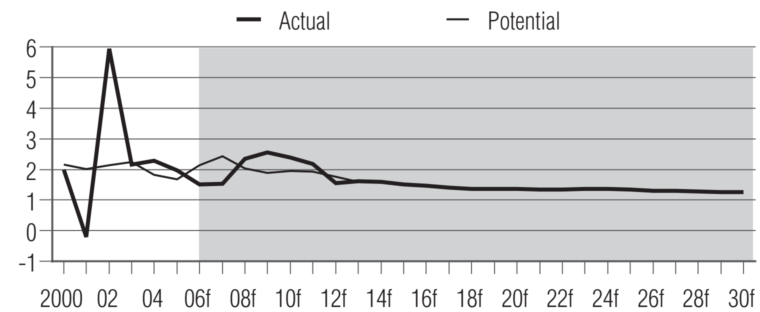
CONSUMPTION

As the strongest population growth in the Atlantic region will be on Prince Edward Island, the province will also have the strongest consumer spending growth. Nominal consumer spending is forecast to grow by a compound annual average of 3.8 per cent over the forecast. Increased competition from the mainland and reduced transportation costs, thanks to the Confederation Bridge, will help keep consumer prices on a par with those in the other Maritime provinces, especially for retail goods.

Consumer spending is forecast to grow by a compound annual average of 3.8 per cent.

Over the long term, the rising share of older people in the population will result in a change in the structure of consumer spending. Older people tend to purchase relatively more services, such as health care and travel, and fewer durable goods. From 2012 to 2030, nominal spending on goods will grow by an average annual compound rate of 3.2 per cent, while spending on services other than rent will grow by 5 per cent annually. As a result, the share of services other than rent in total consumer spending will rise from 32.4 per cent in 2006 to 41.5 per cent in 2030.

Chart 4
Actual versus Potential GDP Growth
(percentage change)

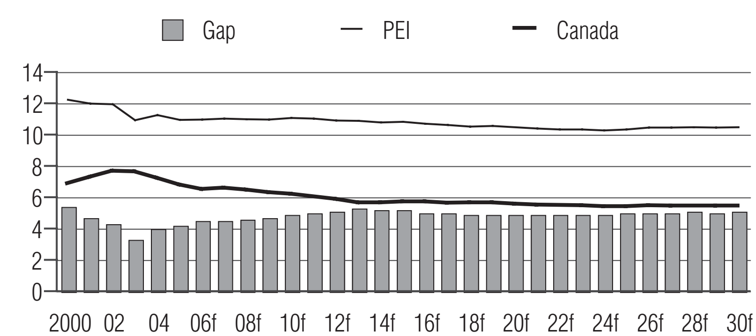


f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

INVESTMENT

Total nominal investment spending in Prince Edward Island is expected to be strong from 2006 through 2030. Growth in food processing, high-tech manufacturing and the tourism industry are expected to help compound growth in non-residential investment reach 4 per cent annually over the forecast period. Machinery and equipment investment will benefit from a relatively strong manufacturing sector and a robust utilities sector. Overall, investment in machinery and equipment is expected to grow at an average annual compound rate of 2.6 per cent over the forecast period.

Chart 5
Unemployment Rate
(per cent)



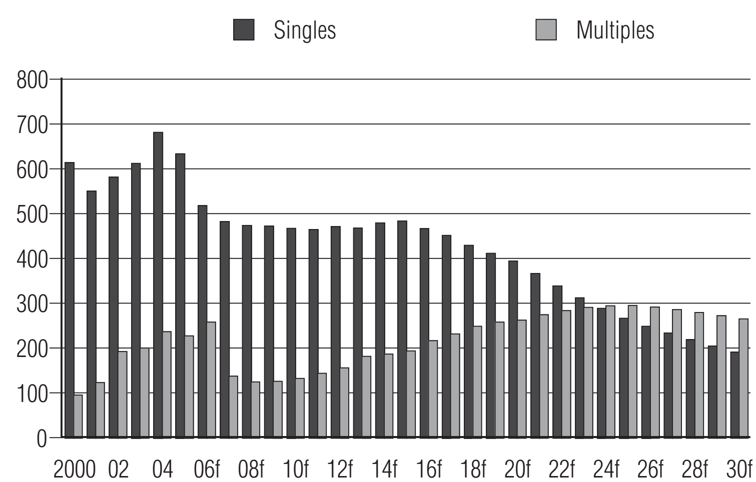
f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

The growing number of immigrants calling the Island home will help keep housing starts high over the first half of the forecast. Starts will average 643 units from 2006 to 2015. Housing starts will decline to 593 units per year during the last half of the forecast, consistent with the national trend. Overall, housing starts are expected to decline by 5.8 per cent in Canada over the forecast horizon, but by only 4.7 per cent on the Island. As seniors continue to age and move into smaller homes and apartments during the last half of the forecast, multiple housing units will post strong gains, offsetting the decline in single housing starts. Multiple housing starts will average 165 units per year from 2006 to 2015, and will grow to an average of 271 units over the last 15 years of the forecast. In contrast, single housing starts are expected to decline substantially, from an average of 479 units for the first 10 years of the forecast to 322 units in the remaining years. (See Chart 6.)

GOVERNMENT

Public finances continue to be a source of concern in the medium term, with the provincial government battling a budgetary deficit estimated to be $12.5 million for fiscal year 2006–07. With prudent expense projections in the next few years, government finances are expected to become healthier. While the other provinces in the Atlantic region face a stagnant or even declining population, positive demographics may provide some relief to the provincial government. On the downside, even though a positive demographic trend will provide a larger tax base, the fact is that a larger proportion of this population will be elderly, and they will put a drain on provincial coffers through increased expenditures on health care. The growing demand for health care will put upward pressure on budget spending in the long term. As a result, nominal spending on government goods and services will expand at a compound rate of 4.4 per cent annually from 2006 to 2030.

Chart 6
Total Housing Starts
(units)



f = forecast
Sources: The Conference Board of Canada; Canada Mortgage and Housing Corporation.

INDUSTRY ANALYSIS

The utilities sector will lead growth in the goods-producing sector with an annual compound growth rate of 2.1 per cent over the forecast horizon. Many large-scale energy projects are under construction on the Island, and the province plans to attain all of its energy from renewable sources by 2015. The manufacturing sector will continue to support growth in the goods-producing industry, posting annual compound growth of 1.8 per cent from 2006 to 2030. This growth will be led by strength in aerospace, food-processing, and engine, turbine and power transmission equipment. Innovation and improved farming practices will help sustain the agriculture industry in the medium term. In the long term, agricultural growth may be constrained by limits in the amount of arable land. Overall, agricultural output is expected to expand at 1.5 per cent, compounded annually, over 2006 to 2030.

Even though a positive demographic trend will provide a larger tax base, a larger proportion of this population will be elderly.

The modest expansion in manufacturing activities and the stable growth in agricultural output will yield stable results for wholesale trade on the Island. Wholesale trade activities are expected to expand moderately by an annual compound average of 1.3 per cent per year through the entire forecast. The strongest sector in the economy over the period will be retail trade, which is expected to advance at an annual compound growth rate of 2.3 per cent. Solid consumer spending, a rising population, increases in wages and salaries per employee and a strong tourism sector will sustain demand for consumer goods, helping retail trade to advance.

Prince Edward Island has long been a favoured destination for tourists from Canada, New England and Japan. Over the last decade, the reduced travel time made possible by the Confederation Bridge has rapidly expanded the number of visitors. This has helped boost investment spending in the tourism industry, resulting in more accommodations, meeting spaces and golf courses. Now considered a premium golf destination, the province should profit from the growing popularity of this sport. However, the tourism industry has been on a bumpy ride over the last few years, primarily as a result of the high level of the Canadian dollar and elevated gasoline prices. Tourism, however, will get a boost from Sunwing Airlines, which started offering service to and from Toronto in June, and from the completion of the wharf in Charlottetown harbour, which is expected to stimulate cruise ship traffic. Additional provincial funding to Golf PEI over the next three years will also help lure tourists in an industry that has an economic impact of more than $90 million. Overall, tourism growth is expected to be solid in the long term, helping boost compound growth in retail sales to 4.3 per cent over the forecast, the highest among all Atlantic provinces.

As baby boomers retire across Canada, Prince Edward Island will see a rise in net interprovincial migration and tourism, contributing to growth in the service sector. This will shift the composition of consumption from goods to services, especially in the latter years of the forecast. The service sector is expected to outpace the goods-producing sector from 2017 until the end of the forecast. Leisure services will gain the most from this shift, as the baby-boomer retirees are expected to be wealthier than previous generations of retirees. With an increased share of older people in the population, services related to health care will also increase significantly. The output of non-commercial services, including health care, will expand at a compound rate of 2.1 per cent annually. Overall, the service sector will experience average compound growth of 1.6 per cent per year from 2006 to 2030, above the growth rate of 1.4 per cent expected for the goods-producing sectors.

Prince Owusu

Nova Scotia

OVERVIEW

The Nova Scotia economy is anticipated to advance by an average of 1 per cent annually from 2006 to 2030, ranking it ninth among the provinces. Growth in most of the domestic industries is expected to soften during the forecast period. In particular, the production of mineral fuels will drop by an average of 1.2 per cent annually as exploration activities lose momentum, with attention shifted from the Scotian shelf to Western Canada and the Territories. The reduction of exploration activities will slow growth in mining services to an average of 1.9 per cent over the forecast, compared with 15.3 per cent between 1994 and 2005. ExxonMobil, one of the biggest petroleum players in Nova Scotia, abandoned half of its exploration licenses in 2004 as more holes turned up dry. This created anxiety among other offshore explorers and led to a loss of over $650 million in exploration commitments at the end of 2006. The uninspiring finding rate could lead to further evaporation of the $917 million in exploratory licenses the province is counting on between now and 2012. This could kill prospects on the Scotian Shelf. Owners of the Sable Island natural gas project have also scaled back reserve estimates in the field, effectively reducing the life of the project by 10 years. The loss in momentum in offshore oil and gas activities does not bode well for the construction industry. Anadarko Petroleum Corp has cancelled the $650-million liquefied natural gas plant it was proposing to build in the Cape Breton area because it could not secure a supply of natural gas for the project. This has dashed the hopes of construction workers counting on the project to compensate for the end of the housing boom.

Nova Scotia will face a number of fundamental demographic challenges over the forecast period. First, the average age of the population will gradually increase as the baby boomers inch closer to retirement. The aging of the baby boomers will put enormous strain on the province's fiscal prospects. While more spending on facilities and services will be required for health and long-term care for the baby boomers, the aging of the population will slow economic growth and thus the government's revenue-generating capacity. A compositional shift in consumer spending will also result as people buy fewer durable goods and consume more services. Second, low fertility rates and negative interprovincial migration will slow population growth in the province.

Nova Scotia will face a number of fundamental demographic challenges over the forecast period.

Weak demographic fundamentals are expected to dominate the population outlook, exerting a profound impact on the province's labour market and the economy. Overall, economic growth is projected to reach an average of 1.9 per cent over 2006–10 and to decelerate to 1.1 per cent over the next decade. The consequences of the demographic change will further slow the economy in the last decade of the forecast. Growth in real gross domestic product (GDP) is expected to average 0.5 per cent from 2021 to 2030. (See Chart 1.)

DEMOGRAPHIC PATTERNS

Nova Scotia's population is expected to assume a bell-like shape over the forecast as international immigrants boost the head count at the beginning of the forecast while a rising death rate weighs down the head count toward the end of the forecast. Rising from 933,949 in 2007, the population is expected to increase yearly by an average of 449 persons in the following three years. The head count will grow faster, by an average of 0.1 per cent, or 605 persons per year, from 2011 to 2020 as more people immigrate from abroad. After reaching an all-time high of 941,517 by 2021, the province's population will begin to decline rapidly to reach 931,712 by the end of the forecast. This represents a loss of 0.1 per cent per annum between 2021 and 2030. The drop reflects weaknesses in most of the key drivers of population growth: natural increase in population (the difference between births and deaths), net interprovincial migration (the difference between people arriving from other provinces and those leaving for other parts of Canada) and net international migration (the difference between people immigrating to Nova Scotia from other countries and those emigrating).

The only good news influencing the provincial population is the positive net inflow of migrants from other countries. A total of 41,430 more people will immigrate to Nova Scotia than will leave for other countries during the forecast period. At 1,158 in 2005, net international migration is projected to grow by an average of 3.3 per cent or 1,543 people per annum from 2006 to 2020. During the last decade of the forecast, growth in net international migration to the province is expected to slow to 0.1 per cent as competition to attract immigrants from abroad increases in developed countries and improved conditions in developing countries reduce the number of economic migrants.

Table 1
Key Demographic Assumptions

Components	Assumptions
Population growth declines	Nova Scotia's population is expected to increase until 2021 and then to decline gently in the last decade of the forecast.
Interprovincial migration restrains population growth	Nova Scotia will continue to lose young people to other provinces. It will lose 714 people more every year than will migrate there from other parts of Canada.
International migration to the rescue	Net international migration will remain strong, with the province receiving a total of 41,430 people over the forecast.
Fertility rate too low	Nova Scotia's fertility rate of 1.38 is well below the replacement rate of 2.1.
Natural rate of population increase reduces gains	The natural rate of Increase is expected to whittle down gains in international migration as deaths begin outpacing births in 2007.

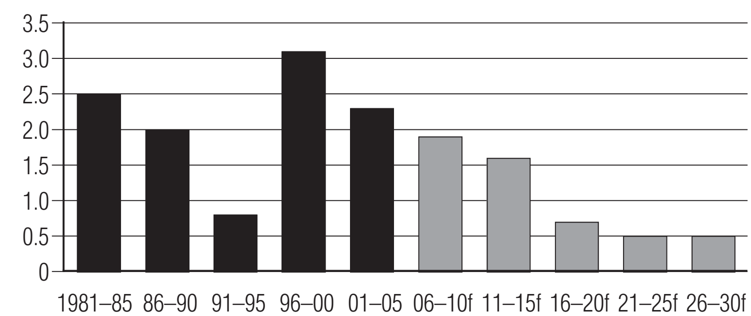
Sources: The Conference Board of Canada; Statistics Canada.

A total of 41,430 more people will arrive than will leave for other countries during the forecast period.

The natural increase in the population, which has been steeply declining since 1961, will actually become negative from 2007 onward—sooner than originally anticipated—largely because of a low fertility rate. The aging of the baby boomers will also add to the slumping natural rate of increase in the long run. As the baby boomers progress into their senior years through the forecast period, the proportion of the population aged 65 years and older will swell from 14.5 per cent in 2006 to 27.3 per cent in 2030. (See Chart 2.) Even with improved health care, this will lead to a steady increase in deaths, which will outpace the number of births in the province over the long term. As this process unfolds, the percentage of women of childbearing age (15 to 44) will decrease from 40.3 per cent in 2006 to 32.8 per cent in 2030. The fertility rate will plateau at 1.38, well below the replacement rate of 2.1, and it is unlikely that the key determinants of the fertility rate—such as child care costs, income, availability of birth control, and female participation in the labour force—will change over the next 25 years in favour of larger families. Taken together, these factors will be responsible for a steady decline in the number of births in the province.

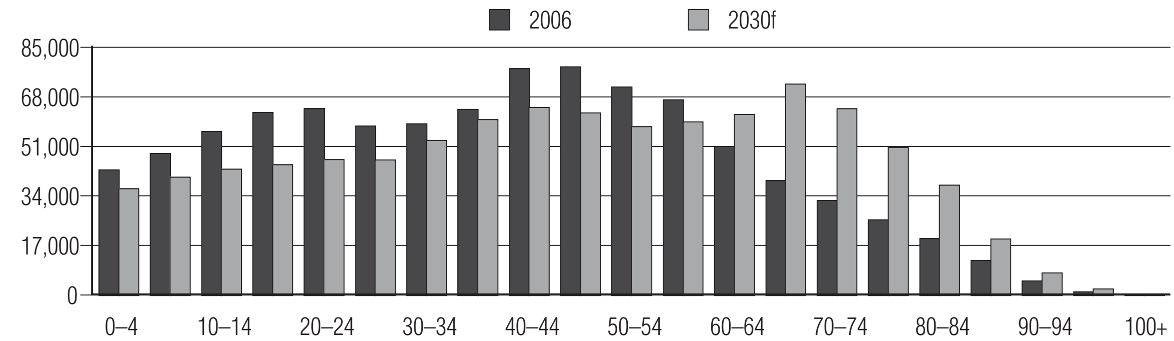
Population growth will be constrained by the steady outflow of Nova Scotians to other parts of Canada throughout the forecast. The province will continue to be a net loser on the interprovincial migration front, losing 17,857 more people than will immigrate from other parts of

Chart 1
Real GDP Growth
(average percentage change, 1997 $)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Chart 2
Population Increases in Older Age Cohorts
(number of people)

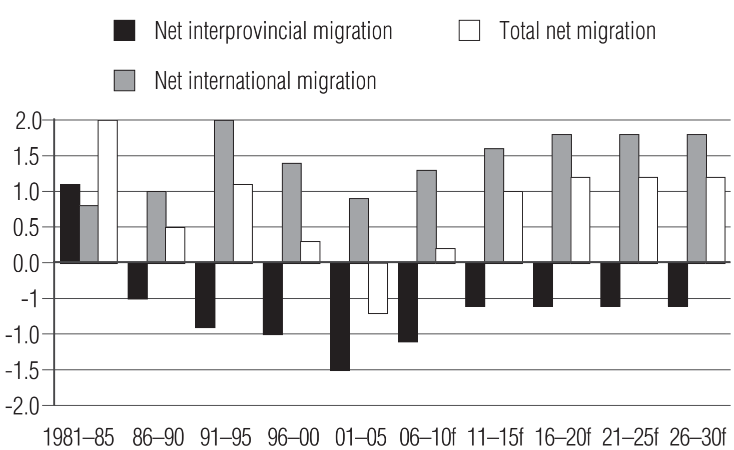


f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Canada—an average of 714 annually over the forecast period. (See Chart 3.) Because many of the Nova Scotians migrating to other parts of Canada will be in the younger age cohorts, the dependency ratio (the ratio of the non-working population to the working population) will rise.

The arrival of fewer international immigrants to the province and the departure of more Nova Scotians for other parts of Canada will add to the declining natural increase; as a result, the provincial population will decline steeply during the last nine years of the forecast.

Chart 3
Nova Scotia's Migration Profile
(thousands of persons)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

LABOUR FORCE

The labour force, defined as the product of the source population—the population aged 15 and over—and the participation rate, will grow more slowly between 2006 and 2011 and will decline thereafter. Growth in the source population is expected to decelerate from an average 0.3 per cent over 2006–15 and to come to a halt in the next decade and a half. In contrast, the participation rate has dropped since hitting an all-time high of 64.7 per cent in 2004 and is expected to continue to nose-dive through the long term to settle at 54.2 per cent by 2030.

The declining participation rate will whittle down all the gains in the source population and mute labour force growth in the first decade of the forecast. As growth in the source population comes to a halt between 2016 and 2030, and the participation rate continues to decline at an even faster pace, labour force growth will actually tumble, declining by 0.8 per cent in the last 15 years of the forecast.

POTENTIAL OUTPUT AND PRODUCTIVITY

This long-term economic forecast is guided by the concept of potential output, which is a measure of the highest level of activity that can be sustained in an economy over a period of time if all inputs of production are fully and efficiently utilized, without surpassing its capacity limits and igniting inflation. The Conference Board uses a structural Cobb-Douglas production function, in which the mix of labour, capital and total factor productivity (TFP) are modelled to produce an estimate of potential output. This estimate depends on potential inputs of labour and capital, and trend total factor productivity, or the technical efficiency with which labour and capital are combined to produce the output.

The workforce available when the economy is operating at full capacity (potential labour force) is used to derive the contribution of labour to potential output. When operating at full economic capacity, the labour force participation rate is at its structural peak and unemployment is at its "natural rate." Therefore, movements in the structural participation rate and the natural rate of unemployment are the two main factors driving changes in labour's contribution to output over the long term.

The natural rate of unemployment defines a minimum level of unemployment that would remain because some people are in transition between jobs and others prefer not to work at the current wage. Unemployment resulting from workers in transition is expected to decline over the forecast. This is because the average age of the labour force will increase over the long term, and older workers are not as likely to quit their jobs to look for another. Thus, the natural rate of unemployment is expected to trend slowly downward over the forecast period, positively contributing to potential labour.

The overall participation rate is expected to decline sharply over the forecast horizon.

On the other hand, the aging labour force will detrimentally affect potential labour through the labour force participation rate. As workers move into older age cohorts, their aggregate labour force participation generally declines as a result of health problems or early retirement. Consequently, with a significant share of baby boomers moving into their retirement years, the overall participation rate is expected to decline sharply over the forecast horizon.

On balance, the negative impact of declining participation rates will outweigh the benefit derived from a lower natural rate of unemployment. Therefore, labour's contribution to potential output will decline steadily over the long term. Overall, labour's annual contribution to potential output growth averaged 0.4 percentage points over 2000–05, but it is projected to slow throughout the medium term and to turn negative starting in 2012.

The contribution of capital to potential output growth is projected to average 0.5 percentage points per year over the 2006–30 period.

The value of productive capital, the second factor in the production process, is assumed to be accurately measured, and the level of capital in the economy at any time is all that is available to contribute to potential output. For the purpose of estimating productive capital in the economy, total public and private capital, excluding residential assets, are aggregated. Over the forecast period, the net capital stock is assumed to increase each year by the amount of new investment, net of depreciation and discarded capital. The contribution of capital to potential output growth is projected to average 0.5 percentage points per year over the 2006–30 period.

Over history, total factor productivity is calculated residually, using the logarithmic form of the Cobb-Douglas production function, so that changes in output not explained by labour or capital are attributed to changes in technical efficiency. It should be noted that, for purposes of this calculation, total output is defined as real output at basic prices for all industries, excluding paid and imputed rent. Paid and imputed rent is excluded because Conference Board estimates of the capital stock do not take into account residential assets, as these do not contribute to the productive capacity of the economy. TFP fluctuates considerably over the business cycle. The reasons for this are wide-ranging, but they include changes in the mix between capital and labour, relative shifts in the types of capital purchased, shifts in labour productivity as labour force skills evolve, and tax changes. In order to remove the effect of these short-term movements on potential output, a Hodrick-Prescott filter is used to smooth out the TFP to produce its trend values. Over the long term, trend TFP growth is expected to be robust. With the growth in the number of workers dwindling, firms will need to maintain growth in TFP by continually investing in productivity-enhancing technologies and the skills development of their workforce. The contribution of TFP to potential growth will remain in line with recent historical performance, averaging roughly 0.7 percentage points annually over the forecast horizon.

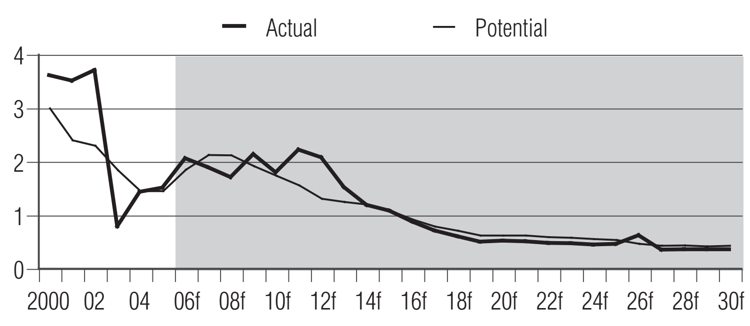
When actual real GDP diverges from potential output, an economy is said to have an output gap. Early in this decade, significant growth in mining activities in the provincial economy helped to spur growth of the economy above its potential. Since the mining industry peaked in 2001, the gap has tended to fluctuate around its potential. In the long term, the economy is expected to perform close to its potential and thus alleviate concerns for inflationary pressures. (See Chart 4.) The Consumer Price Index is projected to remain well within the Bank of Canada's target range, averaging 2 per cent over the forecast horizon.

EMPLOYMENT AND INCOME

In line with the expected slowdown in economic activities, employment growth will ease over the course of the forecast. After a moderate gain of 0.3 per cent per annum over 2006–10, growth in employment is projected to decline by an average of 0.6 per cent over the remainder of the forecast.

Reflecting the moderate medium-term employment gains, Nova Scotia's unemployment rate is expected to fall steadily to reach 6.6 per cent by 2013, representing a decrease of 1.9 percentage points from its 2005 level. After 2013, job losses in the economy will gain momentum; however, the unemployment rate will remain stable at around 6.7 per cent for the remainder of the forecast as the declines in the labour force exceed the number of job losses. Thus, Nova Scotians leaving for better prospects in other parts of the country will minimize the pool of people available to work and keep the unemployment rate in check. By the end of the forecast, the unemployment rate is projected to reach 6.6 per cent, about 1.2 per cent higher than the national average

Chart 4
Actual versus Potential GDP
(percentage change)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Nova Scotia's unemployment rate is expected to fall steadily to reach 6.6 per cent by 2013.

The declining unemployment rate, a sign of a tighter labour markets, and expected productivity gains will boost wages and salaries in the province. (See Chart 5.) Growth in wages and salaries per employee is forecast to average 2.7 per cent per year from 2006 to 2020 and 3 per cent during the last 10 years of the forecast. Federal transfers to the baby boomers will also kick in during these years. In spite of the wage gains and federal transfers to seniors, growth in total personal disposable income in the province is projected to be moderate as the number of wage earners declines in the province. Accounting for inflation, annual growth of real personal disposable income is expected to average 1.4 per cent in over the 2006–15 period and to edge down to 0.8 per cent from 2016 to 2030.

AGGREGATE DEMAND

The changing structure of Nova Scotia's population is expected to influence consumer spending over the next 25 years. Total growth in consumer spending should ease, and a change in expenditure patterns can also be expected as the population ages. As the baby boomers enter their retirement years, growth in consumer spending for services will continue to ease but will still outstrip growth in spending for goods.

Among the consequences of declining and aging population will be a reduction in housing starts. Empty-nest seniors will trade in their family-size homes for smaller accommodations, shifting demand away from single dwelling units to multiple units. Furthermore, a much smaller cohort will replace the large number of people currently in their prime homebuying years. As a result of the demographic change, housing starts are projected to decline over the forecast, from 5,047 units in 2006 to

633 units by the end of 2030, representing a drop of 86.7 per cent, or an average decline of 7.8 per cent annually over the entire forecast. This will limit the expansion in residential construction investment.

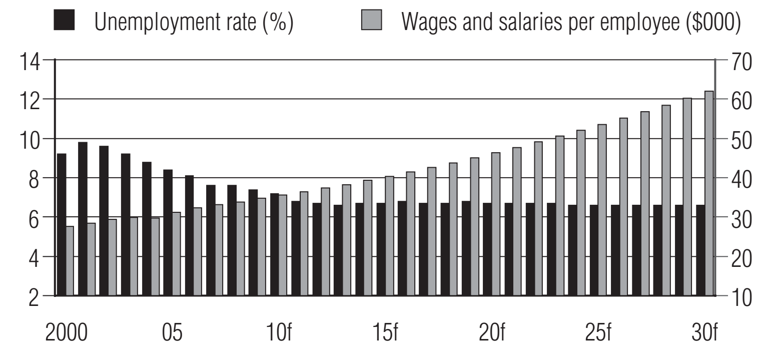
Non-residential construction investment is expected to undergo a roller coaster ride throughout the forecast, with continued fluctuations in offshore exploration and drilling. Lack of natural gas supply has stalled the $650-million liquefied natural gas plant Anadarko proposed to build, dashing the hopes of 700 construction workers in job-starved Cape Breton. With the high downside risks associated with Anadarko's liquefied natural gas project, the Conference Board has chosen not to incorporate the $4-billion petrochemical and natural gas plant proposed by Keltic Petrochemical Ltd until all the ducks for the project fall in line.

The government will have to be fiscally disciplined to prevent the escalation of net debt.

Notwithstanding the lack of major investment in the Scotian Shelf, there is a mix of residential and commercial plaza developments keeping construction workers busy in the province. Banc Development Inc broke ground in the summer of 2006 on its ambitious $300-million retail and residential development at Rocky Lake, while Clayton Development is building a $400-million community with retail spaces near Russell Lake in Dartmouth. These projects, including major capital expenditures in the utility and manufacturing sectors and expansion and modernization of the Halifax International Airport, will help boost non-residential construction investment by 9.8 per cent over 2006–07.

After a brief respite in 2008, intense construction activity will begin in 2009: EnCana will begin the Deep Panuke natural gas project, on a much smaller scale than originally planned, once its economic viability is assured. Associated closely with this project is the expansion of the Maritimes & Northeast Pipeline. These projects will bolster growth in non-residential construction investment by an average of 4.5 per cent over 2009–13. After production begins at Deep Panuke, growth in non-residential construction investment will slow to an average of 2.3 per cent per year over the remainder of the forecast.

Chart 5
Nova Scotia's Tightening Labour Market



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

With a weakening economy generating minimal revenues, the government will have to be fiscally disciplined to prevent the escalation of net debt, currently $12.2 billion. As the forecast progresses, the government will reduce some expenditures to finance critical services, like education and health care. Increased spending on health care will be a response to pressure from the aging baby boomers, and spending will have to be boosted on education to increase innovation and labour productivity as the labour market tightens in the long term. Though spending on health care and education will increase throughout the forecast, spending restraint in other areas will limit the contribution of government spending to economic growth. Growth in government spending on goods and services in real terms will average 2.7 per cent annually over 2006–10 and decelerate to an average of 1.7 per cent through the remainder of the forecast.

INDUSTRY ANALYSIS

Nova Scotia's goods-producing industries will face significant challenges as growth averages only 0.8 per cent annually over the forecast period. Dimmed prospects for offshore energy investment are expected to slow the production of fabricated metals. Dwindling fish stocks after many years of overfishing will also hurt the food-processing sector. More significantly, demand for paper is expected to drop dramatically over the long term as a result of advances in technology and the media, hurting the pulp and paper industry. The weaknesses in these sectors, plus reduced demand for manufactured goods from an aging population, are expected to dampen manufacturing, combining to bring manufacturing growth to 0.7 per cent during the last decade of the forecast. But there will be some bright spots in manufacturing: those engaged in producing pharmaceutical products and medical equipment are expected to do well.

Recent studies by the federal government indicate that cod stocks have not recovered since the moratorium on cod fishing was imposed.

Sable Island offshore gas production has slowed considerably, and the partners have reduced their estimate of total reserves in the fields, to a figure 63 per cent lower than initially estimated. This has fuelled speculation that the lifespan of the project could be 10 years less than the 25 years originally projected. Reserve estimates for Deep Panuke, the second gas field planned for development, have also been reduced to 28.3 billion cubic meters from initial estimates of between 74 and 99 billion cubic meters. The owners have downsized the project by 50 per cent, calling for the production of 200 million cubic metres of gas per day. Gas production, expected to begin sometime in 2011, will peak a year afterward, but growth in mineral fuel will decline with the fast depletion of gas from the larger Sable field. Overall mining output will drop by 0.5 per cent over the forecast.

The outlook is also subdued for other industries. Fishing, which thrived in Nova Scotia until the late 1980s, will face difficult challenges over the forecast. Unfavourable sea temperatures have limited the production of plankton, forcing herring to eat cod eggs. Recent studies by the federal government indicate that cod stocks have not recovered since the moratorium on cod fishing was imposed. Stocks of other fish species are also on the decline, and lobster carapace has been slashed. The fishing industry will advance by only 0.6 per cent annually over the forecast, in contrast to average growth of 14.7 per cent per annum from 1988 to 1991. Weak housing starts, at home and south of the border, and low demand for pulp and paper are expected to result in an average annual decline of 1 per cent in the forestry sector over the forecast.

With seniors, the largest bulk of the population, preoccupied with health issues rather than shopping, demand for consumer goods is expected to slow. Growth in domestic trade is expected to decelerate from an average of 3 per cent per annum from 2006–10 to a mere 1.2 per cent annually over the balance of the forecast. Services, particularly those tailored to the needs of the aging population, plus improvements in education to enhance productivity, will also progress steadily, helping non-commercial services to advance by an average of 1.6 per cent per year over the course of the forecast.

Prince Owusu

New Brunswick

OVERVIEW

Real gross domestic product (GDP) in New Brunswick is projected to grow at a relatively slow average rate of 1.1 per cent from 2006 to 2030, for eighth rank among the provinces. Weaknesses in the construction and transportation sectors will limit overall economic growth as the province grapples with the completion of megaprojects. Forestry will also add to the slow pace of economic growth as the annual allowable cut continues to decline and structural changes in market conditions stifle demand for pulp and paper. Metal mining is the only industry expected to grow by more than 2 per cent over the entire forecast. A recent rally in metal prices has engendered exploration and drilling activities that are likely to yield better results. Two mines that were shut down in 1998 have now reopened, softening the blow of the impending shutdown of the Brunswick mines in 2008.

Metal mining is the only industry expected to grow by more than 2 per cent over the entire forecast.

In the medium term, however, the construction industry will be propped up by energy investments, as well as by capital spending on health-care facilities and municipal infrastructure. Work is underway on Irving Oil's $750-million liquefied natural gas project at the Canaport terminal near Saint John, a project expected to engage more than 500 construction workers for nearly three years. The provincial government is also going ahead with the multimillion-dollar refurbishment of the Point Lepreau nuclear plant. In another large venture, Irving Oil is planning to build a second refinery in New Brunswick that could cost as much as $5 billion.

Weak demographic dynamics will dominate the outlook over the long term. One notable factor will be a rise in the average age of the population. As the proportion of those older than 65 increases, consumption patterns will change for both government and consumers. Spending on health care will have to rise significantly to meet the changing needs of the aging population. In addition, rising net international immigration will be largely offset by a net outflow of people to other parts of Canada. Finally, New Brunswick's fertility rate, one of the lowest in the country, will be a drag on population growth. Total population is projected to shrink every year over the forecast.

New Brunswick's fertility rate will be a drag on population growth.

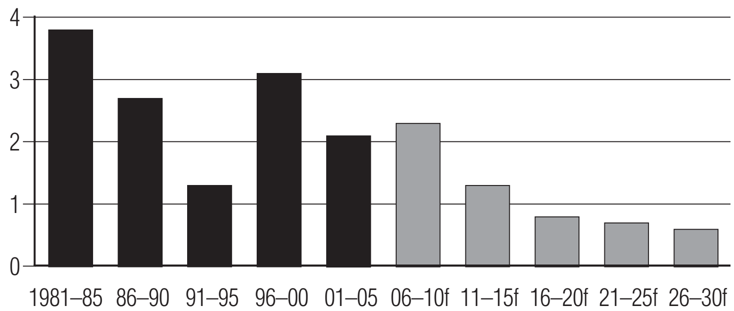
The weakening population outlook will have significant consequences for the province's labour market and overall economic growth. The Conference Board expects growth in real GDP to decelerate from an annual average of 2.3 per cent in the first five years of the forecast to 1.1 per cent over 2011–20 and still further to 0.6 per cent from 2021 to 2030. (See Chart 1.)

DEMOGRAPHIC PATTERNS

Over the long term, demographic fundamentals are among the key factors that influence the outlook for an economy. The structure and composition of population have a significant influence on the labour force, which is a key ingredient in determining potential output. Furthermore, the demographic profile of the population strongly affects consumer spending patterns.

A trend with profound implications for the New Brunswick outlook over the forecast period is reflected in the weak population forecast. (See Table 1.) Since reaching its peak of 752,420 people in 1997, the province's population has been declining as the result of a low fertility rate and the departure of more young people from the province for other parts of Canada. The number of people living in the province will continue to fall until Irving Oil begins work on its proposed second refinery

Chart 1
Real GDP Growth
(average annual compound growth rate)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Table 1
Key Demographic Assumptions

Components	Assumptions
Population declines	New Brunswick's population is expected to decline by an annual average rate of 0.1 per cent over 2006–30, and there will be steady increases in the average age.
Interprovincial migration restrains population growth	New Brunswick will continue to lose its young people to other provinces. It will lose 774 more people annually than will migrate there from other parts of Canada.
International migration remains positive but still low	Net international migration will remain strong: the province will receive a total of 18,250 people over the forecast.
Fertility rate too low	New Brunswick's fertility rate of 1.41 is well below the replacement rate of 2.1.
Natural increase	The natural rate of increase is expected to whittle down gains in international migration as the number of deaths begins outpacing the number of births in 2009.

Sources: The Conference Board of Canada; Statistics Canada.

in 2009, helping to stem the constant losses in net interprovincial migration. The head count will shrink every year after the refinery project wraps up in 2011, with the rate of decline increasing toward the end of the forecast. By the end of the forecast period, total population will stand at 729,444, or 26,744 fewer people than in 2005, representing an average annual decline of 0.1 per cent. This weak demographic outlook will limit overall economic gains.

Two key assumptions underlie New Brunswick's dismal population outlook. First, the natural increase in population (that is, the excess of births over deaths) will continue to decline, actually becoming negative by 2009 with the aging of the population. As throughout Canada, the average age of the population is rising dramatically. Currently 39 years, the average age within the province will hit 46 by the end of the forecast. As the baby boomers move up the population pyramid, the proportion aged 65 and over will swell from 14.2 per cent in 2006 to 28.2 per cent in 2030. (See Chart 2.) The movement of the population into the older age cohorts will ultimately lead to a rise in the number of deaths, despite advances in medical care.

Limited job opportunities will lead workers, especially younger people, to leave the province.

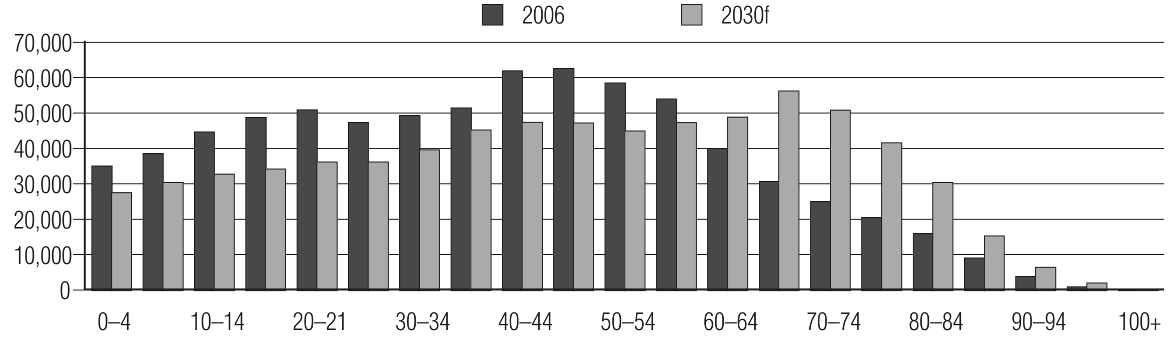
The province's aging population will also constrain the number of births over the forecast period, as a smaller cohort will replace women currently in their childbearing years (between 15 and 44 years old). Those women comprise 40.3 per cent of the total female population in New Brunswick. When, by 2030, this proportion declines to 31.8 per cent, the number of births in the province will drop as well. Magnifying the birth problem is a low fertility rate. New Brunswick's fertility rate, 1.41, is one of the lowest in the country and far below the replacement rate of 2.1. The rising number of deaths and the declining number of births will convert the natural rate of increase into a natural rate of decrease after 2009.

A second major reason for expecting the population to decline in New Brunswick is the province's weak migration profile. Limited job opportunities will lead workers, especially younger people, to leave the province in search of better prospects after construction wraps up at Irving Oil's second refinery project in 2011. The province is expected to lose an average of 811 people more per year than it gains in immigration from other parts of the country from 2012 to the end of the forecast. (See Chart 3.)

LABOUR FORCE

New Brunswick's shrinking population will have a dramatic impact on the province's labour market. A steady exodus, especially of younger people, and the province's

Chart 2
Population Increases in Older Age Cohorts
(number of people)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

low fertility rate will limit growth in the source population over the long term. It is expected to start decelerating in 2011 and to turn negative during the last 14 years of the forecast. On the other hand, the participation rate is expected to deteriorate from its all-time high of 63.9 per cent in 2004, dropping to 54.3 per cent by 2030.

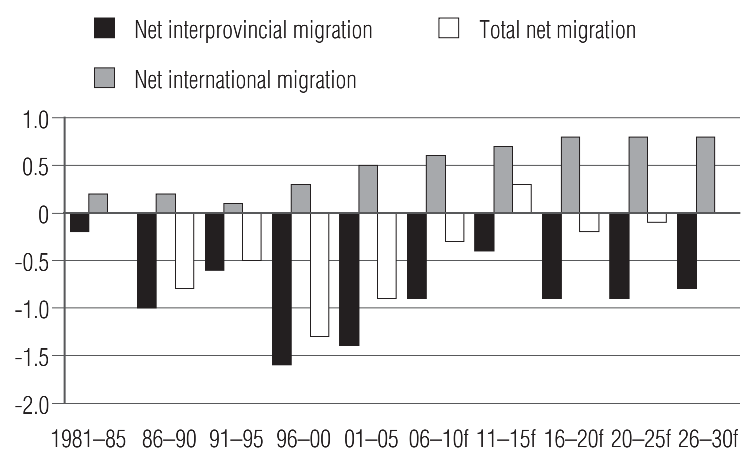
The labour force—defined as the product of the source population (the population aged 15 and over) and the participation rate—is expected to increase slowly over the medium term as growth in the source population offsets the declining participation rate. However, when growth in the source population decelerates and begins to turn negative by 2017, it will add to the declining participation rate to pull down growth in the labour force at a faster rate. The sum of these forces will cause the labour force to decline by 0.9 per cent per annum from 2012 to 2030 to reach 332,695 people, the lowest level since 1989.

POTENTIAL OUTPUT AND PRODUCTIVITY

This long-term economic forecast is guided by the concept of potential output, which is a measure of the highest level of activity that can be sustained in an economy over a period of time if all inputs of production are fully and efficiently utilized without surpassing its capacity limits and igniting inflation. The Conference Board uses a structural Cobb-Douglas production function, in which the mix of labour, capital and total factor productivity (TFP) are modelled to produce an estimate of potential output. This estimate depends on potential inputs of labour, capital and trend total factor productivity, or the technical efficiency with which labour and capital are combined to produce the output.

The workforce available when the economy is operating at full capacity (potential labour force) is used as a measure of the contribution of labour to potential output. When operating at full economic capacity, the labour force participation rate is at its structural peak and unemployment is at its "natural rate." Therefore, movements in the structural participation rate and the natural rate of unemployment are the two main factors driving changes in labour's contribution to output over the long term.

Chart 3
Migration Profile, New Brunswick
(thousands of persons, average)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

The natural rate of unemployment defines a minimum level of unemployment that would remain because some people are in transition between jobs and others prefer not to work at the current wage. Unemployment resulting from workers in transition is expected to decline over the forecast because the average age of the labour force will increase over the long term, and older workers are not as likely to quit their jobs to look for another. Thus, the natural rate of unemployment is expected to trend slowly downward over the forecast period, positively contributing to potential labour.

The negative impact of declining participation rates will outweigh the benefit derived from a lower natural rate of unemployment.

On the other hand, the aging labour force will detrimentally affect potential labour through the labour force participation rate. As workers move into older age cohorts, their aggregate labour force participation generally declines as a result of health problems or early retirement. Consequently, the overall participation rate is expected to decline sharply over the forecast horizon as a significant share of baby boomers move into their retirement years.

On balance, the negative impact of declining participation rates will outweigh the benefit derived from a lower natural rate of unemployment. Therefore, labour's contribution to potential output will decline steadily over the long term. Overall, labour's annual contribution to potential output growth averaged 0.4 percentage points over 2000–05, but it is projected to slow throughout the medium term and to turn negative starting in 2012.

The value of productive capital, the second factor in the production process, is assumed to be accurately measured, as the level of capital in the economy at any time is assumed to be all that is available to contribute to potential output. For the purpose of estimating productive capital in the economy, total public and private capital, excluding residential assets, are aggregated. Over the forecast period, the net capital stock is assumed to increase each year by the amount of new investment, net of depreciation and discarded capital. The contribution of capital to potential output growth is projected to average 0.6 percentage points per year over 2006–30.

Over history, total factor productivity is calculated residually, using the logarithmic form of the Cobb-Douglas production function, so that changes in output not explained by labour or capital are attributed to changes in technical efficiency. It should be noted that, for purposes of this calculation, total output is defined as real output at basic prices for all industries, excluding paid and imputed rent. Paid and imputed rent is excluded because Conference Board estimates of the capital stock do not take into account residential assets, as these do not contribute to the productive capacity of the economy. TFP fluctuates considerably over the business cycle. The reasons for this are wide-ranging but they include changes in the mix between capital and labour, relative shifts in the types of capital purchased, shifts in labour productivity as labour force skills evolve, and tax changes. In order to remove the effect of these short-term movements on potential output, a Hodrick-Prescott filter is used to smooth out the TFP to produce its trend values. Over the long term, trend TFP growth is expected to be robust. With the growth in the number of workers dwindling, firms will need to maintain growth in TFP by continually investing in productivity-enhancing technologies and the skills development of their workforce. The contribution of TFP to growth in potential will average roughly 0.8 percentage points annually over the forecast horizon.

The contribution of capital to potential output growth is projected to average 0.6 percentage points per year over 2006–30.

When actual real GDP diverges from potential output, an economy is said to have an output gap. Significant investment in the provincial economy in 2003 and 2004 helped spur growth of the economy above its potential, but the economy performed below potential in 2005, when the elevated Canadian dollar forced manufacturers to cut back on production. New energy investment will help boost the economy's performance above its potential over 2006–11. In the long term, the economy is expected to perform at close to its potential and thus alleviate concerns for inflationary pressures. (See Chart 4.) The Consumer Price Index is projected to remain well within the Bank of Canada's target range, averaging 2 per cent over the forecast horizon.

EMPLOYMENT AND INCOME

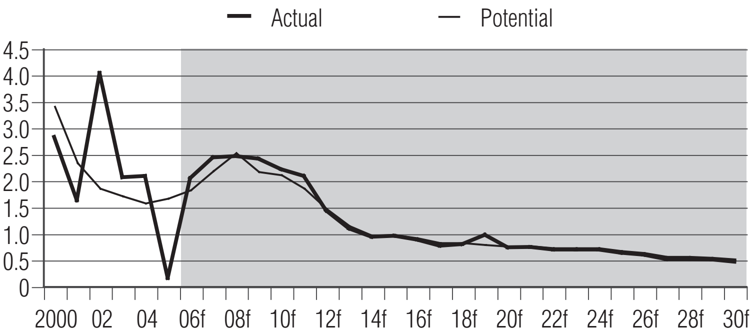
Reflecting the sobering outlook for population and the labour force, the job market will present challenges to New Brunswickers. Only Newfoundland and Labrador will have less job creation than New Brunswick during the entire forecast. Following average gains of 0.7 per cent during the first five years of the forecast, growth in employment is projected to decline by 0.6 per cent per annum over 2011–20. During the last decade of the forecast, job losses will gain momentum, declining by an average of 1 per cent as the economy weakens.

In the medium term, a number of energy investments will help generate jobs, helping the unemployment rate to decline to 7.9 per cent in 2011. After the completion of the energy projects, the unemployment rate will swing up slightly to reach 8.1 per cent in 2016 as job gains slow. However, this upward swing will be temporary, as the slowdown in employment gains will not increase the proportion of unemployed in the province. With subdued job prospects, youth will tend to migrate to other parts of Canada, weakening labour force growth. The unemployment rate will continue to decline, resting at 7.6 per cent at the end of the forecast.

With subdued job prospects, youth will tend to migrate to other parts of Canada, weakening labour force growth.

In spite of the sluggish employment outlook, growth in personal disposable income is expected to be steady over the forecast period. Two key factors underlie this assumption. First, increased productivity and tight labour markets are expected to lead to solid wage increases in the province. (See Chart 5.) Growth in wages and salaries per employee is forecast to increase from an average of 2.2 per cent per year over 2006–10 to an average of 2.8 per cent during the following decade. A further increase of 3.1 per cent is expected in the last decade of the forecast. A second factor boosting personal disposable income is the contribution of transfer payments, which are projected to increase toward the end of the forecast as the baby boomers retire.

Chart 4
Actual versus Potential GDP Growth
(percentage change)

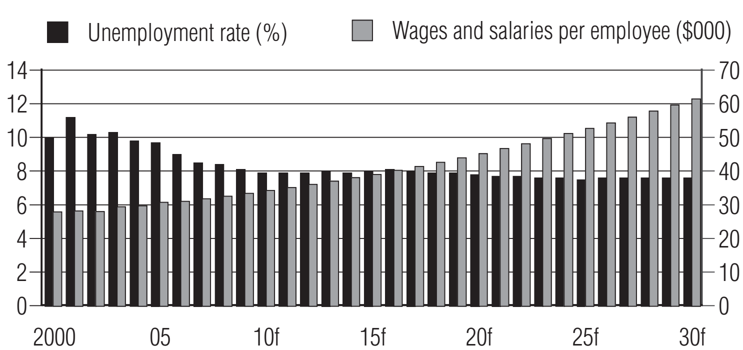


f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

AGGREGATE DEMAND

The changing demographic profile will have a profound impact on government and consumer spending in New Brunswick over the forecast. Real consumer spending is projected to grow by an average of 2 per cent over 2006–10 before cooling off to 1.1 per cent during the next decade and 0.9 per cent during the last ten years of the forecast. As the forecast progresses, the underlying demographic structure of the province will shift consumer expenditure patterns. The retiring baby boomers will gradually consume more services, such as health care, travel and leisure, and fewer durable goods. Over the forecast period, the growth in real consumption of services other than rent will outperform the gains in real consumption of goods by an average of over 1.5 percentage points.

Chart 5
New Brunswick's Tight Labour Market



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Housing starts are projected to decline throughout the forecast, partly because of the exodus of younger people in their prime homebuying years, but also because a smaller age cohort will replace the larger cohort of empty-nest baby boomers. Construction will be dampened by the surplus of resale homes likely to arise when the baby boomers trade their single-family homes for smaller units. After reaching another record-breaking year in 2006, housing starts will plummet throughout the forecast to reach 633 units by 2030, representing a decline of 84 per cent from the beginning of the forecast, or an average of 7.1 per cent per year.

Reflecting the decline in housing starts, investment in residential construction is expected to soften. As a major factor, interest rates are expected to increase over the forecast and there is little pent-up demand for new homes. As a result, growth in residential construction investment will decline to 3.3 per cent per annum in the first five years of the forecast, compared to growth of 11.2 per cent in 2001–05. Growth is projected to decline further by an average of 0.1 per cent per year over the balance of the forecast as the declining population dampens investment in construction of new houses.

Housing starts will plummet to 633 units by 2030, or an average decline of 7.1 per cent per year.

In contrast, non-residential construction investment activity will be brisk in the first two years of the forecast. Work is progressing on Irving Oil's $750-million liquefied natural gas terminal at Canaport near Saint John. The provincial government is also refurbishing the only nuclear plant in the Atlantic region at a cost $1.4 billion. Detailed engineering work, which began in mid 2006, is being followed by construction of a number of facilities for the storage of radioactive materials to be removed from the reactor as part of the re-tubing exercise. Most of the contracts for these works have been awarded to local businesses. Approximately 1,500 people from a variety of vocations will be required for the construction phase, expected to last into 2008. These projects are expected to lift growth in non-residential investment by an average of 19.1 per cent per year in 2006 and 2007. As construction activities wrap up at the Point Lepreau site, Irving Oil will begin construction of a second refinery that is expected to cost at least $5 billion and employ 5,000 workers over three years beginning in 2009. This project will have a moderate impact on growth in real construction output, as most of the investment will be for machinery and equipment. After the completion of these projects, growth in non-residential construction investment is expected to average 3.3 per cent per annum for the remainder of the forecast.

Growth in government spending on goods and services is expected to remain steady.

Growth in government spending on goods and services is expected to remain steady. It will average 4.1 per cent in the first five years of the forecast, thanks to various municipal infrastructure projects plus frontline spending on education, health and long-term care. In the long term, the provincial government will face debt-management issues as it tries to boost productivity through human capital development to meet the rising needs of the aging population. Government spending on goods and services will remain steady in the long term, growing by an average of 3.6 per cent over 2011–30.

INDUSTRY ANALYSIS

The province's forestry sector will face some challenges over the forecast period. A report prepared by Jaakko Pöyry for the government of New Brunswick points to the need for substantial spending on silviculture to increase the annual allowable cut in 35 years. Competing needs from the health-care and education sectors will make it difficult for the government to meet these requirements. Even if the government tries to implement the recommended practices, the gestation period is too long for any benefit to be reaped over the forecast period. Even though lumber exports have experienced decent growth in the last few years in tandem with a rapidly expanding housing market south of the border, long-term prospects are more tempered as advances in technology are expected to limit the use of pulp and paper. To make matters worse, U.S. housing starts are projected to weaken over the forecast period. Growth in the forestry sector will decelerate over 2006–13 and will decline by an average of 0.6 per cent over the remainder of the forecast.

Mining is the only sector that is expected to expand beyond 2 per cent over the entire forecast period. Buoyed by strong metal prices and growing demand from the emerging BRIC economies (Brazil, Russia, India, China), New Brunswick's mining industry has been awash with exploration and drilling activities this year. The high number of mineral claims in good standing—about 20,800 in 2006, compared with 13,000 in 2003—and favourable metal market conditions indicate that healthy near-term spending on mining services will continue.

Blue Note Mining is in the process of spending $48 million to activate the Caribou and Restigouche mines. These mines were shut down in 1998, when metal prices collapsed on the world market. After production begins in the spring of 2007, more than 270 people are expected to turn out 476 million pounds of zinc, 223 million pounds of lead and 5 million ounces of silver over five years. This is good news for the province as it faces the shutdown of the Brunswick mines in 2008.

Corridor Resources, a junior oil and gas company, is also expected to bring several wells into production in 2007, helping to lift gas production to 30 million cubic feet per day. Corridor is in the process of building a pipeline to join the main Maritimes & Northeast line to get the gas to the eastern seaboard market. Real mining output is projected to expand by an average of 9.7 per cent from 2006 to 2008, but the shutdown of the Brunswick mine will temporarily take steam out of the industry, forcing real mining output to decline by an average of 7 per cent in 2009 and 2010. Mining activities are expected to recover, growing by average of 1.7 per cent for the remainder of the forecast.

Benefiting from the ongoing energy investment, metal fabricators, production of machinery and equipment and other metal works are expected to help boost growth in the manufacturing sector to an average of 3.4 per cent from 2006 to 2010. However, growth in fabricated metal production will weaken after the refinery project is completed, adding weight to the slowdown in the production of pulp and paper and seafood processing. As a result, growth in the manufacturing industry will slow to an average of 1.9 per cent per annum over 2011–20 and to 1 per cent during the last decade of the forecast.

Growth in the finance, insurance and real estate industry will slow to 0.9 per cent.

In line with the expansion in the manufacturing sector, growth in transportation is expected to reach 2.1 per cent in the medium term before decelerating to 0.2 per cent for the remainder of the forecast. Crumbling housing starts are expected to reduce mortgage financing, one of the sources of growth for the financial industry. This will limit expansion in the finance and real estate sector. To make matters worse, growth in the finance, insurance and real estate industry will slow to 0.9 per cent over the forecast period as the baby boomers start to draw down savings to finance their retirement and health needs. Spending on public administration and defence will also be limited, as the slowing economy will fail to generate adequate revenue to support government programs. Overall growth in the service-producing sectors is projected to advance by a meagre 1.1 per cent throughout the forecast, compared to 2.9 per cent over 1998–2005.

Valérie Poulin

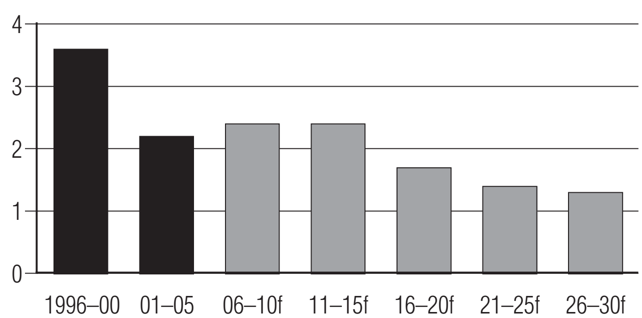
Quebec

OVERVIEW

With favourable financing conditions whipping up consumer expenditures over the last two years, the Quebec economy was relatively successful in overcoming the dampening effects of an appreciating Canadian dollar. Even as the export-sensitive manufacturing sector shed jobs, overall provincial real gross domestic product (GDP) growth at market prices averaged close to 2 per cent over 2005–06. Quebec's real GDP at market prices is expected to progress by an average of 2.4 per cent from 2006 to 2010 and by a moderate 1.7 per cent compound annual rate over the last 20 years of the outlook, in line with potential growth, as demographic changes weigh on economic prospects. (See Chart 1.)

Economic growth will slow over the long term as the aging of baby boomers and a low fertility rate weaken population growth to a compound annual rate of only 0.5 per cent between 2016 and 2030, reducing consumer expenditures and housing demand. The proportion of people aged 65 and older will increase substantially over the forecast period, by more than 10 percentage points to 24.5 per cent, while the number of young people under the age of 20 will shrink from 1,711,849 in 2006 to 1,640,283 in 2030. Housing starts will fall steadily from 44,017 units in 2006 to about 18,687 units in 2030 as demographic factors weaken the number of new households and the need for new housing. Real export growth, the pillar of robust economic activity in the late 1990s, will gradually decelerate over the long term because of slowing U.S. growth and a Canadian currency averaging around US$0.84. The telecommunications, transportation equipment, biotechnology, and metal sectors are expected to be some of the contributors to the trade outlook over the next 25 years.

Chart 1
Real GDP at Market Prices, Quebec
(average annual compound growth rate; 5 years)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

DEMOGRAPHIC PATTERNS

Demographic factors are a critical determinant of the long-term prospects of an economy. The most important demographic trends for Quebec over the next 25 years will be slowing population growth, rising immigration levels, and the aging of the baby-boom generation. (See Table 1.) With an increase in the average age of Quebecers, population growth is expected to drop over the last 20 years of the forecast period. Quebec's population, estimated at 7,640,953 in 2006, will reach 8,642,346 by 2030, an increase of just above one million. The slowdown in population growth in Quebec will be more pronounced than in the rest of Canada and will resemble that of several Western European countries.

Important changes in population structure will influence potential output growth and consumer expenditures. The proportion of people aged 65 and older will increase substantially between 2006 and 2030, from 9.9 per cent to 24.5 per cent. Baby boomers, currently in the 40–59 age group, represent 31.1 per cent of the total population, with the heaviest concentration in the 45–49 age cohort. They will move into the 65–84 age range by the end of the forecast period, with a high concentration in the 65–69 range. Also contributing to the overall aging of the population is an expected drop in the proportion of people aged between 15 and 19, from 6.2 per cent to 5 per cent between 2006 and 2030. These movements will dominate demographic projections for Quebec. (See Chart 2.)

Population growth is determined by three factors: births, deaths and net migration. The population projections in the current outlook assume a fertility rate of 1.48 births per woman, which is well below the replacement rate of 2.1. This low fertility rate and the aging of the population will lower the birth rate. With the death rate expected to increase because of the larger number of older people, the natural rate of increase in the population (births minus deaths) is projected to decline steadily over the next 25 years, with the number of deaths exceeding births starting in 2022.

The weak natural rate of population increase will be partly offset by a net positive inflow of migrants over the forecast horizon. While a net outflow of roughly 11,839 people per year to other provinces is projected between 2006 and 2030, average annual net international migration to Quebec is forecast to rise steadily, from around 34,400 in 2006 to 54,150 by 2030. (See Chart 3.) In light of the unfolding demographic picture and the stated aims of policy-makers, the Conference Board anticipates a gradual rise in international immigration over the long term, much more pronounced than our estimates in last year's long-term provincial forecast. With the natural rate of increase rapidly slipping, net immigration will become virtually the only driving force behind population growth in the province in the latter part of the long-term forecast. Since most immigrants are of working age, growth in the population of labour force age (15 years and over) will generally exceed that of total population.

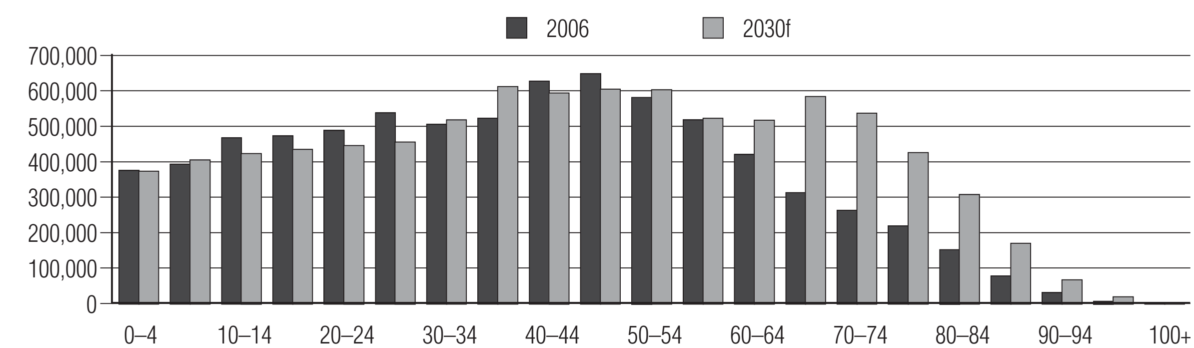
Nevertheless, growth in the source population is projected to decrease from 1.1 per cent annually in 2006 to 0.4 per cent in 2030 as baby boomers gradually retire and the smaller baby-bust generation makes up a greater share of the labour force. In addition, with a higher concentration of the population in older age groups (which typically exhibit lower participation rates), and a peak in female labour force participation, the overall workforce participation rate is expected to level off at 65.6 per cent in 2008. The combination of a falling participation rate and weaker growth in the source population will lead to a deceleration in labour force growth. Average annual compound growth in the labour force will decline from 1.7 per cent in 2000–05 to just 0.2 per cent between 2006 and 2030. This important drop in labour force growth will hurt potential output growth.

Table 1
Key Demographic Assumptions

Components	Assumptions
Population	Quebec's population growth will remain fairly constant at an annual average rate of 0.6 per cent until 2020, then decelerate, advancing by a annual average rate of 0.4 per cent over 2021–30.
Migration	Over the forecast period, on a net basis, an average of 38,471 people will settle in Quebec. Interprovincial migration will be negative over the forecast, but international migration will intensify.
Fertility rate	The fertility rate in Quebec is 1.48, well below the replacement rate of 2.1.
Natural increase in the population	The share of population growth from natural increase is projected to fall; the number of deaths will outpace births from 2022 on.

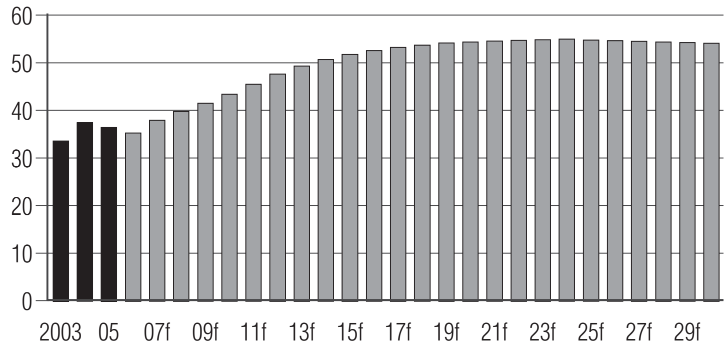
Sources: The Conference Board of Canada; Statistics Canada.

Chart 2
Population Increases in Older Age Cohorts
(number of people)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Chart 3
Net International Migration
(annual average, thousands)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

POTENTIAL OUTPUT AND PRODUCTIVITY

This long-term economic forecast is guided by the concept of potential output, which is the highest level of economic activity an economy can attain without surpassing its capacity limits and igniting inflation. The difference between real GDP and the economy's potential output is called the output gap. Weak economic growth in the early 1990s resulted in a wide output gap. A surge in growth is estimated to have eliminated this gap by 2000.

Once an economy eliminates the output gap, its future non-inflationary growth is limited by the growth of potential output. Estimated potential output growth in Quebec increased from 1.6 per cent in the first half of the 1990s to 2.6 per cent over 1996–2005. (See Chart 4.) Strong capital spending is expected to help sustain the average growth rate of potential output at 2.3 per cent in 2006–10. Growth in potential output is then expected to fall to 1.7 per cent in the last 20 years of the forecast.

The potential output of an economy cannot be observed. It must be calculated on the basis of estimates of total factor productivity (TFP) and the supply of key factors of production: the capital stock and the labour force. TFP reflects the efficiency with which all factors of production are combined to generate final output. This forecast assumes that TFP growth will average 0.8 per cent over 2001–10 and that this trend will be maintained over the last 20 years of the forecast. The net capital stock is assumed to increase each year by the amount of new investment, net of depreciation and discarded capital. The annual contribution of capital to potential output growth is expected to increase from an average of 42.5 per cent over 2006–10 to about 49.8 per cent over the last 20 years of the forecast.

GDP growth will average 2.4 per cent over the balance of the decade as the economy reaches its capacity limits.

Labour's contribution to potential output is based on the "natural rate of unemployment," which is defined as the lowest rate of unemployment that can coexist with stable wage inflation. Given structural imbalances in the labour market and normal job-search time, the unemployment rate consistent with "full employment" cannot be zero. This situation is further complicated by the existence of various income support programs (such as unemployment insurance and welfare), labour market regulations (such as the minimum wage), and the degree of unionization. With these structural factors taken into account, it is possible to derive the natural rate of unemployment as well as the economy's "potential level of employment." Conference Board of Canada research suggests that the natural rate of unemployment is currently 7.8 per cent for Quebec. This rate is assumed to decline to 6.4 per cent over the forecast period, mainly because of reduced income supports for the unemployed and a more educated workforce. Although lowering the natural rate of unemployment improves the prospects for potential output growth, its effect is more than offset by the dampening effect of slower population growth on labour force expansion. The expected decline in labour force growth will gradually lower the annual contribution of labour to potential output growth from a positive contribution in 2006 to a negative contribution starting in 2028.

Over the 1990s, the output gap was significant. However, real GDP has outgrown potential consistently since 1997, by enough to close the output gap by 2000. After a slowdown in 2001, the economy kicked back in 2002, with 2.6 per cent growth. Some momentum was lost in 2003 as growth slumped to just 2 per cent, but growth bounced back moderately to an average of 2.4 per cent in 2004–05. GDP growth will average 2.4 per cent over the balance of the decade as the economy reaches its capacity limits. For the remainder of the forecast period, growth is expected to be roughly in line with potential. As such, Quebec will see average growth of 2.4 per cent from 2011 to 2015. Afterward, growth is forecast to slow, averaging 1.5 per cent annually over the last 15 years of the forecast period. Over the same period, the province's inflation rate, as measured by increases in the Consumer Price Index, is projected to remain well within the Bank of Canada's accepted target range, averaging 2.3 per cent.

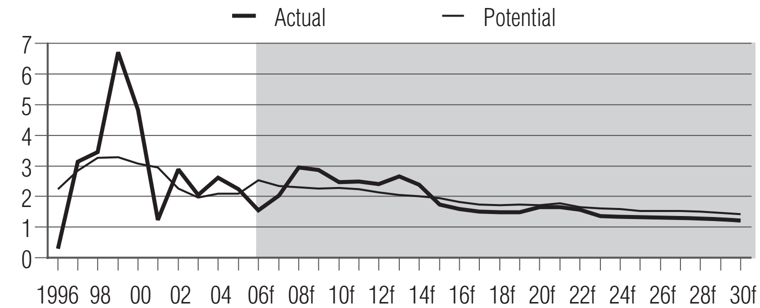
AGGREGATE DEMAND

CONSUMPTION

Despite the challenges involved in predicting household behaviour over the long term, it can be reasonably assumed that cohorts will in general assume the spending habits of those that preceded them. Current spending patterns suggest that, contrary to earlier predictions, population aging will not immediately cause consumption patterns to shift further in favour of services. Data from the 2003 survey of household spending show that the services share of total consumption spending is highest for the youngest (under-35) and oldest (over-74) cohorts but relatively low for households aged 55 to 74. The age range of the baby boomers is now 40 to 59, which means that as household heads, they are concentrated in the 35–44, 45–55 and 55–64 cohorts. By 2030 their age range will be 64 to 83, placing them largely in the 60–69 and 70–79 household cohorts. This means that as a group, their spending habits will resemble the patterns of households presently in this cluster. Thus, given the large size of the boomer generation, consumption spending is unlikely to shift further in favour of services until after 2025, when the baby boomers start to enter the over-74 age cohort.

While demographic change will maintain the goods–services balance in total consumption spending, it is expected to contribute to a deceleration in the pace of growth in consumption outlays. Despite stronger wage growth associated with the departure of baby boomers from the labour force after 2010, slower overall population growth combined with a quickly growing elderly segment will help to trim the pace of expansion in consumption spending. As such, the average annual compound rate of expenditure growth is forecast to ease from 2.9 per cent over 2006–10 to 2.2 per cent between 2011 and 2015. Beyond 2016, growth will continue to slow, averaging 1.7 per cent during the last 15 years of

Chart 4
Actual versus Potential GDP Growth
(percentage change)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

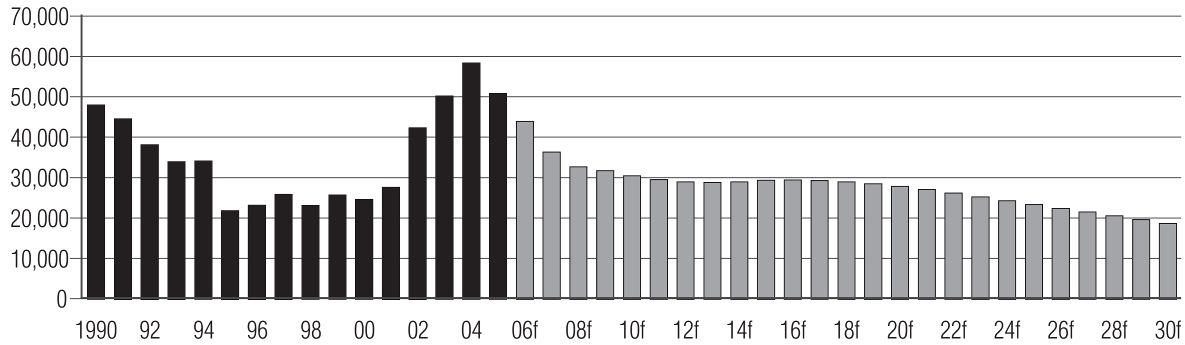
the forecast. As for savings, the rate will peak at 1.3 per cent in 2007. It will then ease slightly over the rest of the forecast period, averaging 0.6 per cent.

The gradual slowing projected for the labour market will also contribute to the slowdown in consumption. Employment growth is expected to ease from an annual average of 2 per cent between 1996 and 2005 to an annual average growth of 0.3 per cent over the forecast period. However, employment growth will slightly edge out labour force growth, allowing for a decline in the unemployment rate from 8.2 per cent in 2006 to 6.4 per cent by 2030.

RESIDENTIAL INVESTMENT

The housing market experienced tremendous growth from 2001 to 2004. As mortgage costs crawled up and pent-up demand was satisfied, housing starts retreated greatly in 2005, with the supply of new homes more in line with demographic needs. Recent Conference Board of Canada research suggests that there will be around 28,000 new households annually in the province in the next few years. Housing starts are expected to retreat again in 2006, from 44,017 units to 36,412 units in 2007, and residential construction will continue to lose momentum over the remainder of the decade. Since the typical baby boomer already owns a house, and since the group will be followed by a cohort with far fewer homebuyers, the number of housing starts is projected to slide gradually to 30,555 units by 2010 and finally to 18,687 units by 2030. (See Chart 5.) Projected real residential investment reflects this housing outlook, with average annual growth falling from 11.7 per cent over 2001–05 to –1.8 per cent between 2006 and 2010. Demographic requirements

Chart 5
Total Housing Starts
(units)



f = forecast
Sources: The Conference Board of Canada; Canada Mortgage and Housing Corporation.

and household formation indicate that residential investment will fall by an average annual compound growth rate of 0.5 per cent over 2011 to 2030.

NON-RESIDENTIAL INVESTMENT

Real non-residential investment is expected to decrease slightly in the short term, by an annual growth rate of 0.5 per cent in 2006–07. The outlook will change in 2008 with a number of projects stimulating construction over the forecast horizon. Non-residential investment is expected to increase by an average of 3.6 per cent in 2008 and 2009, and will go on growing at a good pace, averaging 1.4 per cent annually in the last 20 years of the forecast. The non-residential investment outlook in Quebec over the long term will be dominated by Hydro-Québec's capital developments.

There will be numerous power projects in Quebec over the forecast period, with a number of investment projects included in Hydro-Québec's latest five-year strategic plan. On top of ongoing capital initiatives, Hydro-Québec officially launched work on the construction of the Eastmain-1-A and La Sarcelle hydroelectric generating stations and the partial diversion of the Rupert River for hydroelectricity purposes. Continuing development of the Péribonka, Eastmain 1 and Chute-Allard-Rapides-des-Coeurs hydro-generating projects will also contribute to the construction outlook over the medium term forecast. Hydro-Québec will also purchase 3,000 megawatts (MW) of wind power from various companies in the province between 2005 and 2012. This $3-billion investment in new wind power capacity will be made by individual companies. At the end of 2007, TransCanada will have invested a total of $500 million in Bécancours to develop a natural gas power plant. Together with Petro-Canada, TransCanada will also go forward with a $500-million investment for the construction of a liquefied natural gas terminal in Gros Cacouna over 2008 to 2010.

Business investment in machinery and equipment is expected to perform very well over the long term.

Over the longer term, additional hydroelectric projects of more speculative nature have been included in the investment outlook for the province. Between 2011 and 2015, a $5-billion hydroelectric development for 1500 MW could get under way on the Romaine River in the Mingan region. Over the following five years, another $5-billion project for 1500 MW of electricity is anticipated on the Petit Mécatina River in the Mingan region as well. Finally, the huge $10-billion development on the à la Baleine River could become a reality sometime in the decade after 2020.

A number of sectors besides energy will also be expanding. Intrawest Corporation, which has massively invested in the province in the last few years, will continue the expansion of its Mont Tremblant ski resort at a cost of $1 billion over the next decade.

The fastest growing component of aggregate demand, business investment in machinery and equipment, is expected to perform very well over the long term. Businesses will continue to invest in high-tech machinery to remain competitive in more open international markets. The telecommunications industry has overcome difficulties following the Y2K spending frenzy, and growth in exports of technological products jumped by double digits in 2005. Average annual compound growth in machinery and equipment investment will slow from 5.8 per cent over 2006–15 to a still respectable 3.7 per cent between 2016 and 2030.

FISCAL OUTLOOK

The Quebec government is in a constant struggle to avoid running fiscal deficits. Over 2006–10, real government spending on goods and services will increase by an annual compound growth rate of 2.2 per cent. With rising health-care costs over the longer term, the provincial government has little room to cut taxes further, so this provincial outlook does not incorporate any fiscal relief.

In the long term, our forecast for spending on government goods and services will be driven by opposing factors: slowing revenue growth and fiscal capacity and the spending growth required by rapid increases in the number of people aged over 65, and an increase in the number of schoolchildren after 2020. Therefore, real government spending on goods and services will average 1.6 per cent between 2011 and 2030.

TRADE PROSPECTS

Export-oriented manufacturing industries in Quebec made strong gains between 1996 and 2000 in tandem with a booming U.S. economy. When U.S. demand turned anemic in 2001, however, the trade sector suffered deeply. In addition, the rapid appreciation of the Canadian dollar between 2003 and 2006 affected competitiveness and real export gains. Real exports from Quebec grew only moderately, by an annual compound growth rate of 1.1 per cent, over 2003–05, compared with compound growth of 9.5 per cent from 1996 to 2000.

Plant closures and relocations to lower-wage countries have made headlines repeatedly over the last few years in Quebec. Central Canada, the heartland of the manufacturing industry, has suffered from the rapid rise of the Canadian dollar. As if that were not enough, higher energy costs have been plaguing manufacturers. Threatened by fierce overseas competition, the paper industry is especially suffering from this conjuncture and is therefore experiencing significant downsizing. With mergers and modernization plans, more paper plants may shut down in the next several years.

With rising health-care costs over the longer term, the provincial government has little room to cut taxes further.

The aerospace industry rebounded in 2005, with real exports of airplanes and airplane components nearly 10 per cent higher than in 2004. This has helped strengthen trade prospects: aerospace is one of the most important export sectors, contributing to almost 20 per cent of all exported goods. However, Bombardier has been forced to reduce its workforce in Montréal and abroad, and exports of airplanes had a poor performance in 2006. With a low backlog of orders and the uncertain financial health of some of its American clients, the transportation giant suspended production of one regional jet at the beginning of 2006. The outlook for the aerospace sector has improved since then. In the last half of 2006, Bombardier obtained a contract, worth more than US$700 million, from Italian carrier My Way Airlines for 19 jets. Bombardier has also secured a large contract for $1.5 billion with Northwest Airlines for 36 CRJ900 planes; the order could rise to $5.2 billion if the company exercises all of its options. Except for airplane assembly, the aerospace sector is in good shape, with the export of airplane engines and parts up by nearly 20 per cent in the first ten months of 2006.

Bombardier must secure orders from major airlines before moving ahead with its next major initiative, the CSeries project. The company should make a final decision whether to go forward with the project early in 2007. If Bombardier is able to build its CSeries jets, about 5,000 new assembly jobs will be created in the Montréal area—half at Bombardier and half with suppliers—together with a minimum of 3,000 component-building jobs. Bombardier forecasts a need for 5,800 aircraft of between 100 and 149 seats in the next 20 years, either to replace an inventory of 4,080 older model units or to answer growing demand for 1,720 new units. While the immediate situation for the aerospace industry is not what it was just a few years ago, longer term prospects are quite favourable, as Bombardier is well positioned to benefit from international demand for smaller and more fuel-efficient jets. The company continues to adapt its aircraft production line to remain competitive in global markets. Many smaller, internationally renowned aerospace companies that manufacture engines, parts or flight simulators also crank up Quebec's exports of aerospace products. In particular, robust requirements for military purposes south of the border, the hot energy sector and strong Asian demand have brightened the outlook for Bell Helicopter Textron; the Mirabel company intends to double its production within the next eight years.

Total export growth will subside to an average of 2.4 per cent per year in the last 20 years of the forecast period. The contribution of net exports to GDP growth will be limited over the long term as exporters will have to contend with a Canadian currency hovering around US$0.84 and a moderation in U.S. economic growth. Overall, the United States is expected to record average annual real GDP growth of 2.9 per cent between 2005 and 2010, with growth slowing to an average of 2.8 per cent from 2011 to 2020 and 2.5 per cent over the last 10 years of the forecast. The manufacturing sector will also contribute strongly to the advance in exports, particularly in the telecommunications, transportation equipment, biotechnology, and metal and alloys sectors.

Imports are expected to post relatively robust growth over the forecast period.

Imports are expected to post relatively robust growth over the forecast period because of the high import content of machinery and equipment investment. Real imports are forecast to increase at an average annual compound rate of 3.5 per cent between 2005 and 2010, and 2.5 per cent over the last 20 years of the forecast.

Marie-Christine Bernard

Ontario

OVERVIEW

The economic outlook for Ontario will remain tempered over the near term. Real gross domestic product (GDP) at market prices is expected to advance by 1.7 per cent in 2006 and by 2.4 per cent in 2007. The manufacturing industry is bracing for additional challenges, as weakening consumer demand south of the border will certainly not pull it out of the abyss. Manufacturing output defied the appreciation of the Canadian dollar over the past few years by making gains, but a sharp slowdown in the auto sector is expected to contract real manufacturing output in 2006. With the auto industry restructuring dramatically in response to dwindling U.S. vehicle sales, prospects are modest for manufacturers. Nevertheless, a solid performance by a number of industries—chemical, electrical equipment, machinery and equipment, and refined petroleum and coal products—should enable real total exports to post a better performance in 2007 than in 2006.

The trade sector will continue to weigh on economic growth as imports continue to grow firmly to satisfy the sturdy demand for machinery and equipment and consumer goods. The declining trade balance will chop 2 percentage points from GDP growth in 2006 and 0.6 percentage points in 2007. Stabilizing in 2008, the trade balance should make a small, positive contribution to the economy.

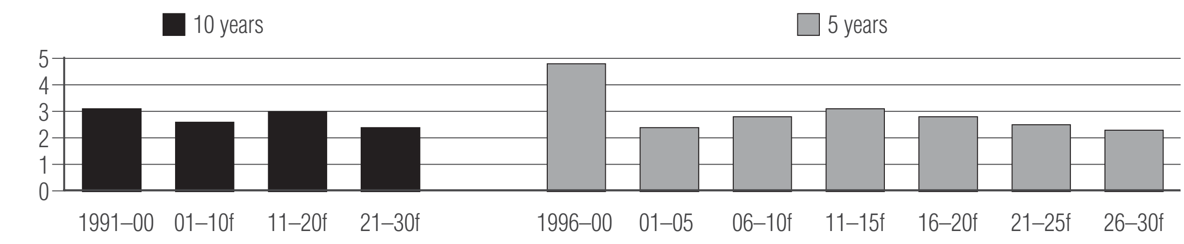
Strong domestic demand will continue to bolster economic activity. Business investment and consumer spending are expected to remain robust. Limited spare capacity in the commercial and industrial markets combined with moderate financing rates will continue to encourage investment in non-residential sectors. Furthermore, public spending commitments to upgrade energy and transportation infrastructure will support the near-term investment forecast.

A solid performance by a number of industries should enable exports to post a better performance in 2007.

Between 2008 and 2011, as prospects improve south of the border and the Canadian currency stabilizes to an average of US$0.854, Ontario should fare much better, with real GDP growth rebounding to 3.4 per cent. The Ontario economy will be among the strongest in Canada over the long term, trailing only Alberta and expanding by a compound annual rate of 2.7 per cent over 2006–30. (See Chart 1.)

Potential output growth is estimated to grow by 2.9 per cent per year on average from 2006 to 2015 and 2.6 per cent over 2016 to 2030. Two key factors will reduce the economy's capacity to expand. First, the proportion of retirees in the population will rise considerably, constraining

Chart 1
Real GDP at Market Prices
(average annual compound growth rate)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

long-term potential labour force growth. Second, the growth of total factor productivity (TFP) is expected to slow as the forecast wears on, as it is assumed that the current pace of technological change will ease.

DEMOGRAPHIC PATTERNS

One of the key determinants of the long-term outlook for Ontario is the demographic projection. Emerging population trends are a crucial factor in the calculation of potential output and the forecasting of future spending patterns. The principal features of Ontario's demographic outlook are the aging of the population, the slowing natural rate of population growth, and the increase in international immigration as a share of the total population. (See Table 1.)

The age structure of Ontario's population will undergo a dramatic shift over the 2006-to-2030 period. (See Chart 2.) The population aged 65 and over, which is estimated to have accounted for 12.9 per cent of the population in 2006, will rise in importance over the outlook, comprising 20.6 per cent of the population by 2030. This shift is primarily the result of the aging of the postwar baby-boom population. Baby boomers are currently aged 40–59, with the largest segment of the cohort between 40 and 44 years old. This cohort will move on to the 60–79 age bracket by the end of the forecast, with a concentration in the 65–69 range. The aging of the population is one of the key features of the current outlook; its implications for overall growth in the economy and the composition of that growth are far-reaching.

Table 1
Key Demographic Assumptions

Components	Assumptions
Population	Ontario's population is expected to grow at an annual average rate of 1.3 per cent over 2006 to 2030, and the average age of the population will steadily increase.
Provincial migration to turn around	Ontario's net interprovincial migration will remain negative until the end of the decade, then recover, averaging 1,363 people per year between 2011 and 2030.
International migration to pick up speed	Net international migration will drive population growth, rising from 113,510 people in 2006 to 162,652 people in 2030.
Fertility rate	The fertility rate in Ontario is 1.49, well below the replacement rate of 2.1.
Natural rate increase in the population	The natural rate of increase in the population (births minus deaths) will continue to rise until 2019–20, then to fall steadily until the end of the forecast.

Sources: The Conference Board of Canada; Statistics Canada.

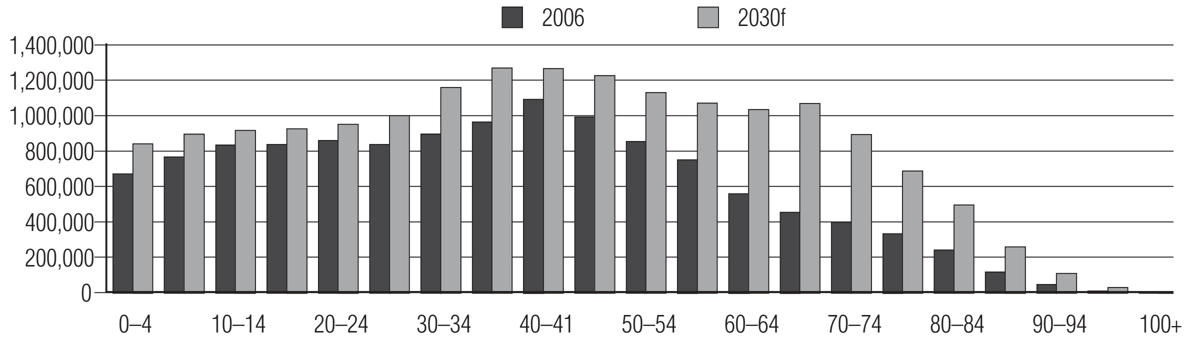
The decline in population growth over the long term will be offset by the increase in immigration.

The natural rate of increase in Ontario's population (the excess of births over deaths) is expected to decline steadily over the forecast horizon, falling from 41,101 in 2006 to 25,805 in 2030. This is partly owing to the gradual decline in the birth rate as the population ages and is replaced by a smaller childbearing cohort. In contrast, the death rate is expected to climb steadily throughout the forecast period. Although improved health care and nutrition have increased life expectancy, the rapid aging of the population will cause the number of deaths to increase by 1.8 per cent per year on average during 2006–30. In comparison, the annual average number of births is expected to increase by 0.9 per cent.

The forecast assumes that population growth will be supported by an increase in net immigration. Net international immigration for Ontario is expected to increase gradually from 113,510 in 2006 to 162,652 in 2030. With the natural rate of increase in the population slipping, net international immigration to Ontario is projected to account for approximately 84 per cent of the total annual increase in the province's population by the end of the forecast period. With solid economic potential in Alberta, the province will continue to face negative net interprovincial migration until 2010. Afterward, net interprovincial migration will favour Ontario, averaging 1,055 over 2011–20 and 1,671 over the last decade of the forecast. (See Chart 3.)

In total, the projected decline in the natural rate of population growth over the long term will be offset by the increase in net immigration. Consequently, modest population growth is expected in Ontario over the forecast period; compound annual population growth is projected to be 1.3 per cent from 2006 to 2030. However,

Chart 2
Population Increases in Older Age Cohorts
(number of people)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

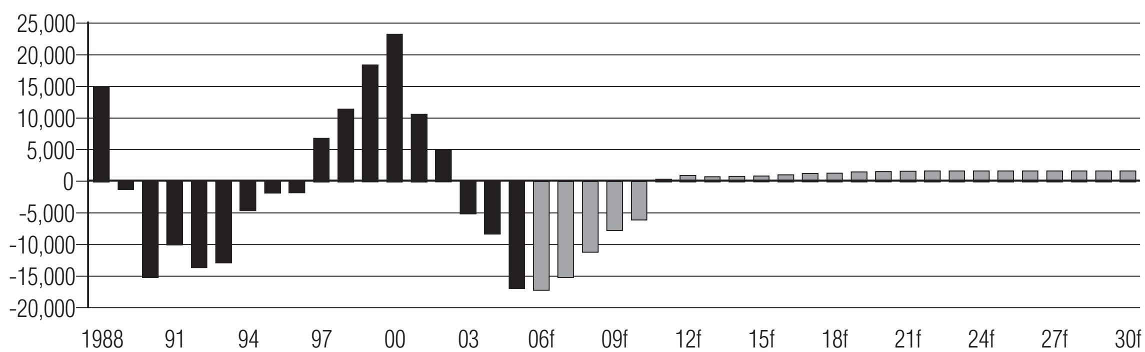
the aging of the population will lead to a pronounced slowing in the growth rate of the population of labour force age. Annual labour force growth is expected to slow from 1.5 per cent over 2006–15 to 1.3 per cent from 2016 to 2030.

POTENTIAL OUTPUT AND PRODUCTIVITY

The long-term economic forecast for Ontario is based on the concept of potential output—that is, the highest level of economic activity an economy can attain without surpassing its capacity limits and igniting inflation. Potential output is not directly measured and, as such, the Conference Board uses a structural production function to obtain an estimate of potential. We assume that the production function takes a Cobb-Douglas form in which the mix of labour, capital and technical efficiency is modelled to produce potential output. With this assumption, our estimate of potential output depends on potential employment, capital and trend total factor productivity.

Potential employment measures the contribution of labour to potential output by estimating the available workforce when the economy is operating at capacity. Under these conditions, the labour force participation rate is at its structural peak and unemployment is at its "natural rate." Therefore, movements in the structural participation rate and the natural rate of unemployment are the two main factors driving changes in labour's contribution to output over the long term.

Chart 3
Net Interprovincial Migration
(persons)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

The natural rate of unemployment defines a minimum level of unemployment that would remain because some people are in transition between jobs and others prefer not to work at the current wage. Unemployment resulting from workers in transition is expected to decline over the forecast. This will occur because there will be an increase in the average age of the labour force, and older workers are not as likely to quit their jobs to look for other work. Thus, the natural rate of unemployment is expected to trend gradually downward over the forecast period, contributing positively to labour potential.

On the other hand, the aging labour force will detrimentally affect labour potential through the labour force participation rate. As workers move into older age cohorts, their aggregate labour force participation generally declines as a result of health problems and early retirement. The overall participation rate is expected to decline sharply over the next 25 years as a significant share of baby boomers move into their retirement years. On balance, the negative effects of declining participation rates will outweigh the benefit derived from a lower natural rate of unemployment. Therefore, labour's contribution to potential output growth will decline steadily over the long term.

The overall participation rate is expected to decline sharply over the next 25 years as a significant share of baby boomers move into their retirement years.

The value of Ontario's productive capital is the second factor of production required to calculate potential output. The Conference Board of Canada does not rely on a measure of potential or optimal capital stock. Instead, we assume that productive capital is accurately measured and that the level of capital available in the economy at any time is all that is available to contribute to potential output. Total public and private capital, excluding residential assets, contributes to the level of productive capital. Over the forecast period, the net capital stock is assumed to increase each year by the amount of new investment, net of depreciation and discarded capital. The contribution of capital to potential output growth will remain steady, with an average of about 1.1 percentage points per year over the 2006–30 period.

The technical efficiency with which capital and labour are utilized to produce output is measured by total factor productivity. Over history, TFP is calculated residually, using the logarithmic form of the Cobb-Douglas production function, so that changes in output that are not explained by labour or capital are attributed to changes in technical efficiency. It should be noted that, for purposes of this calculation, total output is defined as real output at basic prices for all industries, excluding paid and imputed rent. Paid and imputed rent is excluded because the Board's estimates of the capital stock do not take into account residential assets, since these do not contribute to the productive capacity of the economy.

Over the medium term, the economy will expand at a real average rate of 3 per cent.

TFP fluctuates considerably over the business cycle. The reasons for this are wide-ranging but include changes in the mix between capital and labour, relative shifts in the types of capital purchased, shifts in labour productivity as labour force skills evolve, and tax changes. In order to remove the effects of volatile short-term movements, potential output is calculated with trend TFP, which is our residual measure smoothed with a Hodrick-Prescott filter. Over the long term, trend TFP growth is expected to be robust. With the growth in the number of workers dwindling, firms will need to continually invest in productivity-enhancing technology and skills development of their workforce, helping to maintain growth in TFP. The contribution of TFP to growth in potential will be a little stronger than with recent historical performance, roughly 0.9 per cent annually over the forecast horizon.

When actual real GDP diverges from potential output, an economy is said to have an output gap. Over the medium term, the economy will expand at a real average rate of 3 per cent, slightly outpacing estimates of potential growth. As a result, the output gap that opened early in this decade will narrow, closing around 2011. Economic growth over the remainder of the long-term forecast is expected to stay close in potential output—that is, to trend down slightly over the 2012–30 period. (See Chart 4.) The output gap will remain more-or-less closed over the forecast horizon. As such, the Consumer Price Index is projected to remain within the Bank of Canada's accepted target range, averaging 2.4 per cent between 2016 and 2030.

AGGREGATE DEMAND

CONSUMPTION

The demographic shifts expected over the long term will also be felt in the household sector. The unfolding of this process will change not just the pace of growth of consumption expenditures, but also the type of spending that occurs.

In line with the pattern of potential output, employment growth will decelerate in the outer years of the forecast, shrinking to an average 0.9 per cent over 2016–30, compared with an average annual increase of 1.6 per cent from 2006 to 2015. However, even this lower growth pace will be enough to keep the labour market very tight over the long term, with the unemployment rate standing at 5.4 per cent in 2030. This tightness in the province's labour market will lead to relatively healthy increases in average wage growth throughout the forecast.

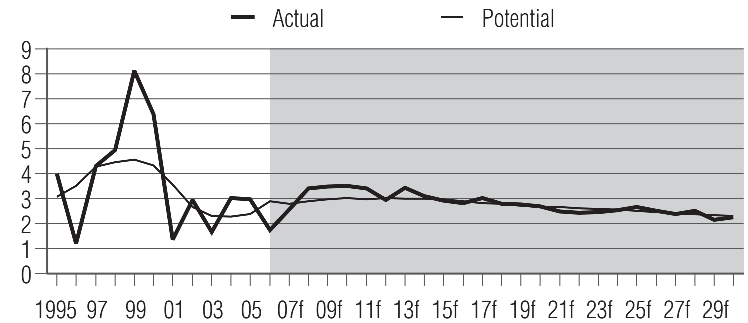
The savings rate will rise gradually over the short term, peaking in 2018.

While demographic change will maintain the goods–services balance in total consumption spending, it is expected to contribute to a deceleration in the pace of growth in consumption outlays. Despite stronger wage growth associated with the boomer-driven labour shortage after 2010, slower overall population growth combined with a quickly growing elderly segment will help to trim the pace of expansion in consumption spending. As such, the average annual compound rate of expenditure growth is forecast to ease from 3.1 per cent over the 2006–15 period to 2.4 per cent from 2016 to 2030. The savings rate will rise gradually over the short term, peaking at 2.9 per cent in 2018. It will then gradually ease over the rest of the forecast period, reaching 1.1 per cent in 2030.

INVESTMENT

Housing construction has been booming in recent years, with total starts peaking at close to 85,000 units over 2003 and 2004—the highest levels since the late 1980s. Although housing starts are well above demographic requirements in most provinces, as indicated by the number of new households Ontario is not facing such a situation at the moment. Strong international immigration into the province will continue to stimulate the residential sector. Therefore, housing starts are expected to remain relatively strong, averaging 79,600 units between 2006 and 2015 and increasing to an average of 89,600 units over the 2016–30 period. As the preferences of an aging population shift toward lower maintenance residences, significant declines in single housing starts are expected over the long term. (See Chart 5.) Meanwhile, the demand for multiple housing dwellings is expected to increase. By 2030, it is estimated that 73 per cent of all new construction will be of multiples, compared with 51 per cent in 2006.

Chart 4
Actual versus Potential GDP Growth
(percentage change)

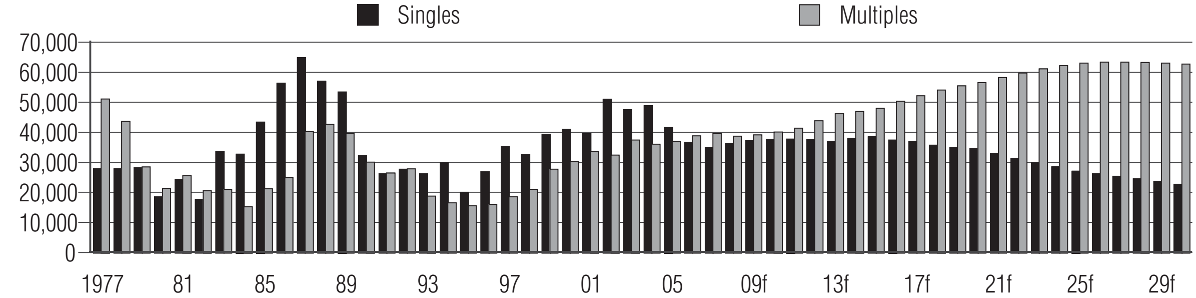


f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Real residential investment will follow a relatively slow growth path over the long term, increasing by an average of 1.6 per cent over 2006 to 2030. Growth will be held back by soft investment for new housing, which will rise by an average of only 0.6 per cent. Consumer housing budgets will be more focused on altering, renovating and improving the existing housing stock to suit an aging population. As such, average annual spending on existing homes is expected to grow by 2.5 per cent.

After gaining momentum during 1996–99, non-residential investment declined over 2000–03 as the lower use of production capacity meant that industries were able to respond to demand without investing much in construction. As industrial capacity utilization rates increase over the short term, businesses will be encouraged to invest in new commercial and industrial space.

Chart 5
Total Housing Starts
(units)



f = forecast
Sources: The Conference Board of Canada; Canada Mortgage and Housing Corporation.

As a result, non-residential investment is expected to recover somewhat over the medium term, rising on average by 1.8 per cent over 2006–10. With the subsequent easing of overall economic growth, non-residential construction is expected to advance at a moderate pace, growing by an average compound growth rate of 2.1 per cent from 2016 to 2030.

The stronger Canadian dollar is providing every incentive for businesses to upgrade.

The explosive growth of investment spending on machinery and equipment in Ontario over the last decade is transforming the economy. The strong growth is mainly attributable to spending on computers, which is expected to persist in the medium term. As a result, investment in machinery and equipment is projected to be the spending growth leader over the entire forecast horizon. Growth in machinery and equipment investment will be fuelled in the medium term by a push to remain competitive in the rapidly expanding, low-inflation, more open international marketplace. Moreover, as much of the machinery and equipment used in Ontario is imported, the stronger Canadian dollar is providing every incentive for businesses to upgrade sooner rather than later. Consequently, investment in machinery and equipment is forecast to remain strong over the medium term, increasing by average annual compound growth of 7.1 per cent from 2006 to 2010.

With most of the restructuring in place and with a maturing in semiconductor technology, growth in machinery and equipment investment will ease to a still-respectable 4.4 per cent from 2016 to 2030. As the pace of computer technology growth slows, the service life of the average new computer is expected to stabilize and perhaps even lengthen, meaning that Ontario companies will not have to replace their computer equipment as often as they do today. However, the need to invest will remain strong, as firms in Ontario will face labour shortages in the latter years of the current outlook with the gradual retirement of the baby boomers.

Increased demand from an aging population for health-care services will put pressure on the provincial government to invest in health infrastructure. Along with construction of hospitals and other medical facilities will come heavy spending on machinery and equipment. Moreover, technological developments are expected to increase the pressure to invest as Ontario's aging baby boomers demand state-of-the-art medical technology.

GOVERNMENT

New accounting practices helped Ontario realized a surplus in fiscal 2005–06. After two years of deficits, Ontario recorded a modest surplus of $298 million, a far cry from the $2.796-billion deficit forecast in the 2005–06 provincial budget. The fiscal turnaround is attributed to changes in accounting policies and higher-than-expected tax revenues. Higher personal and corporate tax revenues were the main reason that revenues for the fiscal year were $2.2 billion over the level projected in the 2005 budget.

Despite the boost in revenues, without the changes in accounting practices the government of Ontario would have recorded a modest $151 million deficit. Previously, grants to hospitals, school boards and colleges—broader public sector (BPS) organizations—were reported as expenses in the relevant ministry. To eliminate double counting and match revenues to expenses, the grants plus (minus) the BPS organizations' operating surpluses (deficits) are now included as provincial ministry expenses. Expenses before consolidation were actually $898 million higher than expected in the 2005 Budget. However, consolidating the BPS organizations decreased the province's expenses by $459 million.

The Ministry of Finance has also exercised fiscal prudence by including a reserve fund of $1 billion in 2006–07 and $1.5 billion in 2007–08 and 2008–09 to protect the fiscal plan against unforeseen events. If the reserves are not required, the deficit is projected to be $900 million in 2006–07 and $700 million in 2007–08, and a surplus of $500 million is projected for 2008–09.

TRADE

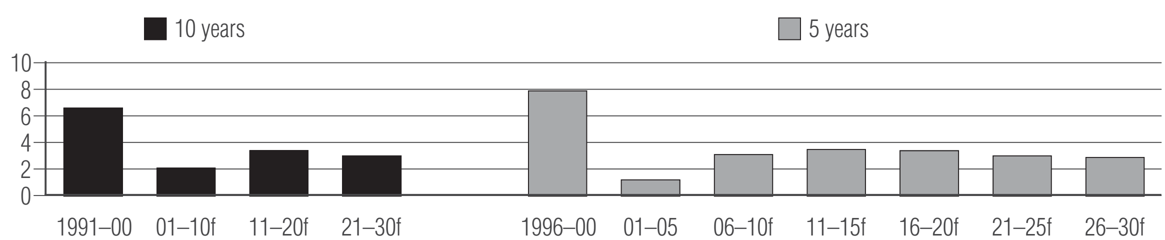
The large appreciation of the Canadian dollar over the last three years has dealt a major blow to Ontario's manufacturing-intensive export sector. Manufacturers, especially those industries requiring significant labour input, are struggling to restructure their businesses in an effort to remain competitive. And while jobs continue to be shed, it seems clear that manufacturers are for the most part intent on staying in Ontario and remaining competitive by investing heavily in productivity-enhancing machinery and equipment. Looking ahead, the trade sector is expected to contribute once again to real GDP growth over the medium term. However, the contribution of net exports to GDP growth will be limited as exporters face moderating U.S. economic growth.

Total exports are projected to grow an average annual compound rate of 3.3 per cent over 2006–15 and then to ease to a pace of 3.1 per cent from 2016 to 2030. Slower U.S. real GDP growth, combined with a strong Canadian dollar averaging around US$0.84 throughout the forecast, will be largely responsible for weighing down export activity. (See Chart 6.) While growth in exports will be much softer than the average growth of 6.6 per cent recorded in the 1990s, exports will continue to grow as a share of total GDP throughout the forecast period—rising to 77 per cent in 2030 from 68 per cent in 2006.

The large appreciation of the Canadian dollar has dealt a major blow to Ontario's manufacturing-intensive export sector.

A strong Canadian currency has helped to elevate imports, but growth will be eased by weaker consumer imports as the pace of household spending slows over the long term. Hence, like exports, imports are projected to increase at a decreasing rate over the forecast period, with growth easing from an average annual compound rate of 3.7 per cent over 2006–15 to 3 per cent from 2016 to 2030.

Chart 6
Real Exports
(average annual compound growth rate)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

CHAPTER 7

Natalia Ward

Manitoba

Manitoba is expected to enjoy a relatively healthy economy over the next 25 years, in good part thanks to a diversifying and expanding manufacturing sector, solid employment growth, and strong government spending. The economy is expected to grow by an average annual compound growth rate of 2.4 per cent over 2006–30. (See Chart 1.)

Manitoba's long-term economic health will slow interprovincial out-migration and strengthen immigration. With both of these factors helping to offset a declining natural rate of population increase, the population growth rate will hold steady over the forecast period. However, the low fertility rate of baby boomers will result in an aging population plus a sharp deceleration in labour force growth. The aging of the population will further strain an already overburdened health-care sector, forcing the government to devote a greater share of its spending to this area.

Manufacturing will remain the strongest component of output over 2006–30, with growth of 3.2 per cent, compounded annually. Even with some short-term challenges in the cattle industry, Manitoba's agriculture outlook remains healthy over the period, with an annual compound growth rate of 2.4 per cent.

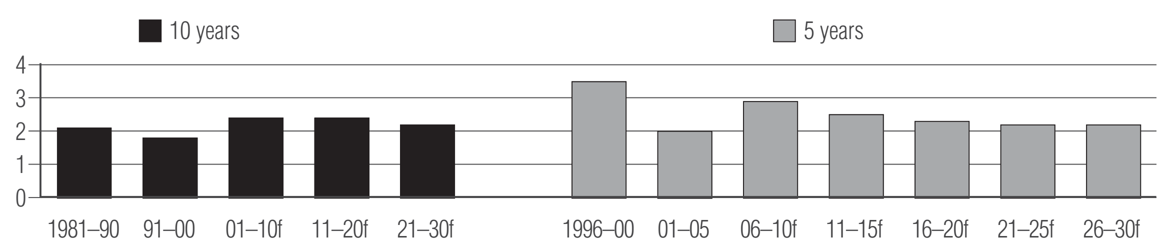
DEMOGRAPHIC PATTERNS

Demographic trends play an important role in long-term economic forecasting. The growth and changing age structure of the population are major determinants of the structure of the labour force, which is an essential component of potential output. Moreover, the demographic profile of the population strongly affects overall demand, influencing the relative strengths and weaknesses of various economic sectors.

The aging of the population will further strain an already overburdened health-care sector.

A province's population profile is determined by three factors: the natural rate of increase (births minus deaths), interprovincial migration, and international immigration. (See Table 1.) The aging of Manitoba's population will slow its natural rate of increase after 2022–23 and will lead to an increase in the death rate, even with increases in life expectancy. At the same time, growth in the number of births in the province will weaken off after 2015–16 as the prime childbearing years end for baby boomers. A fertility rate below the replacement rate

Chart 1
Real GDP at Basic Prices
(average annual compound growth rate)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

will further compound the issue. Manitoba's women of childbearing age are assumed to give birth to an average of 1.81 children over the forecast period—one of Canada's highest provincial fertility rates but short of the replacement rate of 2.1.

Manitoba's population movements between 2006 and 2030 provide graphic evidence of the aging population. (See Chart 2.) The key demographic factor behind this phenomenon is the baby-boom generation. A substantial portion of the baby boomers will be in their retirement years by the end of the forecast. In fact, by 2030, the 65-and-over age cohort is expected to constitute approximately 19.7 per cent of the total population. This will have major consequences for the economy.

The continuous population outflow to other provinces will also suppress Manitoba's population growth. (See Chart 3.) On the bright side, net interprovincial migration should become less negative over the forecast period as growth in the manufacturing and high-tech sectors, combined with government measure to retain and attract young people (such as the recently announced tuition tax credit), generate more employment opportunities and slow out-migration. After an average annual loss of 2,355 persons to interprovincial migration between 2006 and 2015, Manitoba is estimated to lose 1,191 persons annually over 2016–30.

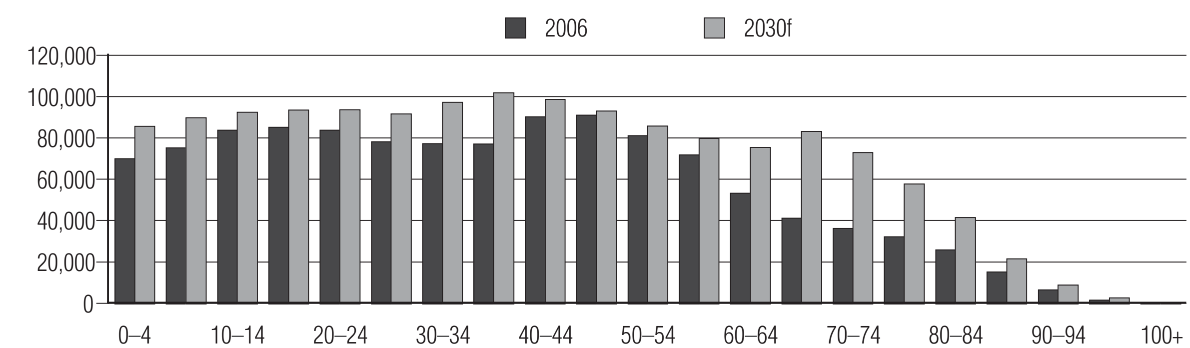
Historically, most new Canadian immigrants choose to live in major urban centres, largely those in Ontario, Quebec and British Columbia. This means that few international immigrants move into smaller provinces, such as Manitoba. However, this tendency may be changing. For the same reasons that are expected to entice more Manitoba residents to stay in the province, a greater number of immigrants are forecast to come into the province. On average, 8,939 international immigrants per year are expected over 2006–15, and Manitoba is forecast to attract an average of 10,859 international immigrants per year between 2016 and 2030.

Table 1
Key Demographic Assumptions

Components	Assumptions
Population	Manitoba's population is expected to grow at an annual average rate of 0.9 per cent over 2006 to 2030, but the average age of the population will steadily increase.
Migration	Net interprovincial migration will continue to decline over the next 25 years, losing on average 1,656 people per year. But net international migration will jump from an average of 6,397 people in 2006 to 9,166 people in 2030.
Fertility rate	The fertility rate in Manitoba is 1.81, second highest among the provinces, but below the replacement rate of 2.1.
Natural increase in the population	The natural increase (deaths minus births) is expected to go up until 2023 and then to begin to decline, adversely affecting population growth.

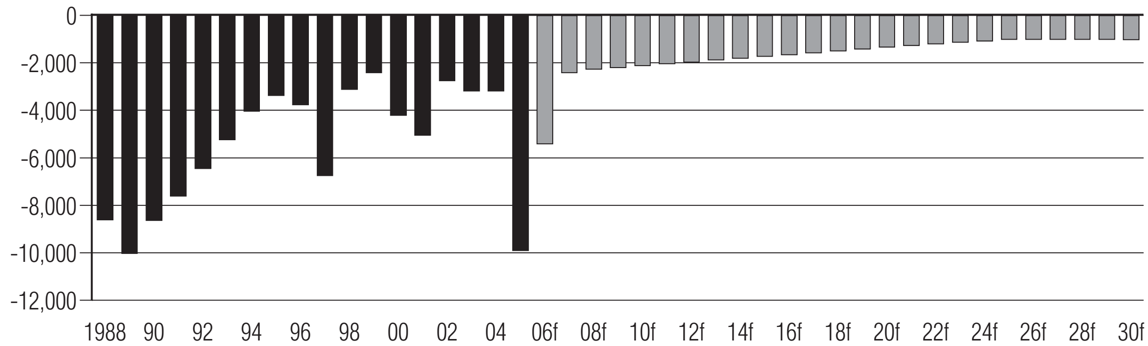
Sources: The Conference Board of Canada; Statistics Canada.

Chart 2
Population Increases in Older Age Cohorts
(number of people)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Chart 3
Net Interprovincial Migration
(number of people)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Strengthening of international immigration to Manitoba throughout the forecast period will more than offset the outflow of interprovincial migrants. Consequently, the province can expect to gain an average of 7,452 persons per year on a net basis over 2006–15 and an average of 9,254 persons per year on a net basis in later years of the forecast. This positive net migration will help offset the slowing of the natural rate of increase, resulting in a steady population growth rate throughout the forecast period. The annual compound growth rate for total population in Manitoba is forecast to be 0.9 per cent over 2006–30, raising total population from 1.177 million in 2006 to 1.471 million by the end of 2030 and maintaining Manitoba's status as the country's fifth largest province.

LABOUR FORCE

Labour force growth is determined by changes in the working-age population—that is, the number of people aged 15 and over—and movements in the participation rate. Because the fertility rate in Manitoba is below the replacement rate, average annual compound growth of the working age population is expected to remain soft over the long term, growing by 1 per cent from 2006 to 2030. The labour force participation rate is expected to continue growing until 2011, to 69.9, before steadily declining to 65.9 by the end of the forecast. More baby boomers will be retiring, and there will be an easing in the number of women entering the labour force. Combined with modest population growth, lower participation rates will translate into compound annual labour force growth of 1 per cent from 2006 to 2015 and 0.6 per cent between 2016 and 2030.

POTENTIAL OUTPUT AND PRODUCTIVITY

This long-term economic forecast is guided by the concept of potential output, which is the highest level of economic activity an economy can attain without surpassing its capacity limits and igniting inflation. Potential output is not directly measured and, as such, the Conference Board uses a structural production function to obtain an estimate of potential. We assume that the production function takes a Cobb-Douglas form, in which the mix of labour, capital and technical efficiency are modelled to produce potential output. With this assumption, our estimate of potential output depends on potential employment, capital, and trend total factor productivity (TFP).

Potential employment measures the contribution of labour to potential output by estimating the available workforce when the economy is operating at capacity. When operating at economic capacity, the labour force participation rate is at its structural peak and unemployment is at its "natural rate." Therefore, movements in the structural participation rate and the natural rate of unemployment are the two main factors driving changes in labour's contribution to output over the long term.

The natural rate of unemployment defines a minimum level of unemployment that would remain because some people are in transition between jobs and others prefer not to work at the current wage. It is expected that unemployment resulting from workers in transition will decline over the forecast. This will occur because there will be an increase in the average age of the labour force, and older workers are not as likely to quit their jobs to look for other work. Thus, the natural rate of unemployment is expected to trend slowly downward over the forecast period, positively contributing to labour potential.

On the other hand, the aging labour force will detrimentally affect labour potential through the labour force participation rate. As workers move into older age cohorts, their aggregate labour force participation generally declines as a result of health problems and early retirement. Consequently, the overall participation rate is expected to decline sharply over the next 25 years as a significant share of baby boomers move into their retirement years. On balance, the negative effects of declining participation rates will outweigh the benefit derived from a lower natural rate of unemployment. Therefore, the average annual contribution of labour to potential output will decline gently over the long term—from 0.5 per cent between 2006 and 2015 to 0.4 per cent between 2016 and 2030.

Over the long term, trend TFP growth is expected to be robust.

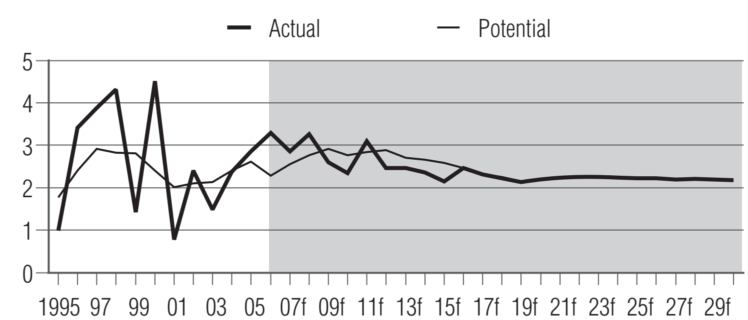
The value of Manitoba's productive capital is the second factor of production required to calculate potential output. The Conference Board of Canada does not rely on a measure of potential or optimal capital stock; instead, we assume that productive capital is accurately measured and that the level of capital available in the economy at any time is all that is available to contribute to potential output. Total public and private capital, excluding residential assets, contributes to the level of productive capital. Over the forecast period, the net capital stock is assumed to increase each year by the amount of new investment, net of depreciation and discarded capital. The contribution of capital to potential output growth will average about 1 per cent per year over the 2006–30 period.

The technical efficiency with which capital and labour are utilized to produce output is measured by total factor productivity. Over history, TFP is calculated residually, using the logarithmic form of the Cobb-Douglas production function, so that changes in output not explained by labour or capital are attributed to changes in technical efficiency. It should be noted that, for purposes of this calculation, total output is defined as real output at basic prices for all industries, excluding paid and imputed rent. Paid and imputed rent is excluded because the Board's estimates of the capital stock do not take into account residential assets, since these do not contribute to the productive capacity of the economy.

TFP fluctuates considerably over the business cycle. The reasons for this are wide ranging but include changes in the mix between capital and labour, relative shifts in the types of capital purchased, shifts in labour productivity as labour force skills evolve, and tax changes. In order to remove the effects of volatile short-term movements, potential output is calculated with trend TFP, which is our residual measure smoothed with a Hodrick-Prescott filter. Over the long term, trend TFP growth is expected to be robust. With the growth in the number of workers dwindling, firms will need to continually invest in productivity-enhancing technology and the skills development of their workforce, helping to maintain growth in TFP. The contribution of TFP to growth in potential will remain in line with recent historical performance, roughly 1 per cent annually over the forecast horizon.

When actual real GDP diverges from potential output, an economy is said to have an output gap. Manitoba's historical dependence on primary industries, especially agriculture, has caused wider swings in actual growth than is normal for a developed economy. Actual real GDP growth is expected to be close in line with potential growth over the long term. (See Chart 4.) Potential GDP is expected to grow at an average of 2.4 per cent over the forecast period.

Chart 4
Actual versus Potential GDP Growth
(percentage change)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

AGGREGATE DEMAND

CONSUMPTION

Nominal spending on consumer-related goods and services will be relatively strong over the long term, with annual compound growth of 4.1 per cent over 2006–30. As the baby boomers approach and reach retirement age, they will gradually spend more of their disposable income on services, such as health care and travel, especially after 2025, and less on durable goods, such as cars and large appliances. Specifically, the proportion of total consumption expenditures on services (excluding rent) is expected to increase from 35 per cent in 2006 to 43 per cent by 2030, while the proportion of total consumption expenditures on goods is expected to fall from 47 per cent in 2006 to 40 per cent in 2030. The share taken by the third and final component of consumer spending—consumer spending on rent (which includes imputed and paid rent)—will remain unchanged at 18 per cent throughout the forecast period.

INVESTMENT

In recent years, most of the private non-residential investment spending on non-energy projects in Manitoba has been concentrated in the manufacturing sector. This expansion has fuelled several industries, including agri-food, aerospace and transportation equipment. The provincial aerospace industry, which has grown into one of the largest in the nation, promises to be a force within Manitoba's manufacturing sector well into the next decade. This diversification better positions the province to withstand shocks to individual industries. In the medium term, several large-scale projects will contribute to robust growth of non-residential investment spending, including a new terminal at the Winnipeg International Airport ($572 million, 2006–09) and Red River Floodway expansion (private share $533 million, 2005–09). Private non-residential investment spending on non-energy projects is forecast to grow annually by 5.8 per cent (nominal) over 2006–15 and by 4.8 per cent from 2016 to 2030.

Non-residential energy investment spending in the province will be driven by four large-scale hydroelectric power projects by Manitoba Hydro scheduled for construction over the first half of the forecast period. The first project is the $1-billion, 200-megawatt Wuskwatim generating station near Nelson House. The project received all regulatory approvals and got underway in August 2006. The generating station is expected to be finished in six years. Three other project proposals are the $1-billion, 600-megawatt Gull generating station, scheduled for 2010–15; the $200-million, 100-megawatt Notigi generating station, scheduled for 2009–14; and the 1380-megawatt Conawapa generating station—the largest hydroelectric project ever built in northern Manitoba—scheduled for 2011–19. Some risks are associated with the timing of the projects and they may not go ahead as proposed. In total, private non-residential investment spending on energy projects is expected to grow at an annualized rate of 12.9 per cent (nominal), compounded annually, between 2006 and 2015 and to moderate to 0.7 per cent growth from 2016 to 2030 once the hydro projects are completed.

Non-residential energy investment spending in the province will be driven by four large-scale hydroelectric power projects.

Government investment spending is also anticipated to post strong growth over the forecast period. The primary focus will be in health care, with the construction of new hospitals, the conversion of old hospitals to long-term care facilities and the purchase of new equipment. Meanwhile, public spending on primary and secondary education will decline as the echo generation—the children of the baby boomers—leave high school. Mitigating this negative pressure is the need for spending on post-secondary education to expand to keep pace with increased demand, as more members of the echo generation enrol in college and university. The provincial government will also need to spend money on upgrading and improving Manitoba's infrastructure, such as sewage systems, waterlines and roads. Overall public and private non-residential investment is forecast to grow at 8.3 per cent (nominal), compounded annually, between 2006 and 2015 and at 3.2 per cent between 2016 and 2030.

Growth in private residential investment is expected to be fairly robust over the forecast period. Private investment in residential construction is expected to advance by 6.3 per cent (nominal), compounded annually, between 2006 and 2015 and 3.8 per cent between 2016 and 2030. Total housing starts are expected to grow by 2.2 per cent, compounded annually, from 2006 to 2015 and then to gain 0.6 per cent from 2016 to 2030. Housing starts are expected to average roughly 5,947 units per year over

2006–30. Over the forecast period a structural change will take place within the housing sector. Most elderly people opt to live in apartment buildings or retirement homes; as the province's population ages, the demand for multi-family dwellings will increase, while the demand for single-family dwellings will decline. Because of this, a greater proportion of total housing starts will be multi-family dwellings. (See Chart 5.) Indeed, multi-family dwellings are expected to comprise 56.5 per cent of total housing starts in Manitoba by 2030, compared to 32.1 per cent in 2006, while the share of single-family starts will decline to 43.5 per cent in 2030 from 67.9 per cent in 2006.

GOVERNMENT

Manitoba's provincial government successfully tackled its deficit with budget cuts in the early 1990s. The effort paid off with ten consecutive balanced budgets, beginning in the 1995–96 fiscal year. In 1999 began what is expected to be a period of sustained long-term growth in government spending. In fact, the annual compound growth rate of nominal government spending on goods and services—a respectable 4.4 per cent from 1996 to 2005—is projected to be strong throughout the forecast at 4.8 per cent from 2006 to 2030. Much of the spending will be directed toward health care to meet the demands of the aging population. This expenditure growth will be financed in part by the federal government through significant increases in transfer payments, particularly the Canada Health and Social Transfer. The increase in federal transfers will also enable the provincial government to increase spending with little or no fiscal belt-tightening.

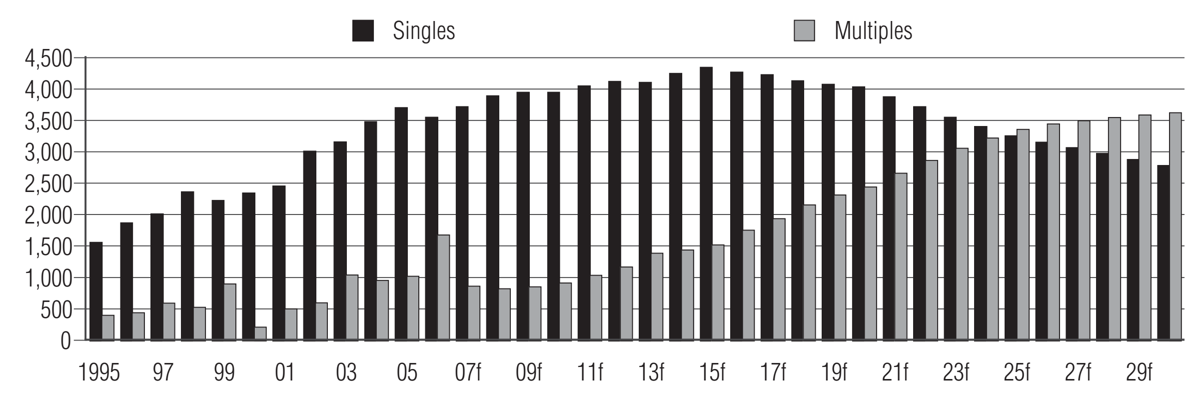
INDUSTRY ANALYSIS

Manitoba was exclusively an agri-food and central shipping centre for many years, but the province has successfully expanded its manufacturing sector to include aerospace, information technology and telecommunications, transportation equipment, farm equipment and machinery, health care products, apparel, and wood processing and building products. The province's manufacturing sector is becoming more diversified every year, and it will play an increasingly significant role in Manitoba's output growth moving forward.

The annual compound growth rate of nominal government spending on goods and services is projected to be strong throughout the forecast.

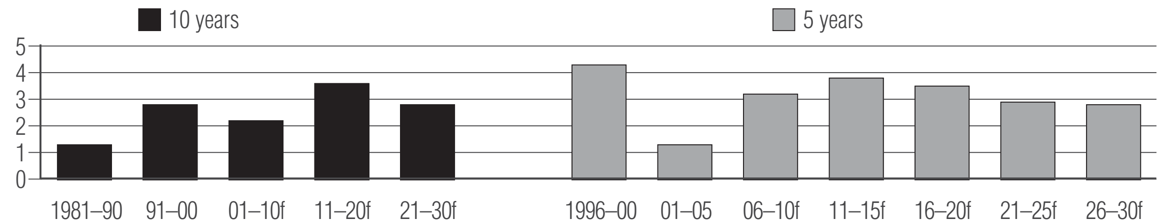
Manitoba is at the northern end of the Mid-Continent Trade Corridor, which runs through the midwestern United States to Mexico, and potentially further south. Trade within the corridor has increased substantially since the North American Free Trade Agreement (NAFTA) came into effect in 1994. NAFTA has been a boon to the province's manufacturers, promoting further investment in the sector. As a result, manufacturing is expected to grow by 3. 5 per cent, compounded annually, over 2006–15 and 3.1 per cent from 2016 to 2030. (See Chart 6.)

Chart 5
Total Housing Starts
(units)



f = forecast
Sources: The Conference Board of Canada; Canada Mortgage and Housing Corporation.

Chart 6
Real Manufacturing Output
(average annual compound growth rate)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Although Manitoba has successfully diversified its economy, agriculture remains an important component. It constituted about 16 per cent of total output in the goods-producing sector in 2006. Manitoba's agriculture industry is expected to post annual compound growth of 2.4 per cent over the entire 2006–30 forecast. There has been short-term volatility in Canadian agriculture, especially in exports, following the discovery of mad cow disease in Canada, but a few underlying trends will emerge over the next 25 years. First, with world population growing from 6.5 billion in 2005 to 8.2 billion by 2030 (according to United Nations estimates), world food demand will increase and exert increasing pressure on agricultural commodity prices. Second, as incomes rise in the developing world and more people are able to afford meat products, demand is expected to rise. Concerns surrounding food safety will continue to challenge the agriculture sector over the medium term, but improved monitoring programs, testing procedures and health policy guidelines such as animal feed restrictions are expected to gradually reduce trade impediments related to food safety. Furthermore, continued trade liberalization, such as the elimination of Mexican import tariffs, is expected to give Canadian meat producers, especially pork producers, increased access to foreign markets. Consequently, the long-term growth potential remains strong for Manitoba's meat and poultry industry. This is especially true for the hog sector, which has seen tremendous growth in recent years.

Agriculture constituted about 16 per cent of total output in the goods-producing sector in 2006.

Overall, goods-producing industries in Manitoba will grow by 2.9 per cent, compounded annually, over 2006–30, while the service sector as a whole is expected to grow by 2.2 per cent. Of the service-producing industries, commercial services are forecast to grow by 2.7 per cent; non-commercial services by 2.4 per cent; transportation, storage and warehousing by 2.3 per cent; and wholesale and retail trade and public sector output by 2.2 per cent—all at annualized rates—over the 2006–30 forecast period.

CHAPTER 8

Natalia Ward

Saskatchewan

OVERVIEW

Saskatchewan's economic growth is expected to be strong for the remainder of this decade, but it will cool off in the long term as demographic changes take hold. The province's real gross domestic product (GDP) is forecast to grow at 2 per cent annually between 2006 and 2015, and by 1.7 per cent per year between 2016 and 2030. (See Chart 1.) Taken together, this yields average growth of 1.8 per cent per year over the entire forecast period, ranking Saskatchewan fifth among Canada's provinces but well below the national average of 2.4 per cent.

Manufacturing will remain the strongest component of output over 2006–30, with growth of 3.3 per cent.

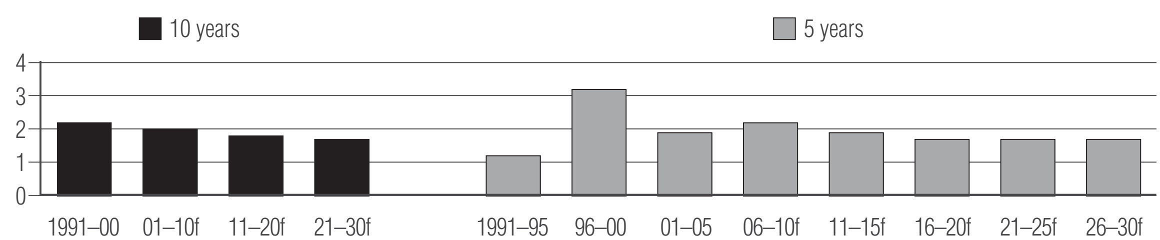
Saskatchewan will face a number of fundamental changes over the next 25 years. First, the average age of the population will gradually increase. This will put an enormous strain on the province's health-care sector and force the government to increase spending to rebuild and maintain health-care resources. Second, the aging of the population will result in a structural change in consumption, as an older population is expected to spend less on durable goods and more on services, especially in the last five to ten years of the outlook. Third, a relatively high fertility rate will be more than offset by steady interprovincial out-migration, resulting in moderate population growth.

Manufacturing will remain the strongest component of output over 2006–30, with growth of 3.3 per cent, compounded annually. Saskatchewan's agricultural outlook remains relatively healthy, with an annual compound growth rate of 1.7 per cent expected between 2006 and 2015 and 1.4 per cent between 2016 and 2030. Finally, mining promises to post solid growth for the remainder of this decade, with average annual growth of 1.4 per cent over the entire forecast period.

DEMOGRAPHIC PATTERNS

Demographic patterns play a crucial role in determining the long-term potential output of an economy. (See Table 1.) The growth and changing age structure of the population influence movements in the labour force, which is a key component of potential output. Age structure also plays an important role in the aggregate demand of an economy by influencing the relative strengths and weaknesses of various sectors of the economy.

Chart 1
Real GDP at Basic Prices
(average annual compound growth rate)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Table 1
Key Demographic Assumptions

Components	Assumptions
Population	Saskatchewan's population is expected to grow at an annual average rate of 0.2 per cent over 2006 to 2030; the average age of the population will steadily increase.
Provincial migration remains negative	Saskatchewan's net interprovincial migration will continue to decline, losing on average 2,529 people per year over the forecast period.
International migration to pick up speed	Net international migration will will rise from 1,014 people in 2005 to 1,802 people in 2030.
Fertility rate	The fertility rate in Saskatchewan is 1.83, the highest among the provinces, but below the replacement rate of 2.1.
Natural increase in the population	The natural rate of increase is projected to dwindle over the forecast period, adversely affecting population growth.

Sources: The Conference Board of Canada; Statistics Canada.

According to the most recent estimates, 985,586 people lived in Saskatchewan in 2006, making it the sixth most populous province in Canada. Based on trends in the province's natural rate of increase (births minus deaths), net interprovincial migration and net international immigration, Saskatchewan's population is expected to increase to 1,049,691 by 2030. This translates into an annual compound population growth rate of only 0.2 per cent over the forecast period.

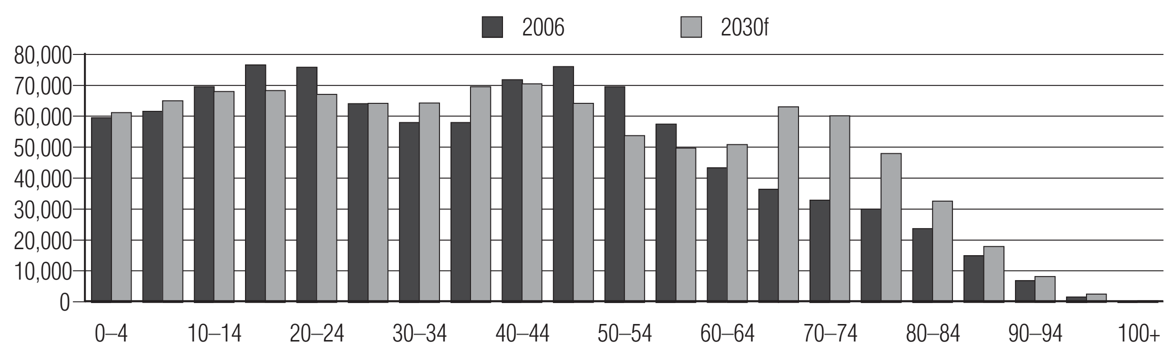
The unique demographic profile that resulted from the baby boom (1947–66), followed by the baby bust (1967–79) and the baby-boom echo (1980–95), is best illustrated by the movements in Saskatchewan's age cohorts between 2006 and 2030. (See Chart 2.) The predominant feature in 2005 is the bulge around the 39–59 age group, corresponding to the baby boomers. This cohort currently represents 28.9 per cent of the province's total population. By 2030, a substantial portion of this generation will be in their retirement years. In fact, the 65–and-over age cohort is expected to increase from 14.9 per cent of the total population in 2006 to 22.2 per cent by 2030. This will have a major impact on Saskatchewan's economy.

The emigration of Saskatchewan residents to other parts of Canada, most significantly to Alberta, continues to drain the province of vital human resources.

Although Saskatchewan has the highest fertility rate of all 10 Canadian provinces—1.86 children per woman of childbearing age, according to the most recent estimates—it still falls short of the replacement rate of 2.1. (See Chart 3.) In addition, many young women leave the province before they have children. As a result of these two factors, the natural rate of increase is expected to fall steadily after 2017–18.

The emigration of Saskatchewan residents to other parts of Canada, most significantly to Alberta, continues to drain the province of vital human resources. Except

Chart 2
Population Increases in Older Age Cohorts
(number of people)

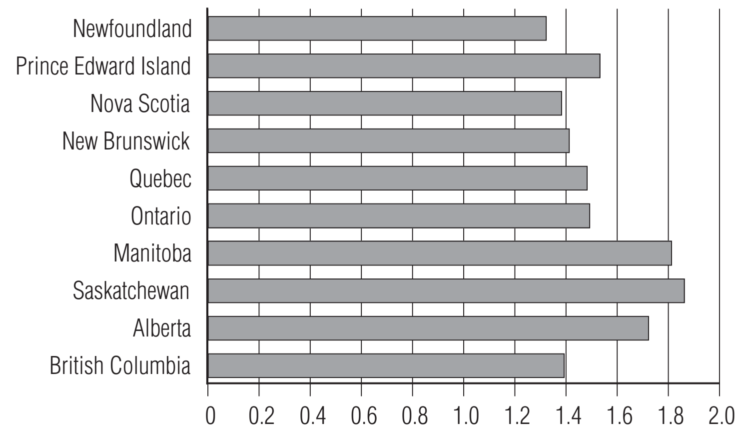


f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

for six years between 1974 and 1985, when net interprovincial migration was positive, more residents have left the province than moved to Saskatchewan from another province in every year since 1961. This forecast paints a similar picture. It is anticipated that net provincial out-migration will continue for the entire forecast period, with an average annual net exodus of roughly 2,500 between 2006 and 2030.

The final component of Saskatchewan's population growth is net international migration. Saskatchewan can expect to attract an average of 1,650 more immigrants per year than the number of people leaving the province for other countries during the forecast period. This is a very small proportion of the total number of immigrants entering Canada; most international immigrants choose to live in the major cities of Quebec, Ontario and British Columbia. Although Saskatchewan is currently home to 3.1 per cent of the Canadian population, over the forecast period it is expected to receive less than one per cent of all immigrants to Canada.

Chart 3
Provincial Fertility Rates, 2002–2003
(children per woman of child bearing age)



Sources: The Conference Board of Canada; Statistics Canada.

LABOUR MARKET OUTCOME

The aging of the population will have a profound effect on the evolution and structure of the labour force. For example, the 15–24 age cohort—a primary source of new workers—currently represents 15.4 per cent of the Saskatchewan's total population; by the end of the forecast it will comprise only 12.9 per cent. Moreover, as the population ages, labour force growth will slow, rising by an average of 0.3 per cent between 2006 and 2015 and declining by 0.1 per cent over the second half of the outlook.

Total employment will inch up by an average of 0.4 per cent between 2006 and 2015 and decline by an average of 0.1 per cent between 2016 and 2030. Overall, total employment in the province is expected to reach 502,888 in 2030. Despite weak employment growth, the unemployment rate is projected to experience a steady decline from 5 per cent in 2006 to 4.2 per cent in 2030, placing Saskatchewan in second-best place among the provinces in 2030 and well below the national average. (See Chart 4.)

POTENTIAL OUTPUT AND PRODUCTIVITY

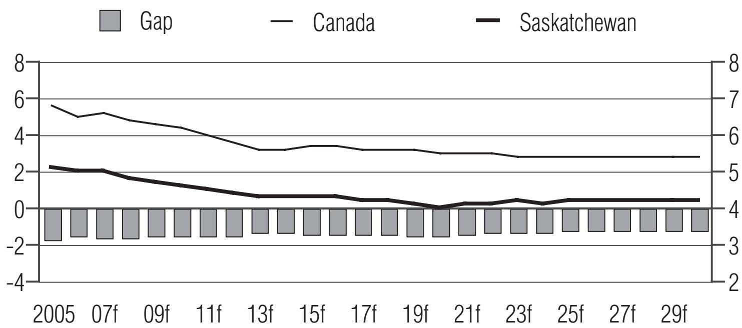
This long-term economic forecast is guided by the concept of potential output, which is the highest level of economic activity an economy can attain without surpassing its capacity limits and igniting inflation. Potential output is not directly measured and, as such, the Conference Board uses a structural production function to obtain an estimate of potential. We assume that the production function takes a Cobb-Douglas form, in which the mix of labour, capital and technical efficiency are modelled to produce potential output. With this assumption, our estimate of potential output depends on potential employment, capital and trend total factor productivity (TFP).

Despite weak employment growth, the unemployment rate is projected to experience a steady decline.

Potential employment measures the contribution of labour to potential output by estimating the available workforce when the economy is operating at capacity. Under these conditions, the labour force participation rate is at its structural peak and unemployment is at its "natural rate." Therefore, movements in the structural participation rate and the natural rate of unemployment are the two main factors driving changes in labour's contribution to output over the long term.

The natural rate of unemployment defines a minimum level of unemployment that would remain because some people are in transition between jobs and others prefer not to work at the current wage. It is expected that unemployment resulting from workers in transition will decline over the forecast. This will occur because there will be an increase in the average age of the labour force, and

Chart 4
Unemployment Rate
(per cent)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

older workers are not as likely to quit their jobs to look for other work. Thus, the natural rate of unemployment is expected to trend slowly downward over the forecast period, positively contributing to labour potential.

On the other hand, the aging labour force will detrimentally affect labour potential through the labour force participation rate. As workers move into older age cohorts, their aggregate labour force participation generally declines as a result of health problems and early retirement. Consequently, the overall participation rate is expected to remain steady over the medium term and to decline after 2011 as a significant share of baby boomers move into their retirement years. Overall, labour's annual contribution to potential output growth is, on average, expected to be 0.1 percentage points between 2006 and 2015 and slightly negative for the remainder of the forecast.

The value of Saskatchewan's productive capital is the second factor of production required to calculate potential output. The Conference Board of Canada does not rely on a measure of potential or optimal capital stock, but assumes instead that productive capital is accurately measured and that the level of capital available in the economy at any time is all that is available to contribute to potential output. Total public and private capital, excluding residential assets, contributes to the level of productive capital. Over the forecast period, the net capital stock is assumed to increase each year by the amount of new investment, net of depreciation and discarded capital. The contribution of capital to potential output growth will average about 1 percentage point per year over the 2006–30 period.

The technical efficiency with which capital and labour are utilized to produce output is measured by total factor productivity. Over history, TFP is calculated residually, using the logarithmic form of the Cobb-Douglas production function, so that changes in output not explained by labour or capital are attributed to changes in technical efficiency. It should be noted that, for purposes of this calculation, total output is defined as real output at basic prices for all industries, excluding paid and imputed rent. Paid and imputed rent is excluded because the Board's estimates of the capital stock do not take into account residential assets, since these do not contribute to the productive capacity of the economy.

The natural rate of unemployment is expected to trend slowly downward over the forecast period.

TFP fluctuates considerably over the business cycle. The reasons for this are wide-ranging but include changes in the mix between capital and labour, relative shifts in the types of capital purchased, shifts in labour productivity as labour force skills evolve, and tax changes. In order to remove the effects of volatile short-term movements, potential output is calculated with trend TFP, which is our residual measure smoothed with a Hodrick-Prescott filter. Over the long term, trend TFP growth is expected to be robust. With the growth in the number of workers dwindling, in order to maintain growth in TFP, firms will need to continually invest in productivity-enhancing technology and the skills development of their workforce. The contribution of TFP to growth in potential will remain in line with recent historical performance, contributing roughly 0.8 percentage points to growth annually over the forecast horizon.

Potential output growth is expected to be slightly higher in the first half of the forecast than in the second half, when the downward trend in labour force growth will begin to dominate gains in labour productivity. Potential output is estimated to grow by 2.2 per cent from 2006 to 2015 and to slow to 1.7 per cent growth over the remainder of the forecast.

Actual GDP growth and potential output rarely converge over the course of a business cycle. Saskatchewan has historically been more dependent on the volatile primary resource industries, especially agriculture, causing wider swings in actual growth than is normal for most developed and diversified economies. When actual GDP growth and potential GDP growth diverge, there is said to be an output gap. Economic growth is expected to be closely in line with potential in the last 15 years of the forecast. (See Chart 5.)

AGGREGATE DEMAND

CONSUMPTION

Slowing employment growth will result in more sluggish consumer spending throughout the forecast period. Nominal consumer spending is projected to grow by 3.6 per cent, compounded annually, between 2006 and 2030.

More importantly, the composition of consumer spending will change radically. As the baby boomers age, their share of purchases of durable goods, such as cars and large appliances, will decrease, and their share of services, especially health care and tourism, will increase. Thus, consumer spending on goods, which represented roughly 47 per cent of total consumption in 2006, is projected to ease gradually to 40.7 per cent by 2030. In contrast, the proportion of total consumption of services (excluding rent) is expected to climb from 34.7 per cent in 2006 to 43 per cent by 2030. The share of consumer spending on rent, which includes imputed and paid rent, is forecast to fall from 18.3 per cent in 2006 to 16.3 per cent in 2030. This is largely because the province's younger cohorts, the primary source of new demand for housing and rental apartments, will decrease in relative size over the forecast period.

The change in the composition of spending will also slow growth in retail sales. Retail sales are projected to average 4.6 per cent nominal growth, compounded annually, over 2006–15, then to grow by 3.7 per cent over 2016–30.

INVESTMENT

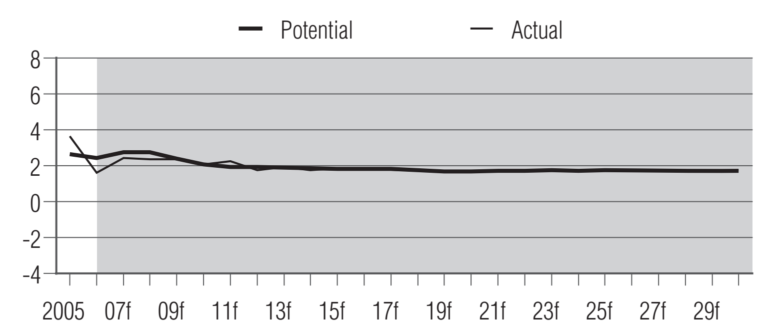
Weakening population growth is projected to hold back residential investment. A significant proportion of Saskatchewan's younger generation—the age cohorts most likely to form households—are expected to leave the province for other parts of Canada. On top of this, aging baby boomers will vacate their single-dwelling units and move into retirement homes, stifling the resale market with excess homes. Overall, private investment in residential construction will soften, with an average annual compound growth rate of 2.6 per cent over the entire forecast period.

After averaging almost 3,380 starts in 2006, the province is expected to have fewer than 2,000 new homes in 2030.

After averaging almost 3,380 starts in 2006, the province is expected to have fewer than 2,000 new homes in 2030. Moreover, as the population ages throughout the forecast period, the housing sector will undergo a compositional change. Since older individuals generally prefer to live in multiple housing units such as apartments and retirement homes, it is anticipated that the proportion of total starts for multiple-unit dwellings will gradually rise. The ratio of multiple and single dwellings will change over the forecast period: 32.9 per cent of all housing units were multiple-unit dwellings in 2006; in 2030 this number is expected to be 63.4 per cent.

Over the long term, most non-energy non-residential construction will come from government investment. Government investment spending will rise over the forecast period, particularly for health care, largely in response to increased demand by the aging baby boomers. This sector will require new hospitals, long-term care facilities, and new and upgraded equipment. Meanwhile, spending on post-secondary education will have to expand to keep pace with increased enrolment from the echo generation. Furthermore, significant repairs will be required during the forecast period on roads, sewers, water mains,

Chart 5
Actual versus Potential GDP Growth
(percentage change)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

and general infrastructure. Overall, private and public non-residential investment will advance by an average of 4 per cent per year in nominal terms over the forecast period. At the same time, investment in machinery and equipment will also expand, by a relatively strong average of 4.7 per cent per year.

GOVERNMENT

The first half of the 1990s was a difficult period for Saskatchewan's government. When the 1990–91 recession led to a dramatic increase in the province's deficit, the government increased taxes and cut expenditures. From 1992 to 1997, annual growth in nominal government spending on goods and services averaged a mere 1 per cent. To make matters worse, reduced transfers from the federal government exacerbated provincial austerity. Painful budgets were the norm throughout the decade. Government spending has now rebounded while revenue streams remain strong. In 1994, Saskatchewan became the first province to restore a positive budgetary balance. Since the 1994–95 fiscal year, the government of Saskatchewan has delivered 10 straight balanced budgets, and another surplus is anticipated in 2006–07.

Changes to tax policy should help foster growth in the oil, natural gas and mining sectors.

Government spending on goods and services is expected to increase by 4.1 per cent in nominal terms, compounded annually, over the entire 2006–30 forecast. Much of this new spending will be directed toward health care to meet the demands of an aging population. The expenditure program to repair Saskatchewan's social safety net will be sponsored in part by the federal government through a significant increase in transfer payments, primarily through the Canada Health and Social Transfer.

Personal income taxes paid by the average family have dropped since 1999, with provincial and federal tax reform. The province has now completed the tax reform strategy announced in the 2000 budget. As well, the small business corporation income tax rate was reduced from 8 per cent to 6 per cent in July 2001 and will soon drop to 5 per cent. These changes to tax policy should help foster growth in the oil, natural gas and mining sectors. The provincial government's reduction in royalty and taxation rates for new oil and natural gas production and its mining incentive package will help increase activity in these key sectors.

The pressures placed on the government's social programs by aging baby boomers are expected to lead to a fiscal balance of close to zero over the entire forecast period, as excess provincial funds will be channelled into further spending on health care. In the latter half of the forecast period, when the echo generation have all entered their prime childbearing years, increased government spending on education will be required, especially to hire teachers and to provide resources for primary and secondary schools.

INDUSTRY ANALYSIS

Since the elimination of the Crow rate subsidy on Western Canadian grains in 1995, Saskatchewan's agri-food industry has become increasingly important for farmers as an alternative to shipping grain. The increased efficiency resulting from the removal of this subsidy has delivered positive results for farmers, helping to re-establish agriculture as one of the most important sectors in the province. Agriculture's share of Saskatchewan's economy will improve over the long term, thanks to increasing global food demand plus the federal government's Agricultural Policy Framework, which puts more emphasis on innovation and technology. If world population expands from 6.5 billion in 2005 (latest available data) to 8.2 billion by 2030, as expected by the United Nations, world food demand will increase and upward pressure will be placed on agricultural prices. After the reopening of the U.S. border, exports of live bovine animals under 30 months of age rose dramatically; they are expected to remain strong in the near term as more countries return to more normalized trade conditions. Moreover, increasing interest in grain-based alternative fuels will support strong demand and elevated prices for grain producers, benefiting the industry. Elevated grain prices could have a negative impact on livestock producers, but this effect will be negligible in the long term. The agriculture sector is expected to grow at an average annualized rate of 1.7 per cent between 2006 and 2015 and to level off to average growth of 1.4 per cent between 2016 and 2030. (See Chart 6.)

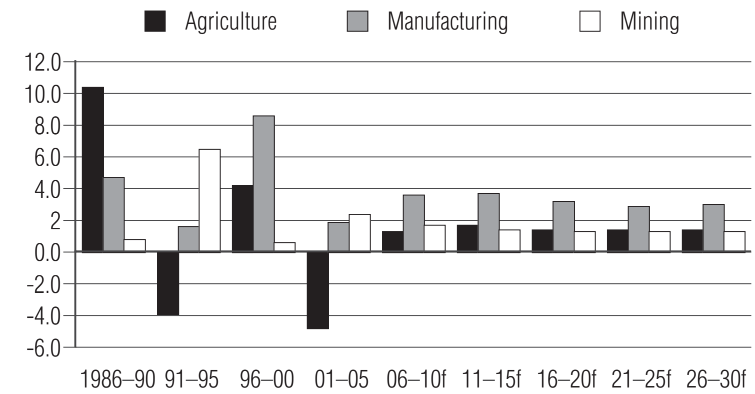
A secondary benefit of Saskatchewan's strong agriculture sector will be reaped by its manufacturing sector. Since it has become expensive to ship grain vast distances, the most cost-effective alternative has become to ship it within the province to agri-food processors. The result has been significant growth in the agri-food industry, a major component of the province's manufacturing sector. Partly as a result of this shift to agri-food production, real manufacturing output is projected to grow by an annual compound rate of 3.3 per cent over 2006–30.

It is unlikely that large investments will be made to extract the remaining oil and gas resources underneath Saskatchewan.

Over the forecast period, growth of 1.4 per cent per year is expected overall for the mining industry, which includes metal mining, non-metal mining and mineral fuels. Continued strength in Saskatchewan's uranium production and positive prospects for the worldwide uranium industry provide the foundation for the robust outlook. Saskatchewan, the largest uranium-producing region in the world, currently accounts for approximately 25 per cent of annual world uranium production. The resources in the province are estimated to be sufficient for more than 40 years at current rates of production. Other minerals produced in Saskatchewan include salt, sodium sulphate, calcium chloride and clays. The metal mining industry in Saskatchewan is forecast to grow by an average of 0.7 per cent, compounded annually, between 2006 and 2030.

Record potash prices will keep the non-metal mining sector strong in the near future. PotashCorp of Saskatchewan, the largest potash producer in the world, accounts for about 25 per cent of global potash production and holds roughly 72 per cent of unused global capacity. By conservative estimates, PotashCorp could supply global demand for potash at current levels for several hundred years. As a result of the increased price of potash, PotashCorp has ramped up production dramatically, and the medium-term outlook for non-metal mining in Saskatchewan is good, with annualized growth of 1.6 per cent over 2006–15. There is an upward risk to the non-metal mining output. Recent exploration results indicate good possibilities for diamond mining. Overall, non-metal mining is expected to advance by an average of 1.2 per cent over 2016–30.

Chart 6
Real Output, Key Industries
(average annual compound growth rate)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Dramatic market forces will be needed to stimulate growth in mineral fuels mining in coming years, largely because of reduced oil resources. More than 80 per cent of Saskatchewan's oil reserves have already been discovered, and a large part of these reserves can be retrieved only through expensive enhanced oil-recovery methods. One project in Weyburn, for example, will inject 95 million cubic feet of carbon dioxide per day into an oil field, boosting production by more than 50 per cent to 30,000 barrels a day and extending the life of the field by 25 years. Although the Conference Board expects the price of oil over the forecast period to average around US$70 per barrel in nominal terms, it is unlikely that large investments will be made to extract the remaining oil and gas resources underneath Saskatchewan. The province's mineral fuels industry is forecast to grow by an average of 1.2 per cent, compounded annually, between 2006 and 2030.

Todd A. Crawford

Alberta

OVERVIEW

The Alberta economy will advance solidly over 2006 to 2030, expanding by a compound average annual rate of 3.2 per cent, and the energy sector will remain a driving force. Sustained high oil prices, an immense non-conventional oil supply and continually improving extraction technology have shifted the focus of the energy market to oil sands production. Long-term prospects for the non-conventional oil industry in Alberta are very favourable. About $67 billion in activities related to the oil sands has already been proposed by several major energy players for 2006–20, while an additional $27 billion in oil sands-related development is slated for the remainder of the outlook. About $28 billion has been spent in the sector since 1995.

Long-term prospects for the non-conventional oil industry in Alberta are very favourable.

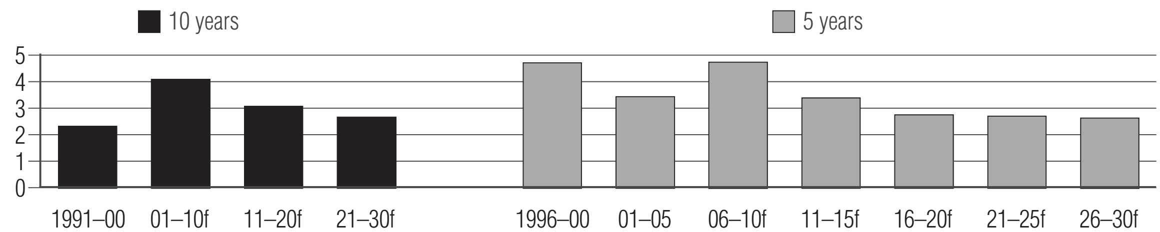
Natural gas spot prices are affected by supply and demand fundamentals in North America. The tight natural gas situation will not reverse itself in the short or medium term. Although the number of wells being drilled for natural gas is being kept elevated by drilling for coal bed methane, production of natural gas is expected to decline over the forecast, especially in Alberta, with the maturing of the Western Canadian Sedimentary Basin (WCSB). Most wells being drilled are shallow and are depleted faster than new reserves can be found. Gas extracted through unconventional methods is not expected to make up the loss from conventional production in the near or medium term.

While the long-term forecast for the province is favourable, an aging population will take its toll on output. Total population growth is projected to weaken, dampening demand for consumer goods and housing. However, record resource revenues and the positive job market will continue to attract businesses and job seekers, boosting Alberta's population growth beyond that of other provinces. Overall, economic growth is expected to reach an average annual compound rate of 4.1 per cent during the first decade of this century before weaker demographic conditions slow the economy to average annual growth of 2.9 per cent over 2011 to 2030, in line with underlying potential output growth. (See Chart 1.)

DEMOGRAPHIC PATTERNS

Demographic patterns play a crucial role in determining the long-term potential output of an economy. The growth and changing age structure of the population influence movements in the labour force, an essential component of potential output. The age structure also plays an important role in determining the aggregate demand of an economy by influencing the relative strengths and weaknesses of various sectors of the economy.

Chart 1
Real GDP at Basic Prices
(per cent, average annual compound growth rate)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

As the population ages, population growth in Alberta is expected to surge initially from a compound rate of 1.6 per cent from 1991 to 2000 to 1.9 per cent from 2001 to 2010. Population growth is then expected to slow to an average compound growth rate of 1.3 per cent over the remainder of the forecast period (2011–30). Alberta's population, estimated to have reached 3,332,812 in 2006, should reach 4,667,681 by 2030.

The share of the population aged 65 and older will increase substantially over the forecast period, from 10.5 per cent in 2006 to 19 per cent in 2030. (See Chart 2.) In 2006, baby boomers were in the 41–60 age cohort, with the heaviest concentration between ages 41 and 46. By 2021, they will represent the 56–75 range, with a high concentration in the 56–61 range. This shift in the demographic profile will have dramatic consequences for the Alberta economy.

Population growth is influenced by births, deaths and net migration. The fertility rate for the province, defined as the average number of births per woman, is projected to remain constant at 1.72 over the forecast period, less than the replacement rate of 2.1 needed to maintain long-term population stability by natural means. The low fertility rate and the aging population will reduce the birth rate; so, with the death rate expected to increase slightly because of the larger number of older people, the natural increase in the population (births minus deaths) is projected to fall steadily through to 2030. (See Chart 3.)

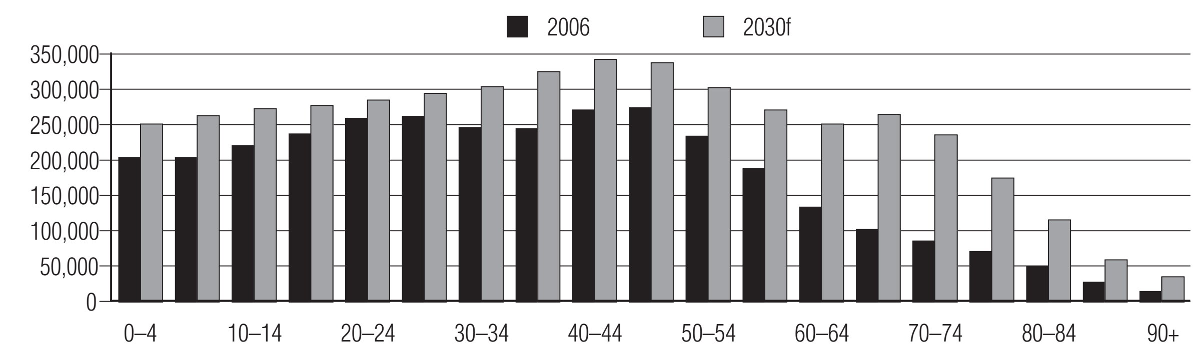
Table 1
Key Demographic Assumptions

Components	Assumptions
Population growth decelerates	As the population ages, population growth in Alberta is expected to slow from an annual compound rate of 1.9 per cent in this decade to 1.5 per cent over 2011–20 and 1.1 per cent in 2021–30.
Provincial migration decelerates	Significant net interprovincial migration will continue in Alberta over the short term, with an average of 28,338 from 2006 to 2010. In the long term, however, interprovincial migration will moderate to an average of 10,260 in 2011–30.
International migration	Average net international migration to Alberta is forecast to average 20,150 over 2011–30.
Fertility rate	The fertility rate in Alberta is projected to be 1.72 over the forecast period, less than the replacement rate of 2.1 needed to maintain long-term population stability by natural means.
Natural increase in the population	The natural rate of increase in the population (births minus deaths) is projected to fall steadily starting in 2014–15.

Sources: The Conference Board of Canada; Statistics Canada.

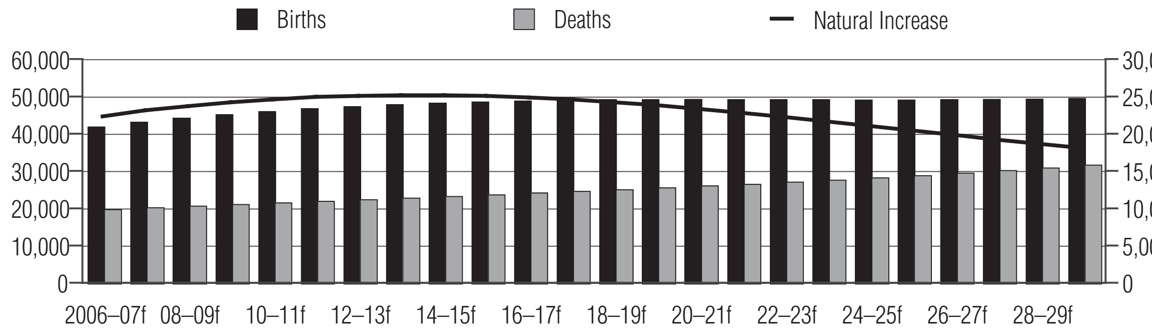
Ongoing expansion in the energy sector will draw a steady flow of workers from other provinces, while the province's favourable tax regime will continue to provide an added incentive for out-of-province businesses and workers to relocate to Alberta. Thus, the weak natural rate of population increase will be partly offset by

Chart 2
Population Increases in Older Age Cohorts
(number of people)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Chart 3
Natural Increase in Population
(number of persons)

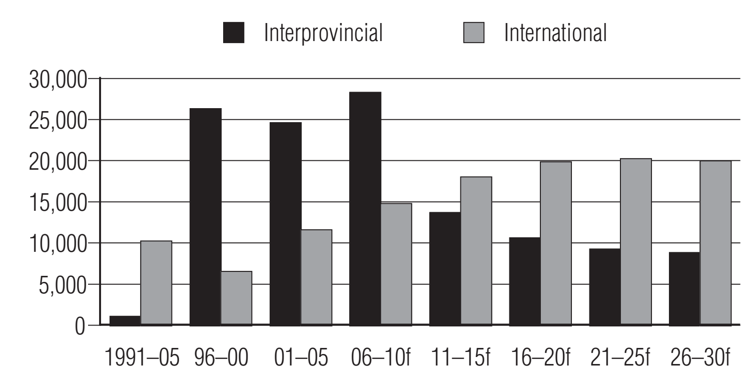


f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

a net positive inflow of migrants to Alberta over the forecast horizon. Alberta's net annual interprovincial migration averaged 26,348 people from 1996 to 2000 and will remain elevated at 26,495 people on average from 2001 to 2010 as weaker economic activity in other parts of the country fuels migration into Alberta. Net interprovincial migration will eventually moderate to an annual average of 11,407 in 2011–20 and to 9,113 over the last 10 years of the forecast. In contrast, average annual net international migration to Alberta is forecast to accelerate, from 11,650 over 2001–05 to 14,827 in 2006–10, then to pick up to average 19,575 during the rest of the forecast. (See Chart 4.)

Growth of the source population (those over 15 years of age) has generally exceeded that of the total population in Alberta. This pattern will continue, partly because most people immigrating to Alberta are of working age, with the largest share in the 15–29 age cohort. Nonetheless, growth in the source population is expected to slow from an average annual compound rate of 2.2 per cent from 2001 to 2010 to 1.5 per cent from 2011 to 2020 and finally to 1.3 per cent in the last decade of the forecast. This slowdown follows the national trend but maintains a growth pace marginally greater than that of most other provinces.

Chart 4
Immigration
(number of persons)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

The labour force participation rate has increased steadily with the influx of women into the labour force. After averaging 73.6 per cent over 2001 to 2010, it is forecast to decrease gradually to 72.6 per cent by 2020 and to reach 69.1 per cent by 2030 as female labour force participation reaches a plateau and as a growing share of the source population retires. Added to the weaker source population growth, the falling participation rate will restrict labour force growth over the forecast period. From an average annual compound growth rate of 2.6 per cent over 2001–10, labour force growth will retreat to 0.9 per cent in 2020 and finally to 0.7 in 2030. This deceleration in labour force growth will dampen potential output growth.

POTENTIAL OUTPUT AND PRODUCTIVITY

This long-term economic forecast is guided by the concept of potential output, which is the highest level of economic activity an economy can attain without surpassing its capacity limits and igniting inflation. Potential output is not directly measured; as such, the Conference Board uses a structural production function to obtain an estimate of potential. We assume that the production function takes a Cobb-Douglas form, in which the mix of labour, capital and technical efficiency are modelled to produce potential output. With this assumption, our estimate of potential output is dependent on potential employment, capital and trend total factor productivity (TFP).

Potential employment measures the contribution of labour to potential output by estimating the available workforce when the economy is operating at capacity. Under these conditions, the labour force participation rate is at its structural peak and unemployment is at its "natural rate." Therefore, movements in the structural participation rate and the natural rate of unemployment are the two main factors driving changes in labour's contribution to output over the long term.

Growth in the source population is expected to slow to 1.3 per cent in the last decade of the forecast.

The natural rate of unemployment defines a minimum level of unemployment that would remain because some people would be in transition between jobs and others would prefer not to work at the current wage. Unemployment resulting from workers in transition is expected to decline over the forecast. This is because of two factors: First, there will be an increase in the average age of the labour force; second, older workers are not as likely to quit their jobs to look for other work. Thus, the natural rate of unemployment is expected to trend slowly downward over the forecast period, positively contributing to labour potential.

On the other hand, the aging labour force will detrimentally affect labour potential through the labour force participation rate. As workers move into older age cohorts, their aggregate labour force participation generally declines as a result of health problems or early retirement. Consequently, the overall participation rate is expected to decline significantly over the next 25 years as the greatest share of baby boomers move into their retirement years. On balance, the negative effect of declining participation rates will outweigh the benefit derived from a lower natural rate of unemployment.

Initially, labour's contribution to potential output is strong, averaging 1.2 percentage points over 2001–10 and accounting for nearly 30 per cent of potential output growth for that period. However, labour's contribution to potential output growth will decline steadily over the forecast. By 2020, labour potential growth will slow to 0.4 percentage points, with its share of overall potential output growth falling to 15 per cent; labour potential growth will fall further by 2030, to 0.3 percentage points, with its share representing only 12 per cent of potential output growth.

The value of Alberta's productive capital is the second factor of production required to calculate potential output. The Conference Board of Canada does not rely on a measure of potential or optimal capital stock; instead, we assume that productive capital is accurately measured and that the level of capital available in the economy at any moment is all that is available to contribute to potential output. Total public and private capital, excluding residential assets, contributes to the level of productive capital. Over the forecast period, the net capital stock is assumed to increase each year by the amount of new investment, net of depreciation and discarded capital. The contribution of capital to potential output growth will average about 2 percentage points per year over 2006–30.

The overall participation rate is expected to decline significantly over the next 25 years.

The technical efficiency with which capital and labour are utilized to produce output is measured by total factor productivity. Over history, TFP is calculated residually, using the logarithmic form of the Cobb-Douglas production function, so that changes in output not explained by labour or capital are attributed to changes in technical efficiency. It should be noted that, for purposes of this calculation, total output is defined as real output at basic prices for all industries, excluding paid and imputed rent. Paid and imputed rent is excluded because the Board's estimates of the capital stock do not take into account residential assets, since these do not contribute to the productive capacity of the economy.

TFP fluctuates considerably over the business cycle. The reasons for this are wide-ranging but include changes in the mix between capital and labour, relative shifts in the types of capital purchased, shifts in labour productivity as labour force skills evolve, and tax changes. In order to remove the effects of volatile short-term movements, potential output is calculated with trend TFP, which is our residual measure smoothed with a Hodrick-Prescott filter. Over the long term, trend TFP growth is expected to be robust. With the growth in the number of workers dwindling, firms will need to continually invest in productivity-enhancing technology and skills development of their workforce, helping to maintain growth in TFP. The contribution of TFP to growth in potential will remain in line with recent historical performance, at roughly 0.6 percentage points annually over the forecast horizon.

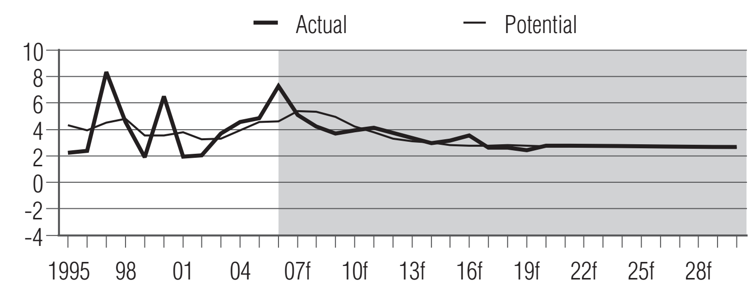
When actual real gross domestic product (GDP) diverges from potential output, an economy is said to have an output gap. Over the medium term (2006–15), average real GDP growth of 4.1 per cent in Alberta will result in a significant narrowing of the output gap that opened earlier in the decade. (See Chart 5.) Economic growth over the remainder of the long term is expected to hold close to growth in potential output—that is, to trend slowly downward to 2.7 per cent by 2030. The output gap will remain more or less closed from 2013 to 2030 and, therefore, will not contribute excessively to inflationary pressures over the forecast horizon. The Consumer Price Index in the province is projected to remain well within the Bank of Canada's accepted target range, averaging 2.3 per cent over the last 15 years of the forecast period.

KEY INDUSTRIAL SECTORS

CRUDE OIL

Events during the past couple of years have shown how tight supply and demand conditions for key energy commodities can quickly send prices skyward and governments scrambling to secure reliable sources. Global spare capacity for crude oil has been worryingly tight, and this has been reflected in energy prices. The billions of dollars of investment slated to increase capacity in Canada's oil sands will be but a drop in the bucket, in view of the rate at which developing economies, such as China and India, are expected to consume oil. Even for industrialized economies like the United States, demand for oil and natural gas is set to continue at an unwavering pace unless significant steps are taken to curb demand. Just to satisfy expected global demand, billions of dollars will need to be invested in oil exploration and development by member states of the Organization of the Petroleum Exporting Countries (OPEC) and in the Caspian region. The small cushion of spare production capacity, currently estimated at 1 to 2 million barrels per day (mmbd), will remain over the forecast, as will the risk to exports from geopolitically sensitive regions such as the Middle East. The Conference Board expects world oil prices to reflect the tight global supply/demand and associated geopolitical risks. The West Texas Intermediate (WTI) price of crude oil will lose some steam, falling to US$42 (2005 real dollars) per barrel by 2012. The price will then rise slowly over the remainder of the forecast, reaching the equilibrium price of US$55 per barrel by 2030.

Chart 5
Actual versus Potential GDP Growth
(percentage change)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Demand for oil and natural gas is set to continue at an unwavering pace unless steps are taken to curb demand.

Security of the energy supply will continue to affect both short- and long-term oil prices. The immediate outlook is clouded by continued tensions in the Middle East, Nigeria, Venezuela and Russia, China's voracious appetite for crude oil, and supply rebuilding in the United States. On the other hand, environmental concerns and a shift to more energy-efficient and renewable sources of energy are likely to dampen oil demand from industrialized countries.

Energy trade will continue to expand rapidly over the forecast period as interdependence intensifies between energy consumers and producers. Consumption will continue to outpace production, forcing governments that import oil and gas to deal more proactively with energy security. For example, the security of fuel transportation through international sea lanes and pipelines is being scrutinized, while types and origins of fuel sources will need to be diversified.

Table 2
International Crude Oil Supply and Demand
(millions of barrels per day)

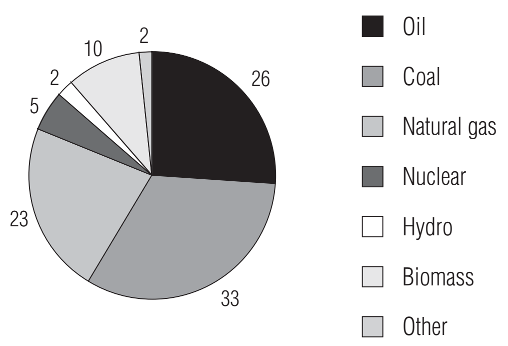
	2005	2010	2015	2030	2005–2030* (per cent)
Demand					
OECD North America	24.9	26.3	28.2	30.8	0.9
United States	20.6	21.6	23.1	25.0	0.8
Canada	2.3	2.5	2.6	2.8	0.8
Mexico	2.1	2.2	2.4	3.1	1.6
OECD Europe	14.4	14.9	15.4	15.4	0.2
OECD Pacific	8.3	8.6	8.8	8.9	0.3
OECD TOTAL	*47.7*	*49.8*	*52.4*	*55.1*	*0.6*
Transition Economies	4.3	4.7	5.0	5.7	1.1
Russia	2.5	2.7	2.9	3.2	1.0
China	6.6	8.4	10.0	15.3	3.4
India	2.6	3.2	3.7	5.4	3.0
Other Asia	5.4	6.1	6.9	9.0	2.9
Latin America	4.9	5.1	5.6	7.0	1.5
Africa	2.7	3.1	3.5	4.9	2.4
Middle East	5.8	7.1	8.1	9.7	2.0
Miscellaneous	3.6	3.8	4.1	4.2	0.6
Total World Demand	**83.6**	**91.3**	**99.3**	**116.3**	**1.3**
Supply					
OECD North America	9.8	9.4	9.0	7.8	–0.9
United States	5.1	5.3	5.0	4.0	–1.0
Canada	1.4	1.1	0.9	0.8	–2.2
Mexico	3.3	3.1	3.1	3.0	–0.5
OECD Europe	4.8	3.8	2.9	1.5	–4.5
OECD Pacific	0.5	0.7	0.5	0.4	–1.2
OECD TOTAL	15.2	13.8	12.4	9.7	–1.8
Transition Economies	11.4	13.7	14.5	16.4	1.5
Russia	9.2	10.5	10.6	11.1	0.7
Developing Countries	15.1	17.9	18.5	17.4	0.6
Non-OPEC Total	*41.7*	*45.4*	*45.4*	*43.4*	*0.2*
Non-OPEC (share of world supply)	*0.59*	*0.60*	*0.57*	*0.49*	*n.a.*
OPEC Middle East	20.7	22.0	25.7	34.5	2.1
OPEC Other	8.4	8.2	9.1	11.2	1.2
OPEC Total	*29.1*	*30.2*	*34.9*	*45.7*	*1.8*
OPEC (share of world supply)	*0.41*	*0.40*	*0.43*	*0.51*	*n.a.*
Non-Conventional Oil	*1.4*	*2.5*	*3.7*	*7.4*	*7.0*
Canada	1.0	2.0	3.0	4.8	6.4
Total World Supply**	**83.6**	**91.3**	**99.3**	**116.3**	**1.3**

*Average annual growth rate;
**Includes NGLs, non-conventional oil and processing gains.
Note: The shaded area represents forecast data.
Sources: The Conference Board of Canada; World Energy Outlook 2006.

Recent technological developments in exploration and production have increased recoverable reserves and prolonged the life of existing fields. These will enable conventional oil production from sources outside OPEC to remain strong until 2010, when production will start to taper off, except in the transition economies. Oil production in the transition economies, notably Russia and the Caspian area, will grow rapidly, especially until about 2015. Although non-OPEC conventional supply will not rise fast enough to meet demand pressures afterward, non-conventional oil production, predominately from Canada's oil sands, will play an important role in offsetting a decline in conventional production. According to the International Energy Agency's (IEA) *World Energy Outlook 2006*, world oil demand is projected to rise by an additional 33 mmbd over the 2005–30 period to 116.3 mmbd, while production will rise by the same amount. (See Table 2.) This demand forecast assumes that recent industry trends, including the introduction and use of energy-efficient methods, will continue at the same pace as in recent years. Fossil fuels will continue to provide the overwhelming bulk of the world's energy needs over the forecast, with oil remaining the single largest fuel in the global primary energy mix. (See Chart 6.)

Increases in demand will vary by region, with the share of world oil consumption in industrialized countries declining from just under 50 per cent in 2005 to 40 per cent by 2030. Almost half of the growth in oil demand in industrialized nations will occur in the United States, specifically the transportation sector, with the rise in car ownership continuing unchecked. Oil will remain a secondary fuel for power generation, and its share will decline marginally in all regions. Industrial, commercial and residential demand for oil will increase at a moderate pace, with all the growth originating in countries outside the Organisation for Economic Co-operation and Development (OECD). However, the international environmental agreement reached in Kyoto in December 1997 may pose a downside risk to projected increases in oil demand in the industrialized countries over the next decade, as there is a push to produce more energy from renewable resources such as hydro and wind.

Chart 6
Global Primary Energy Mix: 2030
(per cent)



Source: World Energy Outlook 2006.

The share of world oil consumed by developing countries is anticipated to increase from its current 40 per cent to 50 per cent by 2030. Particularly in developing countries without natural gas distribution systems, more incremental energy demand is being met by oil, and oil demand is spurred by increased economic and population growth. Rapid industrialization results in rapid increases in demand for commercial fuels.

The share of world oil consumed by developing countries is anticipated to increase.

Oil demand in developing nations is expected to rise at an average annual rate of about 2.5 per cent, with Asia responsible for 65 per cent of this increase. There will be an increase in demand of 8.7 mmbd in China and of 2.8 mmbd in India. Robust oil demand is also expected outside Asia, particularly in South America and Africa.

Although demand will grow steadily over the forecast period, the U.S. Geological Survey contends that worldwide reserves are not running dry. Furthermore, the IEA believes that existing oil reserves should be adequate to satisfy expected requirements over the forecast period. Proven global oil reserves currently exceed the cumulative production projected in the forecast, but additional reserves will need to be moved more quickly into the proven category so that production will not peak too early. Exploration will need to be emphasized.

World oil production is expected to increase from 83.6 mmbd in 2005 to 99.3 mmbd by 2015 and to 116.3 mmbd by 2030. Higher production is expected from OPEC. Non-OPEC conventional production is expected to rise in the next few years, mainly with surging production in Russia and the transition economies. However, this output will taper off after 2010 with the maturing of existing and older fields, especially in OECD countries. World non-conventional production, on the other hand, will surge by 7 per cent over 2005–30, spurred mainly by Canada and Venezuela. Significant investment in a host of major oil sands projects in Alberta will play a major role in increasing non-conventional oil output during that time.

OPEC's share of world oil supply is expected to increase to 48 per cent by 2030.

Because the vast Persian Gulf resources can be produced at a lower cost than can resources outside OPEC, production by OPEC countries, especially in the Middle East, is expected to increase more rapidly than by countries in other regions over the long term. Once non-OPEC production has been accounted for, OPEC members will be able to satisfy world demand by raising production from 33.6 mmbd in 2005 to 42 mmbd in 2015 and 56.3 mmbd by 2030. Accordingly, OPEC's share of world oil supply is expected to increase from 40 per cent in 2005 to 48 per cent by 2030. OPEC's market share could be lower if its policies to reduce production quotas are successful in limiting production and driving prices higher. This would stimulate non-OPEC production of conventional and non-conventional oil and encourage capacity increases of alternative energy technologies.

Significant new investment will be needed in OPEC countries as the world turns to them to satisfy crude oil demand. Until recently, it was generally acknowledged that OPEC members with large reserves and relatively low costs for expanding production capacity could accommodate sizable increases in demand; recent events may have proven otherwise. While it is assumed that investment will be forthcoming, it will lag demand, keeping production from satisfying demand fast enough and resulting in real price pressures. These factors will put upward pressure on the long-term WTI price of crude oil.

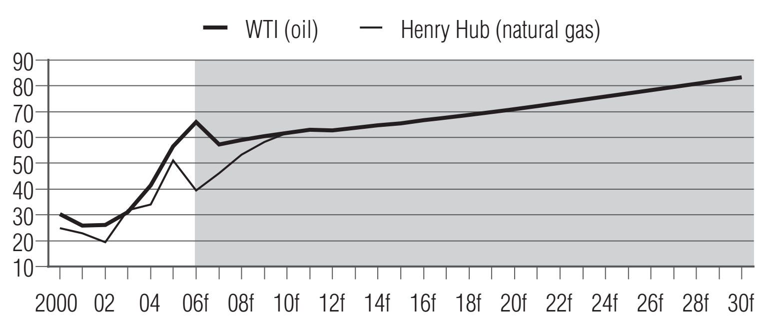
NATURAL GAS

Spot prices for natural gas often move in the same direction as oil prices in North America. This has been especially true over the past two years. The North American natural gas market is heavily integrated, and a significant network of pipelines exists between Canada and the United States. The United States consumes significant amounts of natural gas, and Canada exports 62 per cent of its natural gas production to the United States, so any supply or demand shock for natural gas that originates in the United States is immediately reflected in Canadian prices. About 12 per cent of U.S. factories can switch between fuels. As a result, if the price of oil rises faster than that of natural gas, or vice versa, demand for the cheaper fuel will increase, putting upward pressure on that price.

Historically, in terms of energy content equivalence, the spot price of natural gas has averaged US$5 less than an equivalent amount of crude oil. However, with the supply shock originating in the U.S. Gulf coast resulting from damage caused by hurricanes Katrina and Rita, the spot price of natural gas spiked well beyond that for crude oil to reach an average of US$78.84 per equivalent barrel of oil in October, 2005—about US$16 more than oil. By comparison, during the first half of 2005, the spot price of natural gas averaged US$12.69 less than a barrel of WTI on an energy content equivalence. In the short run, price discrepancies in terms of energy equivalence may persist, as the vast majority of factories worldwide cannot switch between the two types of fuel. In the longer run we can expect this problem to resolve itself through market forces, and the prices for oil and natural gas, in terms of energy content, should converge. (See Chart 7.)

The tight natural gas situation will not reverse itself in the short or medium term. Although a record number of natural gas wells will once again be drilled in Canada this year, production is forecast to decline over the forecast period. Most wells that are being drilled are shallow and are being depleted faster than new reserves can be found. In fact, Alberta, the source of 75 per cent of Canada's natural gas supply, no longer has the huge

Chart 7
Oil and Natural Gas Prices: Energy Content Equivalence
(U.S.$ per barrel)



f = forecast
Sources: The Conference Board of Canada; International Energy Agency.

reserves needed to meet the growing North American demand. According to the National Energy Board's (NEB) energy market assessment, *Looking Ahead to 2010: Natural Gas Markets in Transition*, a tight balance between natural gas supply and demand will continue over the medium term. This will keep natural gas prices high, with significant daily swings until new supply can be established or consumption reduced. Efforts are being made to increase Canada's supply of natural gas over the longer term. This can be accomplished by increasing the import capacity for liquid natural gas as well as by developing frontier and unconventional sources, such as natural gas from coal bed methane. Although production of coal bed methane is still in its infancy, a steadily increasing portion of natural gas wells being drilled are for the purpose of extracting methane from coal seams.

Natural gas now accounts for about 27 per cent of Canadian energy consumption.

Domestic gas demand is also projected to rise in Canada, from 2.4 trillion cubic feet (tcf) in 2000 to 3.3 tcf by 2025, according to the NEB's publication *Canada's Energy Future: Scenarios for Supply and Demand to 2025*. Natural gas now accounts for about 27 per cent of Canadian energy consumption. Trade between Canada and the United States will continue to play an important role in satisfying U.S. demand for natural gas until the end of this decade. Exports to the United States will grow by an average annual rate of 0.6 per cent over the 2001–10 period and then decline by an average annual rate of 1 per cent over last 20 years of the forecast.

According to the NEB, natural gas remains abundant in Canada. As of year-end 2004, Canada's ultimate resource potential, a combination of discovered and undiscovered resources, stood at 14.2 trillion cubic meters (tcm). However, about one-half of the natural gas resources in Canada is located in the WCSB, and about half of that amount has already been produced, mostly in Alberta. The WCSB also contains unconventional sources of natural gas, such as coal bed methane. About 1.7 tcm of undiscovered unconventional natural gas sources exists in the WCSB.

The size and ultimate resource potential of Canada's natural gas resource base is only an estimate, and considerable uncertainty surrounds frontier regions and unconventional sources. In the WCSB, technology and exploration advances have helped to improve resource estimates. However, recent drilling and production data suggest that the WCSB is maturing, forcing estimates of natural gas production in Alberta to be revised downward over the medium and long term.

Domestic gas prices are projected to rise further by a compound annual rate of 3.3 per cent over 2006 to 2030, while export prices will increase by 2.2 per cent, reflecting the downward trend in natural gas production from the WCSB.

OIL AND GAS PRODUCTION

Increases in nominal crude oil prices, new technology and fiscal arrangements have accelerated the development of the oil sands in western Canada. Alberta has four significant oil sands deposits: Athabasca, Cold Lake, Peace River and Wabasca. The potential of this resource is huge, with an estimated 50 tcm of ultimate recoverable resources, only a negligible fraction of which has been produced. About 12 per cent of the resource is estimated to be recoverable, a volume similar to the proven conventional oil reserves in Saudi Arabia. The cost of production has declined substantially from $24.50 per barrel in the early 1980s, and by between $15 and $20 per barrel since 1997. However, the cost of diluents, needed to thin bitumen for transportation, has skyrocketed and will remain high over the medium term. The potential exists, however, to lower operating costs for mining and upgrading to below $10 per barrel over the long term. Nevertheless, skyrocketing natural gas prices, planned and unplanned maintenance and escalating start-up costs related to expansions have made the cost of producing a barrel vary widely in recent years.

Canada is expected to remain a net exporter of oil until the end of the forecast period, as domestic demand will remain weaker than production. Oil sands production is expected to surge over the next 25 years, while conventional and heavy oil will steadily decline. The recent decline of conventional oil production and reserves has been more than offset by advances in production of synthetic crude and bitumen from the oil sands. Numerous oil sands mining and upgrading projects currently in the works or on the horizon will ensure that synthetic crude oil production in Canada makes up 48 per cent of all crude by 2015. Heavy blend (blended heavy oil and bitumen) will make up 37 per cent. Meanwhile light conventional crude oil will fall from 27 per cent to 15 per cent, according to the NEB's *Canada's Oil Sands—Opportunities and Challenges to 2015: An Update*.

Despite decreasing rates of production of natural gas and of heavy, light and medium crude oil from the WCSB, significant increases in synthetic and bitumen production will allow total mineral fuels output in Alberta to rise at a compound average annual rate of 5.5 per cent from 2006 to 2015 and by 2.6 per cent from 2016 to 2030.

ENERGY INVESTMENT

The investment profile for primary energy will be dominated over the medium to long term by the development of the vast oil sands deposits in Alberta. (See Chart 8.) About $67 billion in oil sands, heavy oil mining and extraction activities is projected over the forecast, with close to $28 billion already spent in the sector since 1995 and more than 60 projects announced since 1996.

Downside risks exist for investment in the oil sands, largely growing out of uncertainty over the effects of the Kyoto Protocol.

Long-term prospects are favourable for the non-conventional oil industry in Alberta. Technical improvements in the extraction process have made development of the oil sands very profitable at current oil prices, and federal government changes to improve the tax and royalty system for oil sands production are expected to continue investment spending over the forecast period. Still, potential downside risks exist for investment in the oil sands, largely growing out of uncertainty over the effects of the Kyoto Protocol.

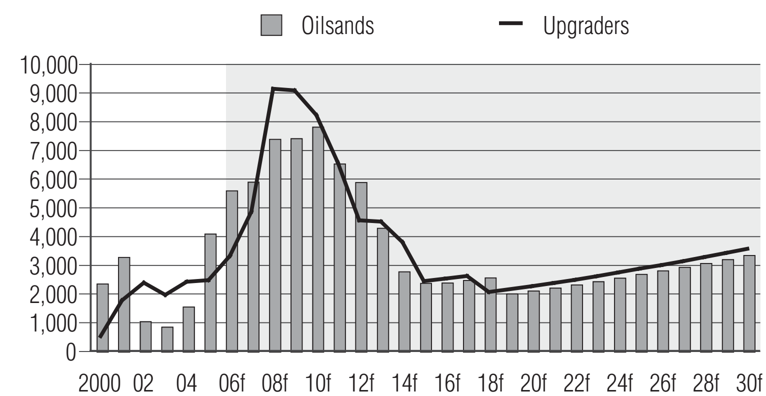
A host of projects are on the horizon in the oil sands, with a few companies making the bulk of the investment commitment. For example, both Suncor and Syncrude will be investing billions in increasing upgrading capacity at existing projects. Suncor plans to reach an upgrading capacity of 0.5 mmbd by 2012 through its multi-year, $5.9-billion Voyageur mining project. Suncor has also announced its intention to invest $1 billion from 2005 to 2007 in its existing Firebag project to increase in-situ bitumen production. Syncrude expects to be upgrading 0.5 mmbd by 2015 through its multi-phase Aurora mining project. Significant cost overruns for the third part of Syncrude's four-phase Aurora mine and upgrader expansion will cost the company an extra $2 billion. The entire project could cost the company upwards of $10 billion.

Shell has also entered the oil sands and upgrading game through its Albian Oil Sands Project (AOSP). The project currently produces about 155,000 barrels per day (bd) of synthetic crude at the Scotford upgrader. A number of expansions at the mine and upgrader in the medium term will bring production to 290,000 bd by the end of the decade; the long-term production goal is to reach 500,000 bd. In total, the AOSP will cost more than $6 billion. Shell has also recently proposed almost $5 billion in new investment over 2006–09 for its so-called Carmon Creek mining project in the smaller Peace River oil sands deposit, although this is still quite speculative.

Construction of Canadian Natural Resources' $10-billion, three-phase Project Horizon oil sands mining and upgrading project started recently. The project, 70 kilometres north of Fort McMurray, Alberta, is expected to produce over 200,000 bd of synthetic crude oil by 2012.

Non-residential investment spending growth in the province, which includes energy investment, will advance solidly by 8.3 per cent annually over 2001–10 and is

Chart 8
Investment Expenditure in Alberta's Oil Sands
($ billions)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

expected to advance by 5.5 per cent in the remainder of the forecast, compounded annually. Total current dollar public and private investment in machinery and equipment is expected to increase at a compound annual rate of 7.9 per cent over 2001–10 and to advance by 4.1 per cent annually over the remaining 20 years of the forecast.

AGGREGATE DEMAND

Conditions suggest that job creation will fare relatively well in the province over the long term, advancing slightly more than the national pace over most of the forecast. Employment opportunities are anticipated to be abundant over the near term, with booming consumer demand and an expanding energy sector. Employment growth is expected to advance solidly at an average annual compound rate of 2.7 per cent from 2001 to 2010. However, as labour force growth begins to wane, so too will the growth in employment. Total employment growth is expected to decelerate, posting average annual compound growth of 1.2 per cent over 2011–20 before declining to 0.8 per cent over 2021 to 2030.

Predicting household behaviour over long periods of time poses challenges, but it can be reasonably assumed that as a household cohort ages it will generally assume the spending habits of the cohort preceding it. Current spending patterns suggest that, contrary to earlier predictions, population aging will not immediately cause consumption spending patterns to shift further in favour of services over goods. Data from the 2003 survey of household spending shows that the services share of total consumption spending is highest for the youngest (under-35) cohort and oldest (over-75) cohorts, but relatively low for households aged 55 to 74.

The age range of the baby boomers is 41 to 60 in 2006, with the heaviest concentration aged between 41 and 46. By 2030, they will represent the 66–85 range, with a high concentration in the 66–71 sub-group. This means that, as a group, their spending habits will resemble the patterns of household presently in this cluster. Thus, given the large size of the baby-boomer generation, consumption spending is unlikely to shift further in favour of services until the last few years of the forecast, when baby boomers start to enter the over-74 cohort.

While demographic change will maintain the goods–services balance in total consumption spending, it is expected to contribute to a deceleration in the pace of growth in consumption outlays. Despite stronger wage growth associated with the boomer-driven labour shortage after 2010, slower overall population growth combined with a quickly growing elderly segment will help to trim the pace of expansion in consumption spending. As such, the average annual compound rate of expenditure growth in Alberta is forecast to ease from 6.6 per cent over 2006–10 to 4.8 per cent over the last 20 years of the forecast. The savings rate in the province will flatten over the forecast, averaging 6.6 per cent from 2006 to 2030.

Energy prices skyrocketed again in 2006, and surging resource revenues have allowed the provincial government to retire its debt much sooner than anticipated. As a result, the provincial government will be able to increase its spending on goods and services. Sustained high energy prices anticipated in the near and medium terms will keep energy revenues strong. With an excellent fiscal situation, total nominal government spending on goods and services will rise by an average annual rate of 6.7 per cent over 2006–10 and will then slow slightly over the remainder of the forecast period, averaging 5.3 per cent in 2011–20 and 4.8 per cent in 2021–30.

Alan Chaffe

British Columbia

OVERVIEW

Real gross domestic product (GDP) in British Columbia is forecast to grow at a compound annual rate of 2.2 per cent over 2006–30. (See Chart 1.) After rebounding strongly from 2004 to 2006, the economy is expected to maintain a healthy pace over the medium term, expanding by a healthy compounded average of 3.1 per cent from 2006 to 2011. The export sector will be stimulated by stronger global demand, especially from the United States and Asia, and the domestic sector will continue to build momentum with increased interprovincial migration. Large-scale infrastructure investment and a host of projects in preparation for the 2010 Olympics will keep activity healthy in the province's construction sector over the medium term. Government coffers are benefiting from the strong economic performance, and a budget surplus of around $2.15 billion is expected in the 2006–07 fiscal year. The provincial government is forecasting further budget surpluses over the medium term and should therefore become a positive force in the economy after a few years of tepid growth.

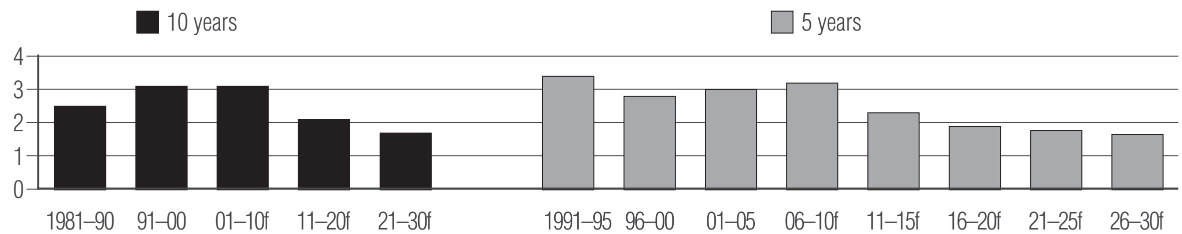
Demographic changes will moderate economic growth in British Columbia over the long term. Population growth will slow over the forecast period, even with positive net interprovincial migration, as the aging of the baby boomers dramatically changes the province's age profile. This shift will also slow growth in domestic demand, with consumer spending patterns and housing activity undergoing the most pronounced changes. While sluggish, population growth will be higher than in most other provinces, with a compound annual rate of 1.1 per cent from 2006 to 2030.

Over the near term, the outlook is quite positive for forestry, the province's key resource sector, as the sector is benefiting from expedited lumber harvests to combat the mountain pine beetle infestation and reductions in Quebec's annual allowable cut. However, the long-term outlook is not quite as upbeat, as the forecast incorporates a decline in real forestry output following the peak of the pine beetle epidemic. Further, the reduction in housing demand, likely to result from an aging North American population, will lead to a corresponding drop in demand for wood products. Although worldwide demand for wood is expected to pick up gradually over the forecast period, the challenge for British Columbia will be to respond to the increased demand in the face of a shrinking timber supply.

DEMOGRAPHIC PATTERNS

The long-term outlook for British Columbia is largely determined by demographic developments. (See Table 1.) Dominating the story over the forecast horizon will be

Chart 1
Real GDP at Basic Prices
(average annual compound growth rate)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Table 1
Key Demographic Assumptions

Components	Assumptions
Population maintains growth	British Columbia's population is expected to grow at an annual average rate of 1.1 per cent over 2006 to 2030, but the average age of the population will steadily increase.
Provincial migration stabilizes	After oscillating over the last few years, British Columbia's net interprovincial migration will stabilize, averaging 5,775 people per year over the forecast period.
International migration to pick up speed	Net international migration will help drive population growth, rising from 33,074 people in 2006 to 46,806 people in 2030.
Fertility rate too low	The fertility rate in British Columbia is 1.39, well below the replacement rate of 2.1.
Natural rate reduces gains	The natural rate of increase is expected to draw down population growth as the number of deaths will begin outpacing the number of births in 2025.

Sources: The Conference Board of Canada; Statistics Canada.

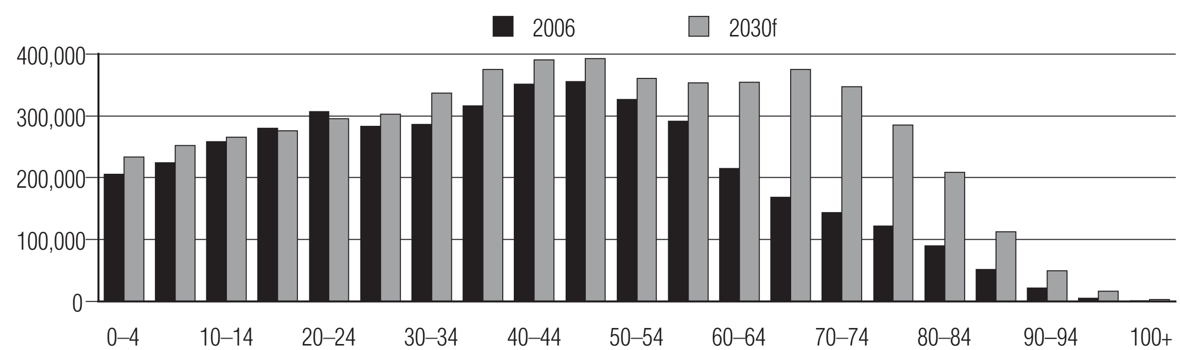
a slower rate of population growth and the aging of the population. Compound annual population growth over the forecast is expected to be 1.1 per cent, increasing British Columbia's total population from 4.19 million in 2006 to 5.28 million in 2030. While this represents one of the strongest provincial population growth rates in the country over most of the forecast period, even this level of population growth is a marked deceleration from the average annual growth of 2.2 per cent from 1990 to 2000.

Over the long term, the age distribution of the population will become increasingly skewed toward older age cohorts, with the share of the population aged 65 and over expected to increase from 14 per cent in 2006 to 25 per cent by the end of 2030. Behind the change is the aging of British Columbia's sizable baby-boom population, which currently accounts for approximately one-third of the provincial total. In 2006, baby boomers ranged in age from 41 to 60, with the largest concentration in the 42–46 age range. As baby boomers continue to age, the population's age profile will alter dramatically. (See Chart 2.)

Compound annual population growth over the forecast is expected to be 1.1 per cent.

With an aging population and with a marked reduction in the number of births, there will be a decline in the province's natural rate of increase (defined as the number of births minus the number of deaths). The number of deaths will even exceed the number of births in 2025. Though advances in medical technology should extend life expectancy, an increasingly larger senior population will ultimately increase the death rate. The annual number of deaths in the province is expected to jump by approximately 60.2 per cent over the long term, from 31,668 in 2006–07 to 50,730 in 2029–30. With the number of births in the province expected to increase by only 11.2 per cent over the same period, from 40,849 to 45,421, the natural rate of increase will decline.

Chart 2
Population in Older Age Cohorts Increases
(number of people)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Over the forecast horizon, a smaller cohort will replace the women currently in their prime childbearing years. The problem posed by a shrinking population of women of childbearing age will be amplified by British Columbia's low fertility rate (that is, the average number of children born to a woman during her lifetime). At 1.39, the rate will fall well below the national fertility rate—and, more importantly, significantly below the standard replacement rate of 2.1.

With growth in the number of deaths outstripping growth in the number of births, the annual natural rate of increase of the population is expected to drop from 9,181 in 2006 to –6,699 in 2030. This deterioration of the natural rate of increase will make migration a more important source of population growth. Net international immigration will account for most of the net inflow in level terms, averaging 38,587 people annually over 2006 to 2015 and increasing to an average of 47,146 people annually from 2016 to 2030.

Net interprovincial migration, a significant source of population growth during the first half of the 1990s, reversed itself in the latter half of the decade, when the economy in British Columbia performed more weakly than that of most other provinces. (See Chart 3.) With the robust performance of the Alberta economy, British Columbia's eastern neighbour has been the destination of choice for many British Columbia's migrants in search of employment, particularly people aged between 15 and 29. The net interprovincial outflows that began in 1998 ended in 2002, with more abundant employment and economic prospects. Net interprovincial migration will be a significant source of population growth over the long term, with inflows expected to average almost 5,016 people per year from 2006 to 2015 and 6,281 from 2016 to 2030, when more of Canada's baby boomers make their move to British Columbia in search of a retirement destination with a temperate climate. Overall, total net international and interprovincial migration will average 43,603 from 2006 to 2015 and 53,426 from 2016 to 2030.

LABOUR FORCE

Labour force growth is determined by changes in the source population (aged 15 and over) and movements in the labour force participation rate. Over the course of the forecast, the number of net new entrants to the labour force will drop substantially, reflecting the aging of the baby boomers and the province's low fertility rate. Source population growth will post an average annual compound gain of 1.4 per cent from 2006 to 2015, and then drop to an average gain of 1.1 per cent from 2016 to 2030.

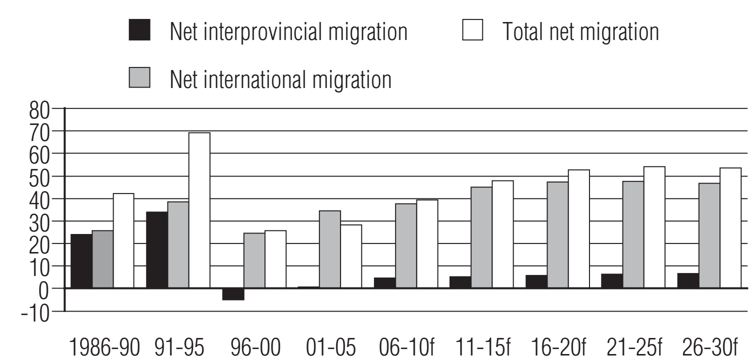
Labour force participation, which fell over most of the 1990s as a result of a sluggish labour market, is expected to improve over the medium term. Although participation rates have nearly converged among younger males and females, a sizable gap still exists in the 55–64 age group. Hence the participation rate for older females is expected to continue making gains over the medium term. Beginning in 2011, the participation rate will start to trend downward as more of the population retires and as retirees from other parts of the country move to British Columbia. Overall, the participation rate is expected to increase from 65.6 per cent in 2006 to 65.8 per cent in 2010, and then to gradually weaken throughout the remainder of the forecast, reaching 58.9 per cent by 2030.

Together, the weaker source population growth and the lower participation rate are expected to result in compound annual labour force growth of 1.2 per cent from 2006 to 2015 and of 0.5 per cent from 2016 to 2030.

POTENTIAL OUTPUT AND PRODUCTIVITY

This long-term economic forecast is guided by the concept of potential output, which is the highest level of economic activity an economy can attain without surpassing its capacity limits and igniting inflation. Potential output is not directly measured, and as such the Conference Board uses a structural production function to obtain an

Chart 3
Immigration
(thousands of persons)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

estimate of potential. We assume that the production function takes a Cobb-Douglas form, in which the mix of labour, capital and technical efficiency are modelled to produce potential output. With this assumption, our estimate of potential output is dependent on potential employment, capital and trend total factor productivity (TFP).

Potential employment measures the contribution of labour to potential output by estimating the available workforce when the economy is operating at capacity. Under these conditions, the labour force participation rate is at its structural peak and unemployment is at its "natural rate." Therefore, movements in the structural participation rate and the natural rate of unemployment are the two main factors driving changes in labour's contribution to output over the long term.

The overall participation rate is expected to decline sharply as baby boomers move into their retirement years.

The natural rate of unemployment defines a minimum level of unemployment that would remain because some people are in transition between jobs and others prefer not to work at the current wage. It is expected that unemployment resulting from workers in transition will decline over the forecast. This will happen with an increase in the average age of the labour force, as older workers are not as likely to quit their jobs to look for other work. Thus, the natural rate of unemployment is expected to trend downward slowly over the forecast period, positively contributing to labour potential.

On the other hand, the aging labour force will detrimentally affect labour potential through the labour force participation rate. As workers move into older age cohorts, their aggregate labour force participation generally declines as a result of health problems and early retirement. Consequently, the overall participation rate is expected to decline sharply over the next 25 years as a significant share of baby boomers move into their retirement years. On balance, the negative effects of declining participation rates will outweigh the benefit derived from a lower natural rate of unemployment. Therefore, labour's contribution to potential output will decline steadily over the long term. Overall, labour's annual contribution to potential output growth will average 0.9 percentage points over the medium term (2006 to 2011) and will decline to an average of 0.3 percentage points over the long term (2012 to 2030).

The value of British Columbia's productive capital is the second factor of production required to calculate potential output. The Conference Board of Canada does not rely on a measure of potential or optimal capital stock, but assumes that productive capital is accurately measured and that the level of capital available in the economy at any time is all that is available to contribute to potential output. Total public and private capital, excluding residential assets, contributes to the level of productive capital. Over the forecast period, the net capital stock is assumed to increase each year by the amount of new investment, net of depreciation and discarded capital. The contribution of capital to potential output growth will average about 0.9 percentage points per year from 2006 to 2030.

The technical efficiency in which capital and labour are utilized to produce output is measured by TFP. Over history, TFP is calculated residually, using the logarithmic form of the Cobb-Douglas production function, so that changes in output not explained by labour or capital are attributed to changes in technical efficiency. It should be noted that, for purposes of this calculation, total output is defined as real output at basic prices for all industries, excluding paid and imputed rent. Paid and imputed rent is excluded because the Board's estimates of the capital stock do not take into account residential assets, since these do not contribute to the productive capacity of the economy.

The contribution of capital to potential output growth will average about 0.9 percentage points per year from 2006 to 2030.

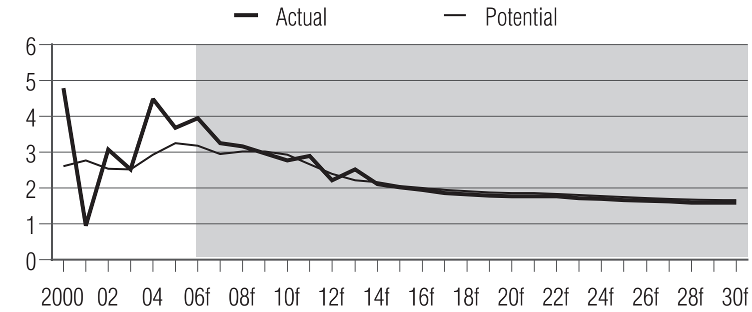
TFP fluctuates considerably over the business cycle. The reasons for this are wide-ranging but include changes in the mix between capital and labour, relative shifts in the types of capital purchased, shifts in labour productivity as labour force skills evolve, and tax changes. In order to remove the effects of volatile short-term movements, potential output is calculated with trend TFP, which is our residual measure smoothed with a Hodrick-Prescott filter. Over the long term, trend TFP growth is expected to be robust. With the growth in the number of workers dwindling, in order to maintain growth in TFP, firms will need to continually invest in productivity-enhancing technology and the skills development of their workforce. The contribution of TFP to growth in potential will remain in line with recent historical performance, roughly 0.7 percentage points annually over the forecast horizon.

The economy is expected to grow at close to potential for the most part over the long term.

When actual real GDP diverges from potential output, an economy is said to have an output gap. In the 1990s the economy performed almost consistently under potential, resulting in a negative output gap. The tables turned in the early 2000s as the economy continued to perform above potential, and the ouput gap closed around 2006. The economy is expected to grow at close to potential for the most part over the long term. (See Chart 4.) Inflationary pressures are forecast to remain relatively subdued over the forecast horizon, averaging 1.9 per cent over the medium term and rising to 2.2 per cent on average from 2012 to 2030.

The impact of diminishing labour force growth on potential output will be cushioned for the most part over the medium term by gains in productivity and strong growth in the capital stock. Overall, the average annual growth rate of potential output is expected to decline from 3 per cent over the medium term to 1.9 per cent in the long term.

Chart 4
Actual versus Potential GDP Growth
(percentage change)



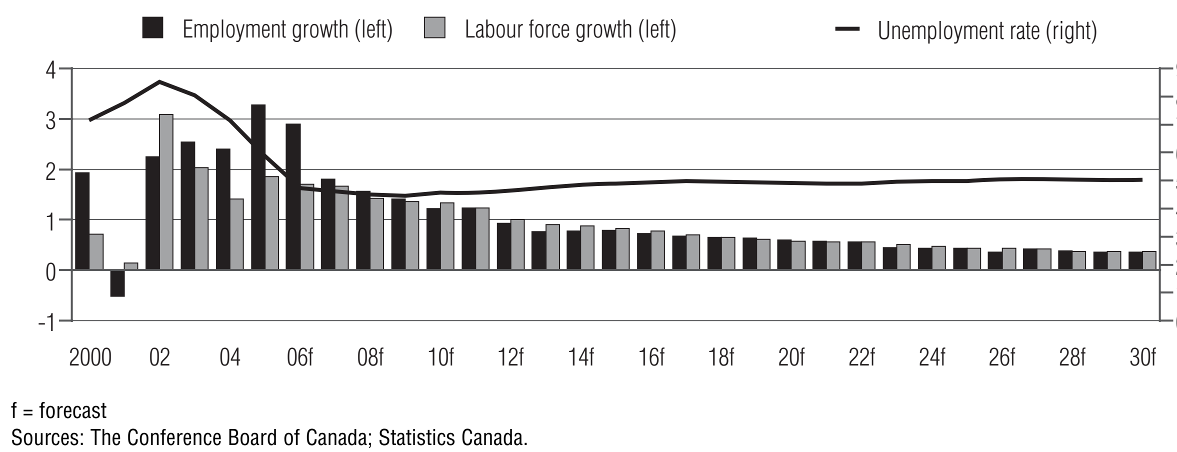
f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

AGGREGATE DEMAND

Employment in British Columbia is expected to continue to outpace the national average over the medium term, posting average annual compound growth of 1.7 per cent from 2006 to 2011. This growth will taper off to only 0.6 per cent from 2102 to 2030. The unemployment rate is expected to average 4.6 per cent over the medium term, and gradually to rise to 5 per cent in 2030. (See Chart 5.)

Over the medium term, baby boomers, now in their peak spending years, will continue to spend heavily on durable goods, such as cars and home furnishings. As this generation retires, their preferences will shift toward services, such as health care and travel, especially after 2020. Consequently, consumer spending on goods is expected to taper off, posting an average compound growth rate of 3.7 per cent from 2006 to 2015 and 3.3 per cent over

Chart 5
Employment and Labour Force Growth and the Unemployment Rate
(percentage)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

2016–30. Overall, consumer spending is forecast to record compound growth of 4.5 per cent over 2006–15 and to decline slightly to 4.2 per cent from 2016 to 2030.

Demographic developments will naturally dictate the level of housing activity over the long term. Largely as a result of net interprovincial outflows, housing starts weakened over the last decade and dropped to their lowest level in more than two decades in 2000. However, the outflows have gradually decreased in recent years, and the housing market has begun to pick up steam. Positive net interprovincial migration combined with historically low mortgage rates have kept housing activity vigorous and are expected to keep activity at a high level for the next few years. However, even with positive net interprovincial migration, total housing starts are forecast to decline gradually over the long term. Multiple housing starts will fare much better than single-family dwellings, as housing for the influx of baby boomers will be concentrated in multiple units. Overall, total starts are forecast to decline at an average annual compound rate of 0.4 per cent from 2006 to 2015 and at an average rate of 1.3 per cent from 2016 to 2030. Nominal investment spending on residential construction will grow by a healthy average annual rate of 4.4 per cent from 2006 to 2015 and by 2.5 per cent over the last 15 years of the forecast.

Even with positive net interprovincial migration, total housing starts are forecast to decline gradually over the long term.

Nominal investment spending on non-residential construction has shown quite a bit of strength recently, and solid gains are expected to continue over the medium term. The non-residential profile is strong thanks to large public projects, including the Richmond-Airport-Vancouver rapid transit (Canada Line) system and various public infrastructure upgrades and new facilities in preparation for the 2010 Winter Olympics. As a result, investment in non-residential construction is expected to knock up a healthy compound annual growth rate of 7.4 per cent over 2006–10.

The expansion in business spending experienced recently and the strong Canadian dollar have led to a rebound in machinery and equipment investment. This investment is expected to grow robustly over the forecast period as businesses remain under pressure to become more globally competitive and strive to increase productivity. Compound annual growth in machinery and equipment is expected to be 4.7 per cent over 2006 to 2015 and 3 per cent from 2016 to 2030.

Fiscal policy is expected to become more expansionary over the medium term.

The fiscal outlook has improved significantly after several years in a deficit position. The provincial government is expected to deliver a surplus of around $2.15 billion in the 2006–07 fiscal year, and smaller surpluses are expected in the two following years. This turnaround is a significant development for British Columbia, enabling the government to become a positive force on the economy over the medium and long terms. As such, fiscal policy is expected to become more expansionary over the medium term. In particular, government spending on services will increase as aging baby boomers place increased demand on the health-care system. In the last decade of the forecast, spending on education is anticipated to increase as new schools are built to accommodate the grandchildren of baby boomers. Nominal government spending on goods and services is expected to post an average annual growth rate of 5.1 per cent over 2006 to 2015 and 4.8 per cent from 2016 to 2030.

INDUSTRY ANALYSIS

FORESTRY

In the short run, the outlook for British Columbia's forestry industry is quite positive. The sector is currently benefiting from increased harvest levels to combat the spread of the mountain pine beetle and reductions in Quebec's harvest levels. Growth will taper off as the North American housing market cools but will remain positive over the medium term. Average annual compound growth in British Columbia's real forestry output is expected to be 1.7 per cent from 2006 to 2010 but to slow to only 0.3 per cent in 2011.

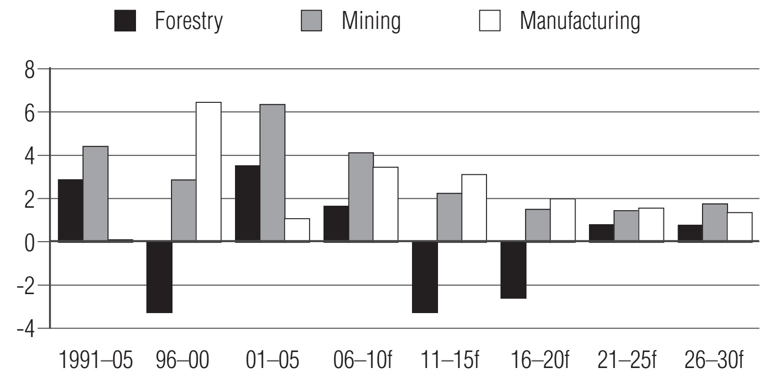
The outlook over the long term is not favourable. Approximately 30 per cent of the province's timber supply is lodgepole pine, and it is estimated that the mountain pine beetle will kill up to 80 per cent of this tree specie. This will obviously have devastating effects on the industry, and harvest levels are expected to drop in the long term. The Conference Board's assumption when compiling the forecast is that harvest levels will begin to drop by 2012 because of a decline in the amount of commercially viable beetle-killed wood. This assumption leads to an industry contraction of 1.1 per cent over 2012 to 2030. (See Chart 6.)

MANUFACTURING

British Columbia's largely resource-based manufacturing sector is dominated by the paper and wood product industries; together they account for nearly half of the province's total manufacturing shipments. Pulp and newsprint producers have faced challenging market conditions during the last two years as excess world supply resulted in significant price weakness. Additionally, firms have been plagued by the sky-high Canadian dollar. However, a reduction in overall industry capacity over the past two years as a result of plant closures, together with a revived U.S. economy, bode well for pulp and newsprint producers.

These industries will continue to play an important role over the long term, although there will be greater emphasis on value-added products for exports. First, the abundance of high-grade fibre in the province will allow the development of more specialized paper products. Second, lumber manufacturing will continue to develop markets for furniture components, doors and windows, while continuing to diversify into engineered lumber products. As such, real manufacturing output will post average compound annual growth of 3.3 per cent from 2006 to 2015 and 1.6 per cent over 2016–30.

Chart 6
Real Output, Key Industries
(average annual compound growth rate)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Table 1—Key Economic Indicators: Canada
(forecast completed: Dec. 19, 2006)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
GDP at market prices (current $)	1,371,425	1,432,938	1,492,091	1,568,613	1,646,326	1,724,364	1,805,494	1,887,083	1,973,378	2,058,360	2,144,673	2,235,106	2,327,404
	6.2	*4.5*	*4.1*	*5.1*	*5.0*	*4.7*	*4.7*	*4.5*	*4.6*	*4.3*	*4.2*	*4.2*	*4.1*
GDP at basic prices (current $)	1,277,530	1,336,573	1,392,816	1,463,970	1,536,207	1,608,592	1,683,861	1,759,570	1,839,909	1,918,706	1,998,659	2,082,721	2,168,427
	6.3	*4.6*	*4.2*	*5.1*	*4.9*	*4.7*	*4.7*	*4.5*	*4.6*	*4.3*	*4.2*	*4.2*	*4.1*
GDP at basic prices (constant 1997 $)	1,072,667	1,102,656	1,134,360	1,170,387	1,206,976	1,243,823	1,281,801	1,315,762	1,353,657	1,388,638	1,422,061	1,456,544	1,490,514
	3.1	*2.8*	*2.9*	*3.2*	*3.1*	*3.1*	*3.1*	*2.6*	*2.9*	*2.6*	*2.4*	*2.4*	*2.3*
Consumer Price Index (1992=1.0)	1.273	1.297	1.315	1.342	1.369	1.397	1.424	1.453	1.483	1.514	1.546	1.578	1.611
	2.2	*1.9*	*1.4*	*2.0*	*2.0*	*2.0*	*2.0*	*2.0*	*2.1*	*2.1*	*2.1*	*2.1*	*2.1*
Implicit price deflator—	1.191	1.212	1.228	1.251	1.273	1.293	1.314	1.337	1.359	1.382	1.405	1.430	1.455
GDP at basic prices (1997=1.0)	*3.2*	*1.8*	*1.3*	*1.9*	*1.8*	*1.6*	*1.6*	*1.8*	*1.6*	*1.7*	*1.7*	*1.7*	*1.7*
Average weekly wages (level $)	717	737	757	778	800	823	846	872	900	930	962	995	1,030
	3.1	*2.8*	*2.7*	*2.8*	*2.8*	*2.8*	*2.8*	*3.1*	*3.2*	*3.4*	*3.4*	*3.5*	*3.5*
Personal income (current $)	1,027,733	1,084,892	1,130,215	1,181,297	1,234,224	1,289,094	1,346,566	1,407,934	1,471,995	1,536,795	1,603,442	1,672,371	1,745,065
	5.0	*5.6*	*4.2*	*4.5*	*4.5*	*4.4*	*4.5*	*4.6*	*4.6*	*4.4*	*4.3*	*4.3*	*4.3*
Personal disposable income (current $)	787,524	833,521	863,836	902,230	943,261	983,919	1,026,295	1,070,453	1,117,033	1,163,948	1,212,592	1,263,548	1,316,614
	4.2	*5.8*	*3.6*	*4.4*	*4.5*	*4.3*	*4.3*	*4.3*	*4.4*	*4.2*	*4.2*	*4.2*	*4.2*
Personal savings rate	1.2	1.8	1.5	1.4	1.4	1.1	1.0	1.0	1.0	1.1	1.2	1.4	1.6
	–54.0	*54.1*	*–19.7*	*–3.3*	*–5.5*	*–17.6*	*–8.5*	*–2.3*	*1.0*	*5.8*	*15.1*	*16.8*	*12.7*
Population (000s)	32,232	32,537	32,835	33,141	33,455	33,779	34,113	34,459	34,816	35,182	35,555	35,933	36,314
	0.9	*0.9*	*0.9*	*0.9*	*0.9*	*1.0*	*1.0*	*1.0*	*1.0*	*1.1*	*1.1*	*1.1*	*1.1*
Labour force (000s)	17,341	17,600	17,891	18,145	18,384	18,619	18,837	19,021	19,190	19,354	19,515	19,663	19,797
	0.9	*1.5*	*1.7*	*1.4*	*1.3*	*1.3*	*1.2*	*1.0*	*0.9*	*0.9*	*0.8*	*0.8*	*0.7*
Employment (000s)	16,169	16,461	16,718	16,978	17,233	17,472	17,708	17,909	18,113	18,270	18,410	18,548	18,689
	1.4	*1.8*	*1.6*	*1.6*	*1.5*	*1.4*	*1.3*	*1.1*	*1.1*	*0.9*	*0.8*	*0.7*	*0.8*
Unemployment rate (percentage)	6.8	6.5	6.6	6.4	6.3	6.2	6.0	5.8	5.6	5.6	5.7	5.7	5.6
Retail sales (current $)	368,612	393,264	415,610	437,978	461,812	486,113	511,431	536,272	561,140	585,885	611,286	637,481	664,792
	6.3	*6.7*	*5.7*	*5.4*	*5.4*	*5.3*	*5.2*	*4.9*	*4.6*	*4.4*	*4.3*	*4.3*	*4.3*
Housing starts (units)	225,481	225,620	202,573	194,703	191,500	189,222	188,284	188,584	189,708	190,876	192,399	193,303	193,744
	–3.4	*0.1*	*–10.2*	*–3.9*	*–1.6*	*–1.2*	*–0.5*	*0.2*	*0.6*	*0.6*	*0.8*	*0.5*	*0.2*

White area represents forecast data.
All data are in millions of dollars, seasonally adjusted at annual rates, unless otherwise specified.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; Canada Mortgage and Housing Corporation.

Table 1—Key Economic Indicators: Canada
(forecast completed: Dec. 19, 2006)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
GDP at market prices (current $)	2,424,179 *4.2*	2,523,292 *4.1*	2,628,366 *4.2*	2,736,642 *4.1*	2,849,361 *4.1*	2,964,791 *4.1*	3,086,636 *4.1*	3,213,481 *4.1*	3,343,519 *4.0*	3,477,693 *4.0*	3,616,655 *4.0*	3,759,102 *3.9*	3,904,788 *3.9*
GDP at basic prices (current $)	2,257,866 *4.1*	2,348,999 *4.0*	2,445,926 *4.1*	2,545,906 *4.1*	2,649,975 *4.1*	2,756,205 *4.0*	2,868,232 *4.1*	2,984,892 *4.1*	3,104,439 *4.0*	3,227,865 *4.0*	3,355,778 *4.0*	3,486,926 *3.9*	3,621,101 *3.8*
GDP at basic prices (constant 1997 $)	1,523,911 *2.2*	1,557,390 *2.2*	1,592,089 *2.2*	1,626,168 *2.1*	1,660,421 *2.1*	1,694,945 *2.1*	1,730,743 *2.1*	1,768,024 *2.2*	1,805,402 *2.1*	1,842,433 *2.1*	1,880,962 *2.1*	1,917,216 *1.9*	1,954,781 *2.0*
Consumer Price Index (1992=1.0)	1.646 *2.2*	1.682 *2.2*	1.720 *2.2*	1.760 *2.3*	1.801 *2.3*	1.843 *2.3*	1.887 *2.3*	1.931 *2.3*	1.976 *2.3*	2.021 *2.3*	2.066 *2.2*	2.110 *2.2*	2.155 *2.1*
Implicit price deflator— **GDP at basic prices** (1997=1.0)	1.482 *1.8*	1.508 *1.8*	1.536 *1.9*	1.566 *1.9*	1.596 *1.9*	1.626 *1.9*	1.657 *1.9*	1.688 *1.9*	1.719 *1.9*	1.752 *1.9*	1.784 *1.8*	1.819 *1.9*	1.852 *1.9*
Average weekly wages (level $)	1,066 *3.5*	1,104 *3.5*	1,144 *3.6*	1,184 *3.6*	1,227 *3.6*	1,270 *3.6*	1,316 *3.6*	1,362 *3.6*	1,411 *3.6*	1,462 *3.6*	1,514 *3.6*	1,568 *3.6*	1,624 *3.6*
Personal income (current $)	1,820,219 *4.3*	1,898,324 *4.3*	1,981,561 *4.4*	2,067,788 *4.4*	2,157,669 *4.3*	2,250,823 *4.3*	2,347,965 *4.3*	2,447,793 *4.3*	2,549,855 *4.2*	2,655,829 *4.2*	2,766,551 *4.2*	2,879,622 *4.1*	2,994,306 *4.0*
Personal disposable income (current $)	1,370,428 *4.1*	1,426,220 *4.1*	1,485,577 *4.2*	1,546,948 *4.1*	1,610,875 *4.1*	1,677,032 *4.1*	1,745,858 *4.1*	1,815,941 *4.0*	1,887,231 *3.9*	1,961,393 *3.9*	2,038,558 *3.9*	2,116,840 *3.8*	2,195,549 *3.7*
Personal savings rate	1.6 *1.2*	1.6 *–4.1*	1.5 *–2.4*	1.4 *–6.2*	1.4 *–6.0*	1.3 *–6.4*	1.1 *–13.7*	0.9 *–16.2*	0.7 *–20.7*	0.6 *–20.1*	0.4 *–32.2*	0.2 *–60.4*	–0.1 *–179.8*
Population (000s)	36,698 *1.1*	37,082 *1.0*	37,466 *1.0*	37,848 *1.0*	38,228 *1.0*	38,603 *1.0*	38,974 *1.0*	39,340 *0.9*	39,699 *0.9*	40,050 *0.9*	40,392 *0.9*	40,727 *0.8*	41,053 *0.8*
Labour force (000s)	19,923 *0.6*	20,043 *0.6*	20,157 *0.6*	20,269 *0.6*	20,378 *0.5*	20,485 *0.5*	20,587 *0.5*	20,685 *0.5*	20,778 *0.5*	20,868 *0.4*	20,954 *0.4*	21,036 *0.4*	21,113 *0.4*
Employment (000s)	18,807 *0.6*	18,917 *0.6*	19,042 *0.7*	19,159 *0.6*	19,268 *0.6*	19,373 *0.5*	19,480 *0.6*	19,576 *0.5*	19,651 *0.4*	19,738 *0.4*	19,822 *0.4*	19,900 *0.4*	19,971 *0.4*
Unemployment rate (percentage)	5.6	5.6	5.5	5.5	5.5	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4
Retail sales (current $)	693,532 *4.3*	723,759 *4.4*	755,412 *4.4*	788,866 *4.4*	823,526 *4.4*	859,006 *4.3*	894,756 *4.2*	931,873 *4.1*	971,353 *4.2*	1,011,925 *4.2*	1,053,435 *4.1*	1,095,718 *4.0*	1,138,735 *3.9*
Housing starts (units)	193,688 *0.0*	193,127 *–0.3*	192,135 *–0.5*	190,686 *–0.8*	188,851 *–1.0*	186,736 *–1.1*	184,362 *–1.3*	181,811 *–1.4*	179,010 *–1.5*	176,013 *–1.7*	172,813 *–1.8*	169,443 *–1.9*	165,926 *–2.1*

White area represents forecast data.
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For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; Canada Mortgage and Housing Corporation.

Table 2—Key Economic Indicators: Newfoundland and Labrador
(forecast completed: Dec. 19, 2006)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
GDP at market prices (current $)	21,498	24,429	23,771	24,288	25,121	25,935	26,765	27,379	27,900	27,795	28,044	29,056	29,637
	10.9	*13.6*	*–2.7*	*2.2*	*3.4*	*3.2*	*3.2*	*2.3*	*1.9*	*–0.4*	*0.9*	*3.6*	*2.0*
GDP at basic prices (current $)	19,850	22,738	22,028	22,452	23,189	23,903	24,630	25,141	25,558	25,344	25,481	26,381	26,847
	11.6	*14.5*	*–3.1*	*1.9*	*3.3*	*3.1*	*3.0*	*2.1*	*1.7*	*–0.8*	*0.5*	*3.5*	*1.8*
GDP at basic prices (constant 1997 $)	13,630	14,019	14,824	14,858	15,006	15,154	15,284	15,376	15,384	15,133	15,013	15,392	15,431
	0.4	*2.9*	*5.7*	*0.2*	*1.0*	*1.0*	*0.9*	*0.6*	*0.0*	*–1.6*	*–0.8*	*2.5*	*0.2*
Consumer Price Index (1992=1.0)	1.261	1.289	1.309	1.333	1.359	1.383	1.408	1.433	1.457	1.481	1.506	1.533	1.561
	2.6	*2.2*	*1.5*	*1.8*	*2.0*	*1.8*	*1.8*	*1.7*	*1.7*	*1.7*	*1.7*	*1.8*	*1.8*
Implicit price deflator— **GDP at basic prices** (1997=1.0)	1.456	1.623	1.486	1.511	1.545	1.577	1.611	1.635	1.661	1.675	1.697	1.714	1.740
	11.1	*11.5*	*–8.4*	*1.7*	*2.3*	*2.1*	*2.2*	*1.5*	*1.6*	*0.8*	*1.3*	*1.0*	*1.5*
Average weekly wages (level $)	650	680	698	717	734	751	766	789	808	827	848	869	891
	4.3	*4.7*	*2.7*	*2.8*	*2.3*	*2.3*	*2.0*	*3.0*	*2.4*	*2.3*	*2.6*	*2.5*	*2.5*
Personal income (current $)	13,458	15,958	14,446	14,957	15,538	16,079	16,610	17,158	17,588	17,937	18,392	18,963	19,494
	3.9	*18.6*	*–9.5*	*3.5*	*3.9*	*3.5*	*3.3*	*3.3*	*2.5*	*2.0*	*2.5*	*3.1*	*2.8*
Personal disposable income (current $)	10,509	12,883	11,219	11,608	12,061	12,465	12,861	13,258	13,576	13,836	14,175	14,600	14,993
	3.2	*22.6*	*–12.9*	*3.5*	*3.9*	*3.4*	*3.2*	*3.1*	*2.4*	*1.9*	*2.5*	*3.0*	*2.7*
Personal savings rate	–0.5	11.7	1.5	1.4	1.3	1.0	1.0	0.9	0.9	0.9	1.0	1.3	1.5
	–395.2	*2224.6*	*–87.4*	*–7.3*	*–6.6*	*–18.1*	*–2.7*	*–15.2*	*0.2*	*0.4*	*14.9*	*26.5*	*18.0*
Population (000s)	515	510	508	507	505	504	502	501	500	499	498	497	496
	–0.5	*–0.8*	*–0.4*	*–0.3*	*–0.3*	*–0.3*	*–0.3*	*–0.3*	*–0.3*	*–0.2*	*–0.2*	*–0.2*	*–0.2*
Labour force (000s)	253	252	252	252	251	250	249	247	245	243	241	239	237
	–0.7	*0.0*	*0.0*	*–0.2*	*–0.3*	*–0.3*	*–0.5*	*–0.7*	*–0.8*	*–0.8*	*–0.8*	*–0.9*	*–1.0*
Employment (000s)	214	215	216	217	220	222	224	223	220	216	213	214	213
	–0.1	*0.2*	*0.5*	*0.5*	*1.5*	*0.9*	*0.8*	*–0.3*	*–1.1*	*–2.1*	*–1.2*	*0.3*	*–0.5*
Unemployment rate (percentage)	15.2	15.0	14.6	14.0	12.4	11.4	10.2	9.9	10.2	11.4	11.7	10.6	10.2
Retail sales (current $)	5,891	6,042	6,288	6,568	6,891	7,193	7,490	7,774	7,985	8,153	8,372	8,644	8,896
	2.4	*2.6*	*4.1*	*4.4*	*4.9*	*4.4*	*4.1*	*3.8*	*2.7*	*2.1*	*2.7*	*3.3*	*2.9*
Housing starts (units)	2,498	2,202	1,701	1,405	1,334	1,283	1,250	1,162	1,109	1,049	1,002	941	887
	–13.0	*–11.8*	*–22.8*	*–17.4*	*–5.1*	*–3.8*	*–2.6*	*–7.0*	*–4.6*	*–5.4*	*–4.5*	*–6.2*	*–5.7*

White area represents forecast data.
All data are in millions of dollars, seasonally adjusted at annual rates, unless otherwise specified.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; Canada Mortgage and Housing Corporation.

Table 2—Key Economic Indicators: Newfoundland and Labrador

(forecast completed: Dec. 19, 2006)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
GDP at market prices (current $)	30,707	31,311	31,862	32,042	32,225	32,558	33,054	33,519	34,445	35,321	36,084	36,655	37,133
	3.6	*2.0*	*1.8*	*0.6*	*0.6*	*1.0*	*1.5*	*1.4*	*2.8*	*2.5*	*2.2*	*1.6*	*1.3*
GDP at basic prices (current $)	27,788	28,252	28,660	28,694	28,726	28,897	29,221	29,507	30,248	30,936	31,506	31,878	32,154
	3.5	*1.7*	*1.4*	*0.1*	*0.1*	*0.6*	*1.1*	*1.0*	*2.5*	*2.3*	*1.8*	*1.2*	*0.9*
GDP at basic prices (constant 1997 $)	15,621	15,702	15,736	15,610	15,486	15,447	15,437	15,423	15,678	15,897	16,044	16,093	16,093
	1.2	*0.5*	*0.2*	*–0.8*	*–0.8*	*–0.2*	*–0.1*	*–0.1*	*1.7*	*1.4*	*0.9*	*0.3*	*0.0*
Consumer Price Index (1992=1.0)	1.590	1.618	1.648	1.680	1.712	1.743	1.776	1.810	1.845	1.880	1.913	1.948	1.983
	1.8	*1.8*	*1.8*	*1.9*	*1.9*	*1.8*	*1.9*	*1.9*	*1.9*	*1.9*	*1.8*	*1.8*	*1.8*
Implicit price deflator— GDP at basic prices (1997=1.0)	1.779	1.799	1.821	1.838	1.855	1.871	1.893	1.913	1.929	1.946	1.964	1.981	1.998
	2.2	*1.1*	*1.2*	*0.9*	*0.9*	*0.8*	*1.2*	*1.1*	*0.8*	*0.9*	*0.9*	*0.9*	*0.9*
Average weekly wages (level $)	913	937	963	990	1,017	1,045	1,074	1,103	1,134	1,166	1,199	1,234	1,270
	2.5	*2.6*	*2.8*	*2.7*	*2.8*	*2.7*	*2.7*	*2.7*	*2.8*	*2.8*	*2.9*	*2.9*	*2.9*
Personal income (current $)	20,022	20,550	21,113	21,665	22,228	22,825	23,430	24,029	24,629	25,262	25,909	26,541	27,169
	2.7	*2.6*	*2.7*	*2.6*	*2.6*	*2.7*	*2.7*	*2.6*	*2.5*	*2.6*	*2.6*	*2.4*	*2.4*
Personal disposable income (current $)	15,373	15,755	16,162	16,562	16,970	17,401	17,838	18,265	18,691	19,140	19,598	20,041	20,475
	2.5	*2.5*	*2.6*	*2.5*	*2.5*	*2.5*	*2.5*	*2.4*	*2.3*	*2.4*	*2.4*	*2.3*	*2.2*
Personal savings rate	1.5	1.5	1.5	1.4	1.3	1.2	1.1	0.9	0.7	0.5	0.3	0.0	–0.3
	3.9	*–3.0*	*–0.7*	*–6.4*	*–7.7*	*–5.1*	*–13.4*	*–17.3*	*–24.8*	*–21.6*	*–36.2*	*–85.8*	*–649.8*
Population (000s)	495	494	493	492	490	488	487	485	483	480	478	475	472
	–0.2	*–0.2*	*–0.2*	*–0.3*	*–0.3*	*–0.3*	*–0.4*	*–0.4*	*–0.4*	*–0.5*	*–0.5*	*–0.5*	*–0.6*
Labour force (000s)	234	232	229	227	224	221	219	216	213	211	208	205	203
	–1.0	*–1.1*	*–1.1*	*–1.2*	*–1.2*	*–1.2*	*–1.2*	*–1.2*	*–1.2*	*–1.3*	*–1.2*	*–1.2*	*–1.3*
Employment (000s)	211	209	207	204	201	199	196	193	191	188	186	183	180
	–0.7	*–1.1*	*–1.1*	*–1.3*	*–1.4*	*–1.2*	*–1.2*	*–1.4*	*–1.5*	*–1.2*	*–1.3*	*–1.5*	*–1.4*
Unemployment rate (percentage)	9.9	9.9	9.8	10.0	10.2	10.2	10.2	10.4	10.6	10.6	10.6	10.8	10.9
Retail sales (current $)	9,152	9,416	9,691	9,972	10,257	10,556	10,846	11,139	11,454	11,781	12,107	12,425	12,743
	2.9	*2.9*	*2.9*	*2.9*	*2.9*	*2.9*	*2.7*	*2.7*	*2.8*	*2.9*	*2.8*	*2.6*	*2.6*
Housing starts (units)	818	737	645	545	438	379	302	257	220	181	170	166	160
	–7.7	*–9.9*	*–12.4*	*–15.5*	*–19.6*	*–13.4*	*–20.3*	*–15.0*	*–14.6*	*–17.8*	*–5.8*	*–2.2*	*–3.7*

White area represents forecast data.
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For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; Canada Mortgage and Housing Corporation.

Table 3—Key Economic Indicators: Prince Edward Island

(forecast completed: Dec. 19, 2006)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
GDP at market prices (current $)	4,152	4,287	4,406	4,601	4,800	4,980	5,171	5,341	5,505	5,677	5,849	6,023	6,216
	3.0	*3.3*	*2.8*	*4.4*	*4.3*	*3.7*	*3.8*	*3.3*	*3.1*	*3.1*	*3.0*	*3.0*	*3.2*
GDP at basic prices (current $)	3,752	3,878	3,984	4,156	4,332	4,487	4,654	4,798	4,938	5,083	5,228	5,375	5,540
	2.7	*3.3*	*2.7*	*4.3*	*4.2*	*3.6*	*3.7*	*3.1*	*2.9*	*3.0*	*2.8*	*2.8*	*3.1*
GDP at basic prices (constant 1997 $)	3,165	3,213	3,263	3,339	3,424	3,505	3,582	3,637	3,695	3,754	3,811	3,867	3,922
	2.0	*1.5*	*1.5*	*2.3*	*2.5*	*2.4*	*2.2*	*1.5*	*1.6*	*1.6*	*1.5*	*1.5*	*1.4*
Consumer Price Index (1992=1.0)	1.285	1.317	1.337	1.362	1.387	1.412	1.437	1.464	1.490	1.516	1.542	1.570	1.599
	3.2	*2.5*	*1.5*	*1.8*	*1.9*	*1.8*	*1.8*	*1.8*	*1.8*	*1.8*	*1.8*	*1.8*	*1.8*
Implicit price deflator— GDP at basic prices (1997=1.0)	1.186	1.207	1.221	1.245	1.265	1.280	1.299	1.319	1.336	1.354	1.372	1.390	1.413
	0.7	*1.8*	*1.2*	*1.9*	*1.6*	*1.2*	*1.5*	*1.5*	*1.3*	*1.3*	*1.3*	*1.3*	*1.7*
Average weekly wages (level $)	488	505	518	530	543	557	571	587	602	619	636	654	673
	2.2	*3.7*	*2.5*	*2.4*	*2.4*	*2.6*	*2.6*	*2.7*	*2.6*	*2.8*	*2.8*	*2.9*	*2.9*
Personal income (current $)	3,594	3,710	3,847	4,001	4,160	4,327	4,503	4,689	4,871	5,062	5,254	5,454	5,661
	2.8	*3.2*	*3.7*	*4.0*	*4.0*	*4.0*	*4.1*	*4.1*	*3.9*	*3.9*	*3.8*	*3.8*	*3.8*
Personal disposable income (current $)	2,832	2,925	3,022	3,142	3,269	3,398	3,534	3,673	3,813	3,958	4,105	4,260	4,419
	2.1	*3.3*	*3.3*	*4.0*	*4.0*	*3.9*	*4.0*	*4.0*	*3.8*	*3.8*	*3.7*	*3.8*	*3.7*
Personal savings rate	–4.8	–5.1	–4.7	–4.9	–5.0	–5.3	–5.4	–5.8	–5.8	–5.8	–5.7	–5.5	–5.3
	–252.6	*–5.2*	*7.0*	*–2.7*	*–3.6*	*–6.0*	*–1.7*	*–6.4*	*–0.7*	*0.3*	*2.2*	*3.1*	*2.7*
Population (000s)	138	138	139	140	140	141	142	143	144	145	146	147	148
	0.2	*0.2*	*0.5*	*0.5*	*0.5*	*0.6*	*0.6*	*0.6*	*0.7*	*0.7*	*0.7*	*0.7*	*0.7*
Labour force (000s)	77	77	78	79	79	80	81	81	81	81	82	82	82
	1.7	*0.6*	*0.8*	*1.1*	*0.9*	*0.9*	*0.8*	*0.5*	*0.3*	*0.3*	*0.2*	*0.2*	*0.1*
Employment (000s)	68	69	69	70	71	71	72	72	72	73	73	73	73
	2.0	*0.6*	*0.7*	*1.1*	*0.9*	*0.8*	*0.8*	*0.6*	*0.3*	*0.4*	*0.2*	*0.3*	*0.2*
Unemployment rate (percentage)	10.9	11.0	11.0	11.0	11.0	11.0	11.0	10.9	10.9	10.8	10.8	10.7	10.6
Retail sales (current $)	1,428	1,493	1,559	1,640	1,726	1,815	1,909	2,000	2,085	2,172	2,259	2,350	2,442
	3.2	*4.6*	*4.4*	*5.2*	*5.2*	*5.2*	*5.2*	*4.8*	*4.2*	*4.2*	*4.0*	*4.0*	*3.9*
Housing starts (units)	862	777	621	600	600	601	609	629	650	667	678	684	684
	–6.2	*–9.9*	*–20.1*	*–3.4*	*0.0*	*0.3*	*1.3*	*3.2*	*3.4*	*2.6*	*1.7*	*0.8*	*0.0*

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Sources: The Conference Board of Canada; Statistics Canada; Canada Mortgage and Housing Corporation.

Table 3—Key Economic Indicators: Prince Edward Island

(forecast completed: Dec. 19, 2006)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
GDP at market prices (current $)	6,417	6,624	6,839	7,063	7,300	7,541	7,788	8,053	8,325	8,606	8,893	9,192	9,494
	3.2	*3.2*	*3.3*	*3.3*	*3.4*	*3.3*	*3.3*	*3.4*	*3.4*	*3.4*	*3.3*	*3.4*	*3.3*
GDP at basic prices (current $)	5,710	5,882	6,063	6,251	6,451	6,653	6,859	7,080	7,308	7,544	7,784	8,034	8,287
	3.1	*3.0*	*3.1*	*3.1*	*3.2*	*3.1*	*3.1*	*3.2*	*3.2*	*3.2*	*3.2*	*3.2*	*3.1*
GDP at basic prices (constant 1997 $)	3,975	4,029	4,084	4,140	4,195	4,253	4,311	4,369	4,426	4,484	4,541	4,598	4,656
	1.4	*1.4*	*1.4*	*1.4*	*1.3*	*1.4*	*1.4*	*1.3*	*1.3*	*1.3*	*1.3*	*1.3*	*1.3*
Consumer Price Index (1992=1.0)	1.630	1.661	1.693	1.726	1.760	1.796	1.833	1.871	1.910	1.950	1.989	2.028	2.069
	1.9	*1.9*	*2.0*	*2.0*	*2.0*	*2.1*	*2.1*	*2.1*	*2.1*	*2.1*	*2.0*	*2.0*	*2.0*
Implicit price deflator— GDP at basic prices (1997=1.0)	1.436	1.460	1.484	1.510	1.538	1.565	1.591	1.621	1.651	1.682	1.714	1.747	1.780
	1.7	*1.6*	*1.7*	*1.7*	*1.8*	*1.7*	*1.7*	*1.9*	*1.9*	*1.9*	*1.9*	*1.9*	*1.9*
Average weekly wages (level $)	693	714	736	758	782	806	830	856	882	909	938	967	997
	3.0	*3.0*	*3.0*	*3.1*	*3.1*	*3.1*	*3.1*	*3.1*	*3.1*	*3.1*	*3.1*	*3.1*	*3.1*
Personal income (current $)	5,878	6,101	6,339	6,589	6,848	7,114	7,393	7,677	7,967	8,267	8,581	8,900	9,220
	3.8	*3.8*	*3.9*	*3.9*	*3.9*	*3.9*	*3.9*	*3.8*	*3.8*	*3.8*	*3.8*	*3.7*	*3.6*
Personal disposable income (current $)	4,582	4,749	4,928	5,114	5,308	5,507	5,715	5,925	6,140	6,361	6,592	6,825	7,057
	3.7	*3.6*	*3.8*	*3.8*	*3.8*	*3.8*	*3.8*	*3.7*	*3.6*	*3.6*	*3.6*	*3.5*	*3.4*
Personal savings rate	–5.3	–5.5	–5.5	–5.7	–5.8	–5.9	–6.2	–6.4	–6.6	–6.8	–7.0	–7.3	–7.7
	–0.4	*–2.1*	*–1.5*	*–2.5*	*–2.3*	*–2.2*	*–3.7*	*–3.4*	*–3.6*	*–3.1*	*–3.4*	*–4.1*	*–4.6*
Population (000s)	149	150	152	153	154	155	156	157	158	158	159	160	161
	0.7	*0.7*	*0.7*	*0.7*	*0.7*	*0.7*	*0.6*	*0.6*	*0.6*	*0.6*	*0.5*	*0.5*	*0.5*
Labour force (000s)	82	82	82	82	82	82	83	83	83	83	83	83	83
	0.1	*0.1*	*0.1*	*0.1*	*0.1*	*0.2*	*0.2*	*0.2*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*
Employment (000s)	73	73	74	74	74	74	74	74	74	74	74	74	74
	0.2	*0.0*	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*0.1*	*0.0*	*0.1*	*0.1*	*0.1*	*0.1*
Unemployment rate (percentage)	10.5	10.6	10.5	10.4	10.3	10.3	10.3	10.3	10.4	10.5	10.5	10.4	10.5
Retail sales (current $)	2,541	2,644	2,752	2,869	2,988	3,111	3,234	3,362	3,499	3,639	3,783	3,929	4,077
	4.0	*4.1*	*4.1*	*4.2*	*4.2*	*4.1*	*4.0*	*4.0*	*4.1*	*4.0*	*4.0*	*3.9*	*3.7*
Housing starts (units)	679	670	658	642	624	604	584	563	542	521	500	478	457
	–0.7	*–1.3*	*–1.9*	*–2.4*	*–2.8*	*–3.2*	*–3.4*	*–3.6*	*–3.7*	*–3.9*	*–4.1*	*–4.3*	*–4.4*

White area represents forecast data.
All data are in millions of dollars, seasonally adjusted at annual rates, unless otherwise specified.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; Canada Mortgage and Housing Corporation.

Table 4—Key Economic Indicators: Nova Scotia
(forecast completed: Dec. 19, 2006)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
GDP at market prices (current $)	31,527	32,602	33,557	34,884	36,297	37,521	38,847	40,079	41,273	42,415	43,556	44,649	45,777
	5.4	*3.4*	*2.9*	*4.0*	*4.1*	*3.4*	*3.5*	*3.2*	*3.0*	*2.8*	*2.7*	*2.5*	*2.5*
GDP at basic prices (current $)	28,557	29,554	30,417	31,574	32,814	33,860	35,000	36,046	37,052	37,998	38,938	39,829	40,748
	5.5	*3.5*	*2.9*	*3.8*	*3.9*	*3.2*	*3.4*	*3.0*	*2.8*	*2.6*	*2.5*	*2.3*	*2.3*
GDP at basic prices (constant 1997 $)	23,361	23,883	24,334	24,749	25,264	25,711	26,256	26,762	27,155	27,478	27,774	28,020	28,233
	1.7	*2.2*	*1.9*	*1.7*	*2.1*	*1.8*	*2.1*	*1.9*	*1.5*	*1.2*	*1.1*	*0.9*	*0.8*
Consumer Price Index (1992=1.0)	1.296	1.327	1.347	1.371	1.397	1.422	1.448	1.475	1.501	1.528	1.554	1.581	1.609
	2.8	*2.4*	*1.5*	*1.7*	*1.9*	*1.8*	*1.8*	*1.8*	*1.8*	*1.8*	*1.8*	*1.7*	*1.8*
Implicit price deflator—	1.222	1.237	1.250	1.276	1.299	1.317	1.333	1.347	1.364	1.383	1.402	1.421	1.443
GDP at basic prices (1997=1.0)	*3.8*	*1.2*	*1.0*	*2.1*	*1.8*	*1.4*	*1.2*	*1.0*	*1.3*	*1.4*	*1.4*	*1.4*	*1.5*
Average weekly wages (level $)	595	615	631	647	663	679	697	716	735	756	777	799	823
	3.1	*3.3*	*2.6*	*2.5*	*2.5*	*2.4*	*2.6*	*2.8*	*2.7*	*2.8*	*2.8*	*2.9*	*2.9*
Personal income (current $)	26,602	27,446	28,420	29,431	30,493	31,526	32,652	33,780	34,876	35,956	37,057	38,171	39,338
	4.6	*3.2*	*3.5*	*3.6*	*3.6*	*3.4*	*3.6*	*3.5*	*3.2*	*3.1*	*3.1*	*3.0*	*3.1*
Personal disposable income (current $)	20,808	21,516	22,182	22,963	23,807	24,589	25,436	26,263	27,079	27,878	28,700	29,549	30,423
	4.1	*3.4*	*3.1*	*3.5*	*3.7*	*3.3*	*3.4*	*3.3*	*3.1*	*2.9*	*2.9*	*3.0*	*3.0*
Personal savings rate	–2.6	–3.6	–3.5	–3.7	–3.8	–4.1	–4.2	–4.5	–4.6	–4.6	–4.5	–4.3	–4.2
	–30.8	*–39.4*	*1.3*	*–4.1*	*–3.9*	*–7.6*	*–2.0*	*–7.7*	*–1.3*	*–0.1*	*2.3*	*3.4*	*2.9*
Population (000s)	937	935	934	934	935	935	936	937	937	938	939	939	940
	–0.1	*–0.2*	*–0.1*	*0.0*	*0.0*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*
Labour force (000s)	484	480	480	482	483	484	485	484	482	481	479	476	473
	–0.2	*–0.9*	*0.0*	*0.4*	*0.3*	*0.2*	*0.1*	*–0.2*	*–0.3*	*–0.3*	*–0.4*	*–0.5*	*–0.6*
Employment (000s)	443	441	444	445	448	450	452	452	451	449	447	444	442
	0.2	*–0.5*	*0.6*	*0.4*	*0.5*	*0.4*	*0.5*	*0.0*	*–0.2*	*–0.5*	*–0.4*	*–0.6*	*–0.5*
Unemployment rate (percentage)	8.4	8.1	7.6	7.6	7.4	7.2	6.8	6.7	6.6	6.7	6.7	6.8	6.7
Retail sales (current $)	10,619	11,352	11,882	12,421	13,013	13,590	14,212	14,779	15,301	15,801	16,306	16,816	17,341
	3.1	*6.9*	*4.7*	*4.5*	*4.8*	*4.4*	*4.6*	*4.0*	*3.5*	*3.3*	*3.2*	*3.1*	*3.1*
Housing starts (units)	4,775	5,047	3,086	2,709	2,470	2,347	2,294	2,321	2,336	2,334	2,312	2,268	2,203
	1.2	*5.7*	*–38.9*	*–12.2*	*–8.8*	*–5.0*	*–2.3*	*1.2*	*0.6*	*–0.1*	*–0.9*	*–1.9*	*–2.9*

White area represents forecast data.
All data are in millions of dollars, seasonally adjusted at annual rates, unless otherwise specified.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; Canada Mortgage and Housing Corporation.

Table 4—Key Economic Indicators: Nova Scotia
(forecast completed: Dec. 19, 2006)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
GDP at market prices (current $)	46,969	48,157	49,361	50,566	51,850	53,175	54,527	55,952	57,465	58,909	60,384	61,905	63,431
	2.6	*2.5*	*2.5*	*2.4*	*2.5*	*2.6*	*2.5*	*2.6*	*2.7*	*2.5*	*2.5*	*2.5*	*2.5*
GDP at basic prices (current $)	41,708	42,644	43,591	44,533	45,544	46,578	47,618	48,721	49,903	51,007	52,133	53,296	54,458
	2.4	*2.2*	*2.2*	*2.2*	*2.3*	*2.3*	*2.2*	*2.3*	*2.4*	*2.2*	*2.2*	*2.2*	*2.2*
GDP at basic prices (constant 1997 $)	28,420	28,584	28,748	28,912	29,071	29,225	29,377	29,532	29,729	29,856	29,987	30,114	30,245
	0.7	*0.6*	*0.6*	*0.6*	*0.5*	*0.5*	*0.5*	*0.5*	*0.7*	*0.4*	*0.4*	*0.4*	*0.4*
Consumer Price Index (1992=1.0)	1.641	1.672	1.706	1.743	1.781	1.821	1.860	1.902	1.943	1.988	2.032	2.076	2.120
	1.9	*1.9*	*2.1*	*2.2*	*2.2*	*2.3*	*2.2*	*2.3*	*2.2*	*2.3*	*2.2*	*2.2*	*2.1*
Implicit price deflator—GDP at basic prices (1997=1.0)	1.468	1.492	1.516	1.540	1.567	1.594	1.621	1.650	1.679	1.708	1.739	1.770	1.801
	1.7	*1.7*	*1.6*	*1.6*	*1.7*	*1.7*	*1.7*	*1.8*	*1.7*	*1.8*	*1.8*	*1.8*	*1.7*
Average weekly wages (level $)	847	873	899	927	955	985	1,015	1,046	1,078	1,111	1,146	1,182	1,219
	3.0	*3.0*	*3.0*	*3.1*	*3.1*	*3.1*	*3.1*	*3.1*	*3.1*	*3.1*	*3.1*	*3.1*	*3.1*
Personal income (current $)	40,540	41,752	43,043	44,372	45,754	47,185	48,650	50,141	51,637	53,169	54,776	56,395	58,007
	3.1	*3.0*	*3.1*	*3.1*	*3.1*	*3.1*	*3.1*	*3.1*	*3.0*	*3.0*	*3.0*	*3.0*	*2.9*
Personal disposable income (current $)	31,302	32,187	33,129	34,098	35,106	36,149	37,215	38,287	39,360	40,463	41,615	42,766	43,899
	2.9	*2.8*	*2.9*	*2.9*	*3.0*	*3.0*	*2.9*	*2.9*	*2.8*	*2.8*	*2.8*	*2.8*	*2.6*
Personal savings rate	–4.2	–4.4	–4.5	–4.7	–4.8	–5.0	–5.2	–5.5	–5.7	–5.9	–6.2	–6.5	–6.9
	–1.1	*–3.2*	*–2.5*	*–3.7*	*–3.4*	*–3.2*	*–5.0*	*–4.6*	*–4.7*	*–4.1*	*–4.4*	*–5.1*	*–5.6*
Population (000s)	941	941	941	942	941	941	941	940	939	937	936	934	932
	0.1	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*–0.1*	*–0.1*	*–0.1*	*–0.1*	*–0.2*	*–0.2*	*–0.2*
Labour force (000s)	470	467	463	460	456	453	449	445	441	437	433	430	426
	–0.7	*–0.7*	*–0.7*	*–0.8*	*–0.8*	*–0.8*	*–0.8*	*–0.8*	*–0.9*	*–0.9*	*–0.9*	*–0.9*	*–0.8*
Employment (000s)	439	435	432	429	425	422	419	416	412	408	405	401	398
	–0.7	*–0.8*	*–0.7*	*–0.7*	*–0.8*	*–0.7*	*–0.7*	*–0.8*	*–1.0*	*–0.9*	*–0.9*	*–0.9*	*–0.9*
Unemployment rate (percentage)	6.7	6.8	6.7	6.7	6.7	6.7	6.6	6.6	6.6	6.6	6.6	6.6	6.6
Retail sales (current $)	17,897	18,467	19,060	19,690	20,341	21,008	21,663	22,341	23,064	23,802	24,559	25,324	26,090
	3.2	*3.2*	*3.2*	*3.3*	*3.3*	*3.3*	*3.1*	*3.1*	*3.2*	*3.2*	*3.2*	*3.1*	*3.0*
Housing starts (units)	2,117	2,014	1,895	1,761	1,616	1,461	1,299	1,133	962	800	731	669	633
	–3.9	*–4.9*	*–5.9*	*–7.0*	*–8.3*	*–9.6*	*–11.1*	*–12.8*	*–15.1*	*–16.8*	*–8.7*	*–8.4*	*–5.4*

White area represents forecast data.
All data are in millions of dollars, seasonally adjusted at annual rates, unless otherwise specified.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; Canada Mortgage and Housing Corporation.

Table 5—Key Economic Indicators: New Brunswick

(forecast completed: Dec. 19, 2006)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
GDP at market prices (current $)	23,797	24,628	25,437	26,514	27,653	28,678	29,678	30,533	31,431	32,328	33,258	34,207	35,133
	3.5	*3.5*	*3.3*	*4.2*	*4.3*	*3.7*	*3.5*	*2.9*	*2.9*	*2.9*	*2.9*	*2.9*	*2.7*
GDP at basic prices (current $)	21,599	22,372	23,113	24,065	25,075	25,968	26,831	27,548	28,306	29,059	29,840	30,640	31,411
	3.5	*3.6*	*3.3*	*4.1*	*4.2*	*3.6*	*3.3*	*2.7*	*2.8*	*2.7*	*2.7*	*2.7*	*2.5*
GDP at basic prices (constant 1997 $)	19,210	19,619	20,083	20,560	21,040	21,490	21,922	22,227	22,474	22,688	22,906	23,109	23,293
	0.5	*2.1*	*2.4*	*2.4*	*2.3*	*2.1*	*2.0*	*1.4*	*1.1*	*1.0*	*1.0*	*0.9*	*0.8*
Consumer Price Index (1992=1.0)	1.274	1.299	1.315	1.338	1.365	1.390	1.415	1.444	1.471	1.499	1.526	1.554	1.583
	2.4	*2.0*	*1.2*	*1.8*	*2.0*	*1.8*	*1.8*	*2.0*	*1.9*	*1.9*	*1.9*	*1.8*	*1.9*
Implicit price deflator—	1.124	1.140	1.151	1.170	1.192	1.208	1.224	1.239	1.260	1.281	1.303	1.326	1.349
GDP at basic prices (1997=1.0)	*3.0*	*1.4*	*0.9*	*1.7*	*1.8*	*1.4*	*1.3*	*1.3*	*1.6*	*1.7*	*1.7*	*1.8*	*1.7*
Average weekly wages (level $)	628	652	670	687	705	725	744	765	787	809	833	859	885
	2.7	*3.9*	*2.8*	*2.5*	*2.7*	*2.7*	*2.7*	*2.9*	*2.8*	*2.9*	*3.0*	*3.1*	*3.1*
Personal income (current $)	20,208	20,748	21,419	22,176	22,994	23,830	24,655	25,481	26,282	27,095	27,922	28,761	29,640
	3.6	*2.7*	*3.2*	*3.5*	*3.7*	*3.6*	*3.5*	*3.3*	*3.1*	*3.1*	*3.1*	*3.0*	*3.1*
Personal disposable income (current $)	15,876	16,340	16,808	17,394	18,048	18,685	19,315	19,930	20,536	21,145	21,774	22,423	23,093
	3.0	*2.9*	*2.9*	*3.5*	*3.8*	*3.5*	*3.4*	*3.2*	*3.0*	*3.0*	*3.0*	*3.0*	*3.0*
Personal savings rate	–0.2	–1.3	–1.8	–1.9	–1.9	–2.1	–2.2	–2.5	–2.5	–2.5	–2.4	–2.3	–2.1
	–112.8	*–668.6*	*–34.4*	*–4.6*	*–3.1*	*–7.5*	*–3.4*	*–15.0*	*–2.0*	*0.1*	*4.4*	*6.5*	*5.8*
Population (000s)	752	750	749	748	749	749	749	749	749	749	748	748	747
	0.0	*–0.3*	*–0.1*	*0.0*	*0.0*	*0.1*	*0.0*	*0.0*	*0.0*	*0.0*	*–0.1*	*–0.1*	*–0.1*
Labour force (000s)	388	391	390	391	392	393	394	393	391	389	386	383	380
	0.0	*0.7*	*–0.3*	*0.4*	*0.3*	*0.2*	*0.1*	*–0.3*	*–0.5*	*–0.6*	*–0.6*	*–0.7*	*–0.8*
Employment (000s)	351	356	357	358	361	362	363	362	360	358	355	353	350
	0.1	*1.5*	*0.2*	*0.5*	*0.6*	*0.5*	*0.1*	*–0.3*	*–0.6*	*–0.6*	*–0.7*	*–0.7*	*–0.8*
Unemployment rate (percentage)	9.7	9.0	8.5	8.4	8.1	7.9	7.9	7.9	8.0	7.9	8.0	8.1	8.0
Retail sales (current $)	8,412	8,967	9,450	9,878	10,355	10,837	11,313	11,744	12,141	12,538	12,944	13,356	13,784
	5.6	*6.6*	*5.4*	*4.5*	*4.8*	*4.7*	*4.4*	*3.8*	*3.4*	*3.3*	*3.2*	*3.2*	*3.2*
Housing starts (units)	3,959	4,503	2,614	2,355	2,288	2,379	2,506	2,000	1,743	1,554	1,449	1,400	1,338
	0.3	*13.7*	*–42.0*	*–9.9*	*–2.8*	*3.9*	*5.4*	*–20.2*	*–12.9*	*–10.9*	*–6.7*	*–3.4*	*–4.4*

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Sources: The Conference Board of Canada; Statistics Canada; Canada Mortgage and Housing Corporation.

Table 5—Key Economic Indicators: New Brunswick
(forecast completed: Dec. 19, 2006)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
GDP at market prices (current $)	36,125	37,196	38,192	39,242	40,364	41,461	42,631	43,842	45,060	46,291	47,546	48,840	50,124
	2.8	*3.0*	*2.7*	*2.7*	*2.9*	*2.7*	*2.8*	*2.8*	*2.8*	*2.7*	*2.7*	*2.7*	*2.6*
GDP at basic prices (current $)	32,232	33,116	33,922	34,777	35,696	36,579	37,518	38,491	39,464	40,443	41,439	42,468	43,484
	2.6	*2.7*	*2.4*	*2.5*	*2.6*	*2.5*	*2.6*	*2.6*	*2.5*	*2.5*	*2.5*	*2.5*	*2.4*
GDP at basic prices (constant 1997 $)	23,484	23,716	23,896	24,079	24,254	24,429	24,606	24,773	24,930	25,072	25,215	25,354	25,486
	0.8	*1.0*	*0.8*	*0.8*	*0.7*	*0.7*	*0.7*	*0.7*	*0.6*	*0.6*	*0.6*	*0.5*	*0.5*
Consumer Price Index (1992=1.0)	1.614	1.646	1.679	1.713	1.750	1.788	1.828	1.868	1.910	1.952	1.993	2.035	2.075
	1.9	*2.0*	*2.0*	*2.1*	*2.2*	*2.2*	*2.3*	*2.2*	*2.3*	*2.2*	*2.1*	*2.1*	*2.0*
Implicit price deflator— GDP at basic prices (1997=1.0)	1.372	1.396	1.420	1.444	1.472	1.497	1.525	1.554	1.583	1.613	1.643	1.675	1.706
	1.8	*1.7*	*1.7*	*1.7*	*1.9*	*1.7*	*1.8*	*1.9*	*1.9*	*1.9*	*1.9*	*1.9*	*1.9*
Average weekly wages (level $)	913	942	972	1,003	1,036	1,069	1,103	1,139	1,175	1,213	1,253	1,294	1,336
	3.2	*3.2*	*3.2*	*3.2*	*3.2*	*3.2*	*3.2*	*3.2*	*3.2*	*3.2*	*3.2*	*3.2*	*3.2*
Personal income (current $)	30,553	31,484	32,462	33,466	34,508	35,578	36,681	37,788	38,897	40,027	41,203	42,379	43,541
	3.1	*3.0*	*3.1*	*3.1*	*3.1*	*3.1*	*3.1*	*3.0*	*2.9*	*2.9*	*2.9*	*2.9*	*2.7*
Personal disposable income (current $)	23,772	24,462	25,188	25,931	26,705	27,498	28,313	29,124	29,933	30,761	31,618	32,470	33,302
	2.9	*2.9*	*3.0*	*3.0*	*3.0*	*3.0*	*3.0*	*2.9*	*2.8*	*2.8*	*2.8*	*2.7*	*2.6*
Personal savings rate	–2.2	–2.3	–2.4	–2.5	–2.7	–2.8	–3.1	–3.3	–3.5	–3.7	–4.0	–4.3	–4.6
	–1.6	*–5.7*	*–4.2*	*–6.4*	*–5.6*	*–5.3*	*–8.2*	*–7.3*	*–7.3*	*–6.2*	*–6.6*	*–7.6*	*–8.1*
Population (000s)	746	745	744	743	742	741	739	737	735	733	730	728	725
	–0.1	*–0.1*	*–0.1*	*–0.1*	*–0.2*	*–0.2*	*–0.2*	*–0.2*	*–0.3*	*–0.3*	*–0.3*	*–0.4*	*–0.4*
Labour force (000s)	377	373	370	366	363	359	356	352	348	344	340	337	333
	–0.9	*–0.9*	*–1.0*	*–1.0*	*–1.0*	*–1.0*	*–1.0*	*–1.0*	*–1.1*	*–1.1*	*–1.1*	*–1.1*	*–1.1*
Employment (000s)	347	344	341	338	335	332	329	325	322	318	315	311	307
	–0.8	*–0.9*	*–0.9*	*–0.9*	*–1.0*	*–0.9*	*–0.9*	*–1.0*	*–1.1*	*–1.1*	*–1.1*	*–1.1*	*–1.2*
Unemployment rate (percentage)	7.9	7.9	7.8	7.7	7.7	7.6	7.6	7.5	7.6	7.6	7.6	7.6	7.6
Retail sales (current $)	14,238	14,710	15,194	15,705	16,232	16,765	17,290	17,826	18,392	18,965	19,542	20,120	20,695
	3.3	*3.3*	*3.3*	*3.4*	*3.4*	*3.3*	*3.1*	*3.1*	*3.2*	*3.1*	*3.0*	*3.0*	*2.9*
Housing starts (units)	1,264	1,178	1,130	1,075	1,019	954	907	884	831	800	731	669	633
	–5.5	*–6.8*	*–4.2*	*–4.9*	*–5.1*	*–6.4*	*–4.9*	*–2.6*	*–5.9*	*–3.8*	*–8.7*	*–8.4*	*–5.4*

White area represents forecast data.
All data are in millions of dollars, seasonally adjusted at annual rates, unless otherwise specified.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; Canada Mortgage and Housing Corporation.

Table 6—Key Economic Indicators: Quebec
(forecast completed: Dec. 19, 2006)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
GDP at market prices (current $)	276,410	285,454	294,920	308,661	322,658	335,762	349,243	363,913	379,291	393,853	407,070	420,385	435,087
	4.0	*3.3*	*3.3*	*4.7*	*4.5*	*4.1*	*4.0*	*4.2*	*4.2*	*3.8*	*3.4*	*3.3*	*3.5*
GDP at basic prices (current $)	256,937	265,469	274,332	286,960	299,820	311,752	324,018	337,468	351,612	364,891	376,788	388,782	402,117
	4.0	*3.3*	*3.3*	*4.6*	*4.5*	*4.0*	*3.9*	*4.2*	*4.2*	*3.8*	*3.3*	*3.2*	*3.4*
GDP at basic prices (constant 1997 $)	225,078	228,745	233,341	239,994	246,689	252,632	258,752	264,778	271,629	277,991	282,789	287,283	291,644
	2.3	*1.6*	*2.0*	*2.9*	*2.8*	*2.4*	*2.4*	*2.3*	*2.6*	*2.3*	*1.7*	*1.6*	*1.5*
Consumer Price Index (1992=1.0)	1.235	1.258	1.274	1.299	1.327	1.353	1.379	1.407	1.438	1.469	1.501	1.533	1.566
	2.3	*1.9*	*1.3*	*2.0*	*2.1*	*2.0*	*2.0*	*2.0*	*2.2*	*2.2*	*2.2*	*2.1*	*2.1*
Implicit price deflator—	1.141	1.161	1.176	1.196	1.215	1.234	1.252	1.274	1.294	1.313	1.332	1.353	1.379
GDP at basic prices (1997=1.0)	*1.6*	*1.7*	*1.3*	*1.7*	*1.6*	*1.5*	*1.5*	*1.8*	*1.6*	*1.4*	*1.5*	*1.6*	*1.9*
Average weekly wages (level $)	669	690	708	727	745	766	787	812	837	864	892	922	953
	2.8	*3.1*	*2.6*	*2.6*	*2.6*	*2.8*	*2.7*	*3.2*	*3.1*	*3.2*	*3.3*	*3.4*	*3.4*
Personal income (current $)	226,390	237,518	246,618	256,675	266,994	277,593	288,249	300,038	312,183	324,083	336,204	348,575	361,710
	4.0	*4.9*	*3.8*	*4.1*	*4.0*	*4.0*	*3.8*	*4.1*	*4.0*	*3.8*	*3.7*	*3.7*	*3.8*
Personal disposable income (current $)	170,294	178,707	184,947	192,274	199,988	207,613	215,245	223,472	232,021	240,369	248,957	257,877	267,196
	3.0	*4.9*	*3.5*	*4.0*	*4.0*	*3.8*	*3.7*	*3.8*	*3.8*	*3.6*	*3.6*	*3.6*	*3.6*
Personal savings rate	1.0	1.3	1.3	1.2	1.1	0.9	0.8	0.6	0.6	0.7	0.8	1.0	1.1
	–69.9	*26.7*	*2.6*	*–5.5*	*–8.3*	*–20.6*	*–8.5*	*–23.3*	*–2.1*	*5.7*	*21.2*	*23.4*	*16.5*
Population (000s)	7,593	7,641	7,681	7,724	7,766	7,808	7,852	7,897	7,943	7,989	8,037	8,084	8,131
	0.7	*0.6*	*0.5*	*0.6*	*0.5*	*0.5*	*0.6*	*0.6*	*0.6*	*0.6*	*0.6*	*0.6*	*0.6*
Labour force (000s)	4,052	4,097	4,140	4,175	4,204	4,229	4,253	4,270	4,281	4,289	4,296	4,300	4,304
	0.7	*1.1*	*1.1*	*0.8*	*0.7*	*0.6*	*0.6*	*0.4*	*0.3*	*0.2*	*0.2*	*0.1*	*0.1*
Employment (000s)	3,717	3,760	3,797	3,841	3,886	3,919	3,944	3,970	4,001	4,010	4,017	4,019	4,025
	1.0	*1.2*	*1.0*	*1.2*	*1.2*	*0.8*	*0.6*	*0.7*	*0.8*	*0.2*	*0.2*	*0.1*	*0.1*
Unemployment rate (percentage)	8.3	8.2	8.3	8.0	7.5	7.3	7.3	7.0	6.5	6.5	6.5	6.5	6.5
Retail sales (current $)	83,262	87,433	91,883	96,427	101,223	106,134	111,071	116,063	120,982	125,725	130,545	135,463	140,615
	6.0	*5.0*	*5.1*	*4.9*	*5.0*	*4.9*	*4.7*	*4.5*	*4.2*	*3.9*	*3.8*	*3.8*	*3.8*
Housing starts (units)	50,910	44,017	36,412	32,782	31,826	30,555	29,596	29,049	28,863	29,004	29,404	29,467	29,352
	–12.9	*–13.5*	*–17.3*	*–10.0*	*–2.9*	*–4.0*	*–3.1*	*–1.8*	*–0.6*	*0.5*	*1.4*	*0.2*	*–0.4*

White area represents forecast data.
All data are in millions of dollars, seasonally adjusted at annual rates, unless otherwise specified.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; Canada Mortgage and Housing Corporation.

Table 6—Key Economic Indicators: Quebec

(forecast completed: Dec. 19, 2006)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2028	2029	2029	2030
GDP at market prices (current $)	451,702	468,301	485,263	501,935	518,915	536,858	555,657	575,262	595,653	616,580	638,098	659,838	681,523
	3.8	*3.7*	*3.6*	*3.4*	*3.4*	*3.5*	*3.5*	*3.5*	*3.5*	*3.5*	*3.5*	*3.4*	*3.3*
GDP at basic prices (current $)	417,211	432,155	447,427	462,378	477,565	493,600	510,363	527,856	546,071	564,769	583,995	603,392	622,690
	3.8	*3.6*	*3.5*	*3.3*	*3.3*	*3.4*	*3.4*	*3.4*	*3.5*	*3.4*	*3.4*	*3.3*	*3.2*
GDP at basic prices (constant 1997 $)	295,981	300,418	305,371	310,393	315,290	319,631	323,945	328,256	332,593	336,966	341,333	345,672	349,916
	1.5	*1.5*	*1.6*	*1.6*	*1.6*	*1.4*	*1.3*	*1.3*	*1.3*	*1.3*	*1.3*	*1.3*	*1.2*
Consumer Price Index (1992=1.0)	1.600	1.636	1.673	1.711	1.750	1.789	1.831	1.874	1.918	1.964	2.010	2.056	2.101
	2.2	*2.3*	*2.3*	*2.3*	*2.3*	*2.3*	*2.4*	*2.4*	*2.3*	*2.4*	*2.3*	*2.3*	*2.2*
Implicit price deflator—GDP at basic prices (1997=1.0)	1.410	1.438	1.465	1.490	1.515	1.544	1.575	1.608	1.642	1.676	1.711	1.746	1.780
	2.2	*2.1*	*1.9*	*1.7*	*1.7*	*2.0*	*2.0*	*2.1*	*2.1*	*2.1*	*2.1*	*2.0*	*1.9*
Average weekly wages (level $)	986	1,020	1,055	1,091	1,129	1,168	1,208	1,249	1,293	1,337	1,383	1,430	1,479
	3.5	*3.4*	*3.4*	*3.5*	*3.5*	*3.4*	*3.4*	*3.4*	*3.4*	*3.4*	*3.4*	*3.4*	*3.4*
Personal income (current $)	375,400	389,386	404,115	419,333	435,155	451,578	468,574	485,932	503,623	521,805	540,590	559,339	577,775
	3.8	*3.7*	*3.8*	*3.8*	*3.8*	*3.8*	*3.8*	*3.7*	*3.6*	*3.6*	*3.6*	*3.5*	*3.3*
Personal disposable income (current $)	276,676	286,336	296,488	306,960	317,856	329,142	340,785	352,536	364,422	376,650	389,204	401,592	413,594
	3.5	*3.5*	*3.5*	*3.5*	*3.5*	*3.6*	*3.5*	*3.4*	*3.4*	*3.4*	*3.3*	*3.2*	*3.0*
Personal savings rate	1.1	1.1	1.0	0.9	0.8	0.7	0.5	0.3	0.1	–0.1	–0.3	–0.6	–0.9
	0.1	*–7.7*	*–5.6*	*–11.7*	*–12.2*	*–13.8*	*–29.1*	*–41.5*	*–75.1*	*–238.7*	*–216.4*	*–85.8*	*–54.1*
Population (000s)	8,178	8,224	8,270	8,315	8,358	8,400	8,440	8,479	8,516	8,550	8,583	8,613	8,642
	0.6	*0.6*	*0.6*	*0.5*	*0.5*	*0.5*	*0.5*	*0.5*	*0.4*	*0.4*	*0.4*	*0.4*	*0.3*
Labour force (000s)	4,304	4,304	4,303	4,302	4,302	4,301	4,301	4,301	4,301	4,301	4,300	4,298	4,294
	0.0	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*–0.1*
Employment (000s)	4,029	4,029	4,031	4,031	4,029	4,028	4,028	4,027	4,024	4,024	4,024	4,022	4,018
	0.1	*0.0*	*0.1*	*0.0*	*–0.1*	*0.0*	*0.0*	*0.0*	*–0.1*	*0.0*	*0.0*	*0.0*	*–0.1*
Unemployment rate (percentage)	6.4	6.4	6.3	6.3	6.3	6.4	6.3	6.4	6.4	6.4	6.4	6.4	6.4
Retail sales (current $)	146,078	151,739	157,579	163,769	170,189	176,770	183,339	190,127	197,366	204,757	212,188	219,570	226,834
	3.9	*3.9*	*3.8*	*3.9*	*3.9*	*3.9*	*3.7*	*3.7*	*3.8*	*3.7*	*3.6*	*3.5*	*3.3*
Housing starts (units)	29,045	28,555	27,900	27,108	26,218	25,274	24,318	23,384	22,472	21,559	20,630	19,673	18,687
	–1.0	*–1.7*	*–2.3*	*–2.8*	*–3.3*	*–3.6*	*–3.8*	*–3.8*	*–3.9*	*–4.1*	*–4.3*	*–4.6*	*–5.0*

White area represents forecast data.
All data are in millions of dollars, seasonally adjusted at annual rates, unless otherwise specified.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; Canada Mortgage and Housing Corporation.

Table 7—Key Economic Indicators: Ontario
(forecast completed: Dec. 19, 2006)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
GDP at market prices (current $)	538,736	553,414	574,943	604,293	635,240	667,176	699,748	733,749	770,666	808,039	846,110	885,240	925,570
	4.1	*2.7*	*3.9*	*5.1*	*5.1*	*5.0*	*4.9*	*4.9*	*5.0*	*4.8*	*4.7*	*4.6*	*4.6*
GDP at basic prices (current $)	497,560	511,155	531,407	558,404	586,949	616,407	646,408	677,831	712,136	746,796	782,078	818,415	855,853
	4.0	*2.7*	*4.0*	*5.1*	*5.1*	*5.0*	*4.9*	*4.9*	*5.1*	*4.9*	*4.7*	*4.6*	*4.6*
GDP at basic prices (constant 1997 $)	447,338	455,582	466,867	482,250	498,524	515,509	532,650	547,881	566,101	583,238	599,922	616,538	634,874
	3.0	*1.8*	*2.5*	*3.3*	*3.4*	*3.4*	*3.3*	*2.9*	*3.3*	*3.0*	*2.9*	*2.8*	*3.0*
Consumer Price Index (1992=1.0)	1.284	1.309	1.327	1.358	1.389	1.419	1.449	1.481	1.515	1.549	1.584	1.620	1.656
	2.2	*1.9*	*1.4*	*2.3*	*2.4*	*2.1*	*2.1*	*2.2*	*2.3*	*2.3*	*2.3*	*2.3*	*2.3*
Implicit price deflator— GDP at basic prices (1997=1.0)	1.112	1.122	1.138	1.158	1.177	1.196	1.214	1.237	1.258	1.280	1.304	1.327	1.348
	1.0	*0.9*	*1.4*	*1.7*	*1.7*	*1.6*	*1.5*	*1.9*	*1.7*	*1.8*	*1.8*	*1.8*	*1.6*
Average weekly wages (level $)	763	777	795	816	838	861	884	912	942	973	1,005	1,039	1,075
	2.5	*1.8*	*2.3*	*2.7*	*2.7*	*2.7*	*2.7*	*3.2*	*3.3*	*3.3*	*3.3*	*3.4*	*3.4*
Personal income (current $)	419,490	438,717	457,906	478,945	500,951	524,329	548,868	575,749	604,676	633,726	663,264	693,908	726,447
	4.8	*4.6*	*4.4*	*4.6*	*4.6*	*4.7*	*4.7*	*4.9*	*5.0*	*4.8*	*4.7*	*4.6*	*4.7*
Personal disposable income (current $)	320,549	335,387	348,182	363,920	380,956	398,171	416,074	435,240	456,113	476,976	498,340	520,770	544,300
	3.8	*4.6*	*3.8*	*4.5*	*4.7*	*4.5*	*4.5*	*4.6*	*4.8*	*4.6*	*4.5*	*4.5*	*4.5*
Personal savings rate	2.6	3.0	2.9	2.9	2.8	2.6	2.5	2.3	2.3	2.3	2.5	2.7	2.8
	–35.2	*17.1*	*–2.2*	*–2.1*	*–3.1*	*–7.5*	*–3.4*	*–9.5*	*0.4*	*2.4*	*6.7*	*8.1*	*6.6*
Population (000s)	12,537	12,659	12,782	12,924	13,074	13,234	13,401	13,580	13,766	13,958	14,154	14,354	14,557
	1.2	*1.0*	*1.0*	*1.1*	*1.2*	*1.2*	*1.3*	*1.3*	*1.4*	*1.4*	*1.4*	*1.4*	*1.4*
Labour force (000s)	6,848	6,936	7,062	7,182	7,301	7,425	7,541	7,647	7,753	7,858	7,964	8,064	8,157
	1.1	*1.3*	*1.8*	*1.7*	*1.7*	*1.7*	*1.6*	*1.4*	*1.4*	*1.4*	*1.3*	*1.3*	*1.2*
Employment (000s)	6,397	6,488	6,589	6,702	6,815	6,936	7,059	7,174	7,299	7,402	7,496	7,588	7,684
	1.3	*1.4*	*1.6*	*1.7*	*1.7*	*1.8*	*1.8*	*1.6*	*1.7*	*1.4*	*1.3*	*1.2*	*1.3*
Unemployment rate (percentage)	6.6	6.5	6.7	6.7	6.7	6.6	6.4	6.2	5.9	5.8	5.9	5.9	5.8
Retail sales (current $)	135,416	141,308	148,900	157,086	165,866	174,957	184,478	194,063	203,985	213,748	223,597	233,768	244,455
	4.9	*4.4*	*5.4*	*5.5*	*5.6*	*5.5*	*5.4*	*5.2*	*5.1*	*4.8*	*4.6*	*4.5*	*4.6*
Housing starts (units)	78,795	75,758	74,589	75,032	76,465	77,900	79,401	81,522	83,383	85,152	86,721	88,044	89,156
	–7.4	*–3.9*	*–1.5*	*0.6*	*1.9*	*1.9*	*1.9*	*2.7*	*2.3*	*2.1*	*1.8*	*1.5*	*1.3*

White area represents forecast data.
All data are in millions of dollars, seasonally adjusted at annual rates, unless otherwise specified.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; Canada Mortgage and Housing Corporation.

Table 7—Key Economic Indicators: Ontario

(forecast completed: Dec. 19, 2006)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
GDP at market prices (current $)	966,622	1,009,186	1,054,759	1,102,457	1,152,115	1,202,124	1,254,988	1,310,052	1,365,698	1,423,156	1,482,957	1,544,167	1,607,288
	4.4	*4.4*	*4.5*	*4.5*	*4.5*	*4.3*	*4.4*	*4.4*	*4.2*	*4.2*	*4.2*	*4.1*	*4.1*
GDP at basic prices (current $)	893,689	932,753	974,753	1,018,813	1,064,678	1,110,653	1,159,211	1,209,809	1,260,853	1,313,598	1,368,554	1,424,809	1,482,882
	4.4	*4.4*	*4.5*	*4.5*	*4.5*	*4.3*	*4.4*	*4.4*	*4.2*	*4.2*	*4.2*	*4.1*	*4.1*
GDP at basic prices (constant 1997 $)	652,420	670,253	688,001	704,935	721,907	739,441	758,079	778,000	797,477	816,479	836,877	854,936	874,168
	2.8	*2.7*	*2.6*	*2.5*	*2.4*	*2.4*	*2.5*	*2.6*	*2.5*	*2.4*	*2.5*	*2.2*	*2.2*
Consumer Price Index (1992=1.0)	1.693	1.733	1.775	1.819	1.865	1.913	1.962	2.012	2.063	2.116	2.169	2.224	2.277
	2.3	*2.3*	*2.5*	*2.5*	*2.6*	*2.6*	*2.6*	*2.6*	*2.5*	*2.6*	*2.5*	*2.5*	*2.4*
Implicit price deflator— GDP at basic prices (1997=1.0)	1.370	1.392	1.417	1.445	1.475	1.502	1.529	1.555	1.581	1.609	1.635	1.667	1.696
	1.6	*1.6*	*1.8*	*2.0*	*2.0*	*1.8*	*1.8*	*1.7*	*1.7*	*1.8*	*1.6*	*1.9*	*1.8*
Average weekly wages (level $)	1,112	1,150	1,190	1,231	1,274	1,318	1,363	1,410	1,459	1,510	1,562	1,616	1,672
	3.5	*3.4*	*3.4*	*3.5*	*3.5*	*3.5*	*3.5*	*3.5*	*3.5*	*3.5*	*3.5*	*3.5*	*3.5*
Personal income (current $)	759,678	794,427	831,582	870,249	910,599	952,333	996,011	1,041,030	1,086,812	1,134,504	1,184,472	1,235,733	1,288,052
	4.6	*4.6*	*4.7*	*4.6*	*4.6*	*4.6*	*4.6*	*4.5*	*4.4*	*4.4*	*4.4*	*4.3*	*4.2*
Personal disposable income (current $)	567,893	592,479	618,713	645,955	674,351	703,678	734,306	765,576	797,213	830,268	864,765	899,940	935,545
	4.3	*4.3*	*4.4*	*4.4*	*4.4*	*4.3*	*4.4*	*4.3*	*4.1*	*4.1*	*4.2*	*4.1*	*4.0*
Personal savings rate	2.9	2.8	2.8	2.7	2.6	2.5	2.3	2.1	1.9	1.8	1.6	1.3	1.1
	0.6	*–2.5*	*–1.5*	*–3.5*	*–3.4*	*–3.5*	*–7.1*	*–8.0*	*–9.5*	*–7.7*	*–10.6*	*–15.1*	*–21.1*
Population (000s)	14,763	14,970	15,179	15,388	15,598	15,807	16,015	16,222	16,426	16,629	16,828	17,024	17,217
	1.4	*1.4*	*1.4*	*1.4*	*1.4*	*1.3*	*1.3*	*1.3*	*1.3*	*1.2*	*1.2*	*1.2*	*1.1*
Labour force (000s)	8,247	8,335	8,420	8,503	8,584	8,663	8,739	8,812	8,881	8,947	9,011	9,072	9,131
	1.1	*1.1*	*1.0*	*1.0*	*1.0*	*0.9*	*0.9*	*0.8*	*0.8*	*0.7*	*0.7*	*0.7*	*0.6*
Employment (000s)	7,761	7,842	7,932	8,020	8,104	8,183	8,263	8,338	8,397	8,459	8,521	8,579	8,634
	1.0	*1.0*	*1.2*	*1.1*	*1.0*	*1.0*	*1.0*	*0.9*	*0.7*	*0.7*	*0.7*	*0.7*	*0.6*
Unemployment rate (percentage)	5.9	5.9	5.8	5.7	5.6	5.5	5.4	5.4	5.5	5.4	5.4	5.4	5.4
Retail sales (current $)	255,495	267,160	279,414	292,410	305,876	319,607	333,502	347,931	363,163	378,899	395,004	411,479	428,335
	4.5	*4.6*	*4.6*	*4.7*	*4.6*	*4.5*	*4.3*	*4.3*	*4.4*	*4.3*	*4.3*	*4.2*	*4.1*
Housing starts (units)	90,048	90,713	91,149	91,358	91,359	91,180	90,842	90,355	89,721	88,939	87,949	86,846	85,622
	1.0	*0.7*	*0.5*	*0.2*	*0.0*	*–0.2*	*–0.4*	*–0.5*	*–0.7*	*–0.9*	*–1.1*	*–1.3*	*–1.4*

White area represents forecast data.
All data are in millions of dollars, seasonally adjusted at annual rates, unless otherwise specified.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; Canada Mortgage and Housing Corporation.

Table 8—Key Economic Indicators: Manitoba
(forecast completed: Dec. 19, 2006)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
GDP at market prices (current $)	42,028	43,951	45,764	48,105	50,198	52,243	54,735	56,928	59,282	61,677	63,969	66,543	69,257
	4.9	*4.6*	*4.1*	*5.1*	*4.4*	*4.1*	*4.8*	*4.0*	*4.1*	*4.0*	*3.7*	*4.0*	*4.1*
GDP at basic prices (current $)	39,111	40,958	42,680	44,855	46,778	48,647	50,957	52,967	55,137	57,340	59,434	61,810	64,319
	5.2	*4.7*	*4.2*	*5.1*	*4.3*	*4.0*	*4.7*	*3.9*	*4.1*	*4.0*	*3.7*	*4.0*	*4.1*
GDP at basic prices (constant 1997 $)	33,502	34,608	35,595	36,761	37,718	38,604	39,802	40,781	41,788	42,774	43,691	44,769	45,805
	2.9	*3.3*	*2.9*	*3.3*	*2.6*	*2.3*	*3.1*	*2.5*	*2.5*	*2.4*	*2.1*	*2.5*	*2.3*
Consumer Price Index (1992=1.0)	1.312	1.340	1.364	1.389	1.419	1.448	1.477	1.506	1.534	1.563	1.594	1.625	1.656
	2.7	*2.2*	*1.8*	*1.9*	*2.1*	*2.0*	*2.0*	*1.9*	*1.9*	*1.9*	*2.0*	*1.9*	*2.0*
Implicit price deflator—	1.167	1.184	1.199	1.220	1.240	1.260	1.280	1.299	1.319	1.341	1.360	1.381	1.404
GDP at basic prices (1997=1.0)	*2.3*	*1.4*	*1.3*	*1.8*	*1.6*	*1.6*	*1.6*	*1.4*	*1.6*	*1.6*	*1.5*	*1.5*	*1.7*
Average weekly wages (level $)	655	664	680	698	716	734	755	778	801	826	852	881	910
	3.6	*1.3*	*2.5*	*2.6*	*2.7*	*2.5*	*2.8*	*3.1*	*3.1*	*3.1*	*3.2*	*3.3*	*3.3*
Personal income (current $)	33,298	34,710	36,057	37,573	39,129	40,650	42,357	44,174	46,025	47,900	49,829	51,858	54,036
	3.1	*4.2*	*3.9*	*4.2*	*4.1*	*3.9*	*4.2*	*4.3*	*4.2*	*4.1*	*4.0*	*4.1*	*4.2*
Personal disposable income (current $)	25,852	27,012	27,965	29,119	30,338	31,478	32,745	34,069	35,433	36,808	38,238	39,763	41,375
	2.0	*4.5*	*3.5*	*4.1*	*4.2*	*3.8*	*4.0*	*4.0*	*4.0*	*3.9*	*3.9*	*4.0*	*4.1*
Personal savings rate	–1.3	–1.4	–1.7	–1.8	–1.9	–2.2	–2.3	–2.5	–2.5	–2.5	–2.3	–2.2	–2.0
	–193.5	*–4.9*	*–21.2*	*–3.9*	*–7.4*	*–16.3*	*–3.9*	*–8.8*	*–0.7*	*1.4*	*5.8*	*8.1*	*7.7*
Population (000s)	1,174	1,177	1,186	1,195	1,204	1,213	1,223	1,233	1,244	1,256	1,268	1,280	1,293
	0.4	*0.3*	*0.8*	*0.7*	*0.7*	*0.8*	*0.8*	*0.9*	*0.9*	*0.9*	*1.0*	*1.0*	*1.0*
Labour force (000s)	609	614	623	631	639	646	654	660	665	671	676	681	685
	0.0	*0.9*	*1.4*	*1.4*	*1.2*	*1.1*	*1.2*	*0.9*	*0.8*	*0.8*	*0.8*	*0.7*	*0.6*
Employment (000s)	580	587	594	602	609	615	624	630	636	640	644	648	653
	0.6	*1.2*	*1.2*	*1.4*	*1.2*	*1.0*	*1.4*	*1.0*	*0.9*	*0.7*	*0.5*	*0.6*	*0.8*
Unemployment rate (percentage)	4.8	4.4	4.6	4.6	4.6	4.8	4.6	4.5	4.4	4.5	4.7	4.8	4.6
Retail sales (current $)	12,464	13,283	14,072	14,802	15,563	16,297	17,106	17,898	18,665	19,425	20,202	21,017	21,879
	6.6	*6.6*	*5.9*	*5.2*	*5.1*	*4.7*	*5.0*	*4.6*	*4.3*	*4.1*	*4.0*	*4.0*	*4.1*
Housing starts (units)	4,731	5,234	4,589	4,725	4,808	4,867	5,091	5,301	5,502	5,694	5,872	6,032	6,174
	6.6	*10.6*	*–12.3*	*3.0*	*1.8*	*1.2*	*4.6*	*4.1*	*3.8*	*3.5*	*3.1*	*2.7*	*2.4*

White area represents forecast data.
All data are in millions of dollars, seasonally adjusted at annual rates, unless otherwise specified.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; Canada Mortgage and Housing Corporation.

Table 8—Key Economic Indicators: Manitoba

(forecast completed: Dec. 19, 2006)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
GDP at market prices (current $)	72,144	75,065	78,165	81,394	84,757	88,205	91,852	95,622	99,491	103,508	107,668	112,012	116,446
	4.2	*4.0*	*4.1*	*4.1*	*4.1*	*4.1*	*4.1*	*4.1*	*4.0*	*4.0*	*4.0*	*4.0*	*4.0*
GDP at basic prices (current $)	66,978	69,652	72,498	75,469	78,564	81,726	85,068	88,522	92,065	95,748	99,565	103,558	107,635
	4.1	*4.0*	*4.1*	*4.1*	*4.1*	*4.0*	*4.1*	*4.1*	*4.0*	*4.0*	*4.0*	*4.0*	*3.9*
GDP at basic prices (constant 1997 $)	46,827	47,827	48,879	49,975	51,101	52,249	53,421	54,610	55,822	57,051	58,310	59,587	60,889
	2.2	*2.1*	*2.2*	*2.2*	*2.3*	*2.2*	*2.2*	*2.2*	*2.2*	*2.2*	*2.2*	*2.2*	*2.2*
Consumer Price Index (1992=1.0)	1.692	1.727	1.763	1.802	1.840	1.879	1.921	1.963	2.006	2.052	2.098	2.144	2.189
	2.1	*2.1*	*2.1*	*2.2*	*2.1*	*2.1*	*2.2*	*2.2*	*2.2*	*2.3*	*2.2*	*2.2*	*2.1*
Implicit price deflator—	1.430	1.456	1.483	1.510	1.537	1.564	1.592	1.621	1.649	1.678	1.707	1.738	1.768
GDP at basic prices (1997=1.0)	*1.9*	*1.8*	*1.8*	*1.8*	*1.8*	*1.7*	*1.8*	*1.8*	*1.7*	*1.8*	*1.7*	*1.8*	*1.7*
Average weekly wages (level $)	941	973	1,006	1,041	1,076	1,113	1,151	1,191	1,232	1,275	1,319	1,364	1,411
	3.4	*3.4*	*3.4*	*3.4*	*3.4*	*3.4*	*3.4*	*3.4*	*3.4*	*3.5*	*3.5*	*3.5*	*3.5*
Personal income (current $)	56,283	58,592	61,098	63,726	66,454	69,294	72,262	75,335	78,530	81,809	85,227	88,748	92,332
	4.2	*4.1*	*4.3*	*4.3*	*4.3*	*4.3*	*4.3*	*4.3*	*4.2*	*4.2*	*4.2*	*4.1*	*4.0*
Personal disposable income (current $)	43,006	44,682	46,495	48,392	50,362	52,408	54,543	56,748	59,041	61,377	63,800	66,279	68,787
	3.9	*3.9*	*4.1*	*4.1*	*4.1*	*4.1*	*4.1*	*4.0*	*4.0*	*4.0*	*3.9*	*3.9*	*3.8*
Personal savings rate	–2.0	–2.1	–2.1	–2.2	–2.4	–2.5	–2.7	–2.9	–3.1	–3.1	–3.3	–3.6	–3.9
	0.0	*–4.5*	*–2.8*	*–5.4*	*–4.7*	*–4.5*	*–7.9*	*–9.4*	*–6.0*	*–1.3*	*–6.9*	*–7.7*	*–8.8*
Population (000s)	1,306	1,320	1,333	1,347	1,361	1,374	1,388	1,402	1,416	1,430	1,444	1,457	1,471
	1.0	*1.0*	*1.0*	*1.0*	*1.0*	*1.0*	*1.0*	*1.0*	*1.0*	*1.0*	*1.0*	*0.9*	*0.9*
Labour force (000s)	689	694	698	703	707	712	717	721	726	730	735	739	744
	0.6	*0.6*	*0.6*	*0.7*	*0.7*	*0.7*	*0.7*	*0.6*	*0.6*	*0.6*	*0.6*	*0.6*	*0.6*
Employment (000s)	657	660	665	670	675	679	684	688	692	696	700	705	709
	0.6	*0.4*	*0.7*	*0.8*	*0.7*	*0.7*	*0.7*	*0.6*	*0.6*	*0.6*	*0.6*	*0.6*	*0.6*
Unemployment rate (percentage)	4.6	4.8	4.7	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.7	4.7	4.7
Retail sales (current $)	22,780	23,718	24,714	25,780	26,879	28,004	29,137	30,383	31,690	32,896	34,223	35,585	37,001
	4.1	*4.1*	*4.2*	*4.3*	*4.3*	*4.2*	*4.0*	*4.3*	*4.3*	*3.8*	*4.0*	*4.0*	*4.0*
Housing starts (units)	6,298	6,402	6,485	6,548	6,592	6,618	6,629	6,624	6,604	6,572	6,528	6,474	6,412
	2.0	*1.6*	*1.3*	*1.0*	*0.7*	*0.4*	*0.2*	*–0.1*	*–0.3*	*–0.5*	*–0.7*	*–0.8*	*–1.0*

White area represents forecast data.
All data are in millions of dollars, seasonally adjusted at annual rates, unless otherwise specified.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; Canada Mortgage and Housing Corporation.

Table 9—Key Economic Indicators: Saskatchewan

(forecast completed: Dec. 19, 2006)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
GDP at market prices (current $)	42,503	44,166	45,879	47,823	49,860	51,854	53,944	55,988	58,062	60,086	62,216	64,326	66,739
	6.2	*3.9*	*3.9*	*4.2*	*4.3*	*4.0*	*4.0*	*3.8*	*3.7*	*3.5*	*3.5*	*3.4*	*3.8*
GDP at basic prices (current $)	40,696	42,311	43,968	45,809	47,740	49,626	51,603	53,533	55,493	57,397	59,406	61,393	63,679
	6.4	*4.0*	*3.9*	*4.2*	*4.2*	*3.9*	*4.0*	*3.7*	*3.7*	*3.4*	*3.5*	*3.3*	*3.7*
GDP at basic prices (constant 1997 $)	31,719	32,227	33,003	33,780	34,572	35,289	36,076	36,703	37,407	38,054	38,754	39,454	40,161
	3.7	*1.6*	*2.4*	*2.4*	*2.3*	*2.1*	*2.2*	*1.7*	*1.9*	*1.7*	*1.8*	*1.8*	*1.8*
Consumer Price Index (1992=1.0)	1.322	1.354	1.379	1.408	1.438	1.468	1.498	1.525	1.555	1.586	1.617	1.648	1.681
	2.3	*2.4*	*1.9*	*2.0*	*2.2*	*2.0*	*2.0*	*1.8*	*2.0*	*2.0*	*2.0*	*1.9*	*2.0*
Implicit price deflator— **GDP at basic prices** (1997=1.0)	1.283	1.313	1.332	1.356	1.381	1.406	1.430	1.458	1.483	1.508	1.533	1.556	1.586
	2.6	*2.3*	*1.5*	*1.8*	*1.8*	*1.8*	*1.7*	*2.0*	*1.7*	*1.7*	*1.6*	*1.5*	*1.9*
Average weekly wages (level $)	636	660	679	697	716	733	753	776	799	823	850	878	907
	3.4	*3.8*	*2.9*	*2.7*	*2.7*	*2.5*	*2.7*	*3.0*	*3.0*	*3.1*	*3.2*	*3.3*	*3.3*
Personal income (current $)	28,058	29,100	30,133	31,249	32,382	33,482	34,663	35,926	37,189	38,473	39,820	41,192	42,651
	3.1	*3.7*	*3.6*	*3.7*	*3.6*	*3.4*	*3.5*	*3.6*	*3.5*	*3.5*	*3.5*	*3.4*	*3.5*
Personal disposable income (current $)	22,100	22,961	23,673	24,537	25,447	26,283	27,178	28,112	29,058	30,015	31,027	32,077	33,180
	2.3	*3.9*	*3.1*	*3.7*	*3.7*	*3.3*	*3.4*	*3.4*	*3.4*	*3.3*	*3.4*	*3.4*	*3.4*
Personal savings rate	–2.4	–3.0	–3.3	–3.4	–3.5	–3.8	–3.9	–4.2	–4.2	–4.2	–4.0	–3.8	–3.7
	–1,032.2	*–24.9*	*–8.3*	*–3.6*	*–4.2*	*–8.2*	*–2.7*	*–6.2*	*–0.7*	*0.6*	*3.3*	*4.6*	*4.1*
Population (000s)	991	986	985	985	987	988	990	992	995	998	1,001	1,004	1,007
	–0.4	*–0.5*	*–0.1*	*0.1*	*0.1*	*0.2*	*0.2*	*0.2*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*
Labour force (000s)	509	514	519	522	525	528	530	531	531	532	532	531	531
	0.5	*1.0*	*0.8*	*0.6*	*0.6*	*0.5*	*0.4*	*0.2*	*0.1*	*0.1*	*0.0*	*–0.1*	*–0.1*
Employment (000s)	484	489	493	497	500	503	506	508	508	509	509	509	508
	0.8	*1.1*	*0.8*	*0.8*	*0.7*	*0.6*	*0.5*	*0.4*	*0.1*	*0.1*	*0.1*	*–0.1*	*0.0*
Unemployment rate (percentage)	5.1	5.0	5.0	4.8	4.7	4.6	4.5	4.4	4.3	4.3	4.3	4.3	4.2
Retail sales (current $)	11,061	11,847	12,489	13,081	13,697	14,285	14,911	15,519	16,097	16,672	17,273	17,885	18,528
	7.8	*7.1*	*5.4*	*4.7*	*4.7*	*4.3*	*4.4*	*4.1*	*3.7*	*3.6*	*3.6*	*3.5*	*3.6*
Housing starts (units)	3,437	3,380	2,740	2,671	2,640	2,602	2,567	2,526	2,485	2,433	2,404	2,373	2,342
	–9.1	*–1.7*	*–18.9*	*–2.5*	*–1.2*	*–1.4*	*–1.3*	*–1.6*	*–1.6*	*–2.1*	*–1.2*	*–1.3*	*–1.3*

White area represents forecast data.
All data are in millions of dollars, seasonally adjusted at annual rates, unless otherwise specified.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; Canada Mortgage and Housing Corporation.

Table 9—Key Economic Indicators: Saskatchewan

(forecast completed: Dec. 19, 2006)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
GDP at market prices (current $)	69,254	71,801	74,402	77,121	79,983	82,894	85,966	89,158	92,424	95,783	99,244	102,824	106,494
	3.8	*3.7*	*3.6*	*3.7*	*3.7*	*3.6*	*3.7*	*3.7*	*3.7*	*3.6*	*3.6*	*3.6*	*3.6*
GDP at basic prices (current $)	66,052	68,446	70,890	73,449	76,145	78,879	81,761	84,758	87,822	90,974	94,222	97,584	101,033
	3.7	*3.6*	*3.6*	*3.6*	*3.7*	*3.6*	*3.7*	*3.7*	*3.6*	*3.6*	*3.6*	*3.6*	*3.5*
GDP at basic prices (constant 1997 $)	40,845	41,530	42,226	42,939	43,674	44,422	45,181	45,963	46,764	47,570	48,381	49,209	50,062
	1.7	*1.7*	*1.7*	*1.7*	*1.7*	*1.7*	*1.7*	*1.7*	*1.7*	*1.7*	*1.7*	*1.7*	*1.7*
Consumer Price Index (1992=1.0)	1.716	1.752	1.790	1.828	1.868	1.908	1.949	1.993	2.036	2.083	2.129	2.176	2.221
	2.1	*2.1*	*2.2*	*2.2*	*2.2*	*2.2*	*2.2*	*2.3*	*2.2*	*2.3*	*2.2*	*2.2*	*2.1*
Implicit price deflator—GDP at basic prices (1997=1.0)	1.617	1.648	1.679	1.711	1.743	1.776	1.810	1.844	1.878	1.912	1.947	1.983	2.018
	2.0	*1.9*	*1.9*	*1.9*	*1.9*	*1.8*	*1.9*	*1.9*	*1.8*	*1.8*	*1.8*	*1.8*	*1.8*
Average weekly wages (level $)	938	970	1,003	1,038	1,074	1,111	1,150	1,190	1,231	1,274	1,319	1,366	1,414
	3.4	*3.4*	*3.4*	*3.5*	*3.5*	*3.5*	*3.5*	*3.5*	*3.5*	*3.5*	*3.5*	*3.5*	*3.5*
Personal income (current $)	44,170	45,764	47,434	49,160	50,969	52,848	54,812	56,831	58,913	61,067	63,322	65,629	67,970
	3.6	*3.6*	*3.6*	*3.6*	*3.7*	*3.7*	*3.7*	*3.7*	*3.7*	*3.7*	*3.7*	*3.6*	*3.6*
Personal disposable income (current $)	34,302	35,479	36,710	37,984	39,319	40,702	42,145	43,616	45,126	46,690	48,321	49,980	51,647
	3.4	*3.4*	*3.5*	*3.5*	*3.5*	*3.5*	*3.5*	*3.5*	*3.5*	*3.5*	*3.5*	*3.4*	*3.3*
Personal savings rate	–3.7	–3.8	–3.9	–4.0	–4.1	–4.2	–4.4	–4.6	–4.8	–5.0	–5.2	–5.5	–5.8
	–0.2	*–2.7*	*–1.8*	*–3.3*	*–2.9*	*–2.8*	*–4.9*	*–4.4*	*–4.5*	*–3.8*	*–4.3*	*–5.1*	*–5.6*
Population (000s)	1,010	1,014	1,017	1,021	1,025	1,028	1,031	1,035	1,038	1,041	1,044	1,047	1,050
	0.3	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*
Labour force (000s)	530	529	528	527	526	526	525	525	525	525	525	525	525
	–0.2	*–0.2*	*–0.2*	*–0.1*	*–0.1*	*–0.1*	*–0.1*	*0.0*	*0.0*	*0.0*	*0.0*	*0.1*	*–0.2*
Employment (000s)	508	507	507	506	505	504	504	503	503	503	503	503	503
	–0.1	*–0.1*	*–0.1*	*–0.2*	*–0.2*	*–0.1*	*–0.1*	*–0.1*	*–0.1*	*0.0*	*0.0*	*0.0*	*0.0*
Unemployment rate (percentage)	4.2	4.1	4.0	4.1	4.1	4.2	4.1	4.2	4.2	4.2	4.2	4.2	4.2
Retail sales (current $)	19,212	19,940	20,686	21,476	22,298	23,138	23,980	24,856	25,800	26,768	27,755	28,762	29,788
	3.7	*3.8*	*3.7*	*3.8*	*3.8*	*3.8*	*3.6*	*3.7*	*3.8*	*3.8*	*3.7*	*3.6*	*3.6*
Housing starts (units)	2,317	2,292	2,276	2,262	2,256	2,245	2,229	2,207	2,179	2,143	2,099	2,046	1,982
	–1.0	*–1.1*	*–0.7*	*–0.6*	*–0.3*	*–0.5*	*–0.7*	*–1.0*	*–1.3*	*–1.6*	*–2.1*	*–2.6*	*–3.1*

White area represents forecast data.
All data are in millions of dollars, seasonally adjusted at annual rates, unless otherwise specified.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; Canada Mortgage and Housing Corporation.

Table 10—Key Economic Indicators: Alberta

(forecast completed: Dec. 19, 2006)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
GDP at market prices (current $)	215,698	234,984	250,441	266,497	281,823	297,859	314,716	331,788	348,337	364,746	382,791	402,615	420,958
	15.4	*8.9*	*6.6*	*6.4*	*5.8*	*5.7*	*5.7*	*5.4*	*5.0*	*4.7*	*4.9*	*5.2*	*4.6*
GDP at basic prices (current $)	208,413	227,507	242,739	258,379	273,280	288,877	305,280	321,895	337,982	353,911	371,463	390,793	408,624
	15.6	*9.2*	*6.7*	*6.4*	*5.8*	*5.7*	*5.7*	*5.4*	*5.0*	*4.7*	*5.0*	*5.2*	*4.6*
GDP at basic prices (constant 1997 $)	137,471	147,121	154,466	160,904	166,805	173,285	180,279	186,842	192,974	198,636	204,784	211,866	217,330
	4.8	*7.0*	*5.0*	*4.2*	*3.7*	*3.9*	*4.0*	*3.6*	*3.3*	*2.9*	*3.1*	*3.5*	*2.6*
Consumer Price Index (1992=1.0)	1.343	1.400	1.451	1.485	1.519	1.551	1.583	1.617	1.652	1.688	1.725	1.761	1.799
	2.1	*4.2*	*3.7*	*2.4*	*2.3*	*2.1*	*2.1*	*2.1*	*2.2*	*2.2*	*2.2*	*2.1*	*2.1*
Implicit price deflator—	1.515	1.546	1.571	1.606	1.638	1.667	1.693	1.723	1.751	1.782	1.814	1.844	1.880
GDP at basic prices (1997=1.0)	*10.2*	*2.1*	*1.6*	*2.2*	*2.0*	*1.8*	*1.6*	*1.7*	*1.7*	*1.7*	*1.8*	*1.7*	*1.9*
Average weekly wages (level $)	774	808	839	867	897	928	961	996	1,032	1,070	1,113	1,157	1,202
	5.5	*4.4*	*3.8*	*3.4*	*3.4*	*3.5*	*3.5*	*3.7*	*3.6*	*3.7*	*4.0*	*3.9*	*3.9*
Personal income (current $)	122,876	134,804	142,747	151,054	159,495	168,295	177,548	186,752	196,078	205,853	216,185	226,865	237,994
	8.4	*9.7*	*5.9*	*5.8*	*5.6*	*5.5*	*5.5*	*5.2*	*5.0*	*5.0*	*5.0*	*4.9*	*4.9*
Personal disposable income (current $)	94,658	104,855	110,382	116,734	123,373	130,016	137,017	143,805	150,727	157,944	165,632	173,646	181,918
	8.2	*10.8*	*5.3*	*5.8*	*5.7*	*5.4*	*5.4*	*5.0*	*4.8*	*4.8*	*4.9*	*4.8*	*4.8*
Personal savings rate	6.5	7.1	6.6	6.6	6.6	6.5	6.7	6.6	6.6	6.7	6.8	7.0	7.2
	–3.5	*8.3*	*–7.0*	*0.4*	*–0.1*	*–1.7*	*2.7*	*–0.8*	*0.0*	*0.7*	*2.2*	*2.8*	*2.3*
Population (000s)	3,268	3,360	3,426	3,493	3,557	3,618	3,677	3,732	3,789	3,845	3,901	3,958	4,014
	2.1	*2.8*	*2.0*	*2.0*	*1.8*	*1.7*	*1.6*	*1.5*	*1.5*	*1.5*	*1.5*	*1.4*	*1.4*
Labour force (000s)	1,858	1,935	2,007	2,058	2,103	2,145	2,184	2,215	2,245	2,274	2,301	2,327	2,352
	0.8	*4.2*	*3.7*	*2.5*	*2.2*	*2.0*	*1.8*	*1.4*	*1.3*	*1.3*	*1.2*	*1.1*	*1.0*
Employment (000s)	1,784	1,865	1,929	1,979	2,024	2,067	2,109	2,141	2,171	2,200	2,224	2,250	2,274
	1.5	*4.5*	*3.5*	*2.6*	*2.3*	*2.1*	*2.1*	*1.5*	*1.4*	*1.3*	*1.1*	*1.2*	*1.1*
Unemployment rate (percentage)	3.9	3.6	3.9	3.8	3.8	3.7	3.4	3.3	3.3	3.3	3.4	3.3	3.3
Retail sales (current $)	48,758	56,642	60,873	64,881	69,104	73,480	78,012	82,266	86,508	90,916	95,600	100,437	105,451
	12.4	*16.2*	*7.5*	*6.6*	*6.5*	*6.3*	*6.2*	*5.5*	*5.2*	*5.1*	*5.2*	*5.1*	*5.0*
Housing starts (units)	40,847	48,825	41,926	38,758	36,056	34,009	32,469	31,396	30,639	29,832	29,297	28,798	28,341
	12.6	*19.5*	*–14.1*	*–7.6*	*–7.0*	*–5.7*	*–4.5*	*–3.3*	*–2.4*	*–2.6*	*–1.8*	*–1.7*	*–1.6*

White area represents forecast data.
All data are in millions of dollars, seasonally adjusted at annual rates, unless otherwise specified.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; Canada Mortgage and Housing Corporation.

Table 10—Key Economic Indicators: Alberta

(forecast completed: Dec. 19, 2006)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
GDP at market prices (current $)	440,048	459,740	481,166	503,647	527,217	551,589	577,313	604,106	631,623	660,223	690,088	720,974	752,789
	4.5	*4.5*	*4.7*	*4.7*	*4.7*	*4.6*	*4.7*	*4.6*	*4.6*	*4.5*	*4.5*	*4.5*	*4.4*
GDP at basic prices (current $)	427,145	446,218	467,012	488,849	511,748	535,406	560,369	586,372	613,075	640,841	669,848	699,858	730,779
	4.5	*4.5*	*4.7*	*4.7*	*4.7*	*4.6*	*4.7*	*4.6*	*4.6*	*4.5*	*4.5*	*4.5*	*4.4*
GDP at basic prices (constant 1997 $)	222,968	228,411	234,635	241,025	247,596	254,333	261,191	268,204	275,369	282,684	290,153	297,772	305,545
	2.6	*2.4*	*2.7*	*2.7*	*2.7*	*2.7*	*2.7*	*2.7*	*2.7*	*2.7*	*2.6*	*2.6*	*2.6*
Consumer Price Index (1992=1.0)	1.838	1.880	1.922	1.967	2.012	2.059	2.106	2.155	2.204	2.255	2.307	2.360	2.414
	2.2	*2.3*	*2.3*	*2.3*	*2.3*	*2.3*	*2.3*	*2.3*	*2.3*	*2.3*	*2.3*	*2.3*	*2.3*
Implicit price deflator— GDP at basic prices (1997=1.0)	1.916	1.954	1.990	2.028	2.067	2.105	2.145	2.186	2.226	2.267	2.309	2.350	2.392
	1.9	*2.0*	*1.9*	*1.9*	*1.9*	*1.9*	*1.9*	*1.9*	*1.8*	*1.8*	*1.8*	*1.8*	*1.8*
Average weekly wages (level $)	1,250	1,300	1,355	1,410	1,468	1,528	1,591	1,656	1,724	1,795	1,868	1,944	2,023
	4.0	*4.0*	*4.2*	*4.1*	*4.1*	*4.1*	*4.1*	*4.1*	*4.1*	*4.1*	*4.1*	*4.1*	*4.1*
Personal income (current $)	249,801	261,981	275,132	288,673	302,799	317,597	333,112	349,043	365,573	382,844	400,981	419,713	438,982
	5.0	*4.9*	*5.0*	*4.9*	*4.9*	*4.9*	*4.9*	*4.8*	*4.7*	*4.7*	*4.7*	*4.7*	*4.6*
Personal disposable income (current $)	190,558	199,451	209,041	218,893	229,156	239,888	251,114	262,554	274,368	286,729	299,659	312,941	326,515
	4.7	*4.7*	*4.8*	*4.7*	*4.7*	*4.7*	*4.7*	*4.6*	*4.5*	*4.5*	*4.5*	*4.4*	*4.3*
Personal savings rate	7.2	7.1	7.1	7.0	6.9	6.8	6.6	6.5	6.3	6.1	6.0	5.7	5.5
	0.2	*–1.0*	*–0.6*	*–1.3*	*–1.3*	*–1.3*	*–2.5*	*–2.4*	*–2.7*	*–2.4*	*–2.9*	*–3.8*	*–4.6*
Population (000s)	4,069	4,124	4,178	4,231	4,284	4,336	4,388	4,438	4,488	4,537	4,585	4,632	4,679
	1.4	*1.3*	*1.3*	*1.3*	*1.2*	*1.2*	*1.2*	*1.2*	*1.1*	*1.1*	*1.1*	*1.0*	*1.0*
Labour force (000s)	2,375	2,398	2,419	2,439	2,459	2,479	2,498	2,517	2,536	2,554	2,573	2,591	2,610
	1.0	*1.0*	*0.9*	*0.8*	*0.8*	*0.8*	*0.8*	*0.8*	*0.7*	*0.7*	*0.7*	*0.7*	*0.7*
Employment (000s)	2,297	2,317	2,339	2,358	2,377	2,397	2,417	2,434	2,450	2,468	2,486	2,504	2,521
	1.0	*0.9*	*0.9*	*0.8*	*0.8*	*0.8*	*0.8*	*0.7*	*0.7*	*0.7*	*0.7*	*0.7*	*0.7*
Unemployment rate (percentage)	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.4	3.4	3.4	3.4	3.4
Retail sales (current $)	110,881	116,555	122,611	128,959	135,550	142,391	149,368	156,592	164,353	172,427	180,746	189,341	198,226
	5.1	*5.1*	*5.2*	*5.2*	*5.1*	*5.0*	*4.9*	*4.8*	*5.0*	*4.9*	*4.8*	*4.8*	*4.7*
Housing starts (units)	27,927	27,554	27,214	26,901	26,607	26,326	26,049	25,760	25,456	25,142	24,822	24,494	24,159
	–1.5	*–1.3*	*–1.2*	*–1.2*	*–1.1*	*–1.1*	*–1.1*	*–1.1*	*–1.2*	*–1.2*	*–1.3*	*–1.3*	*–1.4*

White area represents forecast data.

All data are in millions of dollars, seasonally adjusted at annual rates, unless otherwise specified.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; Canada Mortgage and Housing Corporation.

Table 11—Key Economic Indicators: British Columbia
(forecast completed: Dec. 19, 2006)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
GDP at market prices (current $)	168,364	177,922	185,612	195,264	204,630	213,921	223,657	232,591	242,510	252,157	261,788	271,683	282,221
	7.0	*5.7*	*4.3*	*5.2*	*4.8*	*4.5*	*4.6*	*4.0*	*4.3*	*4.0*	*3.8*	*3.8*	*3.9*
GDP at basic prices (current $)	154,580	163,775	171,038	179,902	188,463	196,925	205,800	213,871	222,916	231,655	240,352	249,312	258,882
	7.2	*5.9*	*4.4*	*5.2*	*4.8*	*4.5*	*4.5*	*3.9*	*4.2*	*3.9*	*3.8*	*3.7*	*3.8*
GDP at basic prices (constant 1997 $)	132,041	137,220	141,613	145,965	150,203	154,307	158,631	162,090	166,137	169,674	173,137	176,545	179,902
	3.7	*3.9*	*3.2*	*3.1*	*2.9*	*2.7*	*2.8*	*2.2*	*2.5*	*2.1*	*2.0*	*2.0*	*1.9*
Consumer Price Index (1992=1.0)	1.253	1.276	1.299	1.325	1.353	1.379	1.407	1.432	1.462	1.491	1.522	1.553	1.585
	2.0	*1.9*	*1.8*	*2.0*	*2.1*	*2.0*	*2.0*	*1.8*	*2.1*	*2.0*	*2.1*	*2.0*	*2.0*
Implicit price deflator—	1.170	1.194	1.208	1.232	1.255	1.276	1.297	1.319	1.342	1.365	1.388	1.412	1.439
GDP at basic prices (1997=1.0)	*3.3*	*2.0*	*1.2*	*2.0*	*1.8*	*1.7*	*1.7*	*1.7*	*1.7*	*1.8*	*1.7*	*1.7*	*1.9*
Average weekly wages (level $)	699	720	743	762	783	803	824	848	874	902	932	963	995
	2.9	*3.0*	*3.1*	*2.6*	*2.7*	*2.6*	*2.7*	*2.9*	*3.0*	*3.2*	*3.3*	*3.3*	*3.3*
Personal income (current $)	129,446	137,802	143,979	150,392	157,038	163,698	170,906	178,348	186,093	194,273	202,765	211,552	220,697
	5.4	*6.5*	*4.5*	*4.5*	*4.4*	*4.2*	*4.4*	*4.4*	*4.3*	*4.4*	*4.4*	*4.3*	*4.3*
Personal disposable income (current $)	100,488	107,335	111,640	116,558	121,821	126,873	132,323	137,829	143,631	149,721	156,082	162,749	169,613
	5.0	*6.8*	*4.0*	*4.4*	*4.5*	*4.1*	*4.3*	*4.2*	*4.2*	*4.2*	*4.2*	*4.3*	*4.2*
Personal savings rate	–5.9	–4.5	–4.5	–4.6	–4.8	–5.0	–5.2	–5.4	–5.5	–5.4	–5.3	–5.1	–4.9
	–12.9	*24.6*	*–1.5*	*–2.1*	*–2.8*	*–5.9*	*–2.5*	*–5.3*	*–0.4*	*0.7*	*2.8*	*3.7*	*3.4*
Population (000s)	4,251	4,301	4,341	4,385	4,432	4,481	4,531	4,583	4,638	4,693	4,750	4,808	4,866
	1.3	*1.2*	*0.9*	*1.0*	*1.1*	*1.1*	*1.1*	*1.2*	*1.2*	*1.2*	*1.2*	*1.2*	*1.2*
Labour force (000s)	2,263	2,301	2,340	2,373	2,406	2,438	2,468	2,493	2,515	2,538	2,559	2,579	2,597
	1.9	*1.7*	*1.7*	*1.4*	*1.4*	*1.3*	*1.2*	*1.0*	*0.9*	*0.9*	*0.8*	*0.8*	*0.7*
Employment (000s)	2,130	2,192	2,232	2,267	2,299	2,327	2,355	2,377	2,396	2,414	2,433	2,451	2,468
	3.3	*2.9*	*1.8*	*1.6*	*1.4*	*1.2*	*1.2*	*0.9*	*0.8*	*0.8*	*0.8*	*0.7*	*0.7*
Unemployment rate (percentage)	5.9	4.7	4.6	4.5	4.5	4.6	4.6	4.6	4.8	4.9	4.9	4.9	5.0
Retail sales (current $)	50,027	53,576	56,825	59,739	62,838	65,900	69,214	72,364	75,512	78,781	82,154	85,630	89,208
	6.0	*7.1*	*6.1*	*5.1*	*5.2*	*4.9*	*5.0*	*4.6*	*4.3*	*4.3*	*4.3*	*4.2*	*4.2*
Housing starts (units)	34,667	36,711	34,297	33,667	33,015	32,679	32,501	32,678	32,997	33,158	33,260	33,297	33,268
	5.3	*5.9*	*–6.6*	*–1.8*	*–1.9*	*–1.0*	*–0.5*	*0.5*	*1.0*	*0.5*	*0.3*	*0.1*	*–0.1*

White area represents forecast data.
All data are in millions of dollars, seasonally adjusted at annual rates, unless otherwise specified.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; Canada Mortgage and Housing Corporation.

Table 11—Key Economic Indicators: British Columbia

(forecast completed: Dec. 19, 2006)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
GDP at market prices (current $)	293,227	304,835	316,889	329,294	342,278	355,567	369,548	384,083	398,972	414,407	430,215	446,657	463,455
	3.9	*4.0*	*4.0*	*3.9*	*3.9*	*3.9*	*3.9*	*3.9*	*3.9*	*3.9*	*3.8*	*3.8*	*3.8*
GDP at basic prices (current $)	268,811	279,248	290,105	301,293	313,007	324,945	337,485	350,524	363,873	377,731	391,917	406,699	421,808
	3.8	*3.9*	*3.9*	*3.9*	*3.9*	*3.8*	*3.9*	*3.9*	*3.8*	*3.8*	*3.8*	*3.8*	*3.7*
GDP at basic prices (constant 1997 $)	183,257	186,632	190,016	193,465	196,966	200,439	203,914	207,402	210,912	214,458	217,986	221,544	225,178
	1.9	*1.8*	*1.8*	*1.8*	*1.8*	*1.8*	*1.7*	*1.7*	*1.7*	*1.7*	*1.6*	*1.6*	*1.6*
Consumer Price Index (1992=1.0)	1.618	1.653	1.690	1.729	1.769	1.810	1.851	1.894	1.938	1.982	2.028	2.074	2.120
	2.1	*2.1*	*2.2*	*2.3*	*2.3*	*2.3*	*2.3*	*2.3*	*2.3*	*2.3*	*2.3*	*2.3*	*2.2*
Implicit price deflator— **GDP at basic prices** (1997=1.0)	1.467	1.496	1.527	1.557	1.589	1.621	1.655	1.690	1.725	1.761	1.798	1.836	1.873
	1.9	*2.0*	*2.0*	*2.0*	*2.0*	*2.0*	*2.1*	*2.1*	*2.1*	*2.1*	*2.1*	*2.1*	*2.0*
Average weekly wages (level $)	1,028	1,063	1,100	1,138	1,177	1,217	1,258	1,301	1,345	1,391	1,439	1,488	1,539
	3.3	*3.4*	*3.5*	*3.4*	*3.4*	*3.4*	*3.4*	*3.4*	*3.4*	*3.4*	*3.4*	*3.4*	*3.4*
Personal income (current $)	230,174	240,206	250,786	261,706	273,093	284,797	296,945	309,460	322,308	335,654	349,588	363,840	378,330
	4.3	*4.4*	*4.4*	*4.4*	*4.4*	*4.3*	*4.3*	*4.2*	*4.2*	*4.1*	*4.2*	*4.1*	*4.0*
Personal disposable income (current $)	176,596	183,973	191,748	199,758	208,104	216,679	225,562	234,634	243,907	253,553	263,596	273,807	284,105
	4.1	*4.2*	*4.2*	*4.2*	*4.2*	*4.1*	*4.1*	*4.0*	*4.0*	*4.0*	*4.0*	*3.9*	*3.8*
Personal savings rate	–4.9	–5.0	–5.1	–5.2	–5.3	–5.4	–5.6	–5.8	–6.0	–6.2	–6.4	–6.7	–7.0
	0.0	*–1.9*	*–1.2*	*–2.4*	*–2.2*	*–2.1*	*–3.8*	*–3.5*	*–3.6*	*–3.1*	*–3.5*	*–4.2*	*–4.7*
Population (000s)	4,924	4,982	5,041	5,099	5,157	5,214	5,270	5,325	5,379	5,431	5,482	5,532	5,580
	1.2	*1.2*	*1.2*	*1.2*	*1.1*	*1.1*	*1.1*	*1.0*	*1.0*	*1.0*	*0.9*	*0.9*	*0.9*
Labour force (000s)	2,614	2,629	2,645	2,660	2,674	2,688	2,701	2,713	2,724	2,736	2,746	2,756	2,766
	0.7	*0.6*	*0.6*	*0.6*	*0.6*	*0.5*	*0.5*	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*
Employment (000s)	2,484	2,500	2,515	2,529	2,544	2,555	2,566	2,578	2,587	2,598	2,608	2,618	2,627
	0.7	*0.6*	*0.6*	*0.6*	*0.6*	*0.5*	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*
Unemployment rate (percentage)	5.0	4.9	4.9	4.9	4.9	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Retail sales (current $)	92,980	97,040	101,248	105,676	110,256	114,896	119,539	124,357	129,505	134,810	140,231	145,766	151,407
	4.2	*4.4*	*4.3*	*4.4*	*4.3*	*4.2*	*4.0*	*4.0*	*4.1*	*4.1*	*4.0*	*3.9*	*3.9*
Housing starts (units)	33,173	33,012	32,783	32,486	32,122	31,694	31,202	30,644	30,023	29,356	28,655	27,927	27,179
	–0.3	*–0.5*	*–0.7*	*–0.9*	*–1.1*	*–1.3*	*–1.6*	*–1.8*	*–2.0*	*–2.2*	*–2.4*	*–2.5*	*–2.7*

White area represents forecast data.
All data are in millions of dollars, seasonally adjusted at annual rates, unless otherwise specified.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; Canada Mortgage and Housing Corporation.

Table 12—Gross Domestic Product at Basic Prices by Industry—Newfoundland and Labrador

(forecast completed: Dec. 19, 2006)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Agriculture	57	57	58	59	60	61	62	63	64	65	66	67	68
	11.5	*–1.0*	*2.0*	*1.7*	*1.7*	*1.6*	*1.6*	*1.6*	*1.6*	*1.6*	*1.7*	*1.5*	*1.5*
Forestry	76	76	75	76	76	77	78	78	79	79	80	80	81
	0.1	*0.0*	*–1.0*	*1.1*	*1.1*	*0.8*	*0.8*	*0.7*	*0.7*	*0.6*	*0.6*	*0.6*	*0.6*
Fishing & trapping	240	243	248	252	256	260	262	264	265	266	267	267	268
	–12.8	*1.5*	*1.8*	*1.9*	*1.6*	*1.4*	*0.9*	*0.6*	*0.5*	*0.4*	*0.2*	*0.2*	*0.1*
Mining	2,434	2,695	3,312	3,116	2,957	2,790	2,600	2,406	2,277	2,122	1,911	2,006	1,996
	0.6	*10.7*	*22.9*	*–5.9*	*–5.1*	*–5.6*	*–6.8*	*–7.4*	*–5.4*	*–6.8*	*–10.0*	*5.0*	*–0.5*
Manufacturing	906	842	852	876	907	941	970	998	1,029	1,057	1,082	1,108	1,136
	–1.8	*–7.1*	*1.2*	*2.9*	*3.5*	*3.8*	*3.0*	*3.0*	*3.0*	*2.7*	*2.4*	*2.4*	*2.5*
Construction	857	753	707	754	863	987	1,120	1,266	1,268	1,084	1,055	1,159	1,086
	7.6	*–12.2*	*–6.1*	*6.7*	*14.5*	*14.4*	*13.5*	*13.0*	*0.2*	*–14.5*	*–2.6*	*9.9*	*–6.3*
Utilities	432	412	421	433	445	456	466	474	483	491	531	574	591
	5.3	*–4.6*	*2.2*	*2.9*	*2.6*	*2.5*	*2.3*	*1.7*	*1.9*	*1.6*	*8.1*	*8.1*	*3.0*
Goods-producing industries	5,000	5,076	5,672	5,567	5,564	5,572	5,558	5,550	5,465	5,165	4,992	5,262	5,225
	1.0	*1.5*	*11.7*	*–1.8*	*0.0*	*0.1*	*–0.3*	*–0.1*	*–1.5*	*–5.5*	*–3.3*	*5.4*	*–0.7*
Transportation, warehousing & information	1,035	1,059	1,124	1,116	1,119	1,124	1,138	1,144	1,136	1,102	1,078	1,105	1,101
	2.3	*2.4*	*6.1*	*–0.7*	*0.3*	*0.4*	*1.3*	*0.6*	*–0.7*	*–3.0*	*–2.2*	*2.6*	*–0.4*
Wholesale & retail trade	1,261	1,289	1,322	1,359	1,398	1,432	1,462	1,484	1,499	1,504	1,513	1,530	1,544
	1.6	*2.3*	*2.5*	*2.8*	*2.9*	*2.4*	*2.1*	*1.5*	*1.0*	*0.3*	*0.6*	*1.1*	*0.9*
Finance, insurance & real estate	1,979	2,033	2,066	2,097	2,127	2,152	2,172	2,184	2,198	2,212	2,222	2,231	2,241
	1.9	*2.7*	*1.6*	*1.5*	*1.4*	*1.2*	*0.9*	*0.6*	*0.6*	*0.7*	*0.4*	*0.4*	*0.5*
Community, business & personal service	2,894	3,033	3,095	3,157	3,219	3,278	3,339	3,389	3,444	3,494	3,537	3,579	3,621
	–0.6	*4.8*	*2.0*	*2.0*	*1.9*	*1.8*	*1.9*	*1.5*	*1.6*	*1.4*	*1.2*	*1.2*	*1.2*
Public administration & defence	1,115	1,184	1,204	1,220	1,237	1,254	1,273	1,283	1,299	1,315	1,329	1,343	1,357
	0.6	*6.1*	*1.7*	*1.4*	*1.4*	*1.4*	*1.5*	*0.8*	*1.3*	*1.2*	*1.1*	*1.1*	*1.0*
Service-producing industries	8,283	8,598	8,811	8,950	9,100	9,240	9,384	9,485	9,577	9,626	9,679	9,788	9,864
	0.9	*3.8*	*2.5*	*1.6*	*1.7*	*1.5*	*1.6*	*1.1*	*1.0*	*0.5*	*0.5*	*1.1*	*0.8*
All industries	13,630	14,019	14,824	14,858	15,006	15,154	15,284	15,376	15,384	15,133	15,013	15,392	15,431
	0.4	*2.9*	*5.7*	*0.2*	*1.0*	*1.0*	*0.9*	*0.6*	*0.0*	*–1.6*	*–0.8*	*2.5*	*0.2*

White area represents forecast data.
All data are in millions of dollars, seasonally adjusted at annual rates.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; Canada Mortgage and Housing Corporation.

Table 12—Gross Domestic Product at Basic Prices by Industry—Newfoundland and Labrador

(forecast completed: Dec. 19, 2006)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Agriculture	69	70	71	72	73	74	75	76	77	78	79	80	81
	1.4	*1.3*	*1.4*	*1.3*	*1.4*	*1.2*	*1.4*	*1.4*	*1.3*	*1.3*	*1.2*	*1.4*	*1.3*
Forestry	81	82	82	83	83	84	84	85	85	86	86	87	87
	0.6	*0.6*	*0.6*	*0.6*	*0.6*	*0.6*	*0.6*	*0.6*	*0.6*	*0.6*	*0.6*	*0.6*	*0.6*
Fishing & trapping	268	268	268	268	268	268	268	268	268	267	267	265	264
	0.1	*0.1*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*–0.1*	*–0.2*	*–0.3*	*–0.4*	*–0.5*
Mining	2,068	2,097	2,045	1,901	1,722	1,498	1,392	1,275	1,486	1,590	1,618	1,573	1,480
	3.6	*1.4*	*–2.4*	*–7.1*	*–9.4*	*–13.0*	*–7.1*	*–8.5*	*16.6*	*7.0*	*1.7*	*–2.8*	*–5.9*
Manufacturing	1,161	1,188	1,215	1,241	1,268	1,295	1,321	1,350	1,377	1,403	1,429	1,456	1,482
	2.3	*2.3*	*2.3*	*2.2*	*2.2*	*2.1*	*2.1*	*2.1*	*2.0*	*1.9*	*1.9*	*1.8*	*1.8*
Construction	1,083	1,021	1,000	937	906	997	1,000	1,007	934	941	954	968	982
	–0.3	*–5.7*	*–2.0*	*–6.4*	*–3.2*	*10.0*	*0.3*	*0.7*	*–7.3*	*0.7*	*1.4*	*1.4*	*1.4*
Utilities	598	604	610	614	620	625	631	636	642	646	651	654	658
	1.1	*1.1*	*1.0*	*0.7*	*1.0*	*0.8*	*0.9*	*0.9*	*0.8*	*0.7*	*0.7*	*0.5*	*0.5*
Goods-producing industries	5,328	5,329	5,292	5,116	4,940	4,841	4,772	4,697	4,868	5,011	5,083	5,082	5,033
	2.0	*0.0*	*–0.7*	*–3.3*	*–3.4*	*–2.0*	*–1.4*	*–1.6*	*3.7*	*2.9*	*1.4*	*0.0*	*–1.0*
Transportation, warehousing & information	1,114	1,116	1,113	1,095	1,076	1,066	1,061	1,054	1,075	1,092	1,102	1,103	1,099
	1.2	*0.2*	*–0.3*	*–1.7*	*–1.7*	*–0.9*	*–0.5*	*–0.6*	*2.0*	*1.6*	*0.9*	*0.1*	*–0.4*
Wholesale & retail trade	1,556	1,568	1,580	1,590	1,600	1,611	1,623	1,634	1,643	1,653	1,664	1,671	1,679
	0.7	*0.8*	*0.8*	*0.7*	*0.6*	*0.7*	*0.7*	*0.7*	*0.6*	*0.6*	*0.7*	*0.4*	*0.5*
Finance, insurance & real estate	2,254	2,271	2,284	2,297	2,315	2,333	2,345	2,358	2,372	2,386	2,401	2,413	2,427
	0.6	*0.8*	*0.6*	*0.5*	*0.8*	*0.8*	*0.5*	*0.6*	*0.6*	*0.6*	*0.6*	*0.5*	*0.6*
Community, business & personal service	3,658	3,696	3,732	3,767	3,799	3,830	3,862	3,894	3,924	3,951	3,980	4,002	4,025
	1.0	*1.0*	*1.0*	*0.9*	*0.8*	*0.8*	*0.8*	*0.8*	*0.8*	*0.7*	*0.7*	*0.6*	*0.6*
Public administration & defence	1,369	1,381	1,392	1,403	1,414	1,424	1,434	1,444	1,454	1,463	1,472	1,479	1,487
	0.9	*0.9*	*0.8*	*0.8*	*0.8*	*0.7*	*0.7*	*0.7*	*0.7*	*0.6*	*0.6*	*0.5*	*0.5*
Service-producing industries	9,951	10,031	10,102	10,152	10,204	10,264	10,324	10,384	10,468	10,545	10,619	10,669	10,718
	0.9	*0.8*	*0.7*	*0.5*	*0.5*	*0.6*	*0.6*	*0.6*	*0.8*	*0.7*	*0.7*	*0.5*	*0.5*
All industries	15,621	15,702	15,736	15,610	15,486	15,447	15,437	15,423	15,678	15,897	16,044	16,093	16,093
	1.2	*0.5*	*0.2*	*–0.8*	*–0.8*	*–0.2*	*–0.1*	*–0.1*	*1.7*	*1.4*	*0.9*	*0.3*	*0.0*

White area represents forecast data.
All data are in millions of dollars, seasonally adjusted at annual rates.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; Canada Mortgage and Housing Corporation.

Table 13—Gross Domestic Product at Basic Prices by Industry—Prince Edward Island

(forecast completed: Dec. 19, 2006)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Agriculture	120	119	121	124	126	128	131	133	135	137	140	142	145
	–9.5	*–1.0*	*2.0*	*2.1*	*1.9*	*1.8*	*1.7*	*1.8*	*1.7*	*1.6*	*1.8*	*1.7*	*1.7*
Forestry	12	12	12	12	12	12	12	12	13	13	13	13	13
	–2.8	*3.2*	*–0.9*	*1.2*	*1.2*	*1.1*	*0.8*	*0.6*	*0.6*	*0.6*	*0.6*	*0.6*	*0.6*
Fishing & trapping	58	62	63	64	65	66	67	67	67	67	67	66	66
	–7.7	*7.0*	*1.6*	*1.9*	*1.6*	*1.4*	*0.9*	*0.2*	*0.0*	*–0.2*	*–0.3*	*–0.4*	*–0.4*
Mining	2.8	1.1	1.1	1.1	1.1	1.1	1.0	1.0	1.0	1.0	1.0	1.0	0.9
	19.9	*–59.1*	*–2.7*	*–1.9*	*–1.5*	*–1.6*	*–1.5*	*–1.4*	*–1.4*	*–1.5*	*–1.5*	*–1.5*	*–1.5*
Manufacturing	400	403	416	430	447	462	474	484	492	501	510	519	526
	2.9	*0.7*	*3.1*	*3.5*	*4.0*	*3.4*	*2.5*	*2.1*	*1.7*	*1.8*	*1.7*	*1.7*	*1.4*
Construction	170	183	160	154	154	158	164	169	172	175	178	180	182
	4.6	*7.3*	*–12.5*	*–4.0*	*0.5*	*2.4*	*3.9*	*3.0*	*2.0*	*1.8*	*1.5*	*1.2*	*0.8*
Utilities	39	38	39	40	42	43	45	46	47	48	49	51	52
	3.2	*–2.5*	*3.0*	*3.7*	*3.5*	*3.3*	*3.2*	*2.6*	*2.9*	*2.6*	*2.2*	*2.3*	*2.3*
Goods-producing industries	802	818	812	825	848	872	894	912	928	943	957	972	984
	0.3	*2.0*	*–0.7*	*1.7*	*2.8*	*2.8*	*2.5*	*2.1*	*1.7*	*1.6*	*1.5*	*1.5*	*1.3*
Transportation, warehousing & information	210	216	216	220	224	227	229	227	227	228	229	230	230
	2.9	*3.0*	*0.1*	*1.6*	*1.9*	*1.5*	*0.9*	*–0.8*	*0.0*	*0.3*	*0.3*	*0.3*	*0.1*
Wholesale & retail trade	360	348	359	372	384	395	406	415	426	436	445	453	462
	4.1	*–3.5*	*3.2*	*3.6*	*3.2*	*2.9*	*2.8*	*2.3*	*2.6*	*2.4*	*2.0*	*1.9*	*1.9*
Finance, insurance & real estate	621	641	654	667	680	692	701	706	711	718	725	732	740
	3.4	*3.1*	*2.0*	*2.0*	*2.0*	*1.7*	*1.4*	*0.7*	*0.7*	*0.9*	*1.1*	*0.9*	*1.1*
Community, business & personal service	804	821	841	866	890	912	934	951	968	985	1,001	1,018	1,034
	2.8	*2.0*	*2.5*	*2.9*	*2.8*	*2.6*	*2.3*	*1.8*	*1.8*	*1.7*	*1.7*	*1.7*	*1.5*
Public administration & defence	384	388	399	408	417	426	436	444	454	463	472	482	491
	0.7	*1.0*	*2.8*	*2.2*	*2.2*	*2.2*	*2.4*	*1.7*	*2.2*	*2.1*	*2.0*	*2.0*	*1.9*
Service-producing industries	2,380	2,413	2,469	2,532	2,594	2,652	2,707	2,743	2,786	2,830	2,872	2,914	2,956
	2.8	*1.4*	*2.3*	*2.5*	*2.5*	*2.2*	*2.0*	*1.4*	*1.6*	*1.6*	*1.5*	*1.5*	*1.4*
All industries	3,165	3,213	3,263	3,339	3,424	3,505	3,582	3,637	3,695	3,754	3,811	3,867	3,922
	2.0	*1.5*	*1.5*	*2.3*	*2.5*	*2.4*	*2.2*	*1.5*	*1.6*	*1.6*	*1.5*	*1.5*	*1.4*

White area represents forecast data.
All data are in millions of dollars, seasonally adjusted at annual rates.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; Canada Mortgage and Housing Corporation.

Table 13—Gross Domestic Product at Basic Prices by Industry—Prince Edward Island

(forecast completed: Dec. 19, 2006)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Agriculture	147	149	151	154	156	158	160	162	165	167	170	172	175
	1.6	*1.5*	*1.5*	*1.4*	*1.5*	*1.3*	*1.5*	*1.4*	*1.4*	*1.5*	*1.4*	*1.5*	*1.4*
Forestry	13	13	13	13	13	13	13	14	14	14	14	14	14
	0.6	*0.6*	*0.6*	*0.6*	*0.6*	*0.6*	*0.6*	*0.6*	*0.6*	*0.6*	*0.6*	*0.6*	*0.6*
Fishing & trapping	66	65	65	65	64	64	63	63	63	62	62	62	61
	–0.5	*–0.5*	*–0.5*	*–0.6*	*–0.6*	*–0.6*	*–0.6*	*–0.6*	*–0.6*	*–0.6*	*–0.6*	*–0.6*	*–0.6*
Mining	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.8	0.8	0.8	0.8	0.8	0.8
	–1.5	*–1.5*	*–1.3*	*–1.5*	*–1.5*	*–1.5*	*–1.5*	*–1.4*	*–1.4*	*–1.4*	*–1.4*	*–1.4*	*–1.4*
Manufacturing	533	540	547	554	562	571	579	586	594	602	609	618	626
	1.3	*1.2*	*1.4*	*1.4*	*1.4*	*1.5*	*1.4*	*1.3*	*1.3*	*1.3*	*1.2*	*1.4*	*1.4*
Construction	182	183	184	184	184	184	184	184	185	185	185	185	185
	0.5	*0.4*	*0.3*	*0.2*	*0.1*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.1*	*0.0*	*0.0*
Utilities	53	54	55	56	57	58	59	60	61	62	64	65	66
	2.0	*2.1*	*2.0*	*1.7*	*2.0*	*1.9*	*1.9*	*1.9*	*1.9*	*1.8*	*1.8*	*1.6*	*1.6*
Goods-producing industries	995	1,005	1,016	1,027	1,038	1,049	1,060	1,071	1,082	1,093	1,103	1,115	1,127
	1.1	*1.0*	*1.1*	*1.0*	*1.1*	*1.1*	*1.1*	*1.0*	*1.0*	*1.0*	*0.9*	*1.1*	*1.0*
Transportation, warehousing & information	230	230	231	231	232	233	234	235	235	236	237	238	239
	0.0	*0.1*	*0.2*	*0.3*	*0.3*	*0.4*	*0.4*	*0.3*	*0.3*	*0.3*	*0.2*	*0.4*	*0.4*
Wholesale & retail trade	471	480	489	499	508	518	528	538	547	557	567	576	586
	1.9	*1.9*	*1.9*	*2.0*	*1.9*	*1.9*	*1.9*	*1.9*	*1.8*	*1.7*	*1.8*	*1.7*	*1.6*
Finance, insurance & real estate	750	759	768	777	786	795	805	814	823	833	842	851	861
	1.3	*1.3*	*1.2*	*1.1*	*1.2*	*1.2*	*1.2*	*1.2*	*1.1*	*1.1*	*1.1*	*1.1*	*1.1*
Community, business & personal service	1,049	1,064	1,081	1,097	1,113	1,130	1,147	1,165	1,182	1,199	1,216	1,233	1,250
	1.5	*1.5*	*1.5*	*1.5*	*1.5*	*1.5*	*1.5*	*1.5*	*1.5*	*1.4*	*1.4*	*1.4*	*1.4*
Public administration & defence	500	509	518	528	537	546	555	565	575	585	594	604	613
	1.8	*1.8*	*1.8*	*1.8*	*1.8*	*1.7*	*1.7*	*1.7*	*1.7*	*1.7*	*1.7*	*1.5*	*1.6*
Service-producing industries	2,999	3,043	3,087	3,131	3,176	3,222	3,269	3,316	3,363	3,409	3,456	3,502	3,548
	1.4	*1.5*	*1.4*	*1.4*	*1.4*	*1.4*	*1.5*	*1.4*	*1.4*	*1.4*	*1.4*	*1.3*	*1.3*
All industries	3,975	4,029	4,084	4,140	4,195	4,253	4,311	4,369	4,426	4,484	4,541	4,598	4,656
	1.4	*1.4*	*1.4*	*1.4*	*1.3*	*1.4*	*1.4*	*1.3*	*1.3*	*1.3*	*1.3*	*1.3*	*1.3*

White area represents forecast data.
All data are in millions of dollars, seasonally adjusted at annual rates.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; Canada Mortgage and Housing Corporation.

Table 14—Gross Domestic Product at Basic Prices by Industry—Nova Scotia

(forecast completed: Dec. 19, 2006)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Agriculture	234	232	237	242	247	251	255	260	264	269	273	278	283
	5.4	*–1.0*	*2.0*	*2.2*	*1.9*	*1.8*	*1.7*	*1.8*	*1.7*	*1.6*	*1.7*	*1.7*	*1.7*
Forestry	196	191	189	191	194	196	198	199	199	200	200	199	198
	–6.9	*–2.8*	*–0.7*	*1.2*	*1.3*	*1.1*	*0.9*	*0.5*	*0.3*	*0.1*	*0.0*	*–0.3*	*–0.4*
Fishing & trapping	268	286	291	296	300	305	308	310	312	313	314	314	315
	–10.6	*6.8*	*1.5*	*1.8*	*1.5*	*1.4*	*1.0*	*0.8*	*0.6*	*0.3*	*0.3*	*0.1*	*0.2*
Mining	455	439	474	482	475	443	465	541	533	501	468	453	454
	8.4	*–3.5*	*8.1*	*1.7*	*–1.4*	*–6.7*	*4.9*	*16.4*	*–1.5*	*–6.0*	*–6.7*	*–3.1*	*0.2*
Manufacturing	2,399	2,396	2,452	2,530	2,624	2,725	2,819	2,889	2,959	3,032	3,104	3,164	3,208
	0.7	*–0.1*	*2.3*	*3.2*	*3.7*	*3.9*	*3.4*	*2.5*	*2.4*	*2.5*	*2.4*	*1.9*	*1.4*
Construction	1,396	1,471	1,350	1,253	1,241	1,205	1,211	1,282	1,315	1,319	1,309	1,290	1,277
	0.3	*5.3*	*–8.2*	*–7.2*	*–0.9*	*–2.9*	*0.4*	*5.9*	*2.6*	*0.4*	*–0.8*	*–1.4*	*–1.0*
Utilities	547	501	533	553	569	585	601	613	627	639	650	660	671
	0.5	*–8.4*	*6.5*	*3.7*	*3.0*	*2.8*	*2.7*	*2.1*	*2.3*	*1.9*	*1.6*	*1.6*	*1.6*
Goods-producing industries	5,496	5,515	5,526	5,547	5,651	5,711	5,856	6,094	6,210	6,273	6,318	6,359	6,406
	0.4	*0.4*	*0.2*	*0.4*	*1.9*	*1.1*	*2.5*	*4.1*	*1.9*	*1.0*	*0.7*	*0.7*	*0.7*
Transportation, warehousing & information	2,099	2,127	2,133	2,148	2,179	2,201	2,235	2,269	2,284	2,292	2,300	2,298	2,292
	2.5	*1.3*	*0.3*	*0.7*	*1.4*	*1.0*	*1.5*	*1.5*	*0.6*	*0.4*	*0.3*	*–0.1*	*–0.3*
Wholesale & retail trade	2,770	2,874	2,962	3,048	3,130	3,206	3,288	3,343	3,404	3,452	3,491	3,526	3,565
	3.0	*3.8*	*3.1*	*2.9*	*2.7*	*2.4*	*2.5*	*1.7*	*1.8*	*1.4*	*1.1*	*1.0*	*1.1*
Finance, insurance & real estate	5,059	5,227	5,345	5,446	5,554	5,656	5,750	5,803	5,855	5,917	5,985	6,038	6,072
	2.1	*3.3*	*2.3*	*1.9*	*2.0*	*1.8*	*1.7*	*0.9*	*0.9*	*1.0*	*1.2*	*0.9*	*0.6*
Community, business & personal service	5,638	5,771	5,929	6,076	6,220	6,361	6,501	6,597	6,702	6,802	6,899	6,979	7,042
	1.7	*2.4*	*2.7*	*2.5*	*2.4*	*2.3*	*2.2*	*1.5*	*1.6*	*1.5*	*1.4*	*1.2*	*0.9*
Public administration & defence	2,398	2,477	2,551	2,596	2,642	2,688	2,738	2,768	2,813	2,854	2,893	2,931	2,967
	0.8	*3.3*	*3.0*	*1.8*	*1.8*	*1.7*	*1.9*	*1.1*	*1.6*	*1.5*	*1.4*	*1.3*	*1.2*
Service-producing industries	17,963	18,476	18,920	19,314	19,725	20,112	20,512	20,780	21,058	21,317	21,568	21,773	21,939
	2.0	*2.9*	*2.4*	*2.1*	*2.1*	*2.0*	*2.0*	*1.3*	*1.3*	*1.2*	*1.2*	*0.9*	*0.8*
All industries	23,361	23,883	24,334	24,749	25,264	25,711	26,256	26,762	27,155	27,478	27,774	28,020	28,233
	1.7	*2.2*	*1.9*	*1.7*	*2.1*	*1.8*	*2.1*	*1.9*	*1.5*	*1.2*	*1.1*	*0.9*	*0.8*

White area represents forecast data.
All data are in millions of dollars, seasonally adjusted at annual rates.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; Canada Mortgage and Housing Corporation.

Table 14—Gross Domestic Product at Basic Prices by Industry—Nova Scotia
(forecast completed: Dec. 19, 2006)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Agriculture	287	292	297	301	306	311	315	320	325	330	335	341	346
	1.7	*1.7*	*1.6*	*1.5*	*1.6*	*1.5*	*1.5*	*1.6*	*1.5*	*1.6*	*1.5*	*1.6*	*1.5*
Forestry	197	195	192	189	185	181	177	173	169	165	160	156	152
	–0.7	*–1.0*	*–1.3*	*–1.7*	*–1.9*	*–2.2*	*–2.3*	*–2.4*	*–2.4*	*–2.5*	*–2.5*	*–2.6*	*–2.7*
Fishing & trapping	315	315	315	315	315	315	315	315	315	314	313	312	311
	0.1	*0.1*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*–0.1*	*–0.2*	*–0.3*	*–0.4*	*–0.5*
Mining	455	463	434	394	395	396	397	398	399	400	401	403	404
	0.2	*1.8*	*–6.4*	*–9.1*	*0.3*	*0.2*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*
Manufacturing	3,247	3,268	3,310	3,356	3,386	3,413	3,438	3,464	3,505	3,525	3,536	3,551	3,564
	1.2	*0.7*	*1.3*	*1.4*	*0.9*	*0.8*	*0.7*	*0.8*	*1.2*	*0.6*	*0.3*	*0.4*	*0.4*
Construction	1,248	1,244	1,238	1,225	1,215	1,203	1,188	1,171	1,151	1,132	1,127	1,123	1,125
	–2.3	*–0.3*	*–0.5*	*–1.0*	*–0.8*	*–1.0*	*–1.2*	*–1.4*	*–1.8*	*–1.7*	*–0.4*	*–0.3*	*0.2*
Utilities	680	689	698	704	713	721	730	739	747	755	763	770	776
	1.3	*1.4*	*1.3*	*1.0*	*1.2*	*1.1*	*1.2*	*1.2*	*1.1*	*1.0*	*1.1*	*0.9*	*0.9*
Goods-producing industries	6,428	6,467	6,483	6,486	6,517	6,541	6,562	6,581	6,611	6,622	6,636	6,656	6,678
	0.4	*0.6*	*0.3*	*0.0*	*0.5*	*0.4*	*0.3*	*0.3*	*0.5*	*0.2*	*0.2*	*0.3*	*0.3*
Transportation, warehousing & information	2,280	2,267	2,257	2,249	2,239	2,228	2,216	2,203	2,199	2,183	2,165	2,150	2,135
	–0.5	*–0.6*	*–0.5*	*–0.3*	*–0.5*	*–0.5*	*–0.5*	*–0.6*	*–0.2*	*–0.7*	*–0.8*	*–0.7*	*–0.7*
Wholesale & retail trade	3,603	3,641	3,680	3,719	3,757	3,797	3,838	3,880	3,918	3,954	3,997	4,034	4,072
	1.1	*1.1*	*1.1*	*1.1*	*1.0*	*1.1*	*1.1*	*1.1*	*1.0*	*0.9*	*1.1*	*0.9*	*0.9*
Finance, insurance & real estate	6,118	6,140	6,167	6,200	6,220	6,245	6,269	6,298	6,340	6,367	6,392	6,419	6,448
	0.8	*0.3*	*0.4*	*0.5*	*0.3*	*0.4*	*0.4*	*0.5*	*0.7*	*0.4*	*0.4*	*0.4*	*0.5*
Community, business & personal service	7,101	7,146	7,204	7,268	7,313	7,359	7,405	7,451	7,508	7,546	7,581	7,611	7,640
	0.8	*0.6*	*0.8*	*0.9*	*0.6*	*0.6*	*0.6*	*0.6*	*0.8*	*0.5*	*0.5*	*0.4*	*0.4*
Public administration & defence	3,001	3,035	3,069	3,103	3,136	3,167	3,199	3,231	3,265	3,296	3,328	3,356	3,384
	1.1	*1.1*	*1.1*	*1.1*	*1.1*	*1.0*	*1.0*	*1.0*	*1.0*	*1.0*	*1.0*	*0.8*	*0.9*
Service-producing industries	22,103	22,229	22,377	22,538	22,666	22,796	22,927	23,063	23,229	23,346	23,463	23,570	23,679
	0.7	*0.6*	*0.7*	*0.7*	*0.6*	*0.6*	*0.6*	*0.6*	*0.7*	*0.5*	*0.5*	*0.5*	*0.5*
All industries	28,420	28,584	28,748	28,912	29,071	29,225	29,377	29,532	29,729	29,856	29,987	30,114	30,245
	0.7	*0.6*	*0.6*	*0.6*	*0.5*	*0.5*	*0.5*	*0.5*	*0.7*	*0.4*	*0.4*	*0.4*	*0.4*

White area represents forecast data.
All data are in millions of dollars, seasonally adjusted at annual rates.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; Canada Mortgage and Housing Corporation.

Table 15—Gross Domestic Product at Basic Prices by Industry—New Brunswick
(forecast completed: Dec. 19, 2006)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Agriculture	507	502	512	523	533	543	551	561	570	580	591	601	612
	10.3	*–1.0*	*2.0*	*2.1*	*1.9*	*1.8*	*1.6*	*1.8*	*1.6*	*1.7*	*1.9*	*1.7*	*1.8*
Forestry	423	447	445	450	456	460	462	464	465	465	465	463	460
	–11.4	*5.9*	*–0.6*	*1.2*	*1.3*	*0.8*	*0.6*	*0.4*	*0.2*	*0.0*	*0.0*	*–0.4*	*–0.7*
Fishing & trapping	95	101	103	104	106	107	108	108	108	108	108	107	107
	–10.1	*6.3*	*1.5*	*1.7*	*1.4*	*1.4*	*1.0*	*0.1*	*–0.1*	*–0.3*	*–0.4*	*–0.4*	*–0.5*
Mining	218	220	247	288	272	250	254	258	263	268	272	277	282
	5.4	*0.7*	*12.3*	*16.8*	*–5.8*	*–8.2*	*1.8*	*1.7*	*1.7*	*1.8*	*1.8*	*1.8*	*1.8*
Manufacturing	2,798	2,831	2,892	3,034	3,173	3,310	3,434	3,536	3,604	3,661	3,720	3,777	3,824
	–5.7	*1.2*	*2.2*	*4.9*	*4.6*	*4.3*	*3.7*	*3.0*	*1.9*	*1.6*	*1.6*	*1.5*	*1.2*
Construction	1,235	1,318	1,327	1,271	1,266	1,245	1,254	1,235	1,214	1,201	1,199	1,200	1,203
	–2.0	*6.7*	*0.7*	*–4.2*	*–0.4*	*–1.6*	*0.7*	*–1.5*	*–1.7*	*–1.1*	*–0.2*	*0.0*	*0.3*
Utilities	592	526	555	576	594	610	626	638	652	664	674	684	693
	0.4	*–11.2*	*5.6*	*3.7*	*3.0*	*2.8*	*2.6*	*2.0*	*2.2*	*1.8*	*1.5*	*1.5*	*1.4*
Goods-producing industries	5,869	5,945	6,082	6,248	6,400	6,525	6,690	6,802	6,876	6,947	7,028	7,108	7,181
	–3.3	*1.3*	*2.3*	*2.7*	*2.4*	*2.0*	*2.5*	*1.7*	*1.1*	*1.0*	*1.2*	*1.1*	*1.0*
Transportation, warehousing & information	1,916	1,970	2,006	2,047	2,088	2,125	2,152	2,165	2,171	2,173	2,178	2,181	2,181
	1.8	*2.8*	*1.8*	*2.1*	*2.0*	*1.8*	*1.2*	*0.6*	*0.3*	*0.1*	*0.2*	*0.1*	*0.0*
Wholesale & retail trade	2,124	2,191	2,280	2,346	2,415	2,483	2,541	2,579	2,622	2,659	2,690	2,719	2,751
	2.7	*3.2*	*4.0*	*2.9*	*2.9*	*2.8*	*2.4*	*1.5*	*1.7*	*1.4*	*1.2*	*1.1*	*1.2*
Finance, insurance & real estate	3,410	3,513	3,588	3,655	3,730	3,803	3,854	3,896	3,921	3,943	3,969	3,992	4,010
	2.6	*3.0*	*2.1*	*1.9*	*2.0*	*2.0*	*1.3*	*1.1*	*0.6*	*0.6*	*0.7*	*0.6*	*0.4*
Community, business & personal service	4,156	4,238	4,331	4,437	4,548	4,664	4,760	4,842	4,910	4,964	5,014	5,059	5,097
	1.4	*2.0*	*2.2*	*2.4*	*2.5*	*2.5*	*2.1*	*1.7*	*1.4*	*1.1*	*1.0*	*0.9*	*0.8*
Public administration & defence	1,770	1,805	1,844	1,875	1,906	1,937	1,971	1,991	2,021	2,048	2,073	2,097	2,120
	2.0	*2.0*	*2.1*	*1.7*	*1.7*	*1.6*	*1.8*	*1.0*	*1.5*	*1.3*	*1.2*	*1.2*	*1.1*
Service-producing industries	13,376	13,718	14,048	14,360	14,687	15,012	15,279	15,472	15,644	15,788	15,924	16,048	16,159
	2.0	*2.6*	*2.4*	*2.2*	*2.3*	*2.2*	*1.8*	*1.3*	*1.1*	*0.9*	*0.9*	*0.8*	*0.7*
All industries	19,210	19,619	20,083	20,560	21,040	21,490	21,922	22,227	22,474	22,688	22,906	23,109	23,293
	0.5	*2.1*	*2.4*	*2.4*	*2.3*	*2.1*	*2.0*	*1.4*	*1.1*	*1.0*	*1.0*	*0.9*	*0.8*

White area represents forecast data.
All data are in millions of dollars, seasonally adjusted at annual rates.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; Canada Mortgage and Housing Corporation.

Table 15—Gross Domestic Product at Basic Prices by Industry—New Brunswick

(forecast completed: Dec. 19, 2006)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2028	2030
Agriculture	623	633	643	654	664	674	684	695	706	717	729	742	754
	1.8	*1.6*	*1.6*	*1.7*	*1.5*	*1.5*	*1.5*	*1.6*	*1.6*	*1.6*	*1.7*	*1.7*	*1.6*
Forestry	457	454	451	448	445	441	438	435	432	429	426	423	420
	–0.7	*–0.7*	*–0.7*	*–0.7*	*–0.7*	*–0.7*	*–0.7*	*–0.7*	*–0.7*	*–0.7*	*–0.7*	*–0.7*	*–0.7*
Fishing & trapping	106	106	105	104	104	103	102	102	101	101	100	99	99
	–0.5	*–0.5*	*–0.6*	*–0.6*	*–0.6*	*–0.6*	*–0.6*	*–0.6*	*–0.6*	*–0.6*	*–0.6*	*–0.6*	*–0.6*
Mining	287	292	297	302	308	313	318	323	329	334	340	346	352
	1.8	*1.7*	*1.7*	*1.7*	*1.7*	*1.7*	*1.7*	*1.7*	*1.7*	*1.7*	*1.7*	*1.7*	*1.7*
Manufacturing	3,874	3,941	3,992	4,043	4,093	4,142	4,189	4,229	4,270	4,305	4,339	4,379	4,413
	1.3	*1.7*	*1.3*	*1.3*	*1.2*	*1.2*	*1.1*	*1.0*	*1.0*	*0.8*	*0.8*	*0.9*	*0.8*
Construction	1,204	1,204	1,209	1,214	1,219	1,223	1,229	1,238	1,244	1,250	1,251	1,252	1,259
	0.0	*0.0*	*0.4*	*0.5*	*0.4*	*0.3*	*0.5*	*0.8*	*0.4*	*0.5*	*0.1*	*0.1*	*0.6*
Utilities	702	710	718	723	731	738	746	754	761	768	775	780	786
	1.2	*1.2*	*1.1*	*0.8*	*1.1*	*1.0*	*1.0*	*1.1*	*1.0*	*0.9*	*0.9*	*0.7*	*0.7*
Goods-producing industries	7,252	7,339	7,414	7,489	7,563	7,634	7,707	7,777	7,843	7,905	7,961	8,022	8,082
	1.0	*1.2*	*1.0*	*1.0*	*1.0*	*1.0*	*0.9*	*0.9*	*0.9*	*0.8*	*0.7*	*0.8*	*0.7*
Transportation, warehousing & information	2,183	2,196	2,198	2,203	2,206	2,211	2,214	2,214	2,213	2,211	2,208	2,207	2,204
	0.1	*0.6*	*0.1*	*0.2*	*0.1*	*0.2*	*0.2*	*0.0*	*0.0*	*–0.1*	*–0.1*	*0.0*	*–0.2*
Wholesale & retail trade	2,782	2,815	2,847	2,879	2,910	2,941	2,973	3,005	3,033	3,058	3,087	3,111	3,135
	1.1	*1.2*	*1.1*	*1.1*	*1.1*	*1.1*	*1.1*	*1.1*	*0.9*	*0.8*	*0.9*	*0.8*	*0.8*
Finance, insurance & real estate	4,036	4,067	4,083	4,098	4,114	4,132	4,150	4,168	4,186	4,202	4,222	4,240	4,258
	0.7	*0.8*	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*0.5*	*0.4*	*0.4*
Community, business & personal service	5,136	5,184	5,219	5,254	5,285	5,317	5,349	5,377	5,404	5,426	5,449	5,470	5,487
	0.8	*0.9*	*0.7*	*0.7*	*0.6*	*0.6*	*0.6*	*0.5*	*0.5*	*0.4*	*0.4*	*0.4*	*0.3*
Public administration & defence	2,140	2,161	2,182	2,202	2,222	2,241	2,259	2,279	2,298	2,317	2,336	2,351	2,368
	1.0	*1.0*	*1.0*	*0.9*	*0.9*	*0.8*	*0.8*	*0.9*	*0.9*	*0.8*	*0.8*	*0.7*	*0.7*
Service-producing industries	16,279	16,424	16,529	16,637	16,738	16,841	16,946	17,043	17,134	17,214	17,302	17,379	17,452
	0.7	*0.9*	*0.6*	*0.7*	*0.6*	*0.6*	*0.6*	*0.6*	*0.5*	*0.5*	*0.5*	*0.4*	*0.4*
All inudstries	23,484	23,716	23,896	24,079	24,254	24,429	24,606	24,773	24,930	25,072	25,215	25,354	25,486
	0.8	*1.0*	*0.8*	*0.8*	*0.7*	*0.7*	*0.7*	*0.7*	*0.6*	*0.6*	*0.6*	*0.5*	*0.5*

White area represents forecast data.
All data are in millions of dollars, seasonally adjusted at annual rates.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; Canada Mortgage and Housing Corporation.

Table 16—Gross Domestic Product at Basic Prices by Industry—Quebec
(forecast completed: Dec. 19, 2006)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Agriculture	2,914	2,839	2,900	2,955	3,014	3,080	3,148	3,217	3,288	3,367	3,448	3,530	3,612
	2.2	*–2.6*	*2.1*	*1.9*	*2.0*	*2.2*	*2.2*	*2.2*	*2.2*	*2.4*	*2.4*	*2.4*	*2.3*
Forestry	1,669	1,657	1,548	1,572	1,597	1,611	1,623	1,631	1,634	1,632	1,624	1,611	1,595
	–4.2	*–0.7*	*–6.6*	*1.6*	*1.6*	*0.9*	*0.7*	*0.5*	*0.2*	*–0.1*	*–0.5*	*–0.8*	*–1.0*
Fishing & trapping	74	79	80	81	82	83	83	84	84	85	85	85	85
	–13.8	*7.1*	*1.5*	*1.0*	*0.8*	*1.4*	*0.8*	*0.7*	*0.5*	*0.3*	*0.1*	*0.2*	*0.1*
Mining	1,152	1,161	1,221	1,306	1,451	1,486	1,484	1,485	1,487	1,489	1,490	1,492	1,493
	–13.7	*0.8*	*5.1*	*7.0*	*11.1*	*2.4*	*–0.2*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*
Manufacturing	47,256	47,705	48,704	50,556	52,619	54,673	56,948	59,227	61,652	63,966	65,707	67,443	69,004
	0.7	*0.9*	*2.1*	*3.8*	*4.1*	*3.9*	*4.2*	*4.0*	*4.1*	*3.8*	*2.7*	*2.6*	*2.3*
Construction	12,846	12,734	12,568	12,591	12,820	12,825	12,844	13,140	13,428	13,603	13,595	13,548	13,690
	0.6	*–0.9*	*–1.3*	*0.2*	*1.8*	*0.0*	*0.2*	*2.3*	*2.2*	*1.3*	*–0.1*	*–0.3*	*1.0*
Utilities	8,250	8,304	8,579	8,894	9,198	9,492	9,781	10,032	10,313	10,565	10,789	11,019	11,251
	4.0	*0.7*	*3.3*	*3.7*	*3.4*	*3.2*	*3.0*	*2.6*	*2.8*	*2.4*	*2.1*	*2.1*	*2.1*
Goods-producing industries	74,160	74,479	75,599	77,954	80,780	83,250	85,911	88,816	91,886	94,706	96,738	98,728	100,731
	0.7	*0.4*	*1.5*	*3.1*	*3.6*	*3.1*	*3.2*	*3.4*	*3.5*	*3.1*	*2.1*	*2.1*	*2.0*
Transportation, warehousing & information	20,132	20,379	20,605	21,092	21,600	22,010	22,439	22,889	23,442	23,960	24,259	24,507	24,745
	3.6	*1.2*	*1.1*	*2.4*	*2.4*	*1.9*	*1.9*	*2.0*	*2.4*	*2.2*	*1.2*	*1.0*	*1.0*
Wholesale & retail trade	27,386	28,432	29,481	30,451	31,299	32,094	32,871	33,556	34,388	35,086	35,688	36,268	36,909
	5.6	*3.8*	*3.7*	*3.3*	*2.8*	*2.5*	*2.4*	*2.1*	*2.5*	*2.0*	*1.7*	*1.6*	*1.8*
Finance, insurance & real estate	38,471	39,574	40,383	41,213	41,891	42,412	42,857	43,226	43,744	44,309	44,699	44,997	45,200
	3.3	*2.9*	*2.0*	*2.1*	*1.6*	*1.2*	*1.0*	*0.9*	*1.2*	*1.3*	*0.9*	*0.7*	*0.4*
Community, business & personal service	51,399	52,164	53,304	54,972	56,456	57,845	59,259	60,629	62,170	63,612	64,779	65,854	66,831
	1.9	*1.5*	*2.2*	*3.1*	*2.7*	*2.5*	*2.4*	*2.3*	*2.5*	*2.3*	*1.8*	*1.7*	*1.5*
Public administration & defence	13,447	13,726	14,012	14,355	14,707	15,064	15,459	15,706	16,043	16,361	16,668	16,972	17,271
	0.1	*2.1*	*2.1*	*2.4*	*2.4*	*2.4*	*2.6*	*1.6*	*2.1*	*2.0*	*1.9*	*1.8*	*1.8*
Service-producing industries	150,835	154,275	157,785	162,083	165,952	169,425	172,884	176,004	179,786	183,328	186,093	188,598	190,956
	3.0	*2.3*	*2.3*	*2.7*	*2.4*	*2.1*	*2.0*	*1.8*	*2.1*	*2.0*	*1.5*	*1.3*	*1.3*
All industries	225,078	228,745	233,341	239,994	246,689	252,632	258,752	264,778	271,629	277,991	282,789	287,283	291,644
	2.3	*1.6*	*2.0*	*2.9*	*2.8*	*2.4*	*2.4*	*2.3*	*2.6*	*2.3*	*1.7*	*1.6*	*1.5*

White area represents forecast data.
All data are in millions of dollars, seasonally adjusted at annual rates.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; Canada Mortgage and Housing Corporation.

Table 16—Gross Domestic Product at Basic Prices by Industry—Quebec
(forecast completed: Dec. 19, 2006)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Agriculture	3,695	3,781	3,871	3,964	4,063	4,162	4,262	4,364	4,464	4,572	4,677	4,789	4,904
	2.3	*2.3*	*2.4*	*2.4*	*2.5*	*2.4*	*2.4*	*2.4*	*2.3*	*2.4*	*2.3*	*2.4*	*2.4*
Forestry	1,573	1,544	1,512	1,479	1,447	1,414	1,382	1,349	1,316	1,284	1,251	1,219	1,186
	–1.4	*–1.8*	*–2.1*	*–2.2*	*–2.2*	*–2.3*	*–2.3*	*–2.4*	*–2.4*	*–2.5*	*–2.5*	*–2.6*	*–2.7*
Fishing & trapping	85	85	85	85	85	85	85	85	85	85	85	84	84
	0.1	*0.1*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*–0.1*	*–0.2*	*–0.3*	*–0.4*	*–0.5*
Mining	1,495	1,497	1,499	1,501	1,503	1,504	1,506	1,509	1,511	1,513	1,515	1,517	1,519
	0.1	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.2*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*
Manufacturing	70,355	71,721	73,410	75,259	77,087	78,564	79,954	81,297	82,681	84,064	85,379	86,785	88,142
	2.0	*1.9*	*2.4*	*2.5*	*2.4*	*1.9*	*1.8*	*1.7*	*1.7*	*1.7*	*1.6*	*1.6*	*1.6*
Construction	14,013	14,220	14,408	14,321	14,181	14,133	14,093	14,162	14,233	14,307	14,383	14,439	14,495
	2.4	*1.5*	*1.3*	*–0.6*	*–1.0*	*–0.3*	*–0.3*	*0.5*	*0.5*	*0.5*	*0.5*	*0.4*	*0.4*
Utilities	11,462	11,678	11,888	12,134	12,350	12,558	12,778	13,003	13,224	13,435	13,652	13,847	14,049
	1.9	*1.9*	*1.8*	*2.1*	*1.8*	*1.7*	*1.7*	*1.8*	*1.7*	*1.6*	*1.6*	*1.4*	*1.5*
Goods-producing industries	102,678	104,526	106,673	108,743	110,715	112,420	114,061	115,769	117,514	119,259	120,942	122,680	124,380
	1.9	*1.8*	*2.1*	*1.9*	*1.8*	*1.5*	*1.5*	*1.5*	*1.5*	*1.5*	*1.4*	*1.4*	*1.4*
Transportation, warehousing & information	24,959	25,211	25,539	25,901	26,253	26,512	26,759	26,975	27,191	27,422	27,642	27,894	28,119
	0.9	*1.0*	*1.3*	*1.4*	*1.4*	*1.0*	*0.9*	*0.8*	*0.8*	*0.8*	*0.8*	*0.9*	*0.8*
Wholesale & retail trade	37,540	38,186	38,826	39,467	40,107	40,763	41,437	42,123	42,777	43,408	44,069	44,636	45,182
	1.7	*1.7*	*1.7*	*1.7*	*1.6*	*1.6*	*1.7*	*1.7*	*1.6*	*1.5*	*1.5*	*1.3*	*1.2*
Finance, insurance & real estate	45,530	45,917	46,351	46,816	47,266	47,645	48,030	48,412	48,804	49,228	49,661	50,105	50,552
	0.7	*0.9*	*0.9*	*1.0*	*1.0*	*0.8*	*0.8*	*0.8*	*0.8*	*0.9*	*0.9*	*0.9*	*0.9*
Community, business & personal service	67,761	68,770	69,881	71,071	72,260	73,311	74,388	75,402	76,422	77,461	78,520	79,573	80,604
	1.4	*1.5*	*1.6*	*1.7*	*1.7*	*1.5*	*1.5*	*1.4*	*1.4*	*1.4*	*1.4*	*1.3*	*1.3*
Public administration & defence	17,557	17,850	18,144	18,439	18,732	19,022	19,314	19,617	19,927	20,230	20,540	20,826	21,122
	1.7	*1.7*	*1.6*	*1.6*	*1.6*	*1.5*	*1.5*	*1.6*	*1.6*	*1.5*	*1.5*	*1.4*	*1.4*
Service-producing industries	193,346	195,935	198,741	201,693	204,618	207,254	209,927	212,530	215,121	217,749	220,432	223,034	225,580
	1.3	*1.3*	*1.4*	*1.5*	*1.5*	*1.3*	*1.3*	*1.2*	*1.2*	*1.2*	*1.2*	*1.2*	*1.1*
All industries	295,981	300,418	305,371	310,393	315,290	319,631	323,945	328,256	332,593	336,966	341,333	345,672	349,916
	1.5	*1.5*	*1.6*	*1.6*	*1.6*	*1.4*	*1.3*	*1.3*	*1.3*	*1.3*	*1.3*	*1.3*	*1.2*

White area represents forecast data.
All data are in millions of dollars, seasonally adjusted at annual rates.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; Canada Mortgage and Housing Corporation.

Table 17—Gross Domestic Product at Basic Prices by Industry—Ontario

(forecast completed: Dec. 19, 2006)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Agriculture	4,040	3,992	4,073	4,151	4,234	4,327	4,426	4,524	4,628	4,734	4,843	4,955	5,069
	4.2	*–1.2*	*2.0*	*1.9*	*2.0*	*2.2*	*2.3*	*2.2*	*2.3*	*2.3*	*2.3*	*2.3*	*2.3*
Forestry	1,016	1,067	1,028	1,042	1,058	1,072	1,082	1,089	1,091	1,090	1,086	1,078	1,070
	6.3	*5.0*	*–3.7*	*1.4*	*1.5*	*1.3*	*1.0*	*0.6*	*0.2*	*–0.1*	*–0.4*	*–0.7*	*–0.7*
Fishing & trapping	16.3	17.4	17.5	17.6	17.6	17.8	18.0	18.1	18.2	18.2	18.3	18.3	18.3
	–10.0	*7.1*	*0.4*	*0.2*	*0.1*	*1.4*	*0.8*	*0.7*	*0.5*	*0.3*	*0.2*	*0.2*	*0.1*
Mining	2,885	2,789	2,826	2,865	2,898	2,915	2,933	2,948	2,965	2,982	3,000	3,018	3,037
	–1.9	*–3.3*	*1.3*	*1.4*	*1.1*	*0.6*	*0.6*	*0.5*	*0.6*	*0.6*	*0.6*	*0.6*	*0.6*
Manufacturing	93,749	93,029	95,217	99,139	103,511	108,222	113,023	117,570	122,963	128,069	133,209	138,385	144,061
	2.1	*–0.8*	*2.4*	*4.1*	*4.4*	*4.6*	*4.4*	*4.0*	*4.6*	*4.2*	*4.0*	*3.9*	*4.1*
Construction	22,799	23,525	23,852	24,552	25,415	26,378	27,324	28,100	28,939	29,732	30,478	31,150	31,731
	2.5	*3.2*	*1.4*	*2.9*	*3.5*	*3.8*	*3.6*	*2.8*	*3.0*	*2.7*	*2.5*	*2.2*	*1.9*
Utilities	10,268	10,433	10,762	11,219	11,671	12,125	12,580	13,001	13,470	13,909	14,319	14,744	15,180
	2.7	*1.6*	*3.2*	*4.2*	*4.0*	*3.9*	*3.8*	*3.4*	*3.6*	*3.3*	*2.9*	*3.0*	*3.0*
Goods-producing industries	134,775	134,853	137,777	142,985	148,805	155,057	161,387	167,251	174,075	180,535	186,953	193,348	200,165
	2.2	*0.1*	*2.2*	*3.8*	*4.1*	*4.2*	*4.1*	*3.6*	*4.1*	*3.7*	*3.6*	*3.4*	*3.5*
Transportation, warehousing & information	36,762	37,234	37,861	38,974	40,065	41,192	42,294	43,359	44,682	45,932	47,145	48,286	49,710
	3.7	*1.3*	*1.7*	*2.9*	*2.8*	*2.8*	*2.7*	*2.5*	*3.1*	*2.8*	*2.6*	*2.4*	*3.0*
Wholesale & retail trade	56,795	59,444	61,799	64,169	66,365	68,587	70,791	72,702	75,100	77,229	79,108	80,992	83,024
	5.8	*4.7*	*4.0*	*3.8*	*3.4*	*3.3*	*3.2*	*2.7*	*3.3*	*2.8*	*2.4*	*2.4*	*2.5*
Finance, insurance & real estate	98,036	100,736	102,855	105,204	107,750	110,380	112,999	115,134	117,917	120,588	123,217	125,856	128,955
	3.3	*2.8*	*2.1*	*2.3*	*2.4*	*2.4*	*2.4*	*1.9*	*2.4*	*2.3*	*2.2*	*2.1*	*2.5*
Community, business & personal service	98,934	100,944	103,602	107,244	111,133	115,121	119,160	122,798	126,902	130,760	134,543	138,328	142,516
	1.8	*2.0*	*2.6*	*3.5*	*3.6*	*3.6*	*3.5*	*3.1*	*3.3*	*3.0*	*2.9*	*2.8*	*3.0*
Public administration & defence	21,844	22,364	23,035	23,733	24,466	25,233	26,079	26,698	27,485	28,254	29,017	29,789	30,564
	2.1	*2.4*	*3.0*	*3.0*	*3.1*	*3.1*	*3.4*	*2.4*	*2.9*	*2.8*	*2.7*	*2.7*	*2.6*
Service-producing industries	312,371	320,722	329,150	339,325	349,779	360,513	371,323	380,691	392,086	402,762	413,029	423,250	434,769
	3.2	*2.7*	*2.6*	*3.1*	*3.1*	*3.1*	*3.0*	*2.5*	*3.0*	*2.7*	*2.5*	*2.5*	*2.7*
All industries	447,338	455,582	466,867	482,250	498,524	515,509	532,650	547,881	566,101	583,238	599,922	616,538	634,874
	3.0	*1.8*	*2.5*	*3.3*	*3.4*	*3.4*	*3.3*	*2.9*	*3.3*	*3.0*	*2.9*	*2.8*	*3.0*

White area represents forecast data.
All data are in millions of dollars, seasonally adjusted at annual rates.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; Canada Mortgage and Housing Corporation.

Table 17—Gross Domestic Product at Basic Prices by Industry—Ontario

(forecast completed: Dec. 19, 2006)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Agriculture	5,185	5,304	5,433	5,563	5,697	5,835	5,975	6,125	6,271	6,422	6,583	6,747	6,916
	2.3	*2.3*	*2.4*	*2.4*	*2.4*	*2.4*	*2.4*	*2.5*	*2.4*	*2.4*	*2.5*	*2.5*	*2.5*
Forestry	1,062	1,054	1,046	1,038	1,030	1,022	1,014	1,006	998	990	982	974	967
	–0.7	*–0.7*	*–0.8*	*–0.8*	*–0.8*	*–0.8*	*–0.8*	*–0.8*	*–0.8*	*–0.8*	*–0.8*	*–0.8*	*–0.8*
Fishing & trapping	18.3	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.3	18.3	18.3	18.2	18.1
	0.1	*0.1*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*–0.1*	*–0.2*	*–0.3*	*–0.4*	*–0.5*
Mining	3,055	3,074	3,092	3,111	3,130	3,150	3,170	3,191	3,212	3,233	3,255	3,277	3,299
	0.6	*0.6*	*0.6*	*0.6*	*0.6*	*0.6*	*0.6*	*0.6*	*0.7*	*0.7*	*0.7*	*0.7*	*0.7*
Manufacturing	149,502	154,842	160,224	165,087	170,036	175,309	181,075	187,327	193,663	199,958	206,655	212,492	218,856
	3.8	*3.6*	*3.5*	*3.0*	*3.0*	*3.1*	*3.3*	*3.5*	*3.4*	*3.3*	*3.3*	*2.8*	*3.0*
Construction	32,275	32,832	33,476	34,112	34,738	35,362	35,988	36,621	37,255	37,898	38,548	39,130	39,746
	1.7	*1.7*	*2.0*	*1.9*	*1.8*	*1.8*	*1.8*	*1.8*	*1.7*	*1.7*	*1.7*	*1.5*	*1.6*
Utilities	15,593	16,019	16,443	16,826	17,269	17,707	18,167	18,641	19,114	19,578	20,056	20,508	20,973
	2.7	*2.7*	*2.6*	*2.3*	*2.6*	*2.5*	*2.6*	*2.6*	*2.5*	*2.4*	*2.4*	*2.2*	*2.3*
Goods-producing industries	206,690	213,144	219,733	225,757	231,919	238,403	245,408	252,928	260,531	268,098	276,098	283,146	290,775
	3.3	*3.1*	*3.1*	*2.7*	*2.7*	*2.8*	*2.9*	*3.1*	*3.0*	*2.9*	*3.0*	*2.6*	*2.7*
Transportation, warehousing & information	51,022	52,361	53,641	54,803	55,921	57,115	58,429	59,871	61,201	62,424	63,821	64,887	66,058
	2.6	*2.6*	*2.4*	*2.2*	*2.0*	*2.1*	*2.3*	*2.5*	*2.2*	*2.0*	*2.2*	*1.7*	*1.8*
Wholesale & retail trade	84,936	86,959	89,034	91,118	93,196	95,282	97,440	99,656	101,771	103,868	106,089	108,178	110,344
	2.3	*2.4*	*2.4*	*2.3*	*2.3*	*2.2*	*2.3*	*2.3*	*2.1*	*2.1*	*2.1*	*2.0*	*2.0*
Finance, insurance & real estate	131,907	135,008	137,956	140,882	143,824	146,761	149,860	153,238	156,458	159,565	162,957	165,962	169,169
	2.3	*2.4*	*2.2*	*2.1*	*2.1*	*2.0*	*2.1*	*2.3*	*2.1*	*2.0*	*2.1*	*1.8*	*1.9*
Community, business & personal service	146,597	150,724	154,779	158,702	162,552	166,556	170,777	175,269	179,582	183,694	188,165	192,136	196,284
	2.9	*2.8*	*2.7*	*2.5*	*2.4*	*2.5*	*2.5*	*2.6*	*2.5*	*2.3*	*2.4*	*2.1*	*2.2*
Public administration & defence	31,328	32,116	32,918	33,733	34,556	35,384	36,225	37,098	37,995	38,890	39,808	40,688	41,598
	2.5	*2.5*	*2.5*	*2.5*	*2.4*	*2.4*	*2.4*	*2.4*	*2.4*	*2.4*	*2.4*	*2.2*	*2.2*
Service-producing industries	445,790	457,169	468,328	479,239	490,048	501,098	512,732	525,132	537,007	548,441	560,839	571,850	583,454
	2.5	*2.6*	*2.4*	*2.3*	*2.3*	*2.3*	*2.3*	*2.4*	*2.3*	*2.1*	*2.3*	*2.0*	*2.0*
All industries	652,420	670,253	688,001	704,935	721,907	739,441	758,079	778,000	797,477	816,479	836,877	854,936	874,168
	2.8	*2.7*	*2.6*	*2.5*	*2.4*	*2.4*	*2.5*	*2.6*	*2.5*	*2.4*	*2.5*	*2.2*	*2.2*

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For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada, Statistics Canada; Canada Mortgage and Housing Corporation.

Table 18—Gross Domestic Product at Basic Prices by Industry—Manitoba

(forecast completed: Dec. 19, 2006)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Agriculture	1,390	1,496	1,535	1,572	1,606	1,640	1,674	1,710	1,745	1,780	1,816	1,854	1,895
	–15.3	*7.7*	*2.6*	*2.4*	*2.2*	*2.1*	*2.1*	*2.1*	*2.1*	*2.0*	*2.0*	*2.1*	*2.2*
Forestry	76	74	73	75	76	77	78	78	78	78	78	77	77
	–1.7	*–1.8*	*–1.2*	*1.8*	*1.8*	*1.2*	*0.8*	*0.5*	*0.1*	*–0.1*	*–0.3*	*–0.3*	*–0.3*
Fishing & trapping	9.4	10.1	10.1	10.3	10.4	10.5	10.6	10.7	10.7	10.7	10.8	10.8	10.8
	–2.6	*7.1*	*0.7*	*1.4*	*0.9*	*1.4*	*0.8*	*0.6*	*0.5*	*0.3*	*0.2*	*0.2*	*0.1*
Mining	566	650	660	701	705	709	713	718	723	728	733	737	742
	2.7	*14.8*	*1.5*	*6.2*	*0.6*	*0.5*	*0.5*	*0.7*	*0.7*	*0.7*	*0.7*	*0.6*	*0.6*
Manufacturing	4,155	4,172	4,297	4,460	4,650	4,852	5,067	5,264	5,474	5,667	5,839	6,112	6,327
	1.4	*0.4*	*3.0*	*3.8*	*4.2*	*4.4*	*4.4*	*3.9*	*4.0*	*3.5*	*3.0*	*4.7*	*3.5*
Construction	1,530	1,816	1,950	2,114	2,139	2,102	2,274	2,384	2,438	2,495	2,545	2,505	2,550
	4.7	*18.7*	*7.4*	*8.4*	*1.2*	*–1.7*	*8.2*	*4.9*	*2.3*	*2.3*	*2.0*	*–1.6*	*1.8*
Utilities	1,233	1,247	1,288	1,337	1,385	1,433	1,480	1,532	1,580	1,624	1,664	1,706	1,749
	29.3	*1.2*	*3.3*	*3.8*	*3.6*	*3.4*	*3.3*	*3.5*	*3.1*	*2.8*	*2.5*	*2.5*	*2.5*
Goods-producing industries	8,959	9,465	9,814	10,269	10,572	10,823	11,295	11,696	12,049	12,382	12,685	13,002	13,352
	1.9	*5.7*	*3.7*	*4.6*	*2.9*	*2.4*	*4.4*	*3.6*	*3.0*	*2.8*	*2.4*	*2.5*	*2.7*
Transportation, warehousing & information	3,672	3,804	3,897	4,025	4,110	4,185	4,312	4,397	4,491	4,578	4,653	4,780	4,885
	4.4	*3.6*	*2.4*	*3.3*	*2.1*	*1.8*	*3.0*	*2.0*	*2.1*	*1.9*	*1.6*	*2.7*	*2.2*
Wholesale & retail trade	4,400	4,454	4,604	4,766	4,911	5,041	5,187	5,305	5,439	5,558	5,662	5,769	5,888
	6.2	*1.2*	*3.4*	*3.5*	*3.0*	*2.7*	*2.9*	*2.3*	*2.5*	*2.2*	*1.9*	*1.9*	*2.1*
Finance, insurance & real estate	6,655	6,883	7,020	7,152	7,286	7,421	7,549	7,643	7,743	7,883	8,025	8,189	8,328
	2.9	*3.4*	*2.0*	*1.9*	*1.9*	*1.9*	*1.7*	*1.2*	*1.3*	*1.8*	*1.8*	*2.0*	*1.7*
Community, business & personal service	7,645	7,786	7,980	8,208	8,439	8,671	8,926	9,157	9,417	9,659	9,887	10,187	10,445
	1.3	*1.9*	*2.5*	*2.9*	*2.8*	*2.7*	*2.9*	*2.6*	*2.8*	*2.6*	*2.4*	*3.0*	*2.5*
Public administration & defence	2,281	2,341	2,411	2,470	2,531	2,593	2,662	2,712	2,779	2,843	2,907	2,972	3,037
	0.6	*2.6*	*3.0*	*2.4*	*2.5*	*2.5*	*2.6*	*1.9*	*2.5*	*2.3*	*2.2*	*2.2*	*2.2*
Service-producing industries	24,653	25,267	25,911	26,621	27,276	27,911	28,636	29,214	29,868	30,521	31,135	31,896	32,583
	3.0	*2.5*	*2.5*	*2.7*	*2.5*	*2.3*	*2.6*	*2.0*	*2.2*	*2.2*	*2.0*	*2.4*	*2.2*
All industries	33,502	34,608	35,595	36,761	37,718	38,604	39,802	40,781	41,788	42,774	43,691	44,769	45,805
	2.9	*3.3*	*2.9*	*3.3*	*2.6*	*2.3*	*3.1*	*2.5*	*2.5*	*2.4*	*2.1*	*2.5*	*2.3*

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Sources: The Conference Board of Canada; Statistics Canada; Canada Mortgage and Housing Corporation.

Table 18—Gross Domestic Product at Basic Prices by Industry—Manitoba

(forecast completed: Dec. 19, 2006)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Agriculture	1,933	1,973	2,015	2,059	2,102	2,145	2,192	2,238	2,287	2,338	2,387	2,439	2,491
	2.0	*2.1*	*2.1*	*2.2*	*2.1*	*2.0*	*2.2*	*2.1*	*2.2*	*2.2*	*2.1*	*2.2*	*2.1*
Forestry	77	77	76	76	76	76	75	75	75	75	74	74	74
	–0.3	*–0.3*	*–0.3*	*–0.3*	*–0.3*	*–0.3*	*–0.3*	*–0.3*	*–0.3*	*–0.3*	*–0.3*	*–0.3*	*–0.3*
Fishing & trapping	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.7	10.7
	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	–0.1	–0.2	–0.3	–0.4	–0.5
Mining	746	751	755	759	764	768	772	777	781	785	790	794	798
	0.6	*0.6*	*0.6*	*0.6*	*0.6*	*0.6*	*0.6*	*0.6*	*0.6*	*0.6*	*0.5*	*0.6*	*0.5*
Manufacturing	6,542	6,748	6,939	7,127	7,344	7,559	7,773	7,995	8,223	8,453	8,680	8,921	9,164
	3.4	*3.2*	*2.8*	*2.7*	*3.1*	*2.9*	*2.8*	*2.8*	*2.9*	*2.8*	*2.7*	*2.8*	*2.7*
Construction	2,560	2,549	2,603	2,657	2,711	2,765	2,818	2,873	2,926	2,979	3,033	3,085	3,139
	0.4	*–0.4*	*2.1*	*2.1*	*2.0*	*2.0*	*1.9*	*1.9*	*1.8*	*1.8*	*1.8*	*1.7*	*1.8*
Utilities	1,790	1,832	1,921	2,039	2,086	2,132	2,181	2,232	2,282	2,332	2,383	2,431	2,481
	2.3	*2.3*	*4.9*	*6.2*	*2.3*	*2.2*	*2.3*	*2.3*	*2.3*	*2.2*	*2.2*	*2.0*	*2.0*
Goods-producing industries	13,658	13,941	14,320	14,728	15,094	15,456	15,823	16,200	16,585	16,971	17,358	17,755	18,157
	2.3	*2.1*	*2.7*	*2.8*	*2.5*	*2.4*	*2.4*	*2.4*	*2.4*	*2.3*	*2.3*	*2.3*	*2.3*
Transportation, warehousing & information	4,986	5,086	5,182	5,282	5,403	5,526	5,651	5,774	5,900	6,029	6,159	6,299	6,437
	2.1	*2.0*	*1.9*	*1.9*	*2.3*	*2.3*	*2.3*	*2.2*	*2.2*	*2.2*	*2.1*	*2.3*	*2.2*
Wholesale & retail trade	6,002	6,120	6,244	6,370	6,495	6,621	6,753	6,885	7,013	7,142	7,278	7,407	7,539
	1.9	*2.0*	*2.0*	*2.0*	*2.0*	*1.9*	*2.0*	*2.0*	*1.9*	*1.8*	*1.9*	*1.8*	*1.8*
Finance, insurance & real estate	8,500	8,660	8,788	8,922	9,083	9,258	9,433	9,609	9,791	9,981	10,179	10,383	10,597
	2.1	*1.9*	*1.5*	*1.5*	*1.8*	*1.9*	*1.9*	*1.9*	*1.9*	*1.9*	*2.0*	*2.0*	*2.1*
Community, business & personal service	10,711	10,984	11,241	11,500	11,784	12,076	12,377	12,684	12,999	13,317	13,646	13,977	14,314
	2.5	*2.5*	*2.3*	*2.3*	*2.5*	*2.5*	*2.5*	*2.5*	*2.5*	*2.4*	*2.5*	*2.4*	*2.4*
Public administration & defence	3,100	3,166	3,233	3,302	3,371	3,441	3,512	3,587	3,664	3,741	3,820	3,895	3,974
	2.1	*2.1*	*2.1*	*2.1*	*2.1*	*2.1*	*2.1*	*2.1*	*2.1*	*2.1*	*2.1*	*2.0*	*2.0*
Service-producing industries	33,299	34,016	34,688	35,376	36,136	36,923	37,727	38,540	39,367	40,209	41,081	41,962	42,861
	2.2	2.2	2.0	2.0	2.2	2.2	2.2	2.2	2.1	2.1	2.2	2.1	2.1
All industries	46,827	47,827	48,879	49,975	51,101	52,249	53,421	54,610	55,822	57,051	58,310	59,587	60,889
	2.2	*2.1*	*2.2*	*2.2*	*2.3*	*2.2*	*2.2*	*2.2*	*2.2*	*2.2*	*2.2*	*2.2*	*2.2*

White area represents forecast data.
All data are in millions of dollars, seasonally adjusted at annual rates.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; Canada Mortgage and Housing Corporation.

Table 19—Gross Domestic Product at Basic Prices by Industry—Saskatchewan

(forecast completed: Dec. 19, 2006)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Agriculture	2,308	2,281	2,332	2,374	2,417	2,463	2,504	2,552	2,595	2,637	2,677	2,717	2,760
	9.1	*–1.2*	*2.2*	*1.8*	*1.8*	*1.9*	*1.7*	*1.9*	*1.7*	*1.6*	*1.5*	*1.5*	*1.6*
Forestry	115	114	113	114	116	117	118	119	119	119	119	118	117
	–20.4	*–1.2*	*–0.9*	*1.1*	*1.3*	*1.0*	*1.0*	*0.7*	*0.4*	*0.1*	*–0.2*	*–0.5*	*–0.9*
Fishing & trapping	1.1	1.2	1.2	1.2	1.2	1.2	1.3	1.3	1.3	1.3	1.3	1.3	1.3
	–7.9	*6.9*	*1.6*	*1.7*	*1.3*	*1.4*	*0.7*	*0.6*	*0.5*	*0.3*	*0.2*	*0.2*	*0.1*
Mining	4,349	4,240	4,375	4,566	4,647	4,730	4,796	4,863	4,930	4,997	5,065	5,133	5,203
	4.6	*–2.5*	*3.2*	*4.4*	*1.8*	*1.8*	*1.4*	*1.4*	*1.4*	*1.4*	*1.4*	*1.4*	*1.4*
Manufacturing	2,356	2,416	2,476	2,569	2,689	2,806	2,930	3,034	3,145	3,247	3,364	3,487	3,605
	4.6	*2.5*	*2.5*	*3.8*	*4.7*	*4.4*	*4.4*	*3.6*	*3.7*	*3.2*	*3.6*	*3.7*	*3.4*
Construction	1,787	1,884	1,901	1,841	1,839	1,825	1,863	1,908	1,936	1,960	1,988	2,021	2,051
	3.7	*5.4*	*0.9*	*–3.2*	*–0.1*	*–0.8*	*2.1*	*2.4*	*1.5*	*1.2*	*1.5*	*1.6*	*1.5*
Utilities	839	850	873	900	927	953	978	999	1,024	1,046	1,065	1,084	1,105
	3.0	*1.2*	*2.8*	*3.1*	*2.9*	*2.8*	*2.6*	*2.2*	*2.5*	*2.1*	*1.8*	*1.9*	*1.9*
Goods-producing industries	11,756	11,785	12,072	12,366	12,636	12,894	13,191	13,476	13,751	14,007	14,278	14,562	14,843
	4.9	*0.2*	*2.4*	*2.4*	*2.2*	*2.0*	*2.3*	*2.2*	*2.0*	*1.9*	*1.9*	*2.0*	*1.9*
Transportation, warehousing & information	3,381	3,420	3,478	3,547	3,624	3,686	3,754	3,792	3,844	3,891	3,960	4,030	4,095
	4.7	*1.1*	*1.7*	*2.0*	*2.2*	*1.7*	*1.8*	*1.0*	*1.4*	*1.2*	*1.8*	*1.8*	*1.6*
Wholesale & retail trade	3,747	3,872	4,007	4,134	4,257	4,357	4,462	4,540	4,628	4,706	4,775	4,842	4,918
	7.0	*3.4*	*3.5*	*3.2*	*3.0*	*2.3*	*2.4*	*1.7*	*2.0*	*1.7*	*1.5*	*1.4*	*1.6*
Finance, insurance & real estate	5,194	5,350	5,442	5,540	5,654	5,756	5,854	5,918	6,013	6,105	6,210	6,306	6,413
	1.6	*3.0*	*1.7*	*1.8*	*2.0*	*1.8*	*1.7*	*1.1*	*1.6*	*1.5*	*1.7*	*1.5*	*1.7*
Community, business & personal service	6,052	6,197	6,354	6,509	6,684	6,842	7,023	7,160	7,316	7,456	7,608	7,760	7,905
	2.1	*2.4*	*2.5*	*2.4*	*2.7*	*2.4*	*2.6*	*2.0*	*2.2*	*1.9*	*2.0*	*2.0*	*1.9*
Public administration & defence	1,773	1,801	1,854	1,887	1,922	1,957	1,996	2,021	2,058	2,092	2,125	2,158	2,191
	2.3	*1.6*	*3.0*	*1.8*	*1.8*	*1.8*	*2.0*	*1.2*	*1.8*	*1.7*	*1.6*	*1.6*	*1.5*
Service-producing industries	20,148	20,640	21,134	21,618	22,140	22,599	23,089	23,431	23,860	24,250	24,679	25,096	25,522
	3.3	*2.4*	*2.4*	*2.3*	*2.4*	*2.1*	*2.2*	*1.5*	*1.8*	*1.6*	*1.8*	*1.7*	*1.7*
All industries	31,719	32,227	33,003	33,780	34,572	35,289	36,076	36,703	37,407	38,054	38,754	39,454	40,161
	3.7	*1.6*	*2.4*	*2.4*	*2.3*	*2.1*	*2.2*	*1.7*	*1.9*	*1.7*	*1.8*	*1.8*	*1.8*

White area represents forecast data.
All data are in millions of dollars, seasonally adjusted at annual rates.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; Canada Mortgage and Housing Corporation.

Table 19—Gross Domestic Product at Basic Prices by Industry—Saskatchewan

(forecast completed: Dec. 19, 2006)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Agriculture	2,799	2,838	2,875	2,915	2,956	2,995	3,034	3,076	3,116	3,160	3,208	3,256	3,301
	1.4	*1.4*	*1.3*	*1.4*	*1.4*	*1.3*	*1.3*	*1.4*	*1.3*	*1.4*	*1.5*	*1.5*	*1.4*
Forestry	116	114	112	110	108	105	103	101	99	96	94	92	90
	–1.2	*–1.5*	*–2.0*	*–2.0*	*–2.0*	*–2.1*	*–2.1*	*–2.2*	*–2.2*	*–2.3*	*–2.3*	*–2.4*	*–2.4*
Fishing & trapping	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
	0.1	*0.1*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*–0.1*	*–0.2*	*–0.3*	*–0.4*	*–0.5*
Mining	5,273	5,344	5,416	5,489	5,563	5,639	5,714	5,790	5,865	5,941	6,017	6,094	6,170
	1.4	*1.3*	*1.3*	*1.3*	*1.4*	*1.4*	*1.3*	*1.3*	*1.3*	*1.3*	*1.3*	*1.3*	*1.3*
Manufacturing	3,720	3,830	3,946	4,066	4,188	4,311	4,432	4,562	4,702	4,843	4,978	5,127	5,281
	3.2	*2.9*	*3.0*	*3.0*	*3.0*	*2.9*	*2.8*	*3.0*	*3.1*	*3.0*	*2.8*	*3.0*	*3.0*
Construction	2,079	2,110	2,143	2,180	2,220	2,256	2,293	2,331	2,364	2,397	2,431	2,463	2,495
	1.4	*1.5*	*1.6*	*1.7*	*1.8*	*1.6*	*1.6*	*1.6*	*1.4*	*1.4*	*1.4*	*1.3*	*1.3*
Utilities	1,123	1,141	1,159	1,174	1,193	1,211	1,231	1,251	1,271	1,289	1,309	1,327	1,345
	1.6	*1.7*	*1.6*	*1.3*	*1.6*	*1.5*	*1.6*	*1.6*	*1.6*	*1.5*	*1.5*	*1.3*	*1.4*
Goods-producing industries	15,111	15,379	15,653	15,936	16,230	16,520	16,808	17,112	17,418	17,728	18,039	18,358	18,683
	1.8	*1.8*	*1.8*	*1.8*	*1.8*	*1.8*	*1.7*	*1.8*	*1.8*	*1.8*	*1.8*	*1.8*	*1.8*
Transportation, warehousing & information	4,158	4,223	4,287	4,360	4,435	4,512	4,587	4,667	4,753	4,842	4,927	5,024	5,123
	1.5	*1.6*	*1.5*	*1.7*	*1.7*	*1.7*	*1.7*	*1.7*	*1.8*	*1.9*	*1.8*	*2.0*	*2.0*
Wholesale & retail trade	4,992	5,073	5,153	5,232	5,312	5,393	5,478	5,567	5,653	5,737	5,827	5,911	5,999
	1.5	*1.6*	*1.6*	*1.5*	*1.5*	*1.5*	*1.6*	*1.6*	*1.5*	*1.5*	*1.6*	*1.4*	*1.5*
Finance, insurance & real estate	6,517	6,611	6,712	6,809	6,913	7,027	7,148	7,259	7,375	7,491	7,606	7,725	7,849
	1.6	*1.4*	*1.5*	*1.4*	*1.5*	*1.7*	*1.7*	*1.5*	*1.6*	*1.6*	*1.5*	*1.6*	*1.6*
Community, business & personal service	8,049	8,192	8,338	8,487	8,636	8,789	8,945	9,110	9,281	9,452	9,625	9,801	9,983
	1.8	*1.8*	*1.8*	*1.8*	*1.8*	*1.8*	*1.8*	*1.8*	*1.9*	*1.8*	*1.8*	*1.8*	*1.9*
Public administration & defence	2,222	2,254	2,286	2,319	2,352	2,384	2,417	2,452	2,488	2,523	2,559	2,593	2,628
	1.4	*1.4*	*1.4*	*1.4*	*1.4*	*1.4*	*1.4*	*1.4*	*1.5*	*1.4*	*1.4*	*1.3*	*1.4*
Service-producing industries	25,937	26,354	26,776	27,206	27,648	28,106	28,577	29,054	29,549	30,045	30,546	31,054	31,582
	1.6	*1.6*	*1.6*	*1.6*	*1.6*	*1.7*	*1.7*	*1.7*	*1.7*	*1.7*	*1.7*	*1.7*	*1.7*
All industries	40,845	41,530	42,226	42,939	43,674	44,422	45,181	45,963	46,764	47,570	48,381	49,209	50,062
	1.7	*1.7*	*1.7*	*1.7*	*1.7*	*1.7*	*1.7*	*1.7*	*1.7*	*1.7*	*1.7*	*1.7*	*1.7*

White area represents forecast data.
All data are in millions of dollars, seasonally adjusted at annual rates.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; Canada Mortgage and Housing Corporation.

Table 20—Gross Domestic Product at Basic Prices by Industry—Alberta

(forecast completed: Dec. 19, 2006)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Agriculture	3,424	3,366	3,441	3,514	3,577	3,645	3,710	3,781	3,849	3,914	3,981	4,049	4,117
	7.1	*–1.7*	*2.2*	*2.1*	*1.8*	*1.9*	*1.8*	*1.9*	*1.8*	*1.7*	*1.7*	*1.7*	*1.7*
Forestry	364	377	379	385	390	395	398	400	400	399	396	392	387
	–5.7	*3.7*	*0.6*	*1.4*	*1.5*	*1.1*	*0.9*	*0.4*	*0.1*	*–0.3*	*–0.7*	*–1.0*	*–1.4*
Fishing & trapping	2.6	3.0	3.0	3.0	3.1	3.1	3.2	3.2	3.2	3.2	3.2	3.2	3.2
	74.2	*13.5*	*1.6*	*1.7*	*1.3*	*1.4*	*0.7*	*0.6*	*0.5*	*0.4*	*0.2*	*0.2*	*0.1*
Mining	21,879	22,741	23,325	24,729	26,348	27,714	28,672	30,969	32,421	33,540	35,382	37,885	38,404
	1.4	*3.9*	*2.6*	*6.0*	*6.5*	*5.2*	*3.5*	*8.0*	*4.7*	*3.5*	*5.5*	*7.1*	*1.4*
Manufacturing	14,142	15,317	16,770	17,575	18,503	19,692	21,052	21,873	22,735	23,548	24,232	24,967	25,811
	8.2	*8.3*	*9.5*	*4.8*	*5.3*	*6.4*	*6.9*	*3.9*	*3.9*	*3.6*	*2.9*	*3.0*	*3.4*
Construction	12,730	14,502	15,313	15,574	15,107	14,836	14,790	14,739	14,792	14,867	15,126	15,540	16,018
	17.1	*13.9*	*5.6*	*1.7*	*–3.0*	*–1.8*	*–0.3*	*–0.3*	*0.4*	*0.5*	*1.7*	*2.7*	*3.1*
Utilities	2,732	2,735	2,896	3,046	3,192	3,335	3,475	3,598	3,732	3,858	3,974	4,093	4,214
	2.3	*0.1*	*5.9*	*5.2*	*4.8*	*4.5*	*4.2*	*3.5*	*3.7*	*3.4*	*3.0*	*3.0*	*3.0*
Goods-producing industries	55,273	59,042	62,128	64,825	67,120	69,619	72,101	75,363	77,932	80,130	83,095	86,929	88,954
	6.8	*6.8*	*5.2*	*4.3*	*3.5*	*3.7*	*3.6*	*4.5*	*3.4*	*2.8*	*3.7*	*4.6*	*2.3*
Transportation, warehousing & information	12,481	13,173	13,719	14,254	14,713	15,260	15,814	16,313	16,766	17,174	17,618	18,144	18,532
	5.9	*5.5*	*4.1*	*3.9*	*3.2*	*3.7*	*3.6*	*3.2*	*2.8*	*2.4*	*2.6*	*3.0*	*2.1*
Wholesale & retail trade	15,105	17,638	18,651	19,551	20,409	21,340	22,313	23,042	23,818	24,573	25,309	26,040	26,803
	10.9	*16.8*	*5.7*	*4.8*	*4.4*	*4.6*	*4.6*	*3.3*	*3.4*	*3.2*	*3.0*	*2.9*	*2.9*
Finance, insurance & real estate	23,751	24,814	25,636	26,434	27,227	28,111	29,203	29,942	30,768	31,633	32,321	33,011	33,884
	4.6	*4.5*	*3.3*	*3.1*	*3.0*	*3.2*	*3.9*	*2.5*	*2.8*	*2.8*	*2.2*	*2.1*	*2.6*
Community, business & personal service	27,373	28,753	30,233	31,511	32,777	34,170	35,821	36,971	38,245	39,459	40,555	41,636	42,833
	2.4	*5.0*	*5.1*	*4.2*	*4.0*	*4.2*	*4.8*	*3.2*	*3.4*	*3.2*	*2.8*	*2.7*	*2.9*
Public administration & defence	5,573	5,955	6,379	6,609	6,838	7,066	7,306	7,492	7,723	7,946	8,166	8,386	8,604
	3.4	*6.8*	*7.1*	*3.6*	*3.5*	*3.3*	*3.4*	*2.5*	*3.1*	*2.9*	*2.8*	*2.7*	*2.6*
Service-producing industries	84,284	90,333	94,617	98,359	101,964	105,946	110,458	113,759	117,321	120,786	123,968	127,217	130,656
	5.0	*7.2*	*4.7*	*4.0*	*3.7*	*3.9*	*4.3*	*3.0*	*3.1*	*3.0*	*2.6*	*2.6*	*2.7*
All industries	137,471	147,121	154,466	160,904	166,805	173,285	180,279	186,842	192,974	198,636	204,784	211,866	217,330
	4.8	*7.0*	*5.0*	*4.2*	*3.7*	*3.9*	*4.0*	*3.6*	*3.3*	*2.9*	*3.1*	*3.5*	*2.6*

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Sources: The Conference Board of Canada; Statistics Canada; Canada Mortgage and Housing Corporation.

Table 20—Gross Domestic Product at Basic Prices by Industry—Alberta
(forecast completed: Dec. 19, 2006)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Agriculture	4,187	4,259	4,327	4,400	4,471	4,543	4,616	4,690	4,770	4,846	4,928	5,012	5,092
	1.7	*1.7*	*1.6*	*1.7*	*1.6*	*1.6*	*1.6*	*1.6*	*1.7*	*1.6*	*1.7*	*1.7*	*1.6*
Forestry	380	373	363	353	343	333	323	313	303	293	283	273	263
	–1.7	*–2.0*	*–2.7*	*–2.7*	*–2.8*	*–2.9*	*–3.0*	*–3.1*	*–3.2*	*–3.3*	*–3.4*	*–3.5*	*–3.6*
Fishing & trapping	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2
	0.1	*0.1*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*–0.1*	*–0.2*	*–0.3*	*–0.4*	*–0.5*
Mining	39,468	40,087	40,966	41,948	43,090	44,105	45,098	46,098	47,112	48,124	49,142	50,157	51,177
	2.8	*1.6*	*2.2*	*2.4*	*2.7*	*2.4*	*2.3*	*2.2*	*2.2*	*2.1*	*2.1*	*2.1*	*2.0*
Manufacturing	26,551	27,356	28,271	29,171	30,054	31,031	31,977	32,988	34,025	35,115	36,188	37,334	38,488
	2.9	*3.0*	*3.3*	*3.2*	*3.0*	*3.3*	*3.0*	*3.2*	*3.1*	*3.2*	*3.1*	*3.2*	*3.1*
Construction	16,443	16,817	17,338	17,912	18,514	19,013	19,635	20,288	21,030	21,712	22,434	23,169	23,952
	2.7	*2.3*	*3.1*	*3.3*	*3.4*	*2.7*	*3.3*	*3.3*	*3.7*	*3.2*	*3.3*	*3.3*	*3.4*
Utilities	4,327	4,443	4,557	4,658	4,776	4,891	5,011	5,135	5,257	5,378	5,502	5,618	5,739
	2.7	*2.7*	*2.6*	*2.2*	*2.5*	*2.4*	*2.5*	*2.5*	*2.4*	*2.3*	*2.3*	*2.1*	*2.1*
Goods-producing industries	91,359	93,337	95,824	98,446	101,250	103,920	106,663	109,515	112,500	115,471	118,480	121,566	124,715
	2.7	*2.2*	*2.7*	*2.7*	*2.8*	*2.6*	*2.6*	*2.7*	*2.7*	*2.6*	*2.6*	*2.6*	*2.6*
Transportation, warehousing & information	18,920	19,331	19,834	20,362	20,897	21,485	22,068	22,670	23,285	23,940	24,600	25,314	26,027
	2.1	*2.2*	*2.6*	*2.7*	*2.6*	*2.8*	*2.7*	*2.7*	*2.7*	*2.8*	*2.8*	*2.9*	*2.8*
Wholesale & retail trade	27,590	28,400	29,249	30,088	30,925	31,787	32,681	33,586	34,486	35,389	36,344	37,266	38,228
	2.9	*2.9*	*3.0*	*2.9*	*2.8*	*2.8*	*2.8*	*2.8*	*2.7*	*2.6*	*2.7*	*2.5*	*2.6*
Finance, insurance & real estate	34,605	35,411	36,276	37,163	38,058	39,047	40,045	41,003	41,956	42,954	43,967	44,990	46,030
	2.1	*2.3*	*2.4*	*2.4*	*2.4*	*2.6*	*2.6*	*2.4*	*2.3*	*2.4*	*2.4*	*2.3*	*2.3*
Community, business & personal service	43,957	45,180	46,480	47,775	49,054	50,462	51,880	53,347	54,823	56,376	57,968	59,612	61,282
	2.6	*2.8*	*2.9*	*2.8*	*2.7*	*2.9*	*2.8*	*2.8*	*2.8*	*2.8*	*2.8*	*2.8*	*2.8*
Public administration & defence	8,816	9,033	9,251	9,471	9,691	9,911	10,133	10,363	10,598	10,833	11,074	11,304	11,543
	2.5	*2.5*	*2.4*	*2.4*	*2.3*	*2.3*	*2.2*	*2.3*	*2.3*	*2.2*	*2.2*	*2.1*	*2.1*
Service-producing industries	133,888	137,353	141,091	144,858	148,626	152,693	156,807	160,969	165,148	169,493	173,952	178,486	183,109
	2.5	*2.6*	*2.7*	*2.7*	*2.6*	*2.7*	*2.7*	*2.7*	*2.6*	*2.6*	*2.6*	*2.6*	*2.6*
All industries	222,968	228,411	234,635	241,025	247,596	254,333	261,191	268,204	275,369	282,684	290,153	297,772	305,545
	2.6	*2.4*	*2.7*	*2.7*	*2.7*	*2.7*	*2.7*	*2.7*	*2.7*	*2.7*	*2.6*	*2.6*	*2.6*

White area represents forecast data.
All data are in millions of dollars, seasonally adjusted at annual rates.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; Canada Mortgage and Housing Corporation.

Table 21—Gross Domestic Product at Basic Prices by Industry—British Columbia
(forecast completed: Dec. 19, 2006)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Agriculture	1,522	1,483	1,516	1,543	1,571	1,601	1,630	1,661	1,691	1,719	1,750	1,780	1,810
	9.0	*–2.6*	*2.2*	*1.8*	*1.8*	*1.9*	*1.8*	*1.9*	*1.8*	*1.7*	*1.8*	*1.7*	*1.7*
Forestry	3,807	4,032	3,975	4,045	4,093	4,134	4,147	3,987	3,828	3,668	3,508	3,348	3,189
	3.1	*5.9*	*–1.4*	*1.8*	*1.2*	*1.0*	*0.3*	*–3.9*	*–4.0*	*–4.2*	*–4.4*	*–4.5*	*–4.8*
Fishing & trapping	104	115	117	119	121	122	123	124	125	125	125	126	126
	–17.5	*10.9*	*1.7*	*1.8*	*1.5*	*1.4*	*0.8*	*0.6*	*0.4*	*0.3*	*0.2*	*0.2*	*0.1*
Mining	3,843	3,904	4,103	4,396	4,563	4,704	4,826	4,925	5,019	5,144	5,257	5,336	5,455
	2.4	*1.6*	*5.1*	*7.2*	*3.8*	*3.1*	*2.6*	*2.0*	*1.9*	*2.5*	*2.2*	*1.5*	*2.2*
Manufacturing	15,774	16,277	16,786	17,334	17,987	18,698	19,454	20,096	20,763	21,307	21,815	22,352	22,833
	3.3	*3.2*	*3.1*	*3.3*	*3.8*	*4.0*	*4.0*	*3.3*	*3.3*	*2.6*	*2.4*	*2.5*	*2.2*
Construction	7,897	8,865	9,407	9,632	9,742	9,619	9,674	9,766	9,961	10,129	10,311	10,495	10,665
	6.1	*12.3*	*6.1*	*2.4*	*1.1*	*–1.3*	*0.6*	*0.9*	*2.0*	*1.7*	*1.8*	*1.8*	*1.6*
Utilities	2,529	2,247	2,331	2,441	2,550	2,658	2,766	2,854	2,951	3,042	3,125	3,211	3,300
	8.4	*–11.2*	*3.8*	*4.7*	*4.5*	*4.2*	*4.1*	*3.2*	*3.4*	*3.1*	*2.7*	*2.8*	*2.7*
Goods-producing industries	35,476	36,922	38,235	39,511	40,627	41,536	42,621	43,412	44,337	45,135	45,891	46,648	47,378
	4.3	*4.1*	*3.6*	*3.3*	*2.8*	*2.2*	*2.6*	*1.9*	*2.1*	*1.8*	*1.7*	*1.6*	*1.6*
Transportation, warehousing & information	14,070	14,717	15,185	15,616	16,086	16,574	17,072	17,364	17,699	17,957	18,210	18,449	18,672
	5.6	*4.6*	*3.2*	*2.8*	*3.0*	*3.0*	*3.0*	*1.7*	*1.9*	*1.5*	*1.4*	*1.3*	*1.2*
Wholesale & retail trade	15,173	16,586	17,261	17,855	18,404	18,921	19,479	19,904	20,419	20,915	21,365	21,810	22,276
	6.7	*9.3*	*4.1*	*3.4*	*3.1*	*2.8*	*3.0*	*2.2*	*2.6*	*2.4*	*2.2*	*2.1*	*2.1*
Finance, insurance & real estate	29,461	30,505	31,396	32,165	32,935	33,745	34,571	35,288	36,147	36,868	37,631	38,364	39,101
	3.8	*3.5*	*2.9*	*2.4*	*2.4*	*2.5*	*2.4*	*2.1*	*2.4*	*2.0*	*2.1*	*1.9*	*1.9*
Community, business & personal service	31,149	31,728	32,618	33,708	34,841	36,016	37,150	38,214	39,407	40,458	41,489	42,513	43,503
	1.5	*1.9*	*2.8*	*3.3*	*3.4*	*3.4*	*3.1*	*2.9*	*3.1*	*2.7*	*2.5*	*2.5*	*2.3*
Public administration & defence	6,676	6,787	6,962	7,154	7,354	7,560	7,784	7,954	8,173	8,386	8,595	8,807	9,017
	2.0	*1.7*	*2.6*	*2.8*	*2.8*	*2.8*	*3.0*	*2.2*	*2.8*	*2.6*	*2.5*	*2.5*	*2.4*
Service-producing industries	96,530	100,323	103,423	106,499	109,621	112,816	116,055	118,723	121,845	124,584	127,291	129,943	132,569
	3.6	*3.9*	*3.1*	*3.0*	*2.9*	*2.9*	*2.9*	*2.3*	*2.6*	*2.2*	*2.2*	*2.1*	*2.0*
All industries	132,041	137,220	141,613	145,965	150,203	154,307	158,631	162,090	166,137	169,674	173,137	176,545	179,902
	3.7	*3.9*	*3.2*	*3.1*	*2.9*	*2.7*	*2.8*	*2.2*	*2.5*	*2.1*	*2.0*	*2.0*	*1.9*

White area represents forecast data.
All data are in millions of dollars, seasonally adjusted at annual rates.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; Canada Mortgage and Housing Corporation.

Table 21—Gross Domestic Product at Basic Prices by Industry—British Columbia

(forecast completed: Dec. 19, 2006)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Agriculture	1,839	1,871	1,900	1,931	1,964	1,993	2,027	2,061	2,097	2,130	2,164	2,201	2,238
	1.6	*1.7*	*1.6*	*1.6*	*1.7*	*1.5*	*1.7*	*1.7*	*1.7*	*1.6*	*1.6*	*1.7*	*1.7*
Forestry	3,029	3,054	3,079	3,104	3,129	3,154	3,179	3,204	3,229	3,254	3,279	3,304	3,329
	–5.0	*0.8*	*0.8*	*0.8*	*0.8*	*0.8*	*0.8*	*0.8*	*0.8*	*0.8*	*0.8*	*0.8*	*0.8*
Fishing & trapping	126	126	126	126	126	126	126	126	126	126	125	125	124
	0.1	*0.1*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*–0.1*	*–0.2*	*–0.3*	*–0.4*	*–0.5*
Mining	5,553	5,622	5,667	5,755	5,869	5,991	6,075	6,092	6,205	6,314	6,425	6,537	6,651
	1.8	*1.2*	*0.8*	*1.6*	*2.0*	*2.1*	*1.4*	*0.3*	*1.8*	*1.8*	*1.8*	*1.7*	*1.7*
Manufacturing	23,287	23,673	24,090	24,496	24,902	25,287	25,656	26,042	26,419	26,794	27,127	27,504	27,880
	2.0	*1.7*	*1.8*	*1.7*	*1.7*	*1.5*	*1.5*	*1.5*	*1.4*	*1.4*	*1.2*	*1.4*	*1.4*
Construction	10,824	10,996	11,173	11,351	11,528	11,700	11,870	12,041	12,205	12,371	12,542	12,702	12,872
	1.5	*1.6*	*1.6*	*1.6*	*1.6*	*1.5*	*1.5*	*1.4*	*1.4*	*1.4*	*1.4*	*1.3*	*1.3*
Utilities	3,382	3,467	3,551	3,626	3,713	3,798	3,888	3,979	4,070	4,159	4,249	4,334	4,420
	2.5	*2.5*	*2.4*	*2.1*	*2.4*	*2.3*	*2.4*	*2.4*	*2.3*	*2.2*	*2.2*	*2.0*	*2.0*
Goods-producing industries	48,040	48,809	49,586	50,389	51,230	52,048	52,820	53,545	54,350	55,147	55,911	56,707	57,515
	1.4	*1.6*	*1.6*	*1.6*	*1.7*	*1.6*	*1.5*	*1.4*	*1.5*	*1.5*	*1.4*	*1.4*	*1.4*
Transportation, warehousing & information	18,885	19,095	19,305	19,537	19,774	20,010	20,234	20,440	20,643	20,858	21,051	21,276	21,498
	1.1	*1.1*	*1.1*	*1.2*	*1.2*	*1.2*	*1.1*	*1.0*	*1.0*	*1.0*	*0.9*	*1.1*	*1.0*
Wholesale & retail trade	22,731	23,231	23,732	24,227	24,718	25,205	25,701	26,210	26,702	27,187	27,706	28,190	28,689
	2.0	*2.2*	*2.2*	*2.1*	*2.0*	*2.0*	*2.0*	*2.0*	*1.9*	*1.8*	*1.9*	*1.7*	*1.8*
Finance, insurance & real estate	39,924	40,671	41,397	42,140	42,890	43,633	44,395	45,204	45,994	46,810	47,624	48,446	49,299
	2.1	*1.9*	*1.8*	*1.8*	*1.8*	*1.7*	*1.7*	*1.8*	*1.7*	*1.8*	*1.7*	*1.7*	*1.8*
Community, business & personal service	44,500	45,437	46,392	47,352	48,315	49,288	50,287	51,299	52,287	53,289	54,292	55,300	56,322
	2.3	*2.1*	*2.1*	*2.1*	*2.0*	*2.0*	*2.0*	*2.0*	*1.9*	*1.9*	*1.9*	*1.9*	*1.8*
Public administration & defence	9,223	9,435	9,649	9,866	10,084	10,301	10,521	10,749	10,982	11,212	11,447	11,670	11,900
	2.3	*2.3*	*2.3*	*2.2*	*2.2*	*2.2*	*2.1*	*2.2*	*2.2*	*2.1*	*2.1*	*1.9*	*2.0*
Service-producing industries	135,262	137,869	140,475	143,122	145,781	148,436	151,139	153,901	156,607	159,357	162,120	164,882	167,708
	2.0	*1.9*	*1.9*	*1.9*	*1.9*	*1.8*	*1.8*	*1.8*	*1.8*	*1.8*	*1.7*	*1.7*	*1.7*
All industries	183,257	186,632	190,016	193,465	196,966	200,439	203,914	207,402	210,912	214,458	217,986	221,544	225,178
	1.9	*1.8*	*1.8*	*1.8*	*1.8*	*1.8*	*1.7*	*1.7*	*1.7*	*1.7*	*1.6*	*1.6*	*1.6*

White area represents forecast data.
All data are in millions of dollars, seasonally adjusted at annual rates.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; Canada Mortgage and Housing Corporation.

Newfoundland Power Inc.
Description of Current Rate Structures

May 2007

NEWFOUNDLAND POWER INC.
2008 GENERAL RATE APPLICATION

DESCRIPTION OF THE RATE STRUCTURES USED BY NEWFOUNDLAND POWER

Customer classes are generally determined by grouping customers that have similar load characteristics.[1] Newfoundland Power's customer rates include a Domestic rate and rates for different classes of General Service customers.[2]

The Company has divided its service into six classes: Domestic; General Service 0–10 kW; General Service 10-100 kW (110 kVA); General Service 110 kVA (100 kW) - 1000 kVA; General Service 1000 kVA and over; and the Street and Area Lighting class. The Company's rate classes are typical of electric utilities where separate classes exist for Domestic and General Service customers.

Following is a description of the development of Newfoundland Power's rate structures for each class of service.

Domestic Class (Rate 1.1)

The Domestic rate includes a basic customer charge per month and a single energy charge that applies to all kWh usage for all months. The single charge for energy consumption has existed since 1983; the declining block rate previously in use was eliminated as it was viewed as promotional. Newfoundland Power's Domestic rate recovers demand costs and energy costs through a blended energy charge. The recovery of demand costs through energy charges is common in Canadian electric utilities' domestic rates.[3]

The use of an energy-only rate for Domestic customers is common throughout Canada.

Customers that do not qualify for the Domestic rate are billed on one of the General Service rates. The rate that applies depends on the demand requirements of the customer.

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1 *The Art of Rate Design*, Walters, Frank S., Edison Electric Institute, 1984, Page 19.

2 General Service customers include businesses, institutions and other end users that do not qualify for the Domestic rate. The General Service customer class designations are based on usage requirements (i.e., small, medium and large) to better reflect the different cost of serving each group. Also, Street and Area Lighting rates are available for Domestic and General Service customers.

3 Several Canadian utilities have an energy blocking structure in their Domestic rate. Hydro Quebec has an inverted pricing structure (i.e., a higher price for the higher usage block). Manitoba Hydro, New Brunswick Power and Maritime Electric have declining block structures (i.e., a lower price for the higher usage block). Utilities in Alberta and Ontario have unbundled energy-only rates for Domestic customers. Unbundled rates are characterized by itemized charges specific to the basis for the charge. For example, there can be one ¢/kWh charge for generation costs, a different ¢/kWh charge for transmission costs and another ¢/kWh charge for distribution costs.

General Service 0 – 10 kW (Rate 2.1)

Rate 2.1 applies to services that generally require small amounts of demand and energy. The average kWh usage for customers on Rate 2.1 is slightly less than 700 kWh per month; this is slightly lower usage than that of a Domestic customer without electric heat. The rate structure is similar to the Domestic rate structure in that it includes a basic customer charge per month and a single energy charge that applies to all kWh usage. However, this rate also includes a minimum charge that applies to customers that require three-phase service.

The three-phase minimum charge reflects the higher costs incurred to provide three-phase service compared to single-phase service. The three-phase minimum charge has historically been set to equal two times the basic customer charge for Rate 2.1.

The current rate structure has existed since the rate class was created in 1968. The recovery of demand costs through energy charges for small General Service customers is a common practice among Canadian utilities.[4]

General Service 10 – 100 kW (110 kVA) (Rate 2.2)

Rate 2.2 includes a basic customer charge, a demand charge, and energy charges set at different levels for two blocks of energy. The rate includes a maximum monthly charge, a minimum monthly charge and also includes the three-phase minimum charge.

The demand and energy charges are of a form referred to as a Wright-Hopkinson Rate Structure (sometimes referred to as the Modified Hopkinson Rate Structure). This rate structure includes an explicit demand charge and energy block sizes that depend on the customer's demand requirements.

In Rate 2.2, the higher priced energy charge applies to kWh consumption up to 150 kWh/kW of billing demand. For example, if a customer has a billing demand of 20 kW, the first block size is 3,000 kWh = 150 kWh/kW x 20 kW. If a customer has a 30 kW billing demand, the first block size is 4,500 kWh.

The first block energy price is higher than the second block to encourage the customer to improve their load factor, promoting efficiency (i.e., better utilization of the capacity available within the power system). If a customer has a load factor that is less than 20%,[5] all the energy usage will be normally billed on the more expensive first block. Customers with monthly load factors higher than 20% are billed the higher priced rate for the first 150 kWh/kW and the lower priced rate for remainder of the kWh usage.

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4 Utilities in all provinces have a block of energy available to small General Service customers that is billed on an energy-only rate. The block size is based on demand for some utilities and energy for others.

5 A 20% load factor is roughly equivalent to using 150 kWh with a 1 kW maximum demand during a month. The equivalent load factor is determined as the average consumption (150 kWh divided by 730 hours per month) divided by the maximum demand (1 kW) which equals approximately 0.2 or 20%.

The current rate structure allows customers to pay a lower unit price per kWh by being efficient and minimizing their peak demand relative to their energy requirement (i.e., maintaining a high load factor). The Wright-Hopkinson Rate Structure for Rate 2.2 has been used since 1978. This type of structure is used elsewhere in Canada. However; a Hopkinson Rate Structure is more prevalent (which includes a demand charge and energy charge but does not have the energy blocking related to demand usage).

Rate 2.2 also has a maximum monthly charge to protect low load factor customers from being over charged. The maximum charge includes a cents per kWh charge plus the basic customer charge and is set at a level to recognize that customers with very low load factors also have on average a much less likelihood that they will have a high demand when the system peaks.

Rate 2.2 has the same three-phase minimum charge that applies to Rate 2.1.

General Service 110 kVA (100kW) – 1000 kVA (Rate 2.3)

Rate 2.3 has the same rate structure as Rate 2.2 with the exception of a maximum kWh limit on the size of the higher priced first block of kWh usage. The maximum first block size of 30,000 kWh only affects customers with demands greater than 200 kVA (i.e., 200 kVA x 150 kWh/ kVA = 30,000 kWh).

The maximum first block size has changed over the years. Historically, the first block size has been set to ensure larger customers in the class were not paying more than their cost of service. The block size has decreased over the years and in 1987 the maximum first block size was set at 30,000 kWh, the same time when Rate 2.4 was created. The justification for creating Rate 2.4 was to ensure that larger general service customers paid a rate that better reflected the cost to serve. The principal difference between Rate 2.3 and Rate 2.4 customers was load factor. Analysis conducted in 1986 showed that customers above the 1000 kVA level exhibited consistently higher load factors on both a monthly and an annual basis.

General Service 1000 kVA and Over (Rate 2.4)

Rate 2.4 includes a basic customer charge, a demand charge, and energy prices set at different levels for two blocks of energy. The rate also includes the maximum monthly charge.

The demand and energy components for Rate 2.4 are based on the Hopkinson rate form. This rate structure includes an explicit demand charge and energy charge(s). However, unlike Rate 2.2 and Rate 2.3, the size of the first block of energy does not vary by demand usage. The first and higher energy charge applies to energy consumption up to 100,000 kWh per month.

The Hopkinson Rate Structure has been used for Rate 2.4 since the rate was first introduced in 1987. Rate 2.4 was created to ensure that larger general service customers paid a rate that better reflected the cost to serve. This structure is commonly used by utilities in Canada in billing large customers.

Street and Area Lighting (Rate 4.1)

The Company offers individual customers and municipalities a Street and Area Lighting Service that is based on the Company owning, installing and maintaining street and area lighting. The price for this service includes fixed monthly rates for lighting fixtures, poles (used exclusively for lighting) and underground servicing. These rates are designed based on five cost components.

- Equipment Costs – This is the carrying cost associated with the installed cost for each type of lighting fixture, pole and underground wiring run. This includes depreciation, return and taxes.
- Maintenance Costs – Average annual labour and material costs including overheads.
- Other System Costs – Includes energy, demand and customer related costs allocated to each type of lighting based on their estimated annual energy use.
- Rural Deficit Adjustment – A percentage is applied to each rate based on the portion of the rural deficit allocated to the Street and Area Lighting class in the cost of service study.
- Revenue Requirement Adjustment - An adjustment factor is applied to ensure the Street and Area Lighting rates obtain the proposed test year revenue for the Street and Area Lighting class. The percentage is determined by dividing the proposed test year revenue for the class by the total revenue that would result occur if no revenue requirement adjustment was applied.

Cost of Service Study

May 2007

Table of Contents

Page

1.0 GENERAL

Cost of service studies are conducted on a regular basis to evaluate the reasonableness of cost recovery by class of service and as a step in the traditional process for establishing the Company's rates.

At the Company's 2003 General Rate proceeding, the Company presented detailed evidence on its cost of service study methodology. Through a mediation process, the parties at the hearing recommended the approval of the cost of service study methodology.

In Board Order No. P.U. 19 (2003) the Board approved the recommendations as presented in the evidence and the Mediation Report.

2.0 2005 PRO-FORMA COST OF SERVICE STUDY

The Company has completed a 2005 Pro-forma Cost of Service Study (the "Cost of Service Study"). The detailed results of the Cost of Service Study are shown in Appendix A.

The results of the study are reported on a basis that is comparable to customer final rates and overall costs recovered from customers. Rate stabilization and municipal tax costs are not included in the Company's revenue requirement but are part of the costs that are recovered from customers. In the past the Company reported its cost of service study results in terms of base rates which did not include the revenue and costs associated with rate stabilization costs, municipal tax costs and funding the rural deficit.

This study reflects the Company's proposed test year costs by updating the 2005 Cost of Service Study to include the impact of the January 2007 wholesale and customer rate change, and the results of the 2006 Depreciation Study. Any difference between total costs and total revenue from final rates resulting from these pro-forma updates was offset by modelling an across-the-board average % change in revenue from base rates for each class of service.

The Cost of Service Study includes a number of relatively minor methodology changes. These changes are highlighted in the following section.

3.0 CHANGES TO THE COST OF SERVICE STUDY

The Company has made three minor changes to the method used to Functionalize, Classify and allocate costs.

i) The Company made a change to how Board Assessments are treated to be more consistent with changes made to Hydro's Cost of Service Study as discussed in Hydro's 2003 General Rate Application Cost of Service Evidence. The Cost of Service Study allocates these costs to each customer class based on revenue. In the past the Board Assessment Expense was treated as an Other Administration and General Expense and allocated to customers based on the assignment of these expenses to various functional and classification breakdowns.

ii) The cash working capital allowance included in rate base is now functionalized and classified based on total operating and maintenance expense including purchased power. Previously it was functionalized and classified based on operating and maintenance expenses excluding purchased power. A review of the Company's lead lag study shows that purchased power is a major contributor to the Company's requirement for a working capital allowance.

iii) A component of the Company's reported purchased power expense is the amortization of the Hydro Equalization Reserve Balance which was approved in P.U. 19 (2003). The amortization is now identified separately from the Company's other purchased power expense and is classified 100% to energy.

4.0 COST OF SERVICE STUDY RESULTS

Appendix A shows the detailed Cost of Service study. The following is a description of the schedules provided in Appendix A.

The results of the Cost of Service Study have been divided into five groups of schedules.

Group 1 - Results
Group 2 - Functional Classification of Rate Base
Group 3 - Functional Classification of Expenses
Group 4 - Determination of Class Allocation Factors
Group 5 - Miscellaneous Schedules

4.1 Group 1: Results

Schedule 1.1 shows the major components that make up the total cost of service (excluding Rate Stabilization Costs, Municipal Taxes or the Rural Subsidy). These include purchased power expenses, operating and maintenance expenses, depreciation expenses, expense credits and return and taxes. The purchased power expense excludes the portion of the expense that is attributed to funding Hydro's rural deficit. The schedule shows the breakdown of these cost components into the various functional classification groups used in the study. Expense credits are revenue that are not generated from rates and are associated with particular functional classification groups.

Schedule 1.2 provides the cost by each functional classification group and the amount allocated to each class of service. The costs do not include Rate Stabilization Costs, Municipal Taxes or the Rural Subsidy.

Schedule 1.3 shows the total cost of service by class of service including Rate Stabilization Costs, Municipal Taxes and the Rural Subsidy. The schedule also subtracts other revenue from total costs to provide a column representing the total costs recovered from customer final rates.

Schedule 1.4 shows the revenue attributed to each class of service. This schedule shows all the components that make up the total billings to customer plus other revenue. The other revenue amount is the portion of the Company's non-electrical revenue that is not accounted for in expense credits. Other revenue is attributed to each class of service based on the total revenue from base rates by class. Expense credits are shown in Schedule 1.1.

Schedule 1.5 compares the revenue by class to the cost by class and shows revenue to cost ratios for the various classes of service. The costs are from Schedule 1.3 and the revenues are from Schedule 1.4.

Schedule 1.6 provides loaders that when added to the classified cost components (demand, energy, customer and specifically assigned costs) result in costs that can be compared to final customer rate components. The % rate loader is applied to each of the classified cost components. The RSA loader is added to the classified energy costs.

Schedule 1.7 expresses the cost of service in terms of unit costs. The units used are the $/kW-kVA for demand costs, ¢/kWh for energy costs, and $/bill for customer related costs. Also provided is a breakdown of demand and customer cost in ¢/kWh and an overall total cost expressed in terms of ¢/kWh.

4.2 Group 2: Functional Classification of Rate Base

Schedule 2.1 shows the original cost of the Company's fixed assets and its breakdown by the various functional classification categories. The total cost is based on the average amount of fixed assets employed during the year.

Schedule 2.2 shows the average accumulated depreciation and its breakdown into functional classification categories.

Schedule 2.3 shows the net contributions in aid of construction ("CIAC"). The net CIAC is the total CIAC received from customers and governments less the CIAC amortized to date.

Schedule 2.4 shows the average rate base. The average rate base includes the total net utility plant, deductions to rate base and additions from rate base. The net utility plant is the original cost of the fixed assets (Schedule 2.1) less the accumulated depreciation (Schedule 2.2).

The deductions from rate base include the net CIAC (Schedule 2.3), future income taxes and the balance in the weather normalization reserve account[1]. The additions to rate base include the outstanding balance associated with financed CIACs (contributions - country homes), deferred charges (mostly pension costs), cash working capital allowance and materials and supplies.

[1] If the balance in the weather normalization reserve is owed from customers, the balance is added to rate base.

4.3 Group 3: Functional Classification of Expenses

Schedule 3.1 lists a summary of the Company's expenses, both regulated and non-regulated, and the cost of service expense category into which each expense is grouped.

Schedule 3.2 shows the functional classification of the Company's expenses by expense category. The schedule includes the following four groups of expenses:

1. Purchased Power Expense. The expense shown in the schedule excludes the portion of the purchase power cost associated with funding Hydro's rural deficit.

2. Direct Operating and Maintenance Expenses. These expenses include those internal costs that can be directly placed into functional groups.

3. General System Costs. These expenses include costs related to general operations, communications and the system control center.

4. Administration and General Expenses. These expenses include the costs of administration, human resources, information systems, finance, and regulatory costs.

Schedule 3.3 shows the breakdown of depreciation expense, net of CIAC amortization, into functional classification categories.

4.4 Group 4: Determination of Class Allocation Factors

Schedule 4.1 provides the customer statistics used to develop the allocators. The statistics include: the number of customers; total energy sales; total billing demand (where applicable); the estimated class load factors based on non-coincident peak ("NCP"); and the estimated class load factors based on coincident peak ("1CP"). Schedule 4.1 also provides the estimated class demands at time of class peak (NCP) and the estimated class demands at time of Hydro's system peak (1CP).

Schedule 4.2 provides the loss factors that are used as one of the inputs in calculating the energy and demand allocation factors.

Schedule 4.3 provides the development of the allocation factors for customer related costs. The allocation factor for each type of customer cost is based on a weighting factor and the number of customers. It should be noted that an allocation factor of 0.0 per cent occurs in a number of instances such as the allocation factor used to allocate customer related secondary costs to transmission customers. This reflects the concept that a transmission customer (a customer that takes their electricity supply from the transmission system) is not responsible for any of the cost of the distribution secondary or primary system.

Schedule 4.4 shows the development of the secondary, primary and transmission allocation factors for energy related costs. The allocation factors are based on energy sales and losses. Three separate allocators are required to ensure that within the cost of service study, a transmission customer is not allocated any of the cost of the distribution secondary or primary system and that a distribution primary customer is not allocated any of the cost of the distribution secondary system.

Schedule 4.5 shows the development of the demand allocators based on the non-coincident peak method. The allocation factors are based on the estimated class peak and the loss factors shown in Schedule 4.1 and Schedule 4.2 respectively. The table shows three sets of allocation factors that are used when allocating the demand related cost associated with either the secondary, primary or transmission levels.

Schedule 4.6 shows the development of the demand allocators based on the single coincident peak method. The allocation factors are based on the estimated class demand at time of system peak and the loss factors shown in Schedule 4.1 and Schedule 4.2 respectively. The table shows three sets of allocation factors that are used when allocating the demand related cost associated with either the secondary, primary or transmission levels.

4.5 Group 5: Miscellaneous Schedules

Schedule 5.1 shows the functional classification splits used in the Cost of Service study. Much of this input data was derived from a variety of functionalization and classification studies. The sources of each functionalization and classification split are detailed in the footnotes in Schedule 5.1.

Schedule 5.2 provides a reconciliation of the total expenses used in the Cost of Service study to the 2005 Annual Report to the Board.

Schedule 5.3 provides a reconciliation of the total revenue used in the Cost of Service study to the 2005 Annual Report to the Board.

Schedule 5.4 provides a reconciliation of the total return and taxes used in the Cost of Service study to the 2005 Annual Report to the Board.

2005 Pro Forma Cost of Service Study

Newfoundland Power Inc.
2005 Pro-Forma Cost of Service Study

TABLE OF CONTENTS

Notes:

1 - Within the Schedules rows and columns may not add due to rounding.

Newfoundland Power Inc.
2005 Pro-Forma Cost of Service Study

FUNCTIONAL CLASSIFICATION OF THE COST OF SERVICE (Excluding RSA, MTA and Rural Subsidy)
(All numbers are times $1,000)

Line No.	Category	Total A	Produced & Purchased Demand B	Produced & Purchased Energy C	Transmission Demand D	Distribution: Substation Demand E	Distribution: Primary Demand F	Distribution: Primary Customer G	Distribution: Transformers Demand H	Distribution: Transformers Customer I	Distribution: Secondary Demand J	Distribution: Secondary Customer K	Distribution: Services Customer L	Distribution: Meters Customer M	Distribution: St. Lighting Customer N	Customer Acc. & Cust. Serv. O	Customer Specific P	Revenue Related Q
1	Purchase Power	277,983	99,194	178,789	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Operating and Maintenance	52,648	3,614	3,489	5,251	4,289	6,077	2,993	1,422	526	1,519	748	3,751	1,283	2,345	14,806	44	489
3	Depreciation	37,704	2,778	2,106	4,547	2,290	7,895	3,889	2,142	792	1,974	972	1,530	872	2,211	3,665	43	0
	Expense Credits																	
	Wheeling Revenues																	
4	Transmission	321	0	0	321	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Distribution	117	0	0	0	0	78	39	0	0	0	0	0	0	0	0	0	0
6	Joint Use Revenue	8,238	0	0	0	0	4,416	2,175	0	0	1,104	544	0	0	0	0	0	0
7	Revenue from Temp. Service and Reconnects	110	0	0	0	0	0	0	0	0	0	0	110	0	0	0	0	0
8	Customer Service Fees	282	0	0	0	0	0	0	0	0	0	0	0	0	0	282	0	0
9	Total Expense Credits	9,068	0	0	321	0	4,494	2,213	0	0	1,104	544	110	0	0	282	0	0
10	Subtotal Expenses	359,267	105,586	184,385	9,477	6,579	9,478	4,668	3,565	1,318	2,389	1,177	5,170	2,154	4,556	18,189	87	489
11	Return and Taxes	77,053	6,028	6,628	8,783	6,077	17,027	8,328	4,813	1,768	4,257	2,082	2,873	1,448	2,573	4,283	85	1
12	Total Cost of Service (Excluding RSA, MTA, Rural Subsidy)	436,320	111,614	191,012	18,260	12,655	26,505	12,997	8,378	3,087	6,646	3,259	8,043	3,602	7,128	22,473	172	490

Newfoundland Power Inc.
2005 Pro-Forma Cost of Service Study

FUNCTIONAL CLASSIFICATION OF THE COST OF SERVICE (Excluding RSA, MTA and Rural Subsidy)

Line No.	Category	
1	Purchase Power	Taken from Schedule 3.2, Line 5. (Excludes the Rural Deficit of $36,325,023.)
2	Operating and Maintenance	Taken from Schedule 3.2, Line 31 less Line 5. (Excludes non-regulated expenses of $1,407,757.)
3	Depreciation	Taken from Schedule 3.3, Line 20
	Expense Credits	
	Wheeling Revenues	
4	Transmission	Allocated based on functional classification of Transmission O&M expenses excluding specifically assigned (Schedule 3.2, Line 8).
5	Distribution	Based on the functional classification of Primary Distribution (Schedule 3.2, Line 13, Colmuns F & G).
6	Joint Use Revenue	Based on the functional classification of Poles, Lines and Fittings (Schedule 3.2, Line 13).
7	Revenue from Temp. Service and Reconnects	Based on functional classification of Services (Schedule 3.2, Line 14).
8	Customer Service Fees	Functional Classification based on 100% Customer Service/ Customer Accounting.
9	Total Expense Credits	Sum of lines 4 through 8.
10	Subtotal Expenses	Total of Lines 1, 2, and 3, less Line 9. (See Schedule 5.2 for the reconcillation to Total Company Expenses as Reported.)
11	Return and Taxes	Functional Classification based on Total Average Rate Base, Schedule 2.4, Line 33. (See Schedule 5.4 for the reconcillation to total Company Return and Taxes as Reported.)
12	Total Cost of Service (Excluding RSA, MTA, Rural Subsidy)	Total of Lines 10 and 11.

ALLOCATION OF THE COST OF SERVICE TO CLASS OF SERVICE (Excluding RSA, MTA and Rural Subsidy)
Total Cost of Service excludes RSA, MTA and Rural Surcharge (All numbers are times $1,000)

Line No.	Class of Service	Rate Code	Total	Produced & Purchased Demand A	Produced & Purchased Energy B	Transmission Demand C	Distribution: Substation Demand D	Distribution: Primary Demand E	Distribution: Primary Customer F	Distribution: Transformers Demand G	Distribution: Transformers Customer H	Distribution: Secondary Demand I	Distribution: Secondary Customer J	Distribution: Services Customer K	Distribution: Meters Customer L	Distribution: St. Lighting Customer M	Customer Acc. & Cust. Serv. N	Specifically Assigned O	Revenue Related P
	Allocation Factors Used ==>			Transmission ICP	Transmission Energy	Transmission ICP	Primary NCP	Primary NCP	Weighted Customers	Secondary NCP	Weighted Customers	Secondary NCP	Weighted Customers	Weighted Customers	Weighted Customers		Weighted Customers		Revenue
	DOMESTIC																		
1	Domestic Regular	1.1	81,739	18,601	30,569	3,043	2,361	4,945	4,835	1,682	1,149	1,335	1,213	3,028	714	0	8,179	0	85
2	Domestic All Electric	1.1	199,867	56,278	83,562	9,207	5,794	12,134	6,394	4,128	1,519	3,275	1,604	4,004	944	0	10,815	0	210
3	Total Domestic	1.1	281,606	74,878	114,131	12,250	8,154	17,079	11,229	5,811	2,668	4,609	2,817	7,032	1,658	0	18,995	0	295
	GENERAL SERVICES																		
4	(0-10 kW)	2.1	9,941	1,790	3,703	293	242	506	688	172	163	137	173	431	234	0	1,397	0	13
5	(10-100 kW)	2.2	47,859	12,325	23,345	2,016	1,474	3,087	464	1,050	110	833	117	349	974	0	1,650	0	63
	(110-1000 kVA)	2.3																	
6	Primary (110-350 kVA)		1,491	382	832	62	49	102	2	0	0	0	0	0	54	0	7	0	2
7	Secondary (110-350 kVA)		27,945	6,970	15,125	1,140	886	1,855	43	631	10	501	11	177	392	0	167	0	37
8	Transmission (350-1000 kVA)		122	30	65	5	0	0	0	0	0	0	0	0	8	0	0	13	0
9	Primary (350-1000 kVA)		7,018	1,851	4,036	303	235	493	3	0	0	0	0	0	79	0	10	0	8
10	Secondary (350-1000 kVA)		23,281	5,923	12,854	969	753	1,577	12	536	3	426	3	48	105	0	45	0	28
11	Total (110-1000 kVA)	2.3	59,858	15,156	32,913	2,480	1,923	4,027	59	1,168	13	926	14	225	638	0	229	13	75
	(1000 kVA and Over)	2.4																	
12	Transmission		381	81	195	13	0	0	0	0	0	0	0	0	2	0	0	89	0
13	Primary		20,412	5,187	12,299	849	614	1,286	2	0	0	0	0	0	72	0	9	70	24
14	Secondary		5,269	1,293	3,051	211	153	321	1	109	0	87	0	5	25	0	6	0	7
15	Total (1000 kVA and Over)	2.4	26,063	6,561	15,545	1,073	767	1,607	3	109	0	87	0	5	100	0	15	159	31
16	**STREET LIGHTING**	4.1	10,993	903	1,376	148	95	199	553	68	131	54	139	0	0	7,128	187	0	12
17	Total		436,320	111,614	191,012	18,260	12,655	26,505	12,997	8,378	3,087	6,646	3,259	8,043	3,602	7,128	22,473	172	490

Newfoundland Power Inc.
2005 Pro-Forma Cost of Service Study

ALLOCATION OF THE COST OF SERVICE TO CLASS OF SERVICE (Excluding RSA, MTA and Rural Subsidy)

NOTES:

Line No.	Category	
17	Total	Total Cost of Service shown in Schedule 1.1, Line 12.

Col.		
A	Produced and Purchased Demand	Transmission demand Allocator for 1CP taken From Schedule 4.6, Column L.
B	Produced and Purchased Energy	Transmission Energy Allocator taken From Schedule 4.4, Column L.
C	Transmission Demand	Transmission demand Allocator for 1CP taken From Schedule 4.6, Column L.
D	Distribution Substation Demand	Primary demand Allocator for NCP taken from Schedule 4.5, Column H.
E	Distribution Primary Demand	Primary demand Allocator for NCP taken from Schedule 4.5, Column H.
F	Distribution Primary Customer	Primary Lines Customer Allocator taken from Schedule 4.3, Column G.
G	Distribution Transformer Demand	Secondary demand Allocator for NCP taken from Schedule 4.5, Column D.
H	Distribution Transformer Customer	Transformer Customer Allocator taken from Schedule 4.3, Column M.
I	Distribution Secondary Demand	Secondary demand Allocator for NCP taken from Schedule 4.5, Column D.
J	Distribution Secondary Customer	Secondary Lines Customer Allocator taken from Schedule 4.3, Column J.
K	Distribution Services Customer	Service Drop Allocator taken from Schedule 4.3, Column P.
L	Distribution Meters Customer	Meters Allocator taken from Schedule 4.3, Column S.
M	Distribution Street Lighting Customer	All Allocated to Street Lighting Rate Class.
N	Cust. Accounting and Cust. Services	Customer Allocator taken from Schedule 4.3, Column D.
O	Customer Specific	Total cost are allocated to class based on the amount of fixed plant dedicated to supplying single customers and the class which those customers belong.
P	Revenue Related	Total cost is allocated based on revenue from class plus RSA and MTA revenue, Column I, from Schedule 1.4.

TOTAL ALLOCATION OF THE COST OF SERVICE
(All dollars are times 1,000)

Line No.	Class of Service	Rate Code	Energy A	Demand B	Customer C	Street Lighting D	Specifically Assigned E	Revenue Related Expenses F	Total before RSA, MTA and Rural Deficit G	Allocated Rural Subsidy H	MTA I	RSA J	Total Cost to Serve K	Allocation of Other Revenue L	Total Cost Recovered in Final Rates M
	DOMESTIC														
1	Domestic Regular	1.1	30,569	31,966	19,119	0	0	85	81,739	6,805	1,992	3,552	94,088	$572	$93,516
2	Domestic All Electric	1.1	83,562	90,815	25,280	0	0	210	199,867	16,640	4,803	9,709	231,019	$1,415	$229,605
3	Total Domestic	1.1	114,131	122,782	44,399	0	0	295	281,606	23,445	6,795	13,261	325,107	$1,987	$323,120
	GENERAL SERVICE														
4	(0-10 kW)	2.1	3,703	3,139	3,085	0	0	13	9,941	828	311	430	11,509	$91	$11,418
5	(10-100 kW)	2.2	23,345	20,786	3,664	0	0	63	47,859	3,984	1,484	2,643	55,969	$427	$55,542
	(110-1000 kVA)	2.3													
6	Primary (110-350 kVA)		832	594	63	0	0	2	1,491	124	45	97	1,757	$13	$1,744
7	Secondary (110-350 kVA)		15,125	11,984	800	0	0	37	27,945	2,327	865	1,743	32,880	$246	$32,634
8	Transmission (350-1000 kVA)		65	34	9	0	13	0	122	10	3	8	143	$1	$143
9	Primary (350-1000 kVA)		4,036	2,883	91	0	0	8	7,018	584	197	472	8,273	$56	$8,216
10	Secondary (350-1000 kVA)		12,854	10,184	214	0	0	28	23,281	1,938	660	1,488	27,367	$187	$27,179
11	Total (110-1000 kVA)	2.3	32,913	25,679	1,177	0	13	75	59,858	4,983	1,771	3,808	70,420	$504	$69,916
	(1000 kVA and Over)	2.4													
12	Transmission		195	95	2	0	89	0	381	32	10	23	446	$3	$443
13	Primary		12,299	7,936	84	0	70	24	20,412	1,699	570	1,446	24,128	$159	$23,969
14	Secondary		3,051	2,173	39	0	0	7	5,269	439	155	354	6,218	$44	$6,174
15	Total (1000 kVA and Over)	2.4	15,545	10,204	124	0	159	31	26,063	2,170	736	1,823	30,792	$205	$30,586
16	**STREET LIGHTING**	4.1	1,376	1,467	1,010	7,128	0	12	10,993	915	291	160	12,359	$84	$12,275
17	Total		191,012	184,057	53,459	7,128	172	490	436,320	36,325	11,387	22,124	506,156	$3,298	$502,858

TOTAL ALLOCATION OF THE COST OF SERVICE

NOTES:

Column

A	Energy cost taken from Schedule 1.2, Column B.
B	Demand cost taken from Schedule 1.2, as the sum of Columns A, C, D, E, G and I.
C	Customer cost taken from Schedule 1.2, as the sum of Columns F, H, J, K, L and N.
D	Direct Street Lighting Cost taken from Schedule 1.2, Column M.
E	Specifically assigned cost taken from Schedule 1.2, Column O.
F	Revenue Related Expenses taken from Schedule 1.2, Column P.
G	Sum of Columns A through F.
H	Rural Surcharge allocated to Class based on total cost before Rural Deficit, Column G.
I	MTA cost taken as equal to MTA revenue as taken from Schedule 1.4 Column G.
J	RSA cost taken as equal to revenue from RSA factor from Schedule 1.4 Column F.
K	SUM of Columns G through J.
L	Taken from the sum of Schedule 1.4, Column C.
M	Column K less Column L.

REVENUE BY CLASS OF SERVICE
(All dollars are times 1,000)

Line No.	Class of Service	Rate Code	Revenue from Base Rates: Base Rates A	Revenue from Base Rates: Forfeited Discounts B	Allocation of Other Revenue C	Remove Rural Subsidy D	Total Before Rural Subsidy E	RSA Revenue F	MTA Revenue G	Rural Subsidy H	Total Revenue + RSA & MTA I	Total Revenue from Final Rates J
	DOMESTIC											
1	Domestic Regular	1.1	80,872	580	572	-6,805	75,220	$3,552	$1,992	$6,805	$87,569	$86,997
2	Domestic All Electric	1.1	199,939	1,372	1,415	-16,640	186,086	$9,709	$4,803	$16,640	$217,238	$215,824
3	Total Domestic		280,812	1,952	1,987	-23,445	261,306	13,261	6,795	23,445	304,807	$302,820
	GENERAL SERVICE											
4	(0-10 kW)	2.1	12,838	103	91	-828	12,204	$430	$311	$828	$13,772	$13,681
5	(10-100 kW)	2.2	60,384	351	427	-3,984	57,177	$2,643	$1,484	$3,984	$65,288	$64,861
	(110-1000 kVA)	2.3										
6	Primary (110-350 kVA)		1,797	7	13	-124	1,692	$97	$45	$124	$1,958	$1,945
7	Secondary (110-350 kVA)		34,887	155	246	-2,327	32,961	$1,743	$865	$2,327	$37,895	$37,649
8	Transmission (350-1000 kVA)		134	1	1	-10	126	$8	$3	$10	$147	$146
9	Primary (350-1000 kVA)		7,979	34	56	-584	7,484	$472	$197	$584	$8,738	$8,682
10	Secondary (350-1000 kVA)		26,558	117	187	-1,938	24,925	$1,488	$660	$1,938	$29,010	$28,823
11	Total (110-1000 kVA)	2.3	71,354	313	504	-4,983	67,187	3,808	1,771	4,983	77,749	$77,246
	(1000 kVA and Over)	2.4										
12	Transmission		402	0	3	-32	373	$23	$10	$32	$438	$435
13	Primary		22,592	22	159	-1,699	21,073	$1,446	$570	$1,699	$24,788	$24,629
14	Secondary		6,189	23	44	-439	5,816	$354	$155	$439	$6,765	$6,721
15	Total (1000 kVA and Over)	2.4	29,182	45	205	-2,170	27,262	1,823	736	2,170	31,991	$31,786
16	**STREET LIGHTING**	4.1	12,013	0	84	-915	11,182	$160	$291	$915	$12,549	$12,464
17	Total		466,583	2,764	3,298	-36,325	436,320	22,124	11,387	36,325	506,156	502,858

REVENUE BY CLASS OF SERVICE

NOTE:

Column

A - From Booked Revenue and Bill Frequency Analysis.
B - From Booked Revenue and Bill Frequency Analysis.
C - Total Allocated to Customer Class based on the Totals for Column A plus B.
D - The rural deficit cost is removed from revenue by allocating the cost to each customer class based on class cost as shown on Schedule 1.3 Column H.
E - Total of Columns A through D. (See Schedule 5.3 for the reconcillation to Total Company Revenue as Reported.)
F - From actual MTA booked and Bill Frequency Analysis.
G - From actual RSA booked and Bill Frequency Analysis.
H - From Column D.
I - Total of Columns E through H.
J - Column I less Column C.

Newfoundland Power Inc.
2005 Pro-Forma Cost of Service Study

REVENUE TO COST RATIO
Including RSA, MTA and Rural Subsidy
(All dollars are times 1,000)

Line No.	Class of Service	Rate Code	Revenue from Final Rates A	Costs B	Revenue to Cost Ratio C
1	**DOMESTIC**	1.1	302,820	323,120	93.7%
	GENERAL SERVICE				
2	(0-10 kW)	2.1	13,681	11,418	119.8%
3	(10-100 kW)	2.2	64,861	55,542	116.8%
4	(110 - 1000 kVA)	2.3	77,246	69,916	110.5%
5	(1000 kVA and Over)	2.4	31,786	30,586	103.9%
6	**STREET LIGHTING**	4.1	12,464	12,275	101.5%
7	Total		502,858	502,858	100.0%

Column
A Revenue from Schedule 1.4, Column J.
B Costs from Schedule 1.3, Column M.
C Column A divided by Column B.

Newfoundland Power
2005 Pro-Forma Cost of Service Study

CLASSIFIED COST LOADERS BY CLASS

			% Loader to be assigned to each Classified Cost Component							RSA Cost Loader (cents/kWh)		
Line No.	Class of Service	Rate Code	Rural Subsidy A	Revenue Related Costs B	Non-Rate Revenue Recovery C	MTA D	Total Costs in Loader E	Total Classified Costs F	% Rate Loader G	RSA H	Sales MWh I	RSA cents/kWh J
	DOMESTIC											
1	Domestic Regular	1.1	6,805	85	(572)	1,992	8,309	81,654	10.18%	3,552	799,968	0.444
2	Domestic All Electric	1.1	16,640	210	(1,415)	4,803	20,239	199,657	10.14%	9,709	2,186,726	0.444
3	Total Domestic	1.1	23,445	295	(1,987)	6,795	28,548	281,311	10.15%	13,261	2,986,694	0.444
	GENERAL SERVICE											
4	(0-10 kW)	2.1	828	13	(91)	311	1,061	9,928	10.68%	430	96,908	0.443
5	(10-100 kW)	2.2	3,984	63	(427)	1,484	5,104	47,795	10.68%	2,643	610,924	0.433
	(110-1000 kVA)	2.3										
6	Primary (110-350 kVA)		124	2	(13)	45	158	1,489	10.64%	97	22,023	0.440
7	Secondary (110-350 kVA)		2,327	37	(246)	865	2,982	27,909	10.69%	1,743	395,816	0.440
8	Transmission (350-1000 kVA)		10	0	(1)	3	13	122	10.42%	8	1,763	0.442
9	Primary (350-1000 kVA)		584	8	(56)	197	734	7,010	10.47%	472	106,839	0.442
10	Secondary (350-1000 kVA)		1,938	28	(187)	660	2,439	23,253	10.49%	1,488	336,384	0.442
11	Total (110-1000 kVA)	2.3	4,983	75	(504)	1,771	6,326	59,783	10.58%	3,808	862,825	0.441
	(1000 kVA and Over)	2.4										
12	Transmission		32	0	(3)	10	39	380	10.37%	23	5,269	0.444
13	Primary		1,699	24	(159)	570	2,135	20,388	10.47%	1,446	325,565	0.444
14	Secondary		439	7	(44)	155	557	5,263	10.58%	354	79,842	0.444
15	Total (1000 kVA and Over)	2.4	2,170	31	(205)	736	2,731	26,032	10.49%	1,823	410,676	0.444
16	**STREET LIGHTING**	4.1	915	12	(84)	291	1,134	10,981	10.33%	160	35,996	0.444
17	Total		36,325	490	(3,298)	11,387	44,905	435,830	10.30%	22,124	5,004,023	0.442

Newfoundland Power Inc.
2005 Pro-Forma Cost of Service Study

CLASSIFIED COST LOADERS BY CLASS

NOTE:

Column

A - See Schedule 1.3, Column H.
B - See Schedule 1.3, Column F.
C - See Schedule 1.3, Column L. (Negative).
D - See Schedule 1.3, Column I.
E - Total of Columns A through D.
F - See Schedule 1.3, Sum of Columns A through E.
G - Column E divided by Column F.
H - See Schedule 1.3, Column J.
I - See Schedule 4.1, Column D.
J - Column H divided by Column I.

2005 Pro-Forma Cost of Service Study

UNIT COSTS BY ENERGY, DEMAND AND CUSTOMER COSTS

Line No.	Class of Service	Rate Code	Billing Statistics From Schedule 4.1: Energy Sales MWh A	Average Number of Customers B	Total Billing Demands kW - kVA C	Unit Energy Costs cent/kWh D	Unit Demand Costs: By Energy Sales cent/kWh E	By Billing Demand $/kW - $/kVA F	Unit Customer Costs: By Energy Sales cent/kWh G	By Number of Customers $/Cust/month H	Specifically Assigned / Street Lighting Cost by Sales cent/kWh I	Total Cost by Sales cent/kWh J
	DOMESTIC											
1	Domestic Regular	1.1	799,968	84,039	0	4.654	4.403	0.00	2.633	20.89	0.000	11.690
2	Domestic All Electric	1.1	2,186,726	111,123	0	4.653	4.574	0.00	1.273	20.88	0.000	10.500
3	Total Domestic	1.1	2,986,694	195,162	0	4.653	4.528	0.00	1.637	20.88	0.000	10.819
	GENERAL SERVICE											
4	(0-10 kW)	2.1	96,908	11,959	0	4.673	3.586	0.00	3.524	23.80	0.000	11.783
5	(10-100 kW)	2.2	610,924	8,072	2,181,835	4.662	3.766	10.54	0.664	41.86	0.000	9.092
	(110-1000 kVA)	2.3										
6	Primary (110-350 kVA)		22,023	31	61,370	4.620	2.985	10.71	0.316	187.01	0.000	7.921
7	Secondary (110-350 kVA)		395,816	746	1,284,173	4.670	3.351	10.33	0.224	98.90	0.000	8.245
8	Transmission (350-1000 kVA)		1,763	2	4,225	4.528	2.157	9.00	0.555	407.60	0.844	8.083
9	Primary (350-1000 kVA)		106,839	45	286,706	4.615	2.981	11.11	0.094	186.74	0.000	7.690
10	Secondary (350-1000 kVA)		336,384	200	989,318	4.664	3.345	11.37	0.070	98.72	0.000	8.080
11	Total (110-1000 kVA)	2.3	862,825	1,024	2,625,793	4.659	3.291	10.81	0.151	105.95	0.002	8.103
	(1000 kVA and Over)	2.4										
12	Transmission		5,269	1	19,111	4.528	1.982	5.46	0.043	188.57	1.861	8.414
13	Primary		325,565	36	786,930	4.617	2.693	11.14	0.028	213.66	0.024	7.362
14	Secondary		79,842	23	244,849	4.670	3.010	9.82	0.053	154.72	0.000	7.733
15	Total (1000 kVA and Over)	2.4	410,676	60	1,050,890	4.626	2.745	10.73	0.033	190.63	0.043	7.448
16	**STREET LIGHTING**	4.1	35,996	9,608	0	4.660	4.497	0.00	3.095	9.66	21.848	34.100
17	Total		5,004,023	225,885	5,858,518	4.653	4.057		1.178	21.75	0.161	10.049

Newfoundland Power Inc.
Cost of Service Study

UNIT COSTS BY ENERGY, DEMAND AND CUSTOMER COSTS

NOTE:

Column

A - See Schedule 4.1, Column D.
B - See Schedule 4.1, Column C.
C - See Schedule 4.1, Column E.
D - [(Total of Energy Related Costs (Schedule 1.3, Column A) divided by Energy Sales (Schedule 1.7, Column A)) times (1 + % Classified Cost Loader (Schedule 1.6, Column G)) times 100] plus RSA Loader (Schedule 1.6, Column J).
E - Demand Related Costs (Schedule 1.3, Column B) divided by Energy Sales (Schedule 1.7, Column A) times (1 + % Classified Cost Loader (Schedule 1.6, Column G)) times 100.
F - Demand Related Costs (Schedule 1.3, Column B) divided by Total Billing Demands (Schedule 1.7, Column C) times (1 + % Classified Cost Loader (Schedule 1.6, Column G)) times 1000.
G - Customer Related Costs (Schedule 1.3, Column C) divided by Energy Sales (Schedule 1.7, Column A) times (1 + % Classified Cost Loader (Schedule 1.6, Column G)) times 100.
H - Customer Related Costs (Schedule 1.3, Column C) divided by Average Number of Customers (Schedule 1.7, Column B) times (1 + % Classified Cost Loader (Schedule 1.6, Column G)) times 1000 divided by 12.
I - Specifically Assigned Costs (Schedule 1.3 Column E) divided by Energy Sales (Schedule 1.7, Column A) times (1 + % Classified Cost Loader (Schedule 1.6, Column G)) times 100.
J - Total of Columns D, E, G and I.

Newfoundland Power Inc.
2005 Pro-Forma Cost of Service Study

FUNCTIONAL CLASSIFICATION OF AVERAGE FIXED ASSETS
(All numbers are times $1,000)

Line No.	Category	Total	Produced & Purchased Demand	Produced & Purchased Energy	Transmission Demand	Distribution: Substation Demand	Primary Demand	Primary Customer	Transformers Demand	Transformers Customer	Secondary Demand	Secondary Customer	Services Customer	Meters Customer	St. Lighting Customer	Cust. Acc. & Cust. Serv.	Specifically Assigned
		A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	Hydro Electric Production	111,789	47,175	64,614	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Other Generation	20,377	20,377	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Transmission	88,121	0	0	87,414	0	0	0	0	0	0	0	0	0	0	0	707
	Substations																
4	Hydro Electric Production	4,518	1,907	2,612	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Other Production	731	731	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Transmission	40,596	0	0	40,425	0	0	0	0	0	0	0	0	0	0	0	171
7	Distribution	78,601	0	0	0	78,237	0	0	0	0	0	0	0	0	0	0	364
	Distribution																
8	Land and Land Clearing	781	0	0	0	0	401	198	0	0	100	49	0	0	32	0	0
9	Conductors, Poles and Fittings	471,303	0	0	0	0	242,159	119,272	0	0	60,540	29,818	0	0	19,514	0	0
10	Transformers	83,942	0	0	0	0	0	0	61,277	22,664	0	0	0	0	0	0	0
11	Services	66,343	0	0	0	0	0	0	0	0	0	0	66,343	0	0	0	0
12	Meters	20,744	0	0	0	0	0	0	0	0	0	0	0	20,744	0	0	0
13	Street lighting	17,951	0	0	0	0	0	0	0	0	0	0	0	0	17,951	0	0
14	Total Direct Utility Plant	1,005,797	70,189	67,226	127,839	78,237	242,560	119,470	61,277	22,664	60,640	29,867	66,343	20,744	37,498	0	1,242
	General Utility Plant																
15	Land and Land Clearing	5,046	147	141	706	313	970	478	245	91	242	119	265	83	150	1,089	6
16	Buildings	31,866	1,374	1,316	5,208	1,882	5,835	2,874	1,474	545	1,459	718	1,596	499	902	6,138	45
17	Computer Equipment	38,736	1,033	990	1,930	688	2,134	1,051	539	199	533	263	584	182	330	28,264	16
18	Misc Equipment	15,235	421	403	2,341	1,008	3,124	1,539	789	292	781	385	855	267	483	2,527	21
19	Transportation	21,109	424	406	2,741	1,808	5,605	2,760	1,416	524	1,401	690	1,533	479	866	429	27
20	Tele-communications	13,122	1,545	1,480	3,211	590	1,828	900	462	171	457	225	500	156	283	1,290	25
21	Total General Utility Plant	125,113	4,945	4,736	16,136	6,288	19,495	9,602	4,925	1,822	4,874	2,401	5,332	1,667	3,014	39,737	140
22	Total	1,130,910	75,134	71,961	143,975	84,525	262,055	129,072	66,202	24,486	65,514	32,268	71,675	22,411	40,512	39,737	1,383

FUNCTIONAL CLASSIFICATION OF AVERAGE FIXED ASSETS

Line No.	Category	Basis for Functional Classification
1	Hydro Electric Production	Classified based on factors shown in Schedule 5.1 Line 4.
2	Other Generation	Classified based on factors shown in Schedule 5.1 Line 5.
3	Transmission	Functional split based on Schedule 5.1 line 19. Common costs Classified based on the transmission common as shown on Schedule 5.1 Line 6.
	Substations	
4	Hydro Electric Production	Functional splits based on schedule 5.1 line 20 and classified as shown in schedule 5.1 line 4.
5	Other Production	Functional splits on based schedule 5.1 line 20 and classified as shown in schedule 5.1 line 5.
6	Transmission	Functional splits based on schedule 5.1 line 20 and common transmission costs classified as shown in schedule 5.1 line 6.
7	Distribution	Functional splits based on schedule 5.1 line 20 and distribution substation common costs classified as shown in schedule 5.1 line 7.
	Distribution	
8	Land and Land Clearing	Functional splits based on schedule 5.1 line 21 and classified as shown in schedule 5.1 lines 8, 9 & 10.
9	Conductors, Poles and Fittings	Functional splits based on schedule 5.1 line 22 and classified as shown in schedule 5.1 lines 11, 12 & 13.
10	Transformers	Classified as shown in schedule 5.1 line 14.
11	Services	Classified as shown in schedule 5.1 line 15.
12	Meters	Classified as shown in schedule 5.1 line 16.
13	Street lighting	Classified as shown in schedule 5.1 line 17.
14	Total Direct Fixed Plant	Total of Lines 1 through 13.
	General Utility Plant	
15	Land and Land Clearing	Functionalized based on general property land and land rights (See Schedule 5.1 line 23). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
16	Buildings	Functionalized based on general property buildings and structures (See Schedule 5.1 line 24). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
17	Computer Equipment	Functionalized based on Computer Hardware and Software (See Schedule 5.1 line 25). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
18	Miscellaneous Equipment	Functionalized based on General Property Other Equipment (See Schedule 5.1 line 26). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
19	Transportation	Functionalized based on Transportation (See Schedule 5.1 line 27). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
20	Tele-communications	Functionalized based on Total Communications (See Schedule 5.1 line 28). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
21	Total General Property	Total of Lines 15 through 20.
22	Total	Total of Lines 14 and 21.

FUNCTIONAL CLASSIFICATION OF AVERAGE ACCUMULATED DEPRECIATION
(All numbers are times $1,000)

Line No.	Category	Total	Produced & Purchased Demand	Produced & Purchased Energy	Transmission Demand	Distribution Substation Demand	Distribution Primary Demand	Distribution Primary Customer	Distribution Transformers Demand	Distribution Transformers Customer'	Distribution Secondary Demand	Distribution Secondary Customer	Distribution Services Customer	Distribution Meters Customer	Distribution St. Lighting Customer	Cust. Acc. & Cust. Serv.	Specifically Assigned
		A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	Hydro Electric Production	35,467	14,967	20,500	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Other Generation	6,384	6,384	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Transmission	45,906	0	0	45,538	0	0	0	0	0	0	0	0	0	0	0	369
	Substations																
4	Hydro Electric Production	1,734	732	1,002	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Other Production	280	280	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Transmission	15,581	0	0	15,516	0	0	0	0	0	0	0	0	0	0	0	65
7	Distribution	30,168	0	0	0	30,028	0	0	0	0	0	0	0	0	0	0	140
	Distribution																
8	Land and Land Clearing	540	0	0	0	0	277	136	0	0	69	34	0	0	23	0	0
9	Conductors, Poles and Fittings	184,774	0	0	0	0	94,816	46,701	0	0	23,704	11,675	0	0	7,877	0	0
10	Transformers	27,682	0	0	0	0	0	0	20,208	7,474	0	0	0	0	0	0	0
11	Services	47,375	0	0	0	0	0	0	0	0	0	0	47,375	0	0	0	0
12	Meters	9,337	0	0	0	0	0	0	0	0	0	0	0	9,337	0	0	0
13	Street lighting	9,330	0	0	0	0	0	0	0	0	0	0	0	0	9,330	0	0
	General Plant																
14	Land and Land Rights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15	Buildings	12,033	519	497	1,967	711	2,203	1,085	557	206	551	271	603	188	341	2,318	17
16	Computer Equipment	18,581	496	475	926	330	1,023	504	259	96	256	126	280	88	158	13,558	8
17	Misc. Equipment	6,938	192	184	1,066	459	1,423	701	359	133	356	175	389	122	220	1,151	9
18	Transportation	9,269	186	178	1,204	794	2,461	1,212	622	230	615	303	673	210	380	189	12
19	Tele-communications	8,563	1,009	966	2,095	385	1,193	587	301	111	298	147	326	102	184	842	16
20	Total	469,942	24,764	23,802	68,310	32,706	103,397	50,927	22,305	8,250	25,849	12,732	49,646	10,047	18,514	18,057	636

FUNCTIONAL CLASSIFICATION OF AVERAGE ACCUMULATED DEPRECIATION

Line No.	Category	Basis for Functional Classification
1	Hydro Electric Production	Classified based on factors shown in Schedule 5.1 Line 4.
2	Other Generation	Classified based on factors shown in Schedule 5.1 Line 5.
3	Transmission	Functional split based on Schedule 5.1 line 19. Classified based on the transmission general as shown on Schedule 5.1 Line 6.
	Substations	
4	Hydro Electric Production	Functional splits based on schedule 5.1 line 20 and classified as shown in schedule 5.1 line 4.
5	Other Production	Functional splits on based schedule 5.1 line 20 and classified as shown in schedule 5.1 line 5.
6	Transmission	Functional splits based on schedule 5.1 line 20 and classified as shown in schedule 5.1 line 6.
7	Distribution	Functional splits based on schedule 5.1 line 20 and classified as shown in schedule 5.1 line 7.
	Distribution	
8	Land and Land Rights	Functional splits based on schedule 5.1 line 21 and classified as shown in schedule 5.1 lines 8, 9 & 10.
9	Conductors, Poles and Fittings	Functional splits based on schedule 5.1 line 22 and classified as shown in schedule 5.1 lines 11, 12 & 13.
10	Transformers	Classified as shown in schedule 5.1 line 14.
11	Services	Classified as shown in schedule 5.1 line 15.
12	Meters	Classified as shown in schedule 5.1 line 16.
13	Street lighting	Classified as shown in schedule 5.1 line 17.
	General Plant	
14	Land and Land Clearing	Functionalized based on general property land and land rights (See Schedule 5.1 line 23). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
15	Buildings	Functionalized based on general property buildings and structures (See Schedule 5.1 line 24). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
16	Computer Equipment	Functionalized based on Computer Hardware and Software (See Schedule 5.1 line 25). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
17	Miscellaneous Equipment	Functionalized based on General Property Other Equipment (See Schedule 5.1 line 26). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
18	Transportation	Functionalized based on Transportation (See Schedule 5.1 line 27). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
19	Tele-communications	Functionalized based on Total Communications (See Schedule 5.1 line 28). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
20	Total	Total of Lines 1 through 19.

FUNCTIONAL CLASSIFICATION OF AVERAGE NET CONTRIBUTIONS IN AID OF CONSTRUCTION (CIAC)
(All numbers are times $1,000)

Line No.	Category	Total	Produced & Purchased Demand	Produced & Purchased Energy	Transmission Demand	Distribution: Substation Demand	Distribution: Primary Demand	Distribution: Primary Customer	Distribution: Transformers Demand	Distribution: Transformers Customer	Distribution: Secondary Demand	Distribution: Secondary Customer	Distribution: Services Customer	Distribution: Meters Customer	Distribution: St. Lighting Customer	Cust. Acc. & Cust. Serv.	Specifically Assigned
		A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	Hydro Electric Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Other Generation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Transmission	1,504	0	0	1,492	0	0	0	0	0	0	0	0	0	0	0	12
	Substations																
4	Hydro Electric Production	36	15	21	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Other Production	6	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Transmission	327	0	0	326	0	0	0	0	0	0	0	0	0	0	0	1
7	Distribution	634	0	0	0	631	0	0	0	0	0	0	0	0	0	0	3
	Distribution																
8	Land and Land Clearing	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	Conductors, Poles and Fittings	16,142	0	0	0	0	8,294	4,085	0	0	2,074	1,021	0	0	668	0	0
10	Transformers	1,137	0	0	0	0	0	0	830	307	0	0	0	0	0	0	0
11	Services	612	0	0	0	0	0	0	0	0	0	0	612	0	0	0	0
12	Meters	468	0	0	0	0	0	0	0	0	0	0	0	468	0	0	0
13	Street lighting	287	0	0	0	0	0	0	0	0	0	0	0	0	287	0	0
	General Plant																
14	Land and Land Rights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15	Buildings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
16	Computer Equipment	(311)	(8)	(8)	(15)	(6)	(17)	(8)	(4)	(2)	(4)	(2)	(5)	(1)	(3)	(227)	(0)
17	Misc. Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Transportation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
19	Tele-communications	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20	Total	20,844	13	13	1,803	626	8,277	4,077	825	305	2,069	1,019	608	467	953	(227)	16

FUNCTIONAL CLASSIFICATION OF AVERAGE NET CONTRIBUTIONS IN AID OF CONSTRUCTION (CIAC)

Line No.	Category	Basis for Functional Classification
1	Hydro Electric Production	Classified based on factors shown in Schedule 5.1 Line 4.
2	Other Generation	Classified based on factors shown in Schedule 5.1 Line 5.
3	Transmission	Functional split based on Schedule 5.1 line 19. Classified based on the transmission general as shown on Schedule 5.1 Line 6.
	Substations	
4	Hydro Electric Production	Functional splits based on schedule 5.1 line 20 and classified as shown in schedule 5.1 line 4.
5	Other Production	Functional splits on based schedule 5.1 line 20 and classified as shown in schedule 5.1 line 5.
6	Transmission	Functional splits based on schedule 5.1 line 20 and classified as shown in schedule 5.1 line 6.
7	Distribution	Functional splits based on schedule 5.1 line 20 and classified as shown in schedule 5.1 line 7.
	Distribution	
8	Land and Land Clearing	Functional splits based on schedule 5.1 line 21 and classified as shown in schedule 5.1 lines 8, 9 & 10.
9	Conductors, Poles and Fittings	Functional splits based on schedule 5.1 line 22 and classified as shown in schedule 5.1 lines 11, 12 & 13.
10	Transformers	Classified as shown in schedule 5.1 line 14.
11	Services	Classified as shown in schedule 5.1 line 15.
12	Meters	Classified as shown in schedule 5.1 line 16.
13	Street lighting	Classified as shown in schedule 5.1 line 17.
	General Plant	
14	Land and Land Clearing	Functionalized based on general property land and land rights (See Schedule 5.1 line 23). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
15	Buildings	Functionalized based on general property buildings and structures (See Schedule 5.1 line 24). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
16	Computer Equipment	Functionalized based on Computer Hardware and Software (See Schedule 5.1 line 25). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
17	Miscellaneous Equipment	Functionalized based on General Property Other Equipment (See Schedule 5.1 line 26). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
18	Transportation	Functionalized based on Transportation (See Schedule 5.1 line 27). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
19	Tele-communications	Functionalized based on Total Communications (See Schedule 5.1 line 28). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
20	Total	Total of Lines 1 through 19.

FUNCTIONAL CLASSIFICATION OF AVERAGE RATE BASE
(All numbers are times $1,000)

Line No.	Category	Total A	Produced & Purchased Demand B	Produced & Purchased Energy C	Transmission Demand D	Distribution Substation Demand E	Primary Demand F	Primary Customer G	Transformers Demand H	Transformers Customer I	Secondary Demand J	Secondary Customer K	Services Customer L	Meters Customer M	St. Lighting Customer N	Cust. Acc. & Cust. Serv. O	Specifically Assigned P	Revenue Related
1	Hydro Electric Production	76,322	32,208	44,114	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Other Generation	13,992	13,992	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Transmission	42,215	0	0	41,876	0	0	0	0	0	0	0	0	0	0	0	339	0
	Substations																	
4	Hydro Electric Production	2,784	1,175	1,609	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Other Production	450	450	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Transmission	25,015	0	0	24,910	0	0	0	0	0	0	0	0	0	0	0	105	0
7	Distribution	48,434	0	0	0	48,209	0	0	0	0	0	0	0	0	0	0	225	0
	Distribution																	
8	Land and Land Clearing	241	0	0	0	0	124	61	0	0	31	15	0	0	9	0	0	0
9	Conductors, Poles and Fittings	286,530	0	0	0	0	147,343	72,572	0	0	36,836	18,143	0	0	11,637	0	0	0
10	Transformers	56,260	0	0	0	0	0	0	41,070	15,190	0	0	0	0	0	0	0	0
11	Services	18,968	0	0	0	0	0	0	0	0	0	0	18,968	0	0	0	0	0
12	Meters	11,407	0	0	0	0	0	0	0	0	0	0	0	11,407	0	0	0	0
13	Street lighting	8,622	0	0	0	0	0	0	0	0	0	0	0	0	8,622	0	0	0
14	Total Direct Net Utility Plant	591,240	47,825	45,723	66,786	48,209	147,467	72,633	41,070	15,190	36,867	18,158	18,968	11,407	20,268	0	669	0
	General Plant																	
15	Land and Land Rights	5,046	147	141	706	313	970	478	245	91	242	119	265	83	150	1,089	6	0
16	Buildings	19,832	855	819	3,242	1,171	3,632	1,789	917	339	908	447	993	311	561	3,820	28	0
17	Computer Equipment	20,156	538	515	1,004	358	1,110	547	280	104	278	137	304	95	172	14,707	9	0
18	Misc. Equipment	8,297	229	220	1,275	549	1,702	838	430	159	425	210	465	146	263	1,376	11	0
19	Transportation	11,840	238	228	1,537	1,014	3,144	1,548	794	294	786	387	860	269	486	241	15	0
20	Tele-communications	4,558	537	514	1,115	205	635	313	160	59	159	78	174	54	98	448	9	0
21	Total General Plant	69,729	2,544	2,436	8,879	3,610	11,192	5,512	2,827	1,046	2,798	1,378	3,061	957	1,730	21,680	78	0
22	Total Net Utility Plant	660,969	50,369	48,160	75,665	51,819	158,659	78,145	43,897	16,236	39,665	19,536	22,029	12,364	21,998	21,680	746	0
	Deductions from Rate Base																	
23	Contributions in Aid of Construction	20,844	13	13	1,803	626	8,277	4,077	825	305	2,069	1,019	608	467	953	(227)	16	0
24	Future Income Taxes - Depreciation/CCA	1,438	110	105	165	113	345	170	96	35	86	43	48	27	48	47	2	0
25	Weather Normalization (hydro equal.)	(6,915)	0	(6,915)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
26	Weather Normalization (Degree Day Norm.)	(3,374)	(362)	(346)	(544)	(373)	(1,141)	0	(316)	0	(285)	0	0	0	0	0	(5)	0
27	Total Deductions	11,993	(240)	(7,143)	1,423	366	7,481	4,247	605	341	1,870	1,062	656	494	1,000	(180)	13	0
	Additions to Rate Base																	
28	Financing - Customers CIACs	572	0	0	0	64	195	96	54	20	49	24	27	15	27	0	0	0
29	Average Deferred Charges	86,063	5,881	5,668	9,242	6,914	12,371	6,093	2,970	1,098	3,093	1,523	6,086	2,021	3,688	19,332	81	0
30	Cash Working Capital Allowance	5,514	1,715	3,040	88	72	101	50	24	9	25	12	63	21	39	247	1	8
31	Materials And Supplies	4,322	113	108	1,397	285	883	435	223	83	221	109	242	76	137	0	11	0
32	Total Additions	96,470	7,709	8,817	10,726	7,335	13,551	6,674	3,271	1,210	3,388	1,669	6,417	2,133	3,891	19,579	93	8
33	Total Average Rate Base	745,446	58,318	64,120	84,969	58,788	164,729	80,573	46,563	17,105	41,182	20,143	27,790	14,004	24,888	41,438	827	8

Newfoundland Power Inc.
2005 Pro-Forma Cost of Service Study

FUNCTIONAL CLASSIFICATION OF AVERAGE RATE BASE

Line No.	Category	Basis for Functional Classification
1	Hydro Electric Production	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2)
2	Other Generation	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2)
3	Transmission	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2)
	Substations	
4	Hydro Electric Production	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
5	Other Production	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
6	Transmission	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
7	Distribution	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
	Distribution	
8	Land and Land Clearing	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
9	Conductors, Poles and Fittings	
10	Transformers	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
11	Services	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
12	Meters	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
13	Street lighting	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
14	Total Direct Net Utility Plant	Total of Line 1 to 13.
	General Plant	
15	Land and Land Rights	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
16	Buildings	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
17	Computer Equipment	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
18	Misc. Equipment	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
19	Transportation	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
20	Tele-communications	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
21	Total General Plant	Total of Lines 15 to 20.
22	Total Net Utility Plant	Total of Line 14 and Line 21.
	Deductions from Rate Base	
23	Contributions in Aid of Construction	Taken from totals shown on Schedule 2.3.
24	Future Income Taxes - Depreciation/CCA	Functional Classification based on Total Net Utility Plant (Line 22).
25	Weather Normalization (hydro equal.)	Classified 100% to Energy.
26	Weather Normalization (Degree Day Norm.)	Functional Classification split based on Total Net Utility Plant (Line 22) excluding Customer Classification Functions
27	Total Deductions	Total of Lines 23 through 26.
	Additions to Rate Base	
28	Financing - Customer CIACs	Functional Classification based on Total Net Utility Plant for Distribution (Line 22, Columns E to N).
29	Average Deferred Charges	Functional Classification based on the Weighted Split for Administration and General. (See Schedule 3.2, Line 28).
30	Cash Working Capital Allowance	Functional Classification based on total operating and maintenance shown on Schedule 1.1, line 1 plus line 2.
31	Materials And Supplies	Functionalized based on Year End Inventory (See Schedule 5.1 Line 31). Classification based on total direct utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned (Schedule 2.1).
32	Total Additions	Total of Lines 28 through 31.
33	Total Rate Base	Line 22 less Line 27 plus Line 32.

LIST OF OPERATING EXPENSES NET OF GENERAL EXPENSES TRANSFERRED TO CAPITAL (GEC) (Excluding RSA and MTA)
(All numbers are times $1,000)

Expense Category Code	Description	Including Non-Regulated Expenses Total	Labour	Non-Labour	Non-Regulated Expenses	Excluding Non-Regulated Expenses Total Excl.	Labour Excl.	Non-Labour Excl.
	PURCHASED POWER WEATHER ADJUSTED							
PPH	Nfld. Hydro - Firm	314,296	-	314,296	-	314,296	-	314,296
PPDL	Nfld. Hydro - Secondary	12	-	12	-	12	-	12
	TOTAL PURCHASED POWER	314,308	-	314,308	-	314,308	-	314,308
	PRODUCTION							
Hydro	Hydro - Direct Operating and Maintenance	1,680	1,241	439	-	1,680	1,241	439
Hydro	Hydro - Water and Fuel - Lubricants	91	-	91	-	91	-	91
Hydro	Hydro - Supervision and misc.	448	309	138	-	448	309	138
Hydro	Hydro - Dam safety evaluations	33	8	25	-	33	8	25
Oth Prod	Other Production - Direct Operating and Maintenance	369	275	93	-	369	275	93
Oth Prod	Other Production - Fuel and Lubricants	26	-	26	-	26	-	26
	TOTAL PRODUCTION	2,646	1,833	813	-	2,646	1,833	813
Gen Sys Opr	SYSTEM OPERATIONS	947	906	41	-	947	906	41
Gen PTD	TOOLS, SAFETY, EQUIPMENT REPAIR & RUBBER GLOVE TESTING	501	37	464	-	501	37	464
Gen PTD	GENERAL OPERATIONS	3,483	2,829	653		3,483	2,829	653
	TOTAL MISC TECHNICAL OPERATING COSTS	4,931	3,772	1,158	-	4,931	3,772	1,158
Gen PTD	ENVIRONMENTAL COST	462	249	213	-	462	249	213
	SUBSTATIONS							
Subs	Direct O&M	2,462	1,598	863	-	2,462	1,598	863
	TRANSMISSION							
Transm	Direct O&M	524	239	284	-	524	239	284
	DISTRIBUTION							
CPF	Direct O&M - Lines/poles/fittings	1,884	1,751	132	-	1,884	1,751	132
Services	Direct O&M - Services	1,405	1,384	21	-	1,405	1,384	21
Strlgts	Direct O&M - Street Lights	898	778	120	-	898	778	120
Transf.	Direct O&M - Transformers	260	228	33	-	260	228	33
Meters	Direct O&M - Meters	489	373	115	-	489	373	115
Gen D	Direct O&M - Vegetation Management	976	167	809	-	976	167	809
Gen D	Pre Issues	375	-	375	-	375	-	375
	TOTAL DISTRIBUTION	6,287	4,681	1,606	-	6,287	4,681	1,606

LIST OF OPERATING EXPENSES NET OF GENERAL EXPENSES TRANSFERRED TO CAPITAL (GEC) (Excluding RSA and MTA)
(All numbers are times $1,000)

Expense Category Code	Description	Including Non-Regulated Expenses Total	Labour	Non-Labour	Non-Regulated Expenses	Excluding Non-Regulated Expenses Total Excl.	Labour Excl.	Non-Labour Excl.
	COMMUNICATIONS							
Gen Comm	Direct O&M - General	1,556	117	1,438	-	1,556	117	1,438
Gen D	Power Quality	48	46	2	-	48	46	2
Gen Comm	Direct O&M - Supervisory Contol Systems	47	46	2	-	47	46	2
	TOTAL COMMUNICATIONS	1,651	208	1,442	-	1,651	208	1,442
	CUSTOMER SERVICE							
Cust Acc	Customer Service Administration, Billing & Meter Reading	3,467	3,093	374	-	3,467	3,093	374
Cust Acc	Credit, Collections & Cash Control	2,777	1,280	1,497		2,777	1,280	1,497
Cust Acc	Inquiry	2,376	2,356	21		2,376	2,356	21
Cust Acc	Uncollectable Bills	1,158	-	1,158	-	1,158	-	1,158
A&G	Energy Services - General CDM Programs	853	349	503		853	349	503
	TOTAL CUSTOMER SERVICE	10,631	7,078	3,553	-	10,631	7,078	3,553
	FINANCE							
A&G	Finance	1,143	890	253		1,143	890	253
Labour Rela	Company Pension Scheme	4,752	-	4,752	-	4,752	-	4,752
Labour Rela	Retirement Allowances	1,060	-	1,060	-	1,060	-	1,060
Ins & Dam.	Risk Management	90	84	5	-	90	84	5
	TOTAL FINANCE	7,044	974	6,070	-	7,044	974	6,070
	CORPORATE COMMUNICATIONS							
A&G	Corporate Communications Supervision, Misc. and General Advertisments	495	406	89	31	464	380	83
Cust Acc	Corporate Communications - Safety Advertisements	171	-	171	-	171	-	171
	TOTAL CORPORATE COMMUNICATIONS	666	406	260	31	635	380	255
	MANAGEMENT INFORMATION SYSTEMS							
A&G	Supervision & Misc.	330	184	146	-	330	184	146
A&G	Computer Operations	470	433	38	-	470	433	38
A&G	Systems Development and Support	1,897	683	1,214	-	1,897	683	1,214
	TOTAL MIS	2,698	1,300	1,398	-	2,698	1,300	1,398
	HUMAN RESOURCE AND EMPLOYEE RELATED COSTS							
A&G	Human Resources Division	1,132	802	330	-	1,132	802	330
A&G	Employee Welfare & Coffee & Lunchroom Supplies	297	59	238	-	297	59	238
	TOTAL HUMAN RESOURCE AND EMPLOYEE RELATED COSTS	1,428	861	567	-	1,428	861	567
	ADMINSTRATION & MISCELLANEOUS							
A&G	Administration, Support Staff and Internal Audit	6,249	3,842	2,407	272	5,977	3,675	2,302
A&G	Misc. Costs - General	851	280	571	1,105	(254)	(84)	(171)
Ins & Dam.	Misc. Costs - Property Insurace & Public Liability (Not Insured)	1,817	3	1,813	-	1,817	3	1,813
Cust Acc	Mail Room	122	-	122	-	122	-	122

LIST OF OPERATING EXPENSES NET OF GENERAL EXPENSES TRANSFERRED TO CAPITAL (GEC) (Excluding RSA and MTA)
(All numbers are times $1,000)

Expense Category Code	Description	Including Non-Regulated Expenses Total	Labour	Non-Labour	Non-Regulated Expenses	Excluding Non-Regulated Expenses Total Excl.	Labour Excl.	Non-Labour Excl.
Revenue Related	PUB Assessments	489	-	489	-	489	-	489
A&G	Property Maintenance	1,295	141	1,154	-	1,295	141	1,154
A&G	Printing Services	308	196	113	-	308	196	113
	TOTAL ADMINISTRATION & MISCELLANEOUS	11,131	4,462	6,669	1,377	9,754	3,932	5,822
Vehicles	VEHICLE MAINTENANCE	1,496	-	1,496	-	1,496	-	1,496
	TOTAL OPERATING AND MAINTENANCE EXPENSES Net of GEC & (Excluding RSA & MTA Expense)	368,363	27,661	340,702	1,408	366,955	27,105	339,850

Expense Category Code	Cost of Service Expense Category
A&G	Administration and General (Excluding Labour Related Costs).
Curtail	Curtailable Credits Paid Customers.
CPF	Operating expenses directly associated with Conductors, Poles and Fittings.
Cust Acc	Operating Expenses associated with Customer Accounting and Customer Service.
Gen Comm	Communication Expenses Related to the VHS/Mobile radio system.
Gen D	General expenses to be split over the categories within distribution.
Gen PTD	General expenses to be split over Production, Transmission and Distribution.
Gen Sys Opr	General expenses associated with the Systems Control Centre.
Gen TD	General expenses to be split over Transmission and Distribution.
Hydro	Operating expenses associated with Hydraulic Generation.
Labour Rela	Administration and general Expenses directly related to Labour.
Meters	Operating expenses directly associated with Meters.
Oth Prod	Operating expenses associated with Diesel and Gas Turbine Generation.
Ins & Dam.	Property Insurance, Public Liability, Risk Management.
PPDL	Purchase Power Costs for Secondary Energy from Deer Lake Power Firmed up by Hydro.
PPH	Purchase Power Costs from Hydro for Firm Energy.
Revenue Related	Operating expenses related to revenue.
Services	Operating expenses directly associated with Services.
Strlgts	Operating expenses directly associated with Street Lighting.
Subs	Operating expenses directly associated with Substations.
Transf.	Operating expenses directly associated with Transformers.
Transm	Operating expenses directly associated with Transmission.

Newfoundland Power Inc.
2005 Pro-Forma Cost of Service Study

FUNCTIONAL CLASSIFICATION OF OPERATING AND MAINTENANCE EXPENSES
(All numbers are times $1000)

Line No.	Catagory	Total A	Produced & Purchased Demand B	Produced & Purchased Energy C	Transmission Demand D	Distribution: Substation Demand E	Primary Demand F	Primary Customer G	Transformers Demand H	Transformers Customer I	Secondary Demand J	Secondary Customer K	Services Customer L	Meters Customer M	St. Lighting Customer N	Customer Acc. & Cust. Serv. O	Specifically Assigned P	Revenue Related Q
	Purchase Power Expense																	
1	Purchases from Hydro - Production related	252,206	75,157	177,049	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Purchases from Hydro - Transmission related	24,033	24,033	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Deer Lake Power Secondary	12	4	9	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	Amortization of Hydro Equalization Reserve	1,732	0	1,732	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Sub Total	277,983	99,194	178,789	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Direct Operating & Maintenance Costs																	
6	Hydraulic Production	2,251	950	1,301	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	Other Production	394	394	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	Transmission	524	0	0	519	0	0	0	0	0	0	0	0	0	0	0	4	0
	Substations																	
9	Hydarulic Plants	89	38	52	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	Other Production	14	14	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	Transmission	803	0	0	800	0	0	0	0	0	0	0	0	0	0	0	3	0
12	Distribution	1,555	0	0	0	1,548	0	0	0	0	0	0	0	0	0	0	7	0
	Distribution																	
13	Lines/poles/fittings	1,884	0	0	0	0	1,010	497	0	0	252	124	0	0	0	0	0	0
14	Services	1,405	0	0	0	0	0	0	0	0	0	0	1,405	0	0	0	0	0
15	Street Lights	898	0	0	0	0	0	0	0	0	0	0	0	0	898	0	0	0
16	Transformers	260	0	0	0	0	0	0	190	70	0	0	0	0	0	0	0	0
17	Meters	489	0	0	0	0	0	0	0	0	0	0	0	489	0	0	0	0
18	Customer Accounting	10,072	0	0	0	0	0	0	0	0	0	0	0	0	0	10,072	0	0
19	Subtotal Direct O&M	20,639	1,397	1,353	1,319	1,548	1,010	497	190	70	252	124	1,405	489	898	10,072	15	0
	General System Expenses																	
20	Related to Distribution	1,399	0	0	0	227	356	175	84	31	89	44	201	67	123	0	1	0
21	Related to Prod, Trans. & Distribution	4,445	438	423	572	489	765	377	180	67	191	94	433	145	265	0	6	0
22	Related to Vehicles	1,496	30	29	194	128	397	196	100	37	99	49	109	34	61	30	2	0
23	System Control Centre Expenses	947	125	121	394	50	78	39	18	7	20	10	44	15	27	0	0	0
24	General Communication Expenses	1,603	131	126	436	113	178	88	42	16	44	22	101	34	62	211	0	0
25	Subtotal General System Expenses	9,890	724	699	1,596	1,007	1,774	874	425	157	444	218	887	295	538	242	9	0
	Administration and General																	
26	Insurance, Injuries & Damages	1,906	145	139	218	149	458	225	127	47	114	56	64	36	63	63	2	0
27	Labour Related	5,812	397	383	624	467	835	411	201	74	209	103	411	136	249	1,305	5	0
28	Other Administration And General Expenses	13,911	951	916	1,494	1,118	2,000	985	480	178	500	246	984	327	596	3,125	13	0
29	PUB Assessments	489	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	489
30	Subtotal Administration and General Expenses	22,119	1,493	1,438	2,336	1,734	3,293	1,622	807	299	823	405	1,458	499	909	4,493	21	489
31	Total O&M (less RSA, MTA and Rural Subsidy)	330,630	102,808	182,278	5,251	4,289	6,077	2,993	1,422	526	1,519	748	3,751	1,283	2,345	14,806	44	489

Newfoundland Power Inc.
2005 Pro-Forma Cost of Service Study

FUNCTIONAL CLASSIFICATION OF OPERATING AND MAINTENANCE EXPENSES

Line No.	Column A - Total Category	From Schedule 3.1 Basis for Functional Classification
	Purchase Power Expense	Excludes the rural deficit of $36,325,023 & Amortization of Hydro Equalization Reserve of $1,732,000.
1	Purchases from Hydro - Production related	Based on functional classification splits shown in Schedule 5.1, Line 1. (Split between Hydro-Production and Hydro-Transmission based on split shown in Schedule 5.1, Line 18.
2	Purchases from Hydro - Transmission related	Based on functional classification splits shown in Schedule 5.1, Line 2. (Split between Hydro-Production and Hydro-Transmission based on split shown in Schedule 5.1, Line 18.
3	Deer Lake Power Secondary	Based on functional classification splits shown in Schedule 5.1, Line 3.
4	Amortization of Hydro Equalization Reserve	Classified 100% to Energy.
5	Sub Total	Total of Lines 1 - 4.
	Direct Operating & Maintenance Costs	
6	Hydraulic Production	Based on classification splits shown in Schedule 5.1, Line 4.
7	Other Production	Based on classification splits shown in Schedule 5.1, Line 5.
8	Transmission	Functional split based on Schedule 5.1 line 19. Classified based on the transmission general as shown on Schedule 5.1 Line 6.
	Substations	
9	Hydarulic Plants	Functional splits based on schedule 5.1 line 20 and classified as shown in schedule 5.1 line 4.
10	Other Production	Functional splits on based schedule 5.1 line 20 and classified as shown in schedule 5.1 line 5.
11	Transmission	Functional splits based on schedule 5.1 line 20 and classified as shown in schedule 5.1 line 6.
12	Distribution	Functional splits based on schedule 5.1 line 20 and classified as shown in schedule 5.1 line 7.
	Distribution	
13	Lines/poles/fittings	Functional splits based on schedule 5.1 line 22 (excluding street lighting) and classified as shown in schedule 5.1 lines 11 & 12.
14	Services	Classified as shown in schedule 5.1 line 15.
15	Street Lights	Classified as shown in schedule 5.1 line 17.
16	Transformers	Classified as shown in schedule 5.1 line 14.
17	Meters	Classified as shown in schedule 5.1 line 16.
18	Customer Accounting	Classified 100% to Customer Accounting (Customer).
19	Subtotal Direct O&M	Total of Lines, 6 to 18.
	General System Expenses	Functional Classification based on a weighted average total of the splits for fixed assets (Schedule 2.1, Line 22) and O&M (Schedule 3.2 Line 19). The weighting used is: 62.6% operating, and 37.4% capital.

	Total A	Produced & Purchased Demand B	Produced & Purchased Energy C	Transmission Demand D	Distribution: Substation Demand E	Primary Demand F	Primary Customer G	Transformers Demand H	Transformers Customer I	Secondary Demand J	Secondary Customer K	Services Customer L	Meters Customer M	St. Lighting Customer N	Cust. Acc. & Cust. Serv. O	Specifically Assigned P	Revenue Related Q
Weighted Splits	100.0%	6.7%	6.5%	8.8%	7.5%	11.7%	5.8%	2.8%	1.0%	2.9%	1.4%	6.6%	2.2%	4.1%	31.9%	0.1%	0.0%

Line No.	Category	Basis for Functional Classification
20	Related to Distribution	Functional Classification based on the weighted split shown for Columns E through N & the distribution portion of Column P.
21	Related to Prod, Trans. & Distribution	Functional Classification based on the weighted split shown for Columns B through N & P.
22	Related to Vehicles	Functional Classification based on splits for vehicle fixed assets (see schedule 2.4 line 19).
23	System Control Centre Expenses	Functionalized based on a study of SCADA plant (see Schedule 5.1). Classification based on functional categories shown for general system expenses in columns B through O.
24	General Communications Expenses	Functionalized based on a study of Communications Expenses (see Schedule 5.1). Classification based on functional categories shown for general system expenses in columns B through O.
25	Subtotal General System Expenses	Total of all Lines 20 to 24.
	Administration and General Expenses	Functional Classification based on a weighted average total of the splits for fixed assets (Schedule 2.1, Line 22) and O&M (Schedule 3.2 Lines 19 plus 25). The weighting used is: 62.6% operating, and 37.4% capital.

Split for Administration and General

	Total A	Produced & Purchased Demand B	Produced & Purchased Energy C	Transmission Demand D	Distribution: Substation Demand E	Primary Demand F	Primary Customer G	Transformers Demand H	Transformers Customer I	Secondary Demand J	Secondary Customer K	Services Customer L	Meters Customer M	St. Lighting Customer N	Cust. Acc. & Cust. Serv. O	Specifically Assigned P	Revenue Related Q
Weighted Splits	100.0%	6.8%	6.6%	10.7%	8.0%	14.4%	7.1%	3.5%	1.3%	3.6%	1.8%	7.1%	2.3%	4.3%	22.5%	0.1%	0.0%

Line No.	Category	Basis for Functional Classification
26	Insurance, Injuries & Damages	Functional Classification based on Net Utility Plant in Service (See Schedule 2.4, Line 22)
27	Labour Related	Functional Classification based on the Weighted Split for Administration and General.
28	Other Administration And General Expenses	Functional Classification based on the Weighted Split for Administration and General.
29	PUB Assessments	Assigned 100% as Revenue Related.
30	Subtotal Administration and General	Total for Lines 26 to 29.
31	Total O&M	Totals of Lines 5, 19, 25 and 30.

FUNCTIONAL CLASSIFACTION OF DEPRECIATION EXPENSES (NET OF AMORTIZED CIAC)
(All numbers are times $1,000)

Line No.	Category	Total	Produced & Purchased Demand	Produced & Purchased Energy	Transmission Demand	Distribution: Substation Demand	Primary Demand	Primary Customer	Transformers Demand	Transformers Customer	Secondary Demand	Secondary Customer	Services Customer	Meters Customer	St. Lighting Customer	Cust. Acc. & Cust. Serv.	Specifically Assigned
		A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	Hydro Electric Production	3,069	1,295	1,774	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Other Generation	1,138	1,138	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Transmission	2,724	0	0	2,702	0	0	0	0	0	0	0	0	0	0	0	22
	Substations																
4	Hydro Electric Production	111	47	64	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Other Production	18	18	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Transmission	994	0	0	990	0	0	0	0	0	0	0	0	0	0	0	4
7	Distribution	1,925	0	0	0	1,916	0	0	0	0	0	0	0	0	0	0	9
	Distribution																
8	Land and Land Clearing	(14)	0	0	0	0	(7)	(3)	0	0	(2)	(1)	0	0	(1)	0	0
9	Conductors, Poles and Fittings	13,126	0	0	0	0	6,744	3,322	0	0	1,686	830	0	0	543	0	0
10	Transformers	2,534	0	0	0	0	0	0	1,850	684	0	0	0	0	0	0	0
11	Services	1,213	0	0	0	0	0	0	0	0	0	0	1,213	0	0	0	0
12	Meters	773	0	0	0	0	0	0	0	0	0	0	0	773	0	0	0
13	Street lighting	1,489	0	0	0	0	0	0	0	0	0	0	0	0	1,489	0	0
	General Plant																
14	Land and Land Rights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15	Buildings	567	24	23	93	34	104	51	26	10	26	13	28	9	16	109	1
16	Computer Equipment	4,580	122	117	228	81	252	124	64	24	63	31	69	22	39	3,342	2
17	Misc. Equipment	660	18	17	101	44	135	67	34	13	34	17	37	12	21	109	1
18	Transportation	2,193	44	42	285	188	582	287	147	54	146	72	159	50	90	45	3
19	Tele-communications	605	71	68	148	27	84	41	21	8	21	10	23	7	13	59	1
20	Total	37,704	2,778	2,106	4,547	2,290	7,895	3,889	2,142	792	1,974	972	1,530	872	2,211	3,665	43

FUNCTIONAL CLASSIFACTION OF DEPRECIATION EXPENSES (NET OF AMORTIZED CIAC)

Line No.	Category	Basis for Functional Classification
1	Hydro Electric Production	Classified based on factors shown in Schedule 5.1 Line 4.
2	Other Generation	Classified based on factors shown in Schedule 5.1 Line 5.
3	Transmission	Functional split based on Schedule 5.1 line 19. Classified based on the transmission general as shown on Schedule 5.1 Line 6.
	Substations	
4	Hydro Electric Production	Functional splits based on schedule 5.1 line 20 and classified as shown in schedule 5.1 line 4.
5	Other Production	Functional splits on based schedule 5.1 line 20 and classified as shown in schedule 5.1 line 5.
6	Transmission	Functional splits based on schedule 5.1 line 20 and classified as shown in schedule 5.1 line 6.
7	Distribution	Functional splits based on schedule 5.1 line 20 and classified as shown in schedule 5.1 line 7.
	Distribution	
8	Land and Land Clearing	Functional splits based on schedule 5.1 line 21 and classified as shown in schedule 5.1 lines 8, 9 & 10.
9	Conductors, Poles and Fittings	Functional splits based on schedule 5.1 line 22 and classified as shown in schedule 5.1 lines 11, 12 & 13.
10	Transformers	Classified as shown in schedule 5.1 line 14.
11	Services	Classified as shown in schedule 5.1 line 15.
12	Meters	Classified as shown in schedule 5.1 line 16.
13	Street lighting	Classified as shown in schedule 5.1 line 17.
	General Plant	
14	Land and Land Clearing	Functionalized based on general property land and land rights (See Schedule 5.1 line 23). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
15	Buildings	Functionalized based on general property buildings and structures (See Schedule 5.1 line 24). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
16	Computer Equipment	Functionalized based on Computer Hardware and Software (See Schedule 5.1 line 25). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
17	Miscellaneous Equipment	Functionalized based on General Property Other Equipment (See Schedule 5.1 line 26). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
18	Transportation	Functionalized based on Transportation (See Schedule 5.1 line 27). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
19	Tele-communications	Functionalized based on Total Communications (See Schedule 5.1 line 28). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
20	Total	Total of Lines 1 through 19.

Newfoundland Power Inc.
2005 Pro-Forma Cost of Service Study

CUSTOMER STATISTICS

Line No.	Class of Service	Rate Class	BILLING INFORMATION: Number of Customers At Year End 2004	Number of Customers At Year End 2005	Number of Customers Average	2005 Energy Sales kWh	2005 Total Billing Demands kW \ kVA	Non-coincident Maximum Class Demands (NCP): Estimated Class Load Factor	Class NCP Demand kW	Class Demand Coincident with System Peak (1CP): Estimated Class Load Factor	Class 1CP Demand kW
			A	B	C	D	E	F	G	H	I
	DOMESTIC										
1	Domestic Regular	1.1	84,359	83,719	84,039	799,968,000	0	43.0%	212,373	51.8%	176,294
2	Domestic All Electric	1.1	109,553	112,693	111,123	2,186,726,000	0	47.9%	521,140	46.8%	533,389
	GENERAL SERVICE										
3	(0-10 kW)	2.1	11,872	12,046	11,959	96,908,000	0	50.9%	21,734	65.2%	16,967
4	(10-100 kW)	2.2	8,029	8,114	8,072	610,924,000	2,181,835	52.6%	132,586	59.7%	116,818
	(110-350 kVA)	2.3									
5	Primary		31	31	31	22,023,490	61,370	56.7%	4,434	68.4%	3,676
6	Secondary		739	752	746	395,815,510	1,284,173	56.7%	79,690	68.4%	66,059
	(350-1000 kVA)	2.3									
7	Transmission		2	2	2	1,763,199	4,225	56.7%	355	68.4%	294
8	Primary		45	44	45	106,839,207	286,706	56.7%	21,510	68.4%	17,831
9	Secondary		197	202	200	336,383,595	989,318	56.7%	67,725	68.4%	56,140
	(1000 kVA and Over)	2.4									
10	Transmission		1	1	1	5,269,000	19,111	66.2%	909	74.4%	808
11	Primary		36	36	36	325,565,000	786,930	66.2%	56,140	74.4%	49,953
12	Secondary		21	24	23	79,842,000	244,849	66.2%	13,768	74.4%	12,251
13	**STREET LIGHTING**	4.1	9,579	9,637	9,608	35,996,000	0	48.0%	8,561	48.0%	8,561
14	Total		224,464	227,301	225,885	5,004,023,000	5,858,518	50.1%	1,140,926	53.9%	1,059,041

Newfoundland Power Inc.
2005 Pro-Forma Cost of Service Study

ENERGY AND DEMAND LOSS FACTORS
(Losses as a percentage of delivered)

Demand Loss Factors

Transmission	1.8491%
Primary	3.2311%
Secondary	3.1348%

Energy Loss Factors

Transmission	1.1466%
Primary	2.0994%
Secondary	2.6744%

Newfoundland Power Inc.
2005 Pro-Forma Cost of Service Study

DEVELOPMENT OF CUSTOMER COST ALLOCATORS

Line No.	Class of Service	Rate Code	Average Number of Customers A	Customer Related Costs: Weighting Factor B	Weighted Number of Customer C	Allocation Factors D	Primary Lines: Weighting Factor E	Weighted Number of Customer F	Allocation Factors G	Secondary Lines: Weighting Factor H	Weighted Number of Customer I	Allocation Factors J	Transformers: Weighting Factor K	Weighted Number of Customer L	Allocation Factors M	Service Drops: Weighting Factor N	Weighted Number of Customer O	Allocation Factors P	Meters: Weighting Factor Q	Weighted Number of Customer R	Allocation Factors S
	DOMESTIC																				
1	Domestic Regular	1.1	84,039	1.0	84,039	36.397%	1.0	84,039	37.205%	1.0	84,039	37.223%	1.0	84,039	37.223%	1.0	84,039	37.651%	1.0	84,039	19.816%
2	Domestic All Electric	1.1	111,123	1.0	111,123	48.127%	1.0	111,123	49.195%	1.0	111,123	49.220%	1.0	111,123	49.220%	1.0	111,123	49.786%	1.0	111,123	26.202%
	GENERAL SERVICE																				
3	(0-10 kW)	2.1	11,959	1.2	14,351	6.215%	1.0	11,959	5.294%	1.0	11,959	5.297%	1.0	11,959	5.297%	1.0	11,959	5.358%	2.3	27,506	6.486%
4	(10-100 kW)	2.2	8,072	2.1	16,951	7.341%	1.0	8,072	3.574%	1.0	8,072	3.575%	1.0	8,072	3.575%	1.2	9,686	4.340%	14.2	114,622	27.028%
	(110-350 kVA)	2.3																			
5	Primary		31	2.3	71	0.031%	1.0	31	0.014%	-	-	0.000%	-	-	0.000%	-	-	0.000%	205.7	6,377	1.504%
6	Secondary		746	2.3	1,716	0.743%	1.0	746	0.330%	1.0	746	0.330%	1.0	746	0.330%	6.6	4,924	2.206%	61.8	46,103	10.871%
	(350-1000 kVA)	2.3																			
7	Transmission		2	2.3	5	0.002%	0.0	-	0.000%	-	-	0.000%	-	-	0.000%	-	-	0.000%	495.2	990	0.234%
8	Primary		45	2.3	104	0.045%	1.0	45	0.020%	-	-	0.000%	-	-	0.000%	-	-	0.000%	205.7	9,257	2.183%
9	Secondary		200	2.3	460	0.199%	1.0	200	0.089%	1.0	200	0.089%	1.0	200	0.089%	6.6	1,320	0.591%	61.8	12,360	2.914%
	(1000 kVA and Over)	2.4																			
10	Transmission		1	2.6	3	0.001%	0.0	-	0.000%	-	-	0.000%	-	-	0.000%	-	-	0.000%	211.6	212	0.050%
11	Primary		36	2.6	94	0.041%	1.0	36	0.016%	-	-	0.000%	-	-	0.000%	-	-	0.000%	236.7	8,521	2.009%
12	Secondary		23	2.6	60	0.026%	1.0	23	0.010%	1.0	23	0.010%	1.0	23	0.010%	6.6	152	0.068%	129.8	2,985	0.704%
13	STREET LIGHTING	4.1	9,608	0.2	1,922	0.832%	1.0	9,608	4.254%	1.0	9,608	4.256%	1.0	9,608	4.256%	-	-	0.000%	-	-	0.000%
14	Total		225,885		230,897	100.0%		225,882	100.0%		225,770	100.0%		225,770	100.0%		223,203	100.0%		424,095	100.0%

NOTES:

Column

A - See Schedule 4.1, Column C.
B - Weighting Factors estimated based on general review of Customer accounting and Customer service activities.
C - Column A times B.
D - Class weighted number of customers divided by the total number of weighted customers for Column C.
E - Equal weighting assigned to all Customers supplied through primary lines.
F - Column A times E.
G - Class weighted number of customers divided by the total number of weighted customers for Column F.
H - Equal weighting assigned to all Customers supplied through secondary lines.
I - Column A times H.
J - Class weighted number of customers divided by the total number of weighted customers for Column I.
K - Equal weighting assigned to all Customers supplied through distribution transformers.
L - Column A times K.
M - Class weighted number of customers divided by the total number of weighted customers for Column L.
N - Based on typical costs to provide Service Drops for customers within each class.
O - Column A times N.
P - Class weighted number of customers divided by the total number of weighted customers for Column O.
Q - Based on typical cost to provide metering for customers within each class.
R - Column A times Q.

S - Class weighted number of customers divided by the total number of weighted customers for Column R.

DEVELOPMENT OF ENERGY ALLOCATORS

Line No.	Class of Service	Rate Code	Secondary Energy Allocator				Primary Energy Allocator				Transmission Energy Allocator			
			Load at Meter kWh	Secondary Energy Loss Factor	Load at Secondary Input kWh	Secondary Allocation Factor	Load at Primary Output kWh	Primary Energy Loss Factor	Load at Primary Input kWh	Primary Allocation Factor	Load at Transmission Output kWh	Transmission Energy Loss Factor	Load at Transmission Input kWh	Transmission Allocation Factor
			A	B	C	D	E	F	G	H	I	J	K	L
	DOMESTIC													
1	Domestic Regular	1.1	799,968,000	0.026744	821,362,344	17.610%	821,362,344	0.020994	838,606,025	16.026%	838,606,025	0.011466	848,221,482	16.004%
2	Domestic All Electric	1.1	2,186,726,000	0.026744	2,245,207,800	48.139%	2,245,207,800	0.020994	2,292,343,693	43.806%	2,292,343,693	0.011466	2,318,627,705	43.747%
	GENERAL SERVICE													
3	(0-10 kW)	2.1	96,908,000	0.026744	99,499,708	2.133%	99,499,708	0.020994	101,588,604	1.941%	101,588,604	0.011466	102,753,419	1.939%
4	(10-100 kW)	2.2	610,924,000	0.026744	627,262,551	13.449%	627,262,551	0.020994	640,431,301	12.239%	640,431,301	0.011466	647,774,487	12.222%
	(110-350 kVA)	2.3												
5	Primary		-	0.026744	-	0.000%	22,353,843	0.020994	22,823,139	0.436%	22,823,139	0.011466	23,084,829	0.436%
6	Secondary		395,815,510	0.026744	406,401,200	8.713%	406,401,200	0.020994	414,933,186	7.929%	414,933,186	0.011466	419,690,810	7.919%
	(350-1000 kVA)	2.3												
7	Transmission		-	0.026744	-	0.000%	-	0.020994	-	0.000%	1,789,647	0.011466	1,810,167	0.034%
8	Primary		-	0.026744	-	0.000%	108,441,795	0.020994	110,718,422	2.116%	110,718,422	0.011466	111,987,919	2.113%
9	Secondary		336,383,595	0.026744	345,379,837	7.405%	345,379,837	0.020994	352,630,742	6.739%	352,630,742	0.011466	356,674,006	6.730%
	(1000 kVA and Over)	2.4												
10	Transmission		-	0.026744	-	0.000%	-	0.020994	-	0.000%	5,348,035	0.011466	5,409,356	0.102%
11	Primary		-	0.026744	-	0.000%	330,448,475	0.020994	337,385,910	6.447%	337,385,910	0.011466	341,254,377	6.439%
12	Secondary		79,842,000	0.026744	81,977,294	1.758%	81,977,294	0.020994	83,698,326	1.599%	83,698,326	0.011466	84,658,011	1.597%
13	**STREET LIGHTING**	4.1	35,996,000	0.026744	36,958,677	0.792%	36,958,677	0.020994	37,734,587	0.721%	37,734,587	0.011466	38,167,252	0.720%
14	Total		4,542,563,104	0.026744	4,664,049,412	100.00%	5,125,293,525	0.020994	5,232,893,937	100.000%	5,240,031,618	0.011466	5,300,113,821	100.000%

DEVELOPMENT OF ENERGY ALLOCATORS

NOTES:

A - See Schedule 4.1, Column D.

B - See Schedule 4.2.

C - Estimated Load at Secondary Input including losses. It is equal to Columns A times (one plus the loss factor).

D - Class load relative to the Total Load for Column C.

E - Equal to Column C and includes customers that are supplied at primary level as shown in Schedule 4.1. 2005 Energy Sales increased
- by 1.5% due to reported energy sales been based at secondary sales levels.

F - See Schedule 4.2.

G - Estimated Load at Primary Input including losses. It is equal to Columns E times (one plus the loss factor from Column F).

H - Class load relative to the Total Load for Column G.

I - Equal to Column G but includes customers that are supplied at transmission level as shown in Schedule 4.1. 2005 Energy Sales increased
- by 1.5% due to reported energy sales been based at secondary sales levels.

J - See Schedule 4.2.

K - Estimated Load at Transmission Input including losses. It is equal to Columns I times (one plus the loss factor from Column J).

L - Class load relative to the Total Load for Column K.

DEVELOPMENT OF NON-COINCIDENT PEAK (NCP) DEMAND ALLOCATORS

Line No.	Class of Service	Rate Code	Secondary Demand Allocator: Load at Meter kW	Secondary Demand Allocator: Secondary Demand Loss Factor	Secondary Demand Allocator: Load at Secondary Input kW	Secondary Demand Allocator: Secondary Allocation Factor	Primary Demand Allocator: Load at Primary Output kW	Primary Demand Allocator: Primary Demand Loss Factor	Primary Demand Allocator: Load at Primary Input kW	Primary Demand Allocator: Primary Allocation Factor	Transmission Demand Allocator: Load at Transmission Output kW	Transmission Demand Allocator: Transmission Demand Loss Factor	Transmission Demand Allocator: Load at Transmission Input kW	Transmission Demand Allocator: Transmission Allocation Factor
			A	B	C	D	E	F	G	H	I	J	K	L
	DOMESTIC													
1	Domestic Regular	1.1	212,373	0.031348	219,031	20.081%	219,031	0.032311	226,108	18.656%	226,108	0.018491	230,289	18.636%
2	Domestic All Electric	1.1	521,140	0.031348	537,477	49.277%	537,477	0.032311	554,844	45.780%	554,844	0.018491	565,103	45.732%
	GENERAL SERVICE													
3	(0-10 kW)	2.1	21,734	0.031348	22,415	2.055%	22,415	0.032311	23,139	1.909%	23,139	0.018491	23,567	1.907%
4	(10-100 kW)	2.2	132,586	0.031348	136,742	12.537%	136,742	0.032311	141,160	11.647%	141,160	0.018491	143,771	11.635%
	(110-350 kVA)	2.3												
5	Primary		-	0.031348	-	0.000%	4,501	0.032311	4,646	0.383%	4,646	0.018491	4,732	0.383%
6	Secondary		79,690	0.031348	82,188	7.535%	82,188	0.032311	84,844	7.000%	84,844	0.018491	86,413	6.993%
	(350-1000 kVA)	2.3												
7	Transmission		-	0.031348	-	0.000%	-	0.032311	-	0.000%	360	0.018491	367	0.030%
8	Primary		-	0.031348	-	0.000%	21,833	0.032311	22,538	1.860%	22,538	0.018491	22,955	1.858%
9	Secondary		67,725	0.031348	69,848	6.404%	69,848	0.032311	72,105	5.949%	72,105	0.018491	73,438	5.943%
	(1000 kVA and Over)	2.4												
10	Transmission		-	0.031348	-	0.000%	-	0.032311	-	0.000%	922	0.018491	939	0.076%
11	Primary		-	0.031348	-	0.000%	56,983	0.032311	58,824	4.854%	58,824	0.018491	59,911	4.848%
12	Secondary		13,768	0.031348	14,200	1.302%	14,200	0.032311	14,658	1.209%	14,658	0.018491	14,929	1.208%
13	**STREET LIGHTING**	4.1	8,561	0.031348	8,829	0.809%	8,829	0.032311	9,114	0.752%	9,114	0.018491	9,283	0.751%
14	Total		1,057,577	0.031348	1,090,730	100.00%	1,174,046	0.032311	1,211,981	100.000%	1,213,263	0.018491	1,235,698	100.000%

Newfoundland Power Inc.
2005 Pro-Forma Cost of Service Study

DEVELOPMENT OF NON-COINCIDENT PEAK (NCP) DEMAND ALLOCATORS

NOTES:

A - See Schedule 4.1, 2005 Class NCP Demand.
B - See Schedule 4.2.
C - Estimated Load at Secondary Input including losses. It is equal to Columns A times (one plus the loss factor).
D - Class load relative to the Total Load for Column C.
E - Equal to Column C but includes customers that are supplied at primary level as shown in Schedule 4.1. 2005 Class NCP Demand increased
- by 1.5% due to reported demand sales been based at secondary sales levels.
F - See Schedule 4.2.
G - Estimated Load at Primary Input including losses. It is equal to Columns E times (one plus the loss factor from Column F).
H - Class load relative to the Total Load for Column G.
I - Equal to Column G but includes customers supplied at transmission level as shown in Schedule 4.1. 2005 Class NCP Demand increased
- by 1.5% due to reported demand sales been based at secondary sales levels.
J - See Schedule 4.2.
K - Estimated Load at Transmission Input including losses. It is equal to Columns I times (one plus the loss factor from Column J).
L - Class load relative to the Total Load for Column K.

DEVELOPMENT OF SINGLE COINCIDENT PEAK (1CP) DEMAND ALLOCATORS

Line No.	Class of Service	Rate Code	Secondary Demand Allocator				Primary Demand Allocator				Transmission Demand Allocator			
			Load at Meter kW	Secondary Demand Loss Factor	Load at Secondary Input kW	Secondary Allocation Factor	Load at Primary Output kW	Primary Demand Loss Factor	Load at Primary Input kW	Primary Allocation Factor	Load at Transmission Output kW	Transmission Demand Loss Factor	Load at Transmission Input kW	Transmission Allocation Factor
			A	B	C	D	E	F	G	H	I	J	K	L
	DOMESTIC													
1	Domestic Regular	1.1	176,294	0.031348	181,821	17.871%	181,821	0.032311	187,696	16.682%	187,696	0.018491	191,166	16.665%
2	Domestic All Electric	1.1	533,389	0.031348	550,110	54.070%	550,110	0.032311	567,885	50.472%	567,885	0.018491	578,385	50.422%
	GENERAL SERVICE													
3	(0-10 kW)	2.1	16,967	0.031348	17,499	1.720%	17,499	0.032311	18,064	1.606%	18,064	0.018491	18,398	1.604%
4	(10-100 kW)	2.2	116,818	0.031348	120,480	11.842%	120,480	0.032311	124,373	11.054%	124,373	0.018491	126,672	11.043%
	(110-350 kVA)	2.3												
5	Primary		-	0.031348	-	0.000%	3,731	0.032311	3,851	0.342%	3,851	0.018491	3,922	0.342%
6	Secondary		66,059	0.031348	68,130	6.696%	68,130	0.032311	70,331	6.251%	70,331	0.018491	71,632	6.245%
	(350-1000 kVA)	2.3												
7	Transmission		-	0.031348	-	0.000%	-	0.032311	-	0.000%	299	0.018491	304	0.027%
8	Primary		-	0.031348	-	0.000%	18,098	0.032311	18,683	1.660%	18,683	0.018491	19,028	1.659%
9	Secondary		56,140	0.031348	57,900	5.691%	57,900	0.032311	59,771	5.312%	59,771	0.018491	60,876	5.307%
	(1000 kVA and Over)	2.4												
10	Transmission		-	0.031348	-	0.000%	-	0.032311	-	0.000%	821	0.018491	836	0.073%
11	Primary		-	0.031348	-	0.000%	50,702	0.032311	52,340	4.652%	52,340	0.018491	53,308	4.647%
12	Secondary		12,251	0.031348	12,635	1.242%	12,635	0.032311	13,043	1.159%	13,043	0.018491	13,284	1.158%
13	**STREET LIGHTING**	4.1	8,561	0.031348	8,829	0.868%	8,829	0.032311	9,114	0.810%	9,114	0.018491	9,283	0.809%
14	Total		986,479	0.031348	1,017,404	100.00%	1,089,935	0.032311	1,125,152	100.000%	1,126,271	0.018491	1,147,097	100.000%

DEVELOPMENT OF SINGLE COINCIDENT PEAK (1CP) DEMAND ALLOCATORS

NOTES:

A - See Schedule 4.1, 2005 Class 1CP Demand.
B - See Schedule 4.2.
C - Estimated Load at Secondary Input including losses. It is equal to Columns A times (one plus the loss factor).
D - Class load relative to the Total Load for Column C.
E - Equal to Column C but includes customers that are supplied at primary level as shown in Schedule 4.1. 2005 Class 1CP Demand increased
- by 1.5% due to reported demand sales been based at secondary sales levels.
F - See Schedule 4.2.
G - Estimated Load at Primary Input including losses. It is equal to Columns E times (one plus the loss factor from Column F).
H - Class load relative to the Total Load for Column G.
I - Equal to Column G but includes customers that are supplied at transmission level as shown in Schedule 4.1. 2005 Class 1CP Demand increased
- by 1.5% due to reported demand sales been based at secondary sales levels.
J - See Schedule 4.2.
K - Estimated Load at Transmission Input including losses. It is equal to Columns I times (one plus the loss factor from Column J).
L - Class load relative to the Total Load for Column K.

FUNCTIONAL CLASSIFICATION SPLITS

Scenarios

Line No.	Utility Plant Category	Total	Produced & Purchased Demand	Produced & Purchased Energy	Transmission Demand	Substation Demand	Distribution Primary Demand	Distribution Primary Customer	Distribution Transformers Demand	Distribution Transformers Customer	Secondary Demand	Secondary Customer	Services Customer	Meters Customer	St. Lighting Customer
		A	B	C	D	E	F	G	H	I	J	K	L	M	N
	PURCHASED POWER														
1	Purchased from Nfld. & Lab. Hydro - Production	100.0%	29.8%	70.2%											
2	Purchased from Nfld. & Lab. Hydro - Transmission	100.0%	100.0%	0.0%											
3	Purchased from Deer Lake Power - Secondary	100.0%	29.8%	70.2%											
	PRODUCTION														
4	Hydro	100.0%	42.2%	57.8%											
5	Other Production	100.0%	100.0%												
	TRANSMISSION														
6	Common	100.0%			100.0%										
	DISTRIBUTION														
7	Substations - Common	100.0%				100.0%									
	Land and Land Use														
8	Primary	100.0%					67.0%	33.0%							
9	Secondary	100.0%									67.0%	33.0%			
10	Street Lighting	100.0%													100.0%
	Conductors, Poles and Fixtures														
11	Primary	100.0%					67.0%	33.0%							
12	Secondary	100.0%									67.0%	33.0%			
13	Street Lighting	100.0%													100.0%
14	Transformers	100.0%							73.0%	27.0%					
15	Services	100.0%											100.0%		
16	Meters	100.0%												100.0%	
17	Street Lights	100.0%													100.0%

MISCELLANEOUS FUNCTIONAL COST ASSIGNMENT FACTORS

Line No.	Cost Item	Total	Production	Transmission
18	Purchased from Nfld. & Labrador Hydro	100.0%	91.3%	8.7%

Line No.	Cost Item	Total	Common	Specifically Assigned
19	Transmission	0.0%	99.20%	0.80%

Line No.	Cost Item	Total	Hydro Producion	Other Production	Total Production	Transmission Common	Transmission Specifically Assigned	Distribution Substation Common	Distribution Specifically Assigned	Cust. Acc. Cust. Serv.
20	Substations	100.0%	3.63%	0.59%	4.22%	32.48%	0.14%	62.87%	0.29%	0.00%

Line No.	Distribution	Distribution Depreciation, Fixed Assets & CIACs Total	Primary	Secondary	St. Lighting	Distribution Acc. Depreciation Total	Primary	Secondary	St. Lighting
21	Land and Land Use	100.0%	76.69%	19.17%	4.14%	100.0%	76.59%	19.15%	4.26%
22	Conductors, Poles and Fixtures	100.0%	76.69%	19.17%	4.14%	100.0%	76.59%	19.15%	4.26%

Line No.	General Plant Related Costs	Total	Production	Transmission	Distribution	Cust. Acc. Cust. Serv.
23	Gen. Prop. Land and Land Rights	100.0%	5.71%	14.09%	58.62%	21.57%
24	Gen. Prop. Buildings and Structures	100.0%	8.44%	16.46%	55.84%	19.26%
25	Computer Hardware and Software	100.0%	5.22%	5.02%	16.80%	72.97%
26	Gen. Prop. Other Equipment	100.0%	5.41%	15.47%	62.54%	16.58%
27	Transportation	100.0%	3.93%	13.07%	80.96%	2.03%
28	Communication - Total	100.0%	23.06%	24.64%	42.47%	9.83%
29	Communication - Scada	100.0%	25.97%	41.59%	32.44%	0.00%
30	Communication - Total Expenses	100.0%	16.02%	27.22%	43.57%	13.19%
31	Inventory	100.0%	5.13%	32.54%	62.33%	0.00%

FUNCTIONAL CLASSIFICATION SPLITS

Line No.	Utility Plant Category	Reason for Functional Classification
1	Purchased from Nfld. & Lab. Hydro - Production	Classified based on the results ,before deficit allocation, of NLH COS Results for 2004 Forecast (Test Year PU 14 (2004))- May 2004.
2	Purchased from Nfld. & Lab. Hydro - Transmission	Classified based on the results ,before deficit allocation, of NLH COS Results for 2004 Forecast (Test Year PU 14 (2004))- May 2004.
3	Purchased from Deer Lake Power - Secondary	Assumed same classification as Nfld. and Lab. Hydro Production related purchased power allocated to NP.
	PRODUCTION	
4	Hydro	Classified based on system load factor from Schedule F, page 105 of 107, of NLH COS for 2004 Forecast (Test Year PU 14 (2004))- May 2004.
5	Other Production	Classified 100% to Demand
	TRANSMISSION	
6	Common	Classified 100% to Demand
	DISTRIBUTION	
7	Substation - Common	Classified 100% to Demand
	Land and Land Use	
8	Primary	Classified between Demand and Customer Based on a minimum system analysis.
9	Secondary	Classified between Demand and Customer Based on a minimum system analysis.
10	Street Lighting	Classified 100% to direct Street Lighting costs.
	Conductors, Poles and Fixtures	
11	Primary	Classified between Demand and Customer Based on a minimum system analysis.
12	Secondary	Classified between Demand and Customer Based on a minimum system analysis.
13	Street Lighting	Classified 100% to direct Street Lighting costs.
14	Transformers	Classified between Demand and Customer Based on a zero intercept method.
15	Services	Classified 100% to Customer
16	Meters	Classified 100% to Customer
17	Street Lights	Classified 100% to Direct Street Lighting.

MISCELLANEOUS FUNCTIONAL COST ASSIGNMENT FACTORS

18	Purchased from Nfld. & Labrador Hydro	Split between production and transmission related purchased power based on results ,before deficit allocation, of Nfld. & Lab. Hydro 2004 Cost of Service Study taken from the NLH COS Results for 2004 Forecast (Test Year PU 14 (2004))- May 2004.
19	Transmission	Based on an analysis of 2005 year end fixed plant.
20	Substations	Based on an analysis of 2003 year end fixed plant.
	Distribution	
21	Land and Land Use	Split between the different functional groups are based on the split for Conductors Poles and Fittings.
22	Conductors, Poles and Fixtures	Functional split based on a study of fixed assets.
23	Gen. Prop. Land and Land Rights	Based on a 2002 General Property Fixed Plant Allocation Study
24	Gen. Prop. Buildings and Structures	Based on a 2002 General Property Fixed Plant Allocation Study
25	Computer Hardware and Software	Based on a 2002 General Property Fixed Plant Allocation Study
26	Gen. Prop. Other Equipment	Based on a 2002 General Property Fixed Plant Allocation Study
27	Transportation	Based on a 2002 General Property Fixed Plant Allocation Study
28	Communication - Total	Based on a 2002 General Property Fixed Plant Allocation Study
29	Communication - Scada	Based on a 2002 General Property Fixed Plant Allocation Study
30	Communication - Total Expenses	Based on a 2002 General Property Fixed Plant Allocation Study
31	Inventory	Based on an allocation of the year end inventory for 2005.

Newfoundland Power Inc.
2005 Pro-Forma Cost of Service Study

RECONCILIATION OF EXPENSES WITH ANNUAL REPORT TO BOARD
(All dollars are times 1,000)

Total Reported Company Expenses	$309,766	(Return 12)
Pro-forma Purchase Power Expense increase	$58,354	(2005 Billing Determinants with 2007 Rates)
Total Pro-forma Company Expenses	$368,120	

The total expenses shown on Schedule 1.1, includes depreciation, non-regulated expenses, and expense credits for the rural surcharge and certain expense associated with revenue not obtained through rates. Also, Curtailable Service Option Credit payments to customers are reported as an expense in the Cost of Service Study as oppose to a reduction to class revenue from rates as recorded by the Company.

Deduct non-regulated expenses[1]	($1,408)	
Expense Credits		
Rural Surcharge	($36,325)	
Wheeling Revenues	($438)	
Joint Use Revenues	($8,238)	
Revenue from Temp. Services and Reconnects	($110)	
Customer Service Fees	($282)	
Total Expense Credits	($45,393)	
Curtailable Credits	$244	(2006 Curtailable Service Option Report)
Pro-forma Depreciation Expense	$37,704	(Base on Proposed 2008 Depreciation Rates)
Total expense before Return and Taxes on Schedule 1.1 Excluding RSA, MTA and the Hydro Rural deficit	$359,267	

1. Non deductable Expenses (Return 10) + associated tax adjustment - Schedule 5.4

Newfoundland Power Inc.
2005 Pro-Forma Cost of Service Study

RECONCILIATION OF REVENUE WITH ANNUAL REPORT TO BOARD
(All dollars are times 1,000)

Total Revenue on Statements			
Revenue from Rates		$407,597	(Return 11)
Pro-forma increase in Revenue from rates		$61,508	
Other Revenue		$12,366	(Return 11)
Total Pro-forma Company Revenue		$481,471	

The total revenue shown on Schedule 1.4 does not include the total other revenue, some is deducted directly from expenses. Also, the total in Schedule 1.4 includes the flow through revenue items RSA and MTA.

Revenue Deducted from expenses in the Cost of service Study			
Wheeling Revenue	$438		(Schedule 1.1)
Joint Use Revenue	$8,238		(Schedule 1.1)
Revenue from temp. Connections & Reconnects	$110		(Schedule 1.1)
Customer Service Fees	$282		(Schedule 1.1)
Total	$9,068	($9,068)	
Less Rural Subsidy		($36,325)	(Schedule 1.3)
Add Curtailable Credits		$244	(2006 Curtailable Service Option Report)
Rounding		($2)	
Total Revenue before Rural Subsidy		$436,320	(Schedule 1.4)
Add Rural Subsidy		$36,325	
Add Pro-forma Changes to RSA and MTA		$33,511	
Total Revenue plus RSA & MTA		$506,156	(Schedule 1.4)

Newfoundland Power Inc.
2005 Pro-Forma Cost of Service Study

RECONCILIATION OF RETURN AND TAXES WITH ANNUAL REPORT TO BOARD
(All dollars are times 1,000)

Return and Taxes From Annual Report to Board

Return on Rate Base (Regulated Earning)	$63,601	(Return 10A)
Total Income Tax	$15,368	(Return 18)
Total Return and Taxes	$78,969	

The Cost of Service Study deducts non-regulated expenses from total expense and the income tax must be adjusted to reflect the increase in taxes that would occur if the non-regulated expenses did not occur.

Tax Adjustment for non-regulated expenses[1].	$493	(Return 10)
Impact of 2007 AAF	($2,409)	
Adjusted Return and Taxes (Schedule 1.1)	$77,053	

Notes: 1 - Taxes adjustment associated with non-regulated expenses. This is equal to:

$$\frac{\text{After Tax Adjustment (Return 10)}}{(1 - \text{Tax Rate } (0.35))} \times \text{Tax Rate } (0.35)$$

2006 Load Research Study

June 16, 2006

NEWFOUNDLAND POWER
A FORTIS COMPANY

Table of Contents

1.0 EXECUTIVE SUMMARY

Load research data provides estimates of class demands on the system at specific times. The class demand estimates are used in the cost of service study to determine the portion of system demand costs that should be recovered from each customer class.

From December 2003 to March 2006, Newfoundland Power conducted a load research program (the "2006 LRP"). The previous class load estimates were obtained from a load research study conducted over the period 1992 to 1994 (the "1994 Study").

The 2006 LRP collected data from a statistically representative sample of customers from each metered customer rate class served by Newfoundland Power. Load recorders, that store customer usage by time interval throughout the day[1], were installed on 470 customer premises. The data collected from the sample was extrapolated to estimate class demands by time interval using a statistical process referred to as ratio estimation.

Generation and transmission demand costs are allocated to customer classes in the cost of service study based on each customer classes' contribution to the winter system peak. The Hydro winter season system peaks normally occur in the early evening around suppertime. Distribution demand costs are allocated to customer classes based on the relative size of the class peak demand. Generally, the Domestic customer class peaks at suppertime and General Service customer classes peak in the morning hours during the weekdays.

The 2006 LRP results indicate there are significant changes to the demand allocators for each rate class compared to the 1994 Study. The primary reasons for the differences in the results are:

(i) a change in the time of Hydro system peak from morning during the period of the 1994 Study to evening peaks during the period of the 2006 LRP; and

(ii) the 2006 LRP class load estimates for General Service Rates 2.1 and 2.2 were derived from a statistically valid study whereas the cost of service estimates used previously were derived based on coincidence estimates applied to billing demand data.

In general, the results indicate an increase in the demand cost allocations to the Domestic class and a decrease in the demand cost allocations to the General Service classes is warranted. The effect of the change in the demand cost allocators may require the rebalancing of revenue requirements from some classes.

2.0 INTRODUCTION

Load research data is used to assess the reasonableness of cost recovery among customer classes. The information gathered is used to determine the portion of system demand costs that should be recovered from each customer class. Load research data provides estimates of class demand on the system at specific times. This differs from the typical energy meter which records the cumulative energy used by customers over a period of time.

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1 Data is stored for every 15 minute period.

The load research data being used to estimate class demands in the embedded cost of service study was from the 1994 Study. In Order No. P.U. 19 2003, the Board approved capital expenditures in the amount of $425,000 for the 2006 LRP.[2] Beginning in December 2003, a comprehensive load research program to encompass the next 3 winter seasons was undertaken. This report provides an analysis of the data collected.

To maximize the efficiency of obtaining load research data for the Province, Newfoundland Power also conducted the sample design and data analysis for both the Island and Labrador interconnected rural customer classes of Newfoundland and Labrador Hydro (Hydro). Hydro was responsible for purchasing and installing the required metering equipment as well as data collection for its customers in Labrador.

3.0 STUDY SCOPE

To adequately study the load characteristics of a class of customers, data representative of their population is required. The 2006 LRP included data collection from a sample of customers from all customer rate classes (excluding Street and Area Lighting[3]) served by Newfoundland Power and the interconnected retail customer rate classes (excluding Street and Area Lighting) served by Hydro[4].

This report summarizes the results of the Newfoundland Power component of the 2006 LRP.

4.0 STUDY METHODOLOGY

4.1 Design Methodology

For purposes of designing a statistically accurate load research program, the sample design followed the sample accuracy level formerly specified in U.S. federal legislation, the *Public Utility Regulatory Policies Act* of 1978 (the "PURPA standard"). This standard is also referenced in the AEIC Load Research Manual, 2nd Edition. The PURPA standard is ±10% relative accuracy at a 90% confidence level.

The Island Interconnected System is a winter peaking system; customer demand requirements are approximately twice as high in winter months than in summer months. Generation and transmission demand costs are allocated by customer classes in the cost of service study based on each customer classes' contribution to the winter system peak (i.e., based on coincident peak).[5] Distribution demand costs are allocated based on the relative size of the class peak demands (i.e., based on non-coincident peak).

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2 Actual Load Research Capital Costs totaled $356,373.53.

3 Class demand estimates for the street and area lighting are derived from a separate study on hours of operation based on hours of darkness determined by operations of photocell devices.

4 Appendix A contains the detailed sample design.

5 The single coincident peak method (1 CP). For the purposes of the load research study, the system peak is based on the time of Hydro's system peak because the majority of the generation and transmission demand costs are related to Hydro's assets.

The sample design for each customer class was designed to achieve the desired statistical accuracy of class demand at time of system peak. To minimize the 2006 LRP cost and achieve the PURPA standard of accuracy, stratified random sampling was employed using the Model Based Statistical Sampling methodology.

4.1.1 Customer Class Considerations

Due to the predominance of domestic electric heating load served by Newfoundland Power, two subclasses within the Domestic rate class were studied. Separate samples were designed for domestic customers that use electric heat as their primary heating source ("Domestic All-Electric subclass") and domestic customers that use an alternate primary heating source ("Domestic Regular subclass")[6]. The separate studies would allow evaluation through the cost of service study of whether cross-subsidization exists between the two Domestic customer subclasses.

The Rate 2.4 customer class includes the Company's largest General Service customers with annual peak demands of 1,000 kVA and greater. Because of the diverse load patterns of these customers and the relatively small number of customers in the class (approximately 55), load research monitoring equipment (i.e., load recorders) was installed on a large proportion of customers in the class.

The sample size for each class is provided in Table 1 below.

Table 1
2006 LRP Sample Sizes

Customer Rate Class	Sample Size
Domestic	
1.1 All-Electric	60
1.1 Regular	90
General Service	
2.1 0 – 10 kW	90
2.2 10 – 100 kW	90
2.3 110 kVA- 1000 kVA	90
2.4 1000 kVA and Over	50
Total	**470**

[6] The distinction between Domestic All-Electric subclass customers that use electric heat as their primary heating source and Domestic Regular subclass customers that use an alternate heating source is based on customer information coded in the Company's Customer Service System.

4.2 Data Analysis

To interpret the data collected from the sample required the sample results to be expanded to represent the class population characteristics[7]. The method chosen for this expansion of data was the Ratio Estimation method.[8] The output of the Ratio Estimation method is a class demand estimate by time interval and the achieved statistical accuracy level.[9]

The load estimates for each class are combined with load estimates for Street and Area Lighting and system losses to derive total load estimates at peak times. To assess the reasonableness of the results, the class load estimates are totalled and then compared to actual total produced and purchased for the time interval (See Table 2).

5.0 2006 LRP RESULTS

This report presents and assesses the results for the 2006 LRP.

For the winter season of 2003/2004, the Hydro system peak occurred on February 16, 2004 at 18:00 hours. For the winter season 2004/2005, the Hydro system peak occurred on December 6, 2004 at 16:45, and for 2005/2006 the peak occurred on January 23, 2006 at 17:45[10]. Graphs showing the load curves for the Newfoundland Power native peak on the Hydro system peak days for the three winter seasons are provided in Appendix B.

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7 Appendix C contains the load estimates and accuracy level derived from the load research data for each month of the 2006 LRP.

8 Ratio estimation requires an interval by interval ratio between demand and annual energy for the sample. It then applies those ratios to the population energy to derive the total class load profiles.

9 A 30 minute interval was chosen to balance data variability while still maintaining the ability to accurately capture load fluctuations.

10 Frazzle ice conditions at NP's generation facilities reduced generation capability during the morning of January 23rd, 2006, causing Hydro system peak to occur at 9:44 am. If Newfoundland Power generation facilities were capable of typical generation levels, the Hydro system peak would have occurred at 5:45 pm. Therefore, for purposes of the load research analysis, the winter peak was assumed to occur at 5:45 pm.

Table 2 provides the breakdown of the estimated loads by rate class and the percentage of load for each estimated peak.

Table 2 Class Contribution at Time of Hydro System Peak						
	2003/2004 Peak February 16, 2004 18:00		**2004/2005 Peak December 6, 2004 16:45**		**2005/2006 Peak January 23, 2006 17:45**	
	Estimated Load (MW)	**% of Peak**	**Estimated Load (MW)**	**% of Peak**	**Estimated Load (MW)**	**% of Peak**
Domestic 1.1	676.9	62.1%	743.5	62.7%	695.9	61.9%
GS 2.1	16.8	1.5%	17.4	1.5%	16.8	1.5%
GS 2.2	107.2	9.9%	119.1	10.0%	120.1	10.7%
GS 2.3	141.2	13.0%	147.3	12.4%	140.9	12.5%
GS 2.4	60.6	5.6%	66.0	5.6%	61.7	5.5%
Streetlights	8.5	0.8%	8.5	0.7%	8.5	0.8%
Losses	77.0	7.1%	84.3	7.1%	79.9	7.1%
Estimated NP Native Peak at Hydro System Peak	1,088.2	100%	1,186.1	100%	1123.8	100%
Actual NP Native Peak at Hydro System Peak	1,099.4		1,142.6		1123.3	

To assess the reasonableness of the results, the total of the class load estimates was compared to the actual total produced and purchased for the time interval. The total of the estimated class loads at time of Hydro system peak was within 3.8% of the actual Newfoundland Power load at time of Hydro system peak. The reasonableness of the results is also confirmed as the demand estimates for the system peak hour for each winter season achieved the design accuracy level in each class.

The largest contribution to peak load was from the Rate 1.1 Domestic rate class with a 62.2% average share over the three winter season peaks. Of the general service rate classes, Rate 2.3 was the largest contributor at a 12.6% average share. Each rate classes' relative contribution to system peak remained fairly consistent for each winter season.

6.0 APPLYING RESULTS IN COST OF SERVICE STUDY

The class peak demand proportions provided in Table 1 provide reasonable estimates of the customer rate class responsibility for the actual system peaks that occurred over the past three winter seasons. However, on a go-forward basis, differing rates of load growth by class would result in the proportional allocations from Table 1 becoming out-of-date. To address this issue Newfoundland Power uses class load factors rather than proportional load estimates for demand cost allocations in the cost of service study[11].

[11] Appendix D provides load factor estimates for each class on a coincident and non-coincident peak basis for use in the Cost of Service study.

Load factor expresses average demand as a percentage of peak demand for a time period (e.g., month or year). The load factors are applied to normalized sales to determine the cost of service demand estimates by class. The demand estimates for each class in the cost of service study are used for demand cost allocation to each class.

Class load factors calculated based on the time of system peak can vary significantly depending on the weather, month it occurs, time of day, and the day of the week. Volatility in cost of service results from year to year can occur if a single peak that occurred at an unusual time period was used in determining demand cost allocations. To ensure reasonable demand cost allocation, Newfoundland Power averages the annual load factors over the period of the study.

Table 3 provides both the annual and average load factors derived for each class based on the data collected. The non-coincident peak class load factors[12] are used in determining distribution demand cost allocations. The coincident-peak class load factors[13] are used in determining generation and transmission demand cost allocations.

Classes with lower load factors are allocated a lower proportion of the system energy costs and a higher proportion of the system demand costs. Whereas classes with high load factors are allocated a higher proportion of the system energy costs and a lower proportion of the system demand costs.

Table 3
Class Load Factors

	Non-Coincident Peak				**Coincident Peak**			
	2003-2004[14]	**2004-2005**	**2005-2006**	**Average**	**2003-2004**	**2004-2005**	**2005-2006**	**Average**
Domestic All-Electric	46.2%	45.6%	51.8%	**47.9%**	48.1%	44.0%	48.3%	**46.8%**
Domestic Regular	48.7%	41.6%	38.8%	**43.0%**	53.4%	50.0%	51.9%	**51.8%**
1.1 Total Domestic	46.4%	44.0%	46.5%	**45.6%**	49.2%	45.6%	48.9%	**47.9%**
GS 2.1	49.2%	49.6%	53.9%	**50.9%**	66.0%	63.8%	65.7%	**65.2%**
GS 2.2	53.3%	54.4%	50.2%	**52.6%**	63.1%	57.8%	58.1%	**59.7%**
GS 2.3	58.4%	58.5%	53.1%	**56.7%**	68.9%	66.7%	69.7%	**68.4%**
GS 2.4[15]	66.0%	64.8%	67.7%	**66.2%**	75.1%	72.9%	75.3%	**74.4%**

12 Non-Coincident peak load factor = (12 months normalized sales ÷ (maximum class demand in 12 months x # of hours in the 12-month period)).

13 Coincident peak load factor = (12 months normalized sales ÷ (class demand at time of system peak x # of hours in the 12-month period)).

14 2003-2004 reflects the time period of April 2003 to March 2004 inclusive. This April to March period was used for each year rather than the calendar year to reflect a full winter season in the calculation of annual load factor.

15 The class peak for General Service Rate 2.4 occurred in the month of July in both summer seasons of the 2006 LRP.

7.0 DIFFERENCES FROM 1994 STUDY

Table 4 provides a comparison of the class load factors from the 2006 LRP and the 1994 Study. There are significant differences in load factors compared to the 1994 Study. The primary reasons for the differences in the results are:

(i) a change in the time of Hydro system peak from morning during the period of the 1994 Study to evening peaks during the period of the 2006 LRP; and

(ii) the 2006 LRP class load estimates for General Service Rates 2.1 and 2.2 were derived from a statistically valid study whereas the cost of service estimates used previously were derived based on coincidence estimates applied to billing demand data.

Further information on the effects of each is provided in the following sections.

Table 4
Change in Class Load Factors (%)

	Non-Coincident Peak			Coincident Peak		
	2006 LRP	**1994 Study**	**Difference**	**2006 LRP**	**1994 Study**	**Difference**
Domestic All-Electric	47.9%	39%	8.9	46.8%	48%	-1.2
Domestic Regular	43.0%	51%	-8.0	51.8%	70%	-18.2
1.1 Total Domestic	45.6%	42%	3.6	47.9%	52%	-4.1
GS 2.1	50.9%	35%	15.9	65.2%	42%	23.2
GS 2.2	52.6%	38%	14.6	59.7%	45%	14.7
GS 2.3	56.7%	51%	5.7	68.4%	52%	16.4
GS 2.4	66.2%	61%	5.2	74.4%	64.8%	9.6

7.1 Change in Time of System Peak

For the past nine winter seasons, the Hydro system peak has occurred during the evening hours of 5 pm to 6 pm. The current consistent pattern of evening system peaks is different from the times of the Hydro system peaks during the 1994 Study. Table 5 provides a listing of the time and amount of Hydro's system peak since 1990.

Morning peaks appear possible given extremely windy and cold morning weather conditions that improve as the day progresses. However, morning peaks are not the norm. Evening peaks occurred for the seven highest system peak days during the three winter seasons of the 2006 LRP. For the years prior to 1992, evening system peaks were also the norm. In addition to weather conditions, the profile of Newfoundland Power's own generation across the hours of the day will also impact the timing of Hydro's system peak. A 1 CP allocation method is approved for generation and transmission demand related costs in the Cost of Service study[16]. Consistent with this approach, it is reasonable to use load factors based on evening peaks when that single peak is most likely to occur.

Table 5
Hydro System Peaks

Year	Date	Time	Peak Load (MW)
1989/90	Feb. 3, 1990	18:00	1,316
1990/91	Jan. 26, 1991	18:52	1,281
1991/92	March 2, 1992	11:43	1,303
1992/93	Feb. 8, 1993	09:16	1,288
1993/94	Feb. 9, 1994	11:00	1,305
1994/95	Feb. 13, 1995	11:51	1,250
1995/96	Jan. 16, 1996	16:58	1,318
1996/97	Mar. 10, 1997	08:01	1,229
1997/98	Jan. 7, 1998	17:11	1,289
1998/99	Dec. 23, 1998	17:46	1,295
1999/00	Dec. 23, 1999	17:43	1,265
2000/01	Dec. 24, 2000	17:24	1,240
2001/02	Jan, 31, 2002	17:48	1,403
2002/03	Feb. 15, 2003	18:03	1,402
2003/04	Feb. 16, 2004	18:00	1,405
2004/05	Dec. 6, 2004	16:45	1,402
2005/06	Jan. 23, 2006	17:45[17]	1,247

7.1.1 Effect on Demand Cost Allocations

Because generation demand costs and transmission demand costs are allocated by class based on their load at time of Hydro system peak, the shift from morning system peak to evening system peak can have a significant impact on demand costs allocated by class.

16 In the 2001 Hydro GRA, Newfoundland Power presented evidence recommending the use of a multiple CP for allocation of generation and transmission demand costs. In Order No. P.U. 7 (2002-2003), the Board approved the use of a 1 CP methodology for allocation of generation and transmission demand costs.

17 Frazzle ice conditions at NP's generation facilities reduced generation capability during the morning of January 23rd, 2006, causing Hydro system peak to occur at 9:44 am. If NP generation facilities were capable of typical generation levels, system peak would have occurred at 5:45 pm. Therefore, for purposes of the load research analysis, the winter peak was assumed to occur at 5:45 pm.

Appendix E provides the class load data by 30 minute intervals for the winter season peak days. The differences in peak times by class is clearly illustrated in the load curves and data provided.

The peak times for each class over the past three winter seasons are provided in Table 6.

Table 6
Time of Class Peaks

	2003/04	2004/05	2005/06
Domestic	17:30	18:00	17:30
General Service Rate 2.1	11:00	11:00	10:00
General Service Rate 2.2	11:00	12:30	11:00
General Service Rate 2.3	09:30	11:00	12:00
General Service Rate 2.4	12:00	10:30	11:00

When system peak occurs during the morning hours, a higher percentage of system demand costs are allocated to General Service customers because the peak demand requirements for these customer classes is higher during those hours. Whereas, when system peak occurs in the evening hours, the Domestic class is allocated a higher percentage of demand costs because the Domestic class peak demand requirements are generally greatest in the evening[18].

The 2006 LRP indicates the Domestic class peaks in the evening when the General Service classes are reducing their load requirements. The higher demand requirements for the Domestic class at the time of system peak results in a higher demand cost allocation to the Domestic class. The lower demand requirements for the General Service classes at the time of system peak results in a lower demand cost allocation to the General Service classes.

7.2 Class Load Factors

This section provides a comparison of the load factors derived from the 2006 LRP and those used in the cost of service study filed with the Board in the 2003 Newfoundland Power General Rate Proceeding.

7.2.1 Domestic Load Factors

Table 7 indicates that the non-coincident peak load factor for the Total Domestic class has changed from 42% to approximately 45.6%. The non-coincident peak load factor is calculated based on the maximum class demand independent of the time of system peak.

[18] Appendix E provides graphs of each class's load pattern on peak days for each winter season.

Table 7
Domestic Load Factors

	Non-Coincident Peak			Coincident Peak		
	2006 LRP	**1994 Study**	**Difference**	**2006 LRP**	**1994 Study**	**Difference**
Domestic All-Electric	47.9%	39%	8.9	46.8%	48%	-1.2
Domestic Regular	43.0%	51%	-8.0	51.8%	70%	-18.2
1.1 Total Domestic	45.6%	42%	3.6	47.9%	52%	-4.1

Table 7 also indicates that the coincident peak load factor for the Total Domestic class has declined from 52% to 47.9%. The coincident peak load factor is calculated based on the class demand at time of system peak so the load factor decline is primarily related to the change in time of system peak.

The decline in coincident peak load factor is most pronounced in the Domestic Regular subclass. The Domestic Regular subclass peaks during the suppertime hours and was highly coincident with the time of Hydro system peak during the 2006 LRP. In the 1994 Study, less demand was required to serve the Domestic Regular subclass because the Hydro system peak occurred in mid-morning.

The coincident peak load factors for the Domestic class from 1994 Study would be similar to the results of the 2006 LRP had the system peaks occurred in the evening during the 1994 Study.

7.2.2 Large General Service Class Load Factors

The 2006 LRP class load factors for the large general service rate classes (Rate 2.3 and Rate 2.4) are higher than determined in the 1994 Study. See Table 8.

Table 8
Large General Service Class Load Factors

	Non-Coincident Peak			Coincident Peak		
	2006 LRP	**1994 Study**	**Difference**	**2006 LRP**	**1994 Study**	**Difference**
GS 2.3	56.7%	51%	5.7	68.4%	52%	16.4
GS 2.4	66.2%	61%	5.2	74.4%	64.8%	9.6

The non-coincident class load factors from the 2006 LRP were higher than the non-coincident class load factors from the 1994 Study for both the Rate 2.3 and Rate 2.4 rate classes.

There is an even higher increase in the coincident peak load factors for the large general service classes. This increase is predominantly related to the change in time of system peak from morning to evening. The coincident peak load factors for the large General Service classes from 1994 Study would be similar to the results of the 2006 LRP had the system peaks occurred in the evening during the 1994 Study.

7.2.3 Small General Service Class Load Factors

Newfoundland Power did not have load research data from the 1994 Study for its Rate 2.1 or its Rate 2.2 customer classes. The Company has historically used the Bary Curve to estimate load factors for these classes.[19] The Bary Curve uses the class load factor based on billing information for the peak month (i.e., using the sum of the monthly demands and total energy for the class) to estimate the percentage of customer maximum demands being used at time of class peak (i.e., coincidence).

The results of the 2006 LRP indicate significantly higher load factors than have been used in the cost of service study. See Table 9.

Table 9
Small General Service Class Load Factors

	Non-Coincident Peak			**Coincident Peak**		
	2006 LRP	**Bary Curve**	**Difference**	**2006 LRP**	**Bary Curve**	**Difference**
GS 2.1	50.9%	35%	15.9	65.2%	42%	23.2
GS 2.2	52.6%	38%	14.6	59.7%	45%	14.7

The accuracy level achieved for these classes at the time of system peak is 90% confidence within ±6.6%. This provides confidence in the reliability of the results. Additional confidence in the results is provided as the load factors derived from the 2006 LRP for these rate classes are comparable with the load factors used by Nova Scotia Power and Maritime Electric for its small general service classes.[20]

[19] The Bary Curve is based on historical load research data from U.S. utilities.

[20] Based on information obtained in 2001. Nova Scotia Power used a load factor of 66% on a coincident peak basis using a 3 CP method for its Small General (<12,000 kWh/year) and General (>12,000 kWh/year) classes of service. Maritime Electric used 61% load factor on a coincident peak basis for its Small General Service class.

8.0 CONCLUSIONS

The class load factors derived from the 2006 LRP are reasonable to use in the cost allocation process. This conclusion is supported by:

(i) the achieved accuracy levels of the class load estimates during the peak periods;
(ii) the reconciliation of the class load estimates to system peak data;
(iii) the relative consistency in the results over the three winter seasons; and
(iv) the relative consistency of the class load factors for the small general service classes with those used by other Atlantic Canada utilities.

The materiality of the differences on cost allocations is assessed through the cost of service study. That assessment is not included in this report. However, the significant change in the demand cost allocations that will result from applying the results of the 2006 LRP may require the rebalancing of revenue requirements from some classes.

Detailed Sample Design

LOAD RESEARCH SAMPLE DESIGN - ISLAND INTERCONNECTED SYSTEM

			Newfoundland Power			NL Hydro			Total
Domestic All Electric	**From**	**To**	**Population**	**Ratio Weight**	**Sample Size**	**Population**	**Ratio Weight**	**Sample Size**	**Sample**
Stratum 1 kWh Range	0	2000	32117	0.3634	12	3814	0.68671	1	13
Stratum 2 kWh Range	2001	2850	19805	0.22409	12	1003	0.18059	1	13
Stratum 3 kWh Range	2851	3550	16555	0.18732	12	737	0.1327	1	13
Stratum 4 kWh Range	3551	4400	12853	0.14543	12	0			12
Stratum 5 kWh Range	4401	-	7048	0.07975	12	0			12

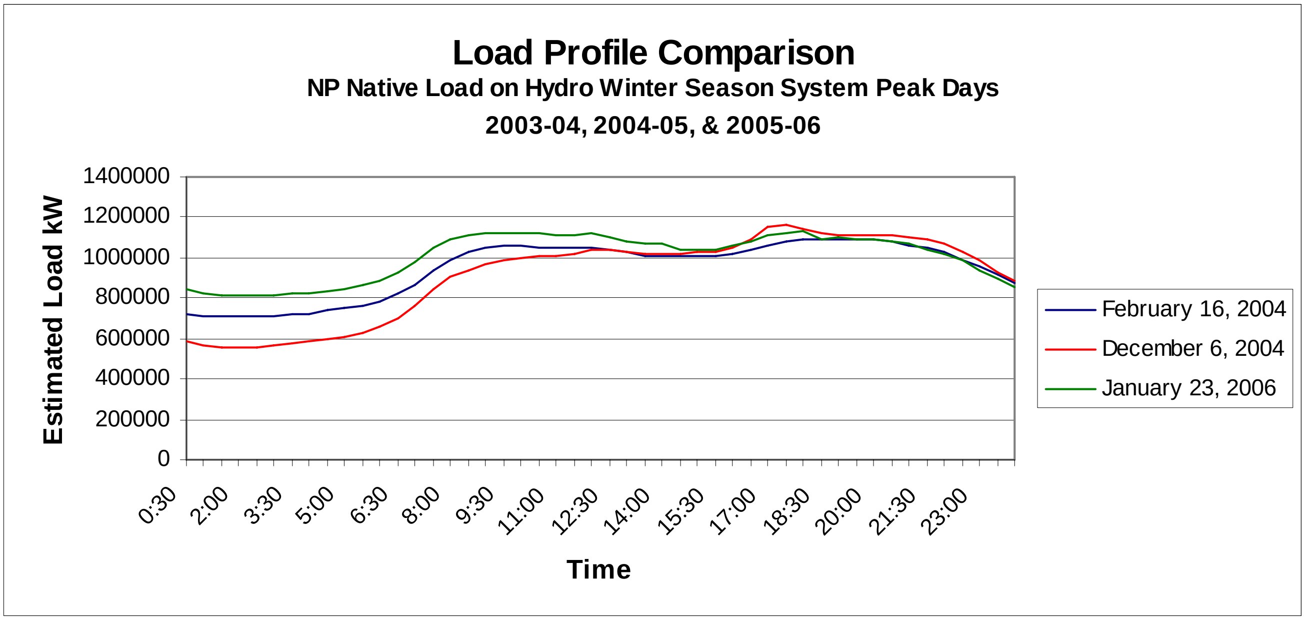
			Newfoundland Power			NL Hydro			Total
Domestic Regular	**From**	**To**	**Population**	**Ratio Weight**	**Sample Size**	**Population**	**Ratio Weight**	**Sample Size**	**Sample**
Stratum 1 kWh Range	0	810	31944	0.42482	18	5167	0.45056	3	21
Stratum 2 kWh Range	811	1140	18834	0.25047	18	3179	0.27721	2	20
Stratum 3 kWh Range	1141	1590	13583	0.18064	18	2115	0.18443	2	20
Stratum 4 kWh Range	1591	2670	7917	0.10529	18	751	0.06549	2	20
Stratum 5 kWh Range	2671	-	2917	0.03879	18	256	0.02232	2	20

			Newfoundland Power			NL Hydro			Total
G. S. 2.1	**From**	**To**	**Population**	**Ratio Weight**	**Sample Size**	**Population**	**Ratio Weight**	**Sample Size**	**Sample**
Stratum 1 kWh Range	0	920	5458	0.61402	18	1146	0.68174	3	21
Stratum 2 kWh Range	921	1560	1426	0.16042	18	263	0.15645	3	21
Stratum 3 kWh Range	1561	2240	944	0.10620	18	145	0.08626	3	21
Stratum 4 kWh Range	2241	3080	661	0.07436	18	99	0.05889	2	20
Stratum 5 kWh Range	3081	-	400	0.04500	18	28	0.01666	2	20

			Newfoundland Power			NL Hydro			Total
G. S. 2.2	**From**	**To**	**Population**	**Ratio Weight**	**Sample Size**	**Population**	**Ratio Weight**	**Sample Size**	**Sample**
Stratum 1 kW Range	0	16	2836	0.39764	18	393	0.4828	2	20
Stratum 2 kW Range	16.1	26	1999	0.28029	18	235	0.2887	2	20
Stratum 3 kW Range	26.1	40	1149	0.16110	18	107	0.13145	2	20
Stratum 4 kW Range	40.1	60	643	0.09016	18	53	0.06511	2	20
Stratum 5 kW Range	60.1	-	505	0.07081	18	26	0.03194	2	20

			Newfoundland Power			NL Hydro			Total
G. S. 2.3	**From**	**To**	**Population**	**Ratio Weight**	**Sample Size**	**Population**	**Ratio Weight**	**Sample Size**	**Sample**
Stratum 1 kW Range	0	138	300	0.32859	18	32	0.4828	3	21
Stratum 2 kW Range	138.1	230	294	0.32202	18	20	0.2887	3	21
Stratum 3 kW Range	230.1	368	169	0.18510	18	4	0.13145	1	19
Stratum 4 kW Range	368.1	553	97	0.10624	18	3	0.06511	1	19
Stratum 5 kW Range	553.1	-	53	0.05805	18	0	0.03194	0	18

System Peak Day Curves



Load Profile Data Winter Season Peak Days 2003-04, 2004-05, & 2005-06			
	February 16, 2004	December 6, 2004	January 23, 2006
0:30	724567	588552	842021
1:00	714595	569634	821868
1:30	707529	559172	813981
2:00	706136	555814	809761
2:30	706003	557750	811764
3:00	711094	562430	814670
3:30	718524	572759	820302
4:00	725540	582441	826267
4:30	737435	594338	834561
5:00	749041	610621	844828
5:30	762960	630996	867172
6:00	779516	654657	887852
6:30	826381	701152	926769
7:00	866086	766005	978883
7:30	937215	848803	1052982
8:00	987708	910142	1095147
8:30	1024702	941734	1111981
9:00	1045505	965775	1117455
9:30	1060264	983646	1125273
10:00	1062191	1000390	1124512
10:30	1054260	1007176	1118654
11:00	1049729	1009589	1110966
11:30	1046301	1023922	1114528
12:00	1049798	1044620	1126503
12:30	1037180	1043066	1101470
13:00	1027920	1032957	1085485
13:30	1005664	1022073	1067156
14:00	1007665	1016168	1067482
14:30	1008890	1017257	1040664
15:00	1003892	1024786	1037569
15:30	1010989	1031059	1043351
16:00	1023024	1047858	1056909
16:30	1042293	1093751	1076446
17:00	1058423	1151617	1112951
17:30	1077249	1160710	1126275
18:00	1095358	1146097	1127206
18:30	1088197	1118135	1094649
19:00	1089042	1110743	1096346
19:30	1090973	1114586	1090896
20:00	1086595	1111274	1089371
20:30	1079553	1113445	1080768
21:00	1064203	1104006	1067529
21:30	1048990	1087270	1039844
22:00	1030779	1067321	1016801
22:30	990132	1028390	984066
23:00	959982	987633	940604
23:30	916767	931222	897857
0:00	873958	887880	857877

Class Load Estimates

Load Estimates - Domestic Regular	Dec-2003	Jan-2004	Feb-2004	Mar-2004	Apr-2004	May-2004	Jun-2004
Residential Sample Size (At System Peak)	88	89	90	90	90	90	90
Monthly Billed Energy (kWh)	85,326,031	85,409,678	76,292,208	77,912,046	67,404,654	62,847,091	55,546,625
Residential Peak Load (kW)	217,407	189,649	172,964	171,263	140,709	160,140	122,456
Date/Time	12/24/2003 18:00	1/11/2004 17:30	2/16/2004 19:30	3/18/2004 19:30	4/25/2004 11:30	5/15/2004 17:30	6/6/2004 10:00
Relative Accuracy at 90% Confidence	11.0%	12.4%	17.2%	15.5%	13.6%	17.2%	20.1%
Residential Load at System Peak	165,765	169,097	172,599	118,449	124,031	102,382	133,009
Date/Time	12/8/2003 17:00	1/16/2004 17:30	2/16/2004 18:00	3/18/2004 9:00	4/26/2004 11:30	5/13/2004 9:45	6/5/2004 12:00
Relative Accuracy at 90% Confidence	12.0%	9.6%	8.8%	11.5%	16.3%	17.2%	14.9%
Coincidence Factor	76.2%	89.2%	99.8%	69.2%	88.1%	63.9%	108.6%
NP Load at Hydro System Peak (kW)	928,461	1,012,102	1,099,424	918,612	833,032	716,820	636,553
Contribution as % of System Peak	17.85%	16.71%	15.70%	12.89%	14.89%	14.28%	20.90%

	Jul-2004	Aug-2004	Sep-2004	Oct-2004	Nov-2004	Dec-2004	Jan-2005
Residential Sample Size (At System Peak)	90	90	90	94	94	95	95
Monthly Billed Energy (kWh)	51,155,628	49,951,680	53,962,437	62,139,275	68,413,897	89,576,601	87,533,456
Residential Peak Load (kW)	147,519	109,371	127,588	159,837	171,648	205,610	222,267
Date/Time	7/1/2004 12:30	8/25/2004 16:00	9/21/2004 20:30	10/30/2004 11:30	11/21/2004 11:30	12/27/2004 17:30	1/22/2005 18:00
Relative Accuracy at 90% Confidence	18.6%	16.7%	14.4%	16.4%	15.1%	8.8%	14.1%
Residential Load at System Peak	85,881	95,741	81,097	112,501	160,701	184,859	230,026
Date/Time	7/12/2004 12:00	8/30/2004 17:00	9/22/2004 12:00	10/29/2004 19:15	11/22/2004 17:15	12/6/2004 16:45	1/6/2005 18:00
Relative Accuracy at 90% Confidence	17.8%	13.0%	16.2%	13.8%	14.7%	11.0%	9.2%
Coincidence Factor	58.2%	87.5%	63.6%	70.4%	93.6%	89.9%	103.5%
NP Load at Hydro System Peak (kW)	539,794	518,595	622,336	785,877	851,521	1,142,661	1121749
Contribution as % of System Peak	15.91%	18.46%	13.03%	14.32%	18.87%	16.18%	20.51%

	Feb-2005	Mar-2005	Apr-2005	May-2005	Jun-2005	Jul-2005	Aug-2005
Residential Sample Size (At System Peak)	99	98	100	100	100	100	100
Monthly Billed Energy (kWh)	73,581,622	77,240,317	67,198,630	61,429,912	53,541,812	49,266,984	49,644,687
Residential Peak Load (kW)	181,109	154,212	151,204	130,318	121,996	112,794	110,993
Date/Time	2/20/2005 11:30	3/6/2005 12:00	4/2/2005 12:00	5/15/2005 10:30	6/19/2005 10:00	7/1/2005 11:00	8/28/2005 10:30
Relative Accuracy at 90% Confidence	16.7%	21.3%	21.7%	15.8%	16.6%	14.8%	18.7%
Residential Load at System Peak	143,603	150,898	134,704	109,695	120,401	81,431	90,607
Date/Time	2/22/2005 8:30	3/5/2005 18:45	3/31/2005 20:00	5/20/2005 12:00	6/14/2005 17:00	7/15/2005 11:45	8/5/2005 12:00
Relative Accuracy at 90% Confidence	12.0%	12.7%	15.8%	17.8%	11.5%	19.8%	19.1%
Coincidence Factor	79.3%	97.9%	89.1%	84.2%	98.7%	72.2%	81.6%
NP Load at Hydro System Peak (kW)	1,049,084	925,250	871,642	725,616	636,815	504,391	500,522
Contribution as % of System Peak	13.7%	16.3%	15.5%	15.1%	18.9%	16.1%	18.1%

	Sep-2005	Oct-2005	Nov-2005	Dec-2005	Jan-2006	Feb-2006	Mar-2006
Residential Sample Size (At System Peak)	100	99	99	99	95	98	97
Residential Billed Energy (MWh)	51,710,134	61,507,680	65,662,690	86,596,566	82,190,170	74,251,713	76,250,505
Residential Peak Load (kW)	130,732	125,381	118,776	235,058	226,196	198,227	149,085
Date/Time	9/18/2005 11:00	10/26/2005 18:30	11/29/2005 8:00	12/24/2005 17:30	1/2/2006 17:00	2/25/2006 17:30	3/11/2006 9:00
Relative Accuracy at 90% Confidence	16.7%	10.7%	16.6%	11.7%	13.2%	12.2%	13.9%
Residential Load at System Peak	100,016	117,281	149,150	181,902	175,535	140,721	139,159
Date/Time	9/12/2005 17:15	10/12/2005 19:30	11/28/2005 17:30	12/22/2005 19:15	1/23/2006 17:45	2/23/2006 8:45	3/1/2006 8:15
Relative Accuracy at 90% Confidence	15.8%	11.5%	10.9%	10.3%	9.6%	11.4%	12.3%
Coincidence Factor	76.5%	93.5%	125.6%	77.4%	77.6%	71.0%	93.3%
System Peak (kW)	565,831	685,036	847,527	1,040,708	1,123,322	1,026,356	1,003,642
Contribution as % of System Peak	17.7%	17.1%	17.6%	17.5%	15.6%	13.7%	13.9%

Load Estimates - Domestic All-Electric

	Dec-2003	Jan-2004	Feb-2004	Mar-2004	Apr-2004	May-2004	Jun-2004
Residential Sample Size (At System Peak)	60	60	60	61	60	59	59
Monthly Billed Energy (kWh)	235,388,690	269,918,521	243,460,519	241,039,146	184,873,202	155,597,889	118,229,232
Residential Peak Load (kW)	483,894	519,347	537,116	474,963	420,827	326,276	321,629
Date/Time	12/24/2003 18:00	1/11/2004 17:30	2/16/2004 19:30	3/18/2004 19:30	4/25/2004 11:30	5/15/2004 17:30	6/6/2004 10:00
Relative Accuracy at 90% Confidence	20.3%	13.0%	9.5%	11.0%	13.9%	16.5%	17.2%
Residential Load at System Peak	429,408	483,787	500,611	391,578	401,925	268,727	298,911
Date/Time	12/8/2003 17:00	1/16/2004 17:30	2/16/2004 18:00	3/18/2004 9:00	4/26/2004 11:30	5/13/2004 9:45	6/5/2004 12:00
Relative Accuracy at 90% Confidence	26.4%	11.8%	10.4%	12.0%	18.6%	18.0%	19.1%
Coincidence Factor	88.7%	93.2%	93.2%	82.4%	95.5%	82.4%	92.9%
NP Load at Hydro System Peak (kW)	928,461	1,012,102	1,099,424	918,612	833,032	716,820	636,553
Contribution as % of System Peak	46.2%	47.8%	45.5%	42.6%	48.2%	37.5%	47.0%

	Jul-2004	Aug-2004	Sep-2004	Oct-2004	Nov-2004	Dec-2004	Jan-2005
Residential Sample Size (At System Peak)	59	59	59	59	59	60	59
Monthly Billed Energy (kWh)	87,800,315	79,359,674	101,378,704	142,768,784	194,440,867	259,009,990	291,361,937
Residential Peak Load (kW)	173,560	205,976	274,028	372,417	416,887	549,311	544,572
Date/Time	7/1/2004 12:30	8/25/2004 16:00	9/21/2004 20:30	10/30/2004 11:30	11/21/2004 11:30	12/27/2004 17:30	1/22/2005 18:00
Relative Accuracy at 90% Confidence	25.2%	18.9%	16.5%	12.2%	13.2%	9.7%	9.4%
Residential Load at System Peak	167,786	203,072	173,457	315,255	370,708	560,739	507,868
Date/Time	7/12/2004 12:00	8/30/2004 17:00	9/22/2004 12:00	10/29/2004 19:15	11/22/2004 17:15	12/6/2004 16:45	1/6/2005 18:00
Relative Accuracy at 90% Confidence	17.1%	26.6%	22.7%	11.1%	9.8%	6.9%	9.4%
Coincidence Factor	96.7%	98.6%	63.3%	84.7%	88.9%	102.1%	93.3%
NP Load at Hydro System Peak (kW)	539,794	518,595	622,336	785,877	851,521	1,142,661	1121749
Contribution as % of System Peak	31.1%	39.2%	27.9%	40.1%	43.5%	49.1%	45.3%

	Feb-2005	Mar-2005	Apr-2005	May-2005	Jun-2005	Jul-2005	Aug-2005
Residential Sample Size (At System Peak)	62	62	62	62	62	62	62
Monthly Billed Energy (kWh)	238,172,553	245,656,100	195,439,699	155,545,991	114,893,778	84,566,508	83,254,888
Residential Peak Load (kW)	492,619	441,945	356,954	390,586	298,881	190,309	185,192
Date/Time	2/20/2005 11:30	3/6/2005 12:00	4/2/2005 12:00	5/15/2005 10:30	6/19/2005 10:00	7/1/2005 11:00	8/28/2005 10:30
Relative Accuracy at 90% Confidence	12.1%	10.2%	13.1%	14.8%	18.4%	23.4%	21.2%
Residential Load at System Peak	493,598	406,662	386,538	292,618	244,520	124,890	142,285
Date/Time	2/22/2005 8:30	3/5/2005 18:45	3/31/2005 20:00	5/20/2005 12:00	6/14/2005 17:00	7/15/2005 11:45	8/5/2005 12:00
Relative Accuracy at 90% Confidence	11.3%	9.5%	13.1%	15.2%	20.4%	19.7%	26.8%
Coincidence Factor	100.2%	92.0%	108.3%	74.9%	81.8%	65.6%	76.8%
NP Load at Hydro System Peak (kW)	1,049,084	925,250	871,642	725,616	636,815	504,391	500,522
Contribution as % of System Peak	47.1%	44.0%	44.3%	40.3%	38.4%	24.8%	28.4%

	Sep-2005	Oct-2005	Nov-2005	Dec-2005	Jan-2006	Feb-2006	Mar-2006
Residential Sample Size (At System Peak)	62	63	63	62	62	61	62
Monthly Billed Energy (kWh)	94,728,649	144,580,505	183,007,448	246,431,641	262,424,182	248,160,180	244,247,555
Residential Peak Load (kW)	219,191	367,530	431,440	481,918	479,698	474,518	493,598
Date/Time	9/18/2005 11:00	10/26/2005 18:30	11/29/2005 8:00	12/24/2005 17:30	1/2/2006 17:00	2/25/2006 17:30	3/1/2006 9:00
Relative Accuracy at 90% Confidence	16.0%	15.0%	11.6%	9.0%	8.9%	8.1%	9.1%
Residential Load at System Peak	198,141	283,627	383,435	486,571	516,635	503,737	489,151
Date/Time	9/12/2005 17:15	10/12/2005 19:30	11/28/2005 17:30	12/22/2005 19:15	1/23/2006 17:45	2/23/2006 8:15	3/1/2006 8:15
Relative Accuracy at 90% Confidence	14.4%	11.7%	11.0%	7.1%	8.7%	8.1%	8.5%
Coincidence Factor	90.4%	77.2%	88.9%	101.0%	107.7%	106.2%	99.1%
NP Load at Hydro System Peak (kW)	565,831	685,036	847,527	1,040,708	1,123,322	1,026,356	1,003,642
Contribution as % of System Peak	35.0%	41.4%	45.2%	46.8%	46.0%	49.1%	48.7%

Load Estimates - Total Domestic Rate 1.1

	Dec-2003	Jan-2004	Feb-2004	Mar-2004	Apr-2004	May-2004	Jun-2004
Residential Sample Size (At System Peak)	148	149	150	151	150	149	149
Monthly Billed Energy (kWh)	320,141,976	355,614,588	318,809,595	319,282,639	253,270,237	217,100,374	174,370,276
Residential Peak Load (kW)	708,643	715,973	710,966	650,607	558,655	491,997	438,667
Date/Time	12/24/2003 18:00	1/11/2004 17:30	2/16/2004 19:30	3/18/2004 19:30	4/25/2004 11:30	5/15/2004 17:30	6/6/2004 10:00
Relative Accuracy at 90% Confidence	15.4%	10.0%	8.3%	8.9%	11.1%	12.4%	13.8%
Residential Load at System Peak	596,370	657,114	676,820	508,052	520,699	369,629	430,615
Date/Time	12/8/2003 17:00	1/16/2004 17:30	2/16/2004 18:00	3/18/2004 9:00	4/26/2004 11:30	5/13/2004 9:45	6/5/2004 12:00
Relative Accuracy at 90% Confidence	19.6%	9.1%	8.0%	9.7%	14.8%	13.9%	14.0%
Coincidence Factor	84.2%	91.8%	95.2%	78.1%	93.2%	75.1%	98.2%
NP Load at Hydro System Peak (kW)	928,461	1,012,102	1,099,424	918,612	833,032	716,820	636,553
Contribution as % of System Peak	64.2%	64.9%	61.6%	55.3%	62.5%	51.6%	67.6%

	Jul-2004	Aug-2004	Sep-2004	Oct-2004	Nov-2004	Dec-2004	Jan-2005
Residential Sample Size (At System Peak)	149	149	149	153	153	155	155
Monthly Billed Energy (kWh)	138,955,943	129,311,354	155,341,141	204,908,059	262,854,764	348,586,591	378,895,393
Residential Peak Load (kW)	330,310	311,691	397,819	531,780	594,825	758,470	774,423
Date/Time	7/1/2004 12:30	8/25/2004 16:00	9/21/2004 20:30	10/30/2004 11:30	11/21/2004 11:30	12/27/2004 17:30	1/22/2005 18:00
Relative Accuracy at 90% Confidence	16.5%	14.0%	12.3%	9.8%	10.3%	7.4%	7.8%
Residential Load at System Peak	251,303	293,029	252,220	422,562	539,034	743,539	747,906
Date/Time	7/12/2004 12:00	8/30/2004 17:00	9/22/2004 12:00	10/29/2004 19:15	11/22/2004 17:15	12/6/2004 16:45	1/6/2005 18:00
Relative Accuracy at 90% Confidence	12.9%	18.6%	16.7%	9.1%	8.2%	5.9%	7.0%
Coincidence Factor	76.1%	94.0%	63.4%	79.5%	90.6%	98.0%	96.6%
NP Load at Hydro System Peak (kW)	539,794	518,595	622,336	785,877	851,521	1,142,661	1121749
Contribution as % of System Peak	46.6%	56.5%	40.5%	53.8%	63.3%	65.1%	66.7%

	Feb-2005	Mar-2005	Apr-2005	May-2005	Jun-2005	Jul-2005	Aug-2005
Residential Sample Size (At System Peak)	161	160	162	162	162	162	162
Monthly Billed Energy (kWh)	311,754,175	322,896,417	262,638,329	216,975,903	168,435,590	133,833,492	132,899,575
Residential Peak Load (kW)	681,341	601,363	517,311	515,098	417,196	303,480	296,302
Date/Time	2/20/2005 11:30	3/6/2005 12:00	4/2/2005 12:00	5/15/2005 10:30	6/19/2005 10:00	7/1/2005 11:00	8/28/2005 10:30
Relative Accuracy at 90% Confidence	9.9%	9.2%	11.0%	11.8%	14.2%	15.7%	15.0%
Residential Load at System Peak	669,965	565,423	525,736	400,889	366,295	208,020	234,082
Date/Time	2/22/2005 8:30	3/5/2005 18:45	3/31/2005 20:00	5/20/2005 12:00	6/14/2005 17:00	7/15/2005 11:45	8/5/2005 12:00
Relative Accuracy at 90% Confidence	7.8%	7.7%	10.4%	12.1%	14.2%	14.1%	17.8%
Coincidence Factor	98%	94%	102%	78%	88%	69%	79%
NP Load at Hydro System Peak (kW)	1,049,084	925,250	871,642	725,616	636,815	504,391	500,522
Contribution as % of System Peak	63.9%	61.1%	60.3%	55.2%	57.5%	41.2%	46.8%

	Sep-2005	Oct-2005	Nov-2005	Dec-2005	Jan-2006	Feb-2006	Mar-2006
Residential Sample Size (At System Peak)	162	162	162	161	155	159	159
Monthly Billed Energy (kWh)	146,438,783	206,088,185	248,670,138	333,028,207	344,614,352	322,411,893	320,498,060
Residential Peak Load (kW)	352,382	484,861	539,947	734,032	726,452	693,739	641,333
Date/Time	9/18/2005 11:00	10/26/2005 18:30	11/29/2005 8:00	12/24/2005 17:30	1/2/2006 17:00	2/25/2006 17:30	3/1/2006 9:00
Relative Accuracy at 90% Confidence	11.7%	11.4%	9.8%	7.2%	7.1%	11.7%	7.8%
Residential Load at System Peak	296,370	400,075	535,884	671,307	695,863	649,286	624,660
Date/Time	9/12/2005 17:15	10/12/2005 19:30	11/28/2005 17:30	12/22/2005 19:15	1/23/2006 17:45	2/23/2006 8:15	3/1/2006 8:15
Relative Accuracy at 90% Confidence	11.1%	8.9%	8.5%	5.9%	6.9%	10.4%	7.2%
Coincidence Factor	84.1%	82.5%	99.2%	91.5%	95.8%	93.6%	97.4%
NP Load at Hydro System Peak (kW)	565,831	685,036	847,527	1,040,708	1,123,322	1,026,356	1,003,642
Contribution as % of System Peak	52.4%	58.4%	63.2%	64.5%	61.9%	63.3%	62.2%

Load Estimates - Rate 2.1- General Service 0-10 kw

	Dec-2003	Jan-2004	Feb-2004	Mar-2004	Apr-2004	May-2004	Jun-2004
Rate 2.1 Sample Size at System Peak	92	93	93	93	92	91	91
Monthly Billed Energy (kWh)	9,220,003	10,393,724	9,593,927	9,817,972	8,110,608	7,371,997	6,591,345
Rate 2.1 Peak Load (kW)	20,171	20,394	22,504	21,386	18,953	19,715	19,152
Date/Time	12/22/2003 10:00	1/15/2004 11:30	2/17/2004 11:00	3/9/2004 10:30	4/1/2004 10:30	5/10/2004 10:30	6/1/2004 10:00
Relative Accuracy at 90% Confidence	12.4%	8.2%	8.2%	13.2%	14.4%	23.8%	22.9%
Rate 2.1 Load at System Peak	14,524	15,194	16,773	16,599	17,509	15,704	11,583
Date/Time	12/8/2003 17:00	1/16/2004 17:30	2/16/2004 18:00	3/18/2004 9:00	4/26/2004 11:30	5/13/2004 9:45	6/5/2004 12:00
Relative Accuracy at 90% Confidence	7.5%	6.9%	5.7%	6.3%	15.1%	8.6%	11.1%
Coincidence Factor	72.0%	74.5%	74.5%	77.6%	92.4%	79.7%	60.5%
NP Load at Hydro System Peak (kW)	928,461	1,012,102	1,099,424	918,612	833,032	716,820	636,553
Rate 2.1 Contribution as % of System Peak	1.56%	1.50%	1.5%	1.8%	2.1%	2.2%	1.8%

	Jul-2004	Aug-2004	Sep-2004	Oct-2004	Nov-2004	Dec-2004	Jan-2005
Rate 2.1 Sample Size at System Peak	91	91	91	95	95	96	97
Monthly Billed Energy (kWh)	6,371,885	6,266,352	6,254,607	7,064,375	8,204,611	9,714,333	10,826,617
Rate 2.1 Peak Load (kW)	16,886	16,890	16,618	17,521	20,200	22,405	21,711
Date/Time	7/30/2004 10:30	8/10/2004 11:00	9/22/2004 12:00	10/29/2004 10:00	11/29/2004 11:30	12/7/2004 11:00	1/10/2005 11:30
Relative Accuracy at 90% Confidence	19.2%	26.7%	19.9%	17.6%	16.5%	11.7%	9.9%
Rate 2.1 Load at System Peak	12,332	8,095	16,618	11,476	12,315	17,435	17,605
Date/Time	7/12/2004 12:00	8/30/2004 17:00	9/22/2004 12:00	10/29/2004 19:15	11/22/2004 17:15	12/6/2004 16:45	1/6/2005 18:00
Relative Accuracy at 90% Confidence	16.7%	13.9%	19.9%	8.7%	7.1%	6.6%	6.6%
Coincidence Factor	73.0%	47.9%	100.0%	65.5%	61.0%	77.8%	81.1%
NP Load at Hydro System Peak (kW)	539,794	518,595	622,336	785,877	851,521	1,142,661	1121749
Rate 2.1 Contribution as % of System Peak	2.3%	1.6%	2.7%	1.5%	1.4%	1.5%	1.6%

	Feb-2005	Mar-2005	Apr-2005	May-2005	Jun-2005	Jul-2005	Aug-2005
Rate 2.1 Sample Size at System Peak	100	101	101	102	104	104	105
Monthly Billed Energy (kWh)	9,236,664	9,626,168	8,134,658	7,324,631	6,441,744	6,307,202	6,248,167
Rate 2.1 Peak Load (kW)	23,866	21,063	20,889	18,523	17,678	17,458	16,429
Date/Time	2/22/2005 11:00	3/1/2005 15:30	4/19/2005 11:00	5/24/2005 12:30	6/14/2005 10:30	7/14/2005 12:00	8/22/2005 10:30
Relative Accuracy at 90% Confidence	20.3%	27.7%	17.9%	29.1%	19.4%	25.3%	20.6%
Rate 2.1 Load at System Peak	16,380	13,954	17,792	13,990	10,431	10,279	14,161
Date/Time	2/22/2005 8:30	3/5/2005 18:45	3/31/2005 20:00	5/20/2005 12:00	6/14/2005 17:00	7/15/2005 11:45	8/5/2005 12:00
Relative Accuracy at 90% Confidence	7.8%	6.4%	23.7%	11.3%	13.6%	12.6%	14.1%
Coincidence Factor	68.6%	66.2%	85.2%	75.5%	59.0%	58.9%	86.2%
NP Load at Hydro System Peak (kW)	1,049,084	925,250	871,642	725,616	636,815	504,391	500,522
Rate 2.1 Contribution as % of System Peak	1.6%	1.5%	2.0%	1.9%	1.6%	2.0%	2.8%

	Sep-2005	Oct-2005	Nov-2005	Dec-2005	Jan-2006	Feb-2006	Mar-2006
Rate 2.1 Sample Size at System Peak	102	102	103	98	99	100	98
Monthly Billed Energy (kWh)	6,051,657	6,972,161	7,740,881	9,052,402	9,898,852	9,105,961	9,214,934
Rate 2.1 Peak Load (kW)	15,158	17,177	18,274	20,176	19,613	20,351	18,742
Date/Time	9/29/2005 10:30	10/27/2005 13:00	11/28/2005 10:00	12/22/2005 9:30	1/23/2006 10:30	2/20/2006 10:00	3/1/2006 9:30
Relative Accuracy at 90% Confidence	21.1%	28.5%	22.0%	17.2%	8.5%	16.2%	7.8%
Rate 2.1 Load at System Peak	7,683	10,706	12,451	14,879	16,750	16,681	15,121
Date/Time	9/12/2005 17:15	10/12/2005 19:30	11/28/2005 17:30	12/22/2005 19:15	1/23/2006 17:45	2/23/2006 8:15	3/1/2006 8:15
Relative Accuracy at 90% Confidence	7.9%	9.9%	9.4%	7.1%	5.6%	7.7%	6.0%
Coincidence Factor	50.7%	62.3%	68.1%	73.7%	85.4%	82.0%	80.7%
NP Load at Hydro System Peak (kW)	565,831	685,036	847,527	1,040,708	1,130,873	1,026,356	1,003,642
Rate 2.1 Contribution as % of System Peak	1.4%	1.6%	1.5%	1.4%	1.5%	1.6%	1.5%

Load Estimates - Rate 2.2 - General Service 10 - 100 kw

	Dec-2003	Jan-2004	Feb-2004	Mar-2004	Apr-2004	May-2004	Jun-2004
Rate 2.2 Sample Size at System Peak	90	90	90	90	90	90	90
Monthly Billed Energy (kWh)	55,311,753	64,349,693	59,187,147	60,546,723	49,550,308	44,824,863	40,266,774
Rate 2.2 Peak Load (kW)	113,997	123,577	126,947	112,851	106,633	97,204	93,056
Date/Time	12/15/2003 10:30	1/15/2004 10:00	2/16/2004 11:00	3/9/2004 10:30	4/26/2004 10:30	5/19/2004 10:00	6/1/2004 10:30
Relative Accuracy at 90% Confidence	5.7%	4.9%	5.3%	4.6%	5.8%	8.3%	8.5%
Rate 2.2 Load at System Peak	93,834	95,330	107,215	102,948	99,720	96,740	72,295
Date/Time	12/8/2003 17:00	1/16/2004 17:30	2/16/2004 18:00	3/18/2004 9:00	4/26/2004 11:30	5/13/2004 9:45	6/5/2004 12:00
Relative Accuracy at 90% Confidence	4.8%	4.8%	3.8%	4.7%	5.8%	6.7%	6.8%
Coincidence Factor	82.3%	77.1%	84.5%	91.2%	93.5%	99.5%	77.7%
NP Load at Hydro System Peak (kW)	928,461	1,012,102	1,099,424	918,612	833,032	716,820	636,553
Rate 2.2 Contribution as % of System Peak	10.1%	9.4%	9.8%	11.2%	12.0%	13.5%	11.4%

	Jul-2004	Aug-2004	Sep-2004	Oct-2004	Nov-2004	Dec-2004	Jan-2005
Rate 2.2 Sample Size at System Peak	90	88	88	92	93	94	95
Monthly Billed Energy (kWh)	39,581,329	38,987,597	38,276,013	43,231,744	51,194,588	60,029,849	67,536,084
Rate 2.2 Peak Load (kW)	85,282	83,665	91,954	97,741	108,144	124,334	126,967
Date/Time	7/15/2004 10:30	8/9/2004 11:00	9/21/2004 9:30	10/29/2004 10:30	11/22/2004 11:00	12/6/2004 11:30	1/6/2005 12:30
Relative Accuracy at 90% Confidence	7.4%	7.1%	9.4%	6.6%	7.2%	4.9%	4.3%
Rate 2.2 Load at System Peak	68,024	54,508	77,897	72,136	83,636	119,149	110,478
Date/Time	7/12/2004 12:00	8/30/2004 17:00	9/22/2004 12:00	10/29/2004 19:15	11/22/2004 17:15	12/6/2004 16:45	1/6/2005 18:00
Relative Accuracy at 90% Confidence	5.8%	6.1%	7.2%	7.0%	4.7%	4.4%	3.4%
Coincidence Factor	79.8%	65.1%	84.7%	73.8%	77.3%	95.8%	87.0%
NP Load at Hydro System Peak (kW)	539,794	518,595	622,336	785,877	851,521	1,142,661	1121749
Rate 2.2 Contribution as % of System Peak	12.6%	10.5%	12.5%	9.2%	9.8%	10.4%	9.8%

	Feb-2005	Mar-2005	Apr-2005	May-2005	Jun-2005	Jul-2005	Aug-2005
Rate 2.2 Sample Size at System Peak	98	98	98	98	98	98	98
Monthly Billed Energy (kWh)	57,935,121	61,155,318	51,797,670	45,758,378	39,833,633	39,866,302	38,943,156
Rate 2.2 Peak Load (kW)	124,479	114,671	107,746	98,989	86,598	84,228	80,794
Date/Time	2/15/2005 10:00	3/1/2005 10:00	4/14/2005 9:00	200505/16 10:30	6/8/2005 10:00	7/20/2005 10:30	8/22/2005 13:30
Relative Accuracy at 90% Confidence	4.4%	5.1%	7.4%	8.0%	7.5%	6.9%	8.2%
Rate 2.2 Load at System Peak	107,432	89,245	95,777	93,817	61,478	78,965	72,971
Date/Time	2/22/2005 8:30	3/5/2005 18:45	3/31/2005 20:00	5/20/2005 12:00	6/14/2005 17:00	7/15/2005 11:45	8/5/2005 12:00
Relative Accuracy at 90% Confidence	4.1%	5.1%	7.2%	5.7%	6.0%	5.1%	6.4%
Coincidence Factor	86.3%	77.8%	88.9%	94.8%	71.0%	93.8%	90.3%
NP Load at Hydro System Peak (kW)	1,049,084	925,250	871,642	725,616	636,815	504,391	500,522
Rate 2.2 Contribution as % of System Peak	10.2%	9.6%	11.0%	12.9%	9.7%	15.7%	14.6%

	Sep-2005	Oct-2005	Nov-2005	Dec-2005	Jan-2006	Feb-2006	Mar-2006
Rate 2.2 Sample Size at System Peak	97	97	96	97	97	97	97
Monthly Billed Energy (kWh)	37,919,781	44,037,851	49,512,018	57,262,756	64,153,511	60,078,257	60,881,052
Rate 2.2 Peak Load (kW)	83,229	94,017	104,777	117,102	138,979	126,718	118,419
Date/Time	9/26/2005 11:00	10/12/2005 10:30	11/29/2005 11:00	12/22/2005 10:00	1/23/2006 11:00	2/28/2006 11:00	3/1/2006 10:00
Relative Accuracy at 90% Confidence	8.8%	7.3%	6.4%	5.3%	4.9%	5.1%	4.9%
Rate 2.2 Load at System Peak	53,474	65,981	83,394	95,557	120,112	107,247	108,404
Date/Time	9/12/2005 17:15	10/12/2005 19:30	11/28/2005 17:30	12/22/2005 19:15	1/23/2005 17:45	2/23/2006 8:15	3/1/2006 8:15
Relative Accuracy at 90% Confidence	4.9%	5.8%	5.2%	5.9%	4.4%	5.1%	4.5%
Coincidence Factor	64.2%	70.2%	79.6%	81.6%	86.4%	84.6%	91.5%
NP Load at Hydro System Peak (kW)	565,831	685,036	847,527	1,040,708	1,123,322	1,026,356	1,003,642
Rate 2.2 Contribution as % of System Peak	9.5%	9.6%	9.8%	9.2%	10.7%	10.4%	10.8%

Load Estimates - Rate 2.3 - General Service 110-100 KVA

	Dec-2003	Jan-2004	Feb-2004	Mar-2004	Apr-2004	May-2004	Jun-2004
Rate 2.3 Sample Size	89	90	90	90	90	90	90
Monthly Billed Energy (kWh)	78,059,352	86,923,871	81,151,214	82,657,669	69,945,367	66,398,322	60,203,210
Rate 2.3 Peak Load (kW)	151,415	166,883	166,827	152,848	138,435	134,875	118,803
Date/Time	12/3/2003 9:30	1/15/2004 9:30	2/17/2004 10:30	3/18/2004 9:00	4/21/2004 8:30	5/31/2004 8:30	6/1/2004 8:30
Relative Accuracy at 90% Confidence	12.1%	4.1%	4.6%	5.0%	5.1%	6.0%	11.8%
Rate 2.3 Load at System Peak	122,204	131,371	141,160	152,848	130,453	131,183	87,337
Date/Time	12/8/2003 17:00	1/16/2004 17:30	2/16/2004 18:00	3/18/2004 9:00	4/26/2004 11:30	5/13/2004 9:45	6/5/2004 12:00
Relative Accuracy at 90% Confidence	4.6%	4.1%	4.4%	5.0%	5.7%	4.9%	11.6%
Coincidence Factor	80.7%	78.7%	84.6%	100.0%	94.2%	97.3%	73.5%
NP Load at Hydro System Peak (kW)	928,461	1,012,102	1,099,424	918,612	833,032	716,820	636,553
Rate 2.3 Contribution as % of System Peak	13.2%	13.0%	12.8%	16.6%	15.7%	18.3%	13.7%

	Jul-2004	Aug-2004	Sep-2004	Oct-2004	Nov-2004	Dec-2004	Jan-2005
Rate 2.3 Sample Size	90	90	90	95	95	95	94
Monthly Billed Energy (kWh)	61,121,862	58,489,761	58,956,453	66,151,396	73,818,218	82,244,428	91,086,984
Rate 2.3 Peak Load (kW)	117,011	108,537	122,844	142,652	145,203	167,945	166,919
Date/Time	7/7/2004 10:30	8/12/2004 10:00	9/22/2004 9:30	10/29/2004 10:00	11/29/2004 10:30	12/7/2004 11:00	1/10/2005 10:00
Relative Accuracy at 90% Confidence	9.7%	4.3%	9.1%	12.2%	6.9%	4.9%	4.8%
Rate 2.3 Load at System Peak	100,253	80,305	114,331	105,512	115,447	147,305	137,673
Date/Time	7/12/2004 12:00	8/30/2004 17:00	9/22/2004 12:00	10/29/2004 19:15	11/22/2004 17:15	12/6/2004 16:45	1/6/2005 18:00
Relative Accuracy at 90% Confidence	5.9%	4.5%	7.4%	8.4%	6.0%	5.5%	4.4%
Coincidence Factor	85.7%	74.0%	93.1%	74.0%	79.5%	87.7%	82.5%
NP Load at Hydro System Peak (kW)	539,794	518,595	622,336	785,877	851,521	1,142,661	1121749
Rate 2.3 Contribution as % of System Peak	18.6%	15.5%	18.4%	13.4%	13.6%	12.9%	12.3%

	Feb-2005	Mar-2005	Apr-2005	May-2005	Jun-2005	Jul-2005	Aug-2005
Rate 2.3 Sample Size	97	97	97	96	96	96	96
Monthly Billed Energy (kWh)	78,123,788	82,322,865	71,858,575	65,774,476	60,405,101	60,818,345	58,181,489
Rate 2.3 Peak Load (kW)	165,787	156,448	144,710	135,216	122,153	113,185	111,949
Date/Time	2/22/2005 9:00	3/1/2005 9:30	4/15/2005 8:30	5/16/2005 10:00	6/14/2005 8:30	7/12/2005 10:00	8/31/2005 14:00
Relative Accuracy at 90% Confidence	5.1%	6.1%	4.9%	6.2%	7.8%	5.5%	5.9%
Rate 2.3 Load at System Peak	163,805	121,523	111,284	122,123	88,850	108,303	98,965
Date/Time	2/22/2005 8:30	3/5/2005 18:45	3/31/2005 20:00	5/20/2005 12:00	6/14/2005 17:00	7/15/2005 11:45	8/5/2005 12:00
Relative Accuracy at 90% Confidence	4.9%	4.8%	4.0%	5.2%	4.7%	4.4%	4.3%
Coincidence Factor	98.8%	77.7%	76.9%	90.3%	72.7%	95.7%	88.4%
NP Load at Hydro System Peak (kW)	1,049,084	925,250	871,642	725,616	636,815	504,391	500,522
Rate 2.3 Contribution as % of System Peak	15.6%	13.1%	12.8%	16.8%	14.0%	21.5%	19.8%

	Sep-2005	Oct-2005	Nov-2005	Dec-2005	Jan-2006	Feb-2006	Mar-2006
Rate 2.3 Sample Size	93	96	97	96	93	93	91
Monthly Billed Energy (kWh)	56,619,196	66,247,316	71,311,846	78,600,505	85,694,678	79,576,642	80,070,965
Rate 2.3 Peak Load (kW)	112,128	135,254	147,561	153,748	184,962	167,604	152,821
Date/Time	9/13/2005 10:30	10/26/2005 9:30	11/7/2005 10:00	12/22/2005 9:30	1/23/2006 12:00	2/28/2006 9:00	3/1/2006 9:00
Relative Accuracy at 90% Confidence	7.4%	6.6%	7.2%	5.3%	5.6%	5.9%	6.9%
Rate 2.3 Load at System Peak	82,522	95,508	114,914	112,973	140,877	163,932	152,253
Date/Time	9/12/2005 17:15	10/12/2005 19:30	11/28/2005 17:30	12/22/2005 19:15	1/23/2006 17:45	2/23/2006 8:15	3/1/2006 8:15
Relative Accuracy at 90% Confidence	6.5%	4.8%	4.6%	4.7%	4.3%	5.7%	6.3%
Coincidence Factor	73.6%	70.6%	77.9%	73.5%	76.2%	97.8%	99.6%
NP Load at Hydro System Peak (kW)	565,831	685,036	847,527	1,040,708	1,123,322	1,026,356	1,003,642
Rate 2.3 Contribution as % of System Peak	14.6%	13.9%	13.6%	10.9%	12.5%	16.0%	15.2%

Load Estimates - Rate 2.4 - 1000 KVA and Over

	Dec-2003	Jan-2004	Feb-2004	Mar-2004	Apr-2004	May-2004	Jun-2004
Rate 2.4 Sample Size	13	17	17	16	19	19	19
Monthly Billed Energy (kWh)	33,252,409	35,619,245	32,324,557	34,120,939	31,288,583	33,584,492	33,751,017
Rate 2.4 Peak Load (kW)	67,303	68,292	68,928	66,422	63,182	64,657	65,860
Date/Time	12/15/2003 12:00	1/8/2004 11:30	2/16/2004 12:00	3/17/2004 13:00	4/16/2004 12:00	5/19/2004 11:00	6/22/2004 11:00
Relative Accuracy at 90% Confidence	8.7%	7.3%	5.9%	5.9%	9.8%	4.8%	5.8%
Rate 2.4 Load at System Peak	58,432	56,689	60,625	64,290	56,502	63,419	47,022
Date/Time	12/8/2003 17:00	1/16/2004 17:30	2/16/2004 18:00	3/18/2004 9:00	4/26/2004 11:30	5/13/2004 9:45	6/5/2004 12:00
Relative Accuracy at 90% Confidence	6.5%	4.0%	4.5%	10.1%	6.7%	6.3%	7.5%
Coincidence Factor	86.8%	83.0%	88.0%	96.8%	89.4%	98.1%	71.4%
NP Load at Hydro System Peak (kW)	928,461	1,012,102	1,099,424	918,612	833,032	716,820	636,553
Rate 2.4 Contribution as % of System Peak	6.3%	5.6%	5.5%	7.0%	6.8%	8.8%	7.4%

	Jul-2004	Aug-2004	Sep-2004	Oct-2004	Nov-2004	Dec-2004	Jan-2005
Rate 2.4 Sample Size	21	21	27	30	36	38	44
Monthly Billed Energy (kWh)	35,253,152	34,885,833	32,792,508	33,639,271	34,011,430	35,244,055	36,961,841
Rate 2.4 Peak Load (kW)	70,485	66,282	70,061	65,165	66,818	67,870	60,379
Date/Time	7/23/2004 10:30	8/3/2004 11:00	9/16/2004 10:30	10/19/2004 14:00	11/4/2004 12:30	12/7/2004 10:30	1/10/2005 12:00
Relative Accuracy at 90% Confidence	5.6%	4.5%	10.4%	12.6%	7.5%	4.4%	7.5%
Rate 2.4 Load at System Peak	57,235	53,622	57,451	48,513	59,141	66,009	52,171
Date/Time	7/12/2004 12:00	8/30/2004 17:00	9/22/2004 12:00	10/29/2004 19:15	11/22/2004 17:15	12/6/2004 16:45	1/6/2005 18:00
Relative Accuracy at 90% Confidence	5.9%	4.3%	4.9%	13.4%	4.4%	5.1%	4.1%
Coincidence Factor	81.2%	80.9%	82.0%	74.4%	88.5%	97.3%	86.4%
NP Load at Hydro System Peak (kW)	539,794	518,595	622,336	785,877	851,521	1,142,661	1121749
Rate 2.4 Contribution as % of System Peak	10.6%	10.3%	9.2%	6.2%	6.9%	5.8%	4.7%

	Feb-2005	Mar-2005	Apr-2005	May-2005	Jun-2005	Jul-2005	Aug-2005
Rate 2.4 Sample Size	39	38	37	31	31	32	37
Monthly Billed Energy (kWh)	31,942,129	35,344,297	32,400,256	33,744,929	34,356,267	37,327,117	35,061,771
Rate 2.4 Peak Load (kW)	64,588	64,035	60,356	68,735	65,154	71,850	64,783
Date/Time	2/21/2005 11:30	3/11/2005 11:30	4/27/2005 10:30	5/30/2005 11:30	6/27/2005 12:30	7/13/2005 11:00	8/11/2005 11:30
Relative Accuracy at 90% Confidence	3.4%	6.0%	5.7%	10.7%	5.9%	4.8%	4.3%
Rate 2.4 Load at System Peak	59,834	49,227	53,554	58,445	61,492	69,401	58,975
Date/Time	2/22/2005 8:30	3/5/2005 18:45	3/31/2005 20:00	5/20/2005 12:00	6/14/2005 17:00	7/15/2005 11:45	8/5/2005 12:00
Relative Accuracy at 90% Confidence	2.6%	3.4%	2.7%	4.6%	26.2%	6.4%	4.0%
Coincidence Factor	92.6%	76.9%	88.7%	85.0%	94.4%	96.6%	91.0%
NP Load at Hydro System Peak (kW)	1,049,084	925,250	871,642	725,616	636,815	504,391	500,522
Rate 2.4 Contribution as % of System Peak	5.7%	5.3%	6.1%	8.1%	9.7%	13.8%	11.8%

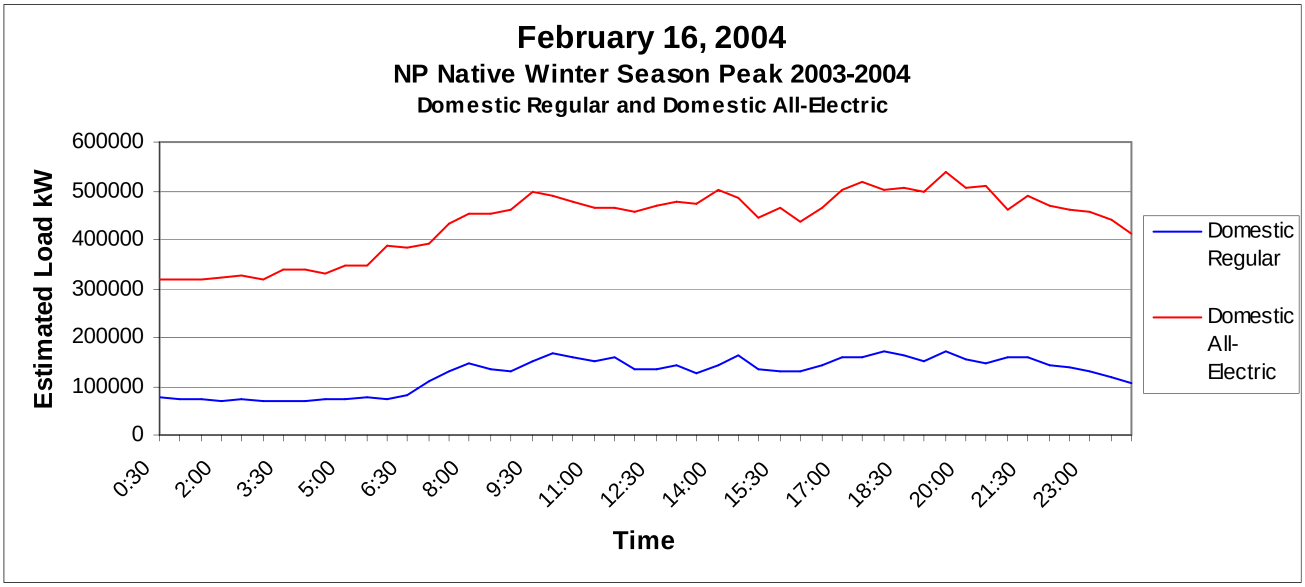
	Sep-2005	Oct-2005	Nov-2005	Dec-2005	Jan-2006	Feb-2006	Mar-2006
Rate 2.4 Sample Size	38	40	44	45	45	45	45
Monthly Billed Energy (kWh)	31,980,988	32,766,861	32,670,366	33,743,819	34,644,416	31,736,116	35,811,810
Rate 2.4 Peak Load (kW)	68,834	65,398	64,614	60,987	65,307	62,719	65,309
Date/Time	9/1/2005 13:00	10/12/2005 12:30	11/3/2005 15:00	12/19/2005 10:00	1/24/2006 10:00	2/23/2006 13:30	3/1/2006 13:30
Relative Accuracy at 90% Confidence	9.5%	12.8%	10.7%	5.2%	2.8%	3.1%	2.2%
Rate 2.4 Load at System Peak	44,937	58,495	55,861	50,136	61,695	59,338	59,347
Date/Time	9/12/2005 17:15	10/12/2005 19:30	11/28/2005 17:30	12/22/2005 19:15	1/23/2005 17:45	2/23/2006 8:15	3/1/2006 8:15
Relative Accuracy at 90% Confidence	8.1%	12.9%	7.8%	4.4%	4.7%	3.1%	2.4%
Coincidence Factor	65.3%	89.4%	86.5%	82.2%	94.5%	94.6%	90.9%
NP Load at Hydro System Peak (kW)	565,831	685,036	847,527	1,040,708	1,123,322	1,026,356	1,003,642
Rate 2.4 Contribution as % of System Peak	7.9%	8.5%	6.6%	4.8%	5.5%	5.8%	5.9%

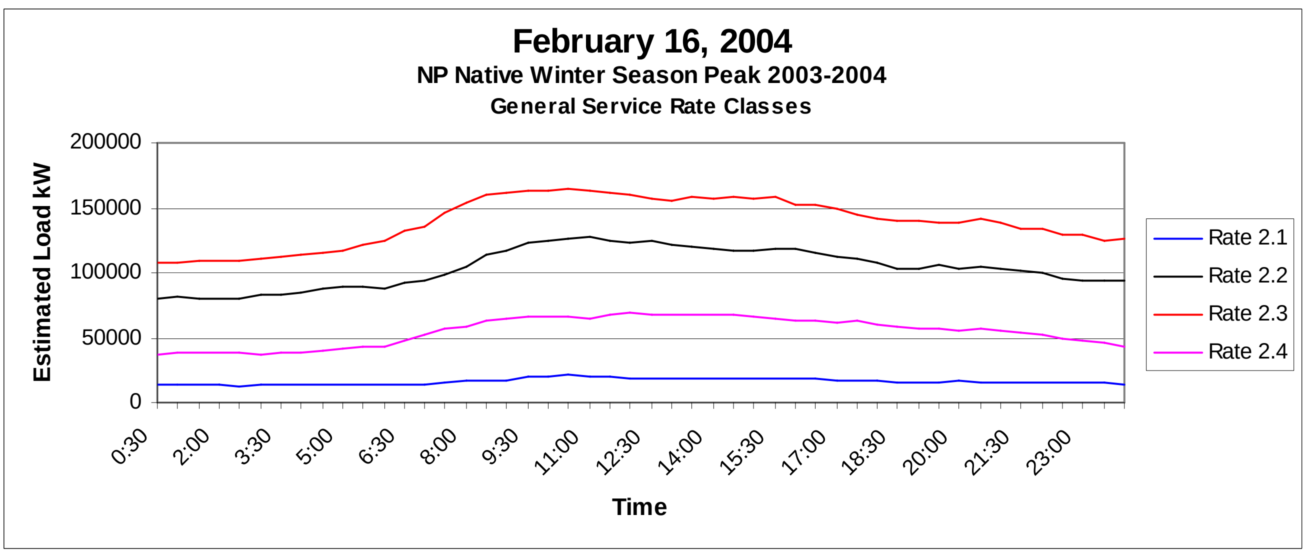
Class Load Factor Calculations

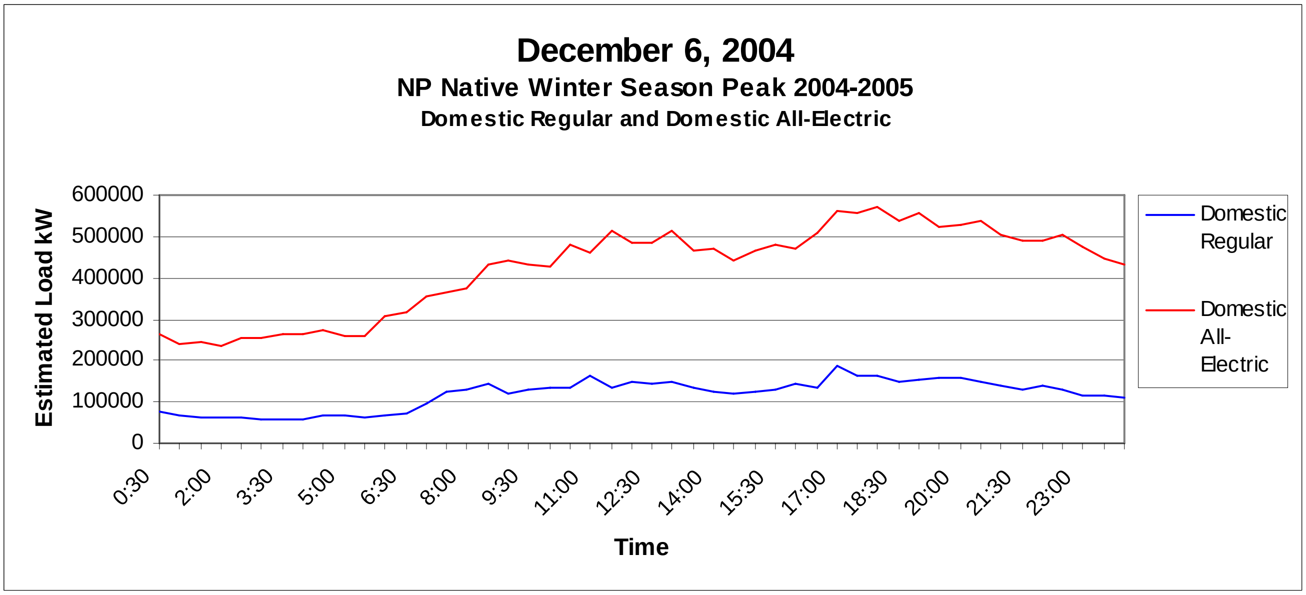
Class Load Factor Calculations	Rate 110	Rate 112	Domestic 1.1	Rate 2.1	Rate 2.2	Rate 2.3	Rate 2.4
Coincident Peak							
Winter Season 2003-04							
Normalised Class Sales	809,910,748	2,114,058,340	2,923,969,088	97,284,741	594,730,894	854,001,710	399,808,549
Class Load	172,599	500,611	676,820	16,773	107,215	141,160	60,625
Load Factor	53.4%	48.1%	49.2%	66.0%	63.1%	68.9%	75.1%
Winter Season 2004-05							
Normalised Class Sales	812,000,172	2,166,701,315	2,978,701,487	97,676,482	604,721,394	863,108,020	408,167,994
Class Load	184,859	560,739	743,539	17,435	119,149	147,305	63,779
Load Factor	50.0%	44.0%	45.6%	63.8%	57.8%	66.7%	72.9%
Winter Season 2005-06							
Normalised Class Sales	797,935,013	2,183,698,232	2,981,633,245	96,474,771	611,599,514	860,460,640	406,909,087
Class Load	175,535	516,635	695,863	16,750	120,112	140,877	61,695
Load Factor	51.9%	48.3%	48.9%	65.7%	58.1%	69.7%	75.3%
Average Load Factor	**51.8%**	**46.8%**	**47.9%**	**65.2%**	**59.7%**	**68.4%**	**74.4%**
Non-Coincident Peak							
2003 - 04							
Date	1/11/2004	1/11/2004	1/11/2004	2/17/2004	2/16/2004	1/15/2004	2/16/2004
Normalised Class Sales	808,556,975	2,099,950,115	2,908,507,090	97,284,741	594,730,894	854,001,710	399,808,549
Class Load	189,649	519,347	715,973	22,504	126,947	166,883	68,928
Load Factor	48.7%	46.2%	46.4%	49.2%	53.3%	58.4%	66.0%
2004 - 05							
Date	1/22/2005	1/22/2005	1/22/2005	12/7/2004	1/6/2005	12/7/2004	7/23/2004
Normalised Class Sales	812,672,623	2,180,034,351	2,992,706,974	97,676,482	606,374,677	863,108,020	401,291,307
Class Load	222,267	544,572	774,423	22,405	126,967	167,945	70,485
Load Factor	41.6%	45.6%	44.0%	49.6%	54.4%	58.5%	64.8%
2005 - 06							
Date	12/24/2005	12/24/2005	12/24/2005	2/20/2006	1/23/2006	1/23/2006	7/13/2005
Normalised Class Sales	799,377,228	2,187,686,976	2,987,064,204	96,056,444	611,599,514	860,460,640	426,155,293
Class Load	235,058	481,918	734,032	20,351	138,979	184,962	71,850
Load Factor	38.8%	51.8%	46.5%	53.9%	50.2%	53.1%	67.7%
Average Load Factor	**43.0%**	**47.9%**	**45.6%**	**50.9%**	**52.6%**	**56.7%**	**66.2%**

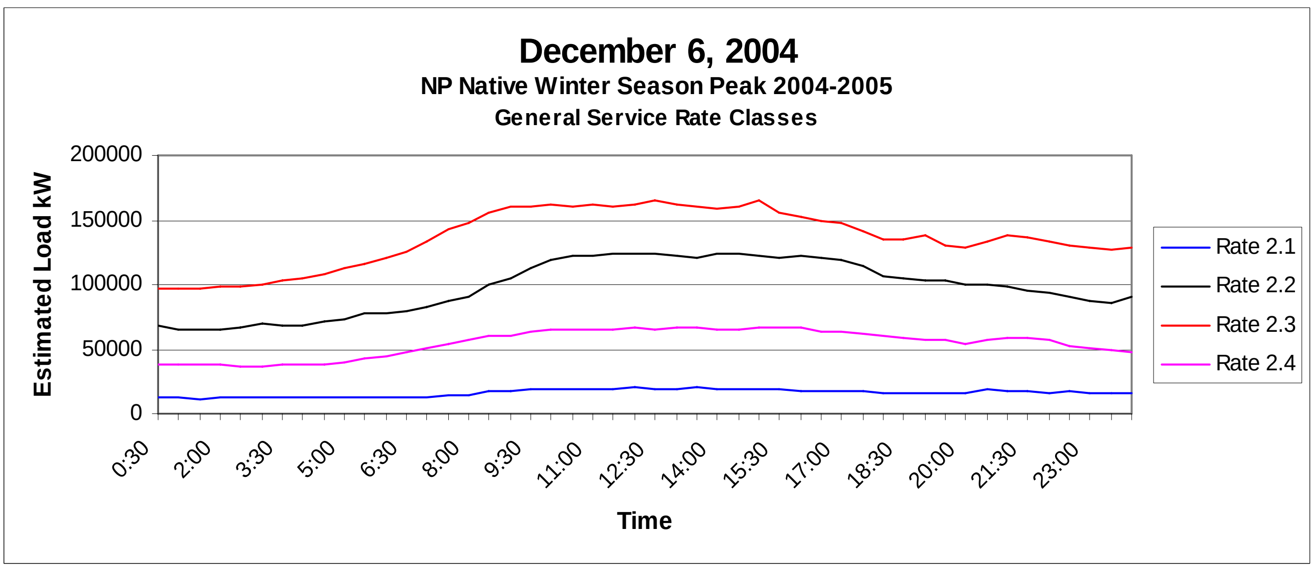
*** Note:** The Domestic & All-Electric subclass (Rates 110 & 112) Non-Coincident Peak load factors are calculated based upon the subclass demands at time of class peak. For this reason it is possible for the non-coincident peak load factors to be higher than the coincident load factors for the domestic subclasses.

Peak Day Loads by Class






December 6, 2004
NP Native Winter Season Peak 2004-2005
Domestic Regular and Domestic All-Electric
Estimated Load kW
600000
500000
400000
300000
200000
100000
0
0:30
2:00
3:30
5:00
6:30
8:00
9:30
11:00
12:30
14:00
15:30
17:00
18:30
20:00
21:30
23:00
Time
Domestic Regular
Domestic All-Electric


December 6, 2004
NP Native Winter Season Peak 2004-2005
General Service Rate Classes
Estimated Load kW
200000
150000
100000
50000
0
0:30
2:00
3:30
5:00
6:30
8:00
9:30
11:00
12:30
14:00
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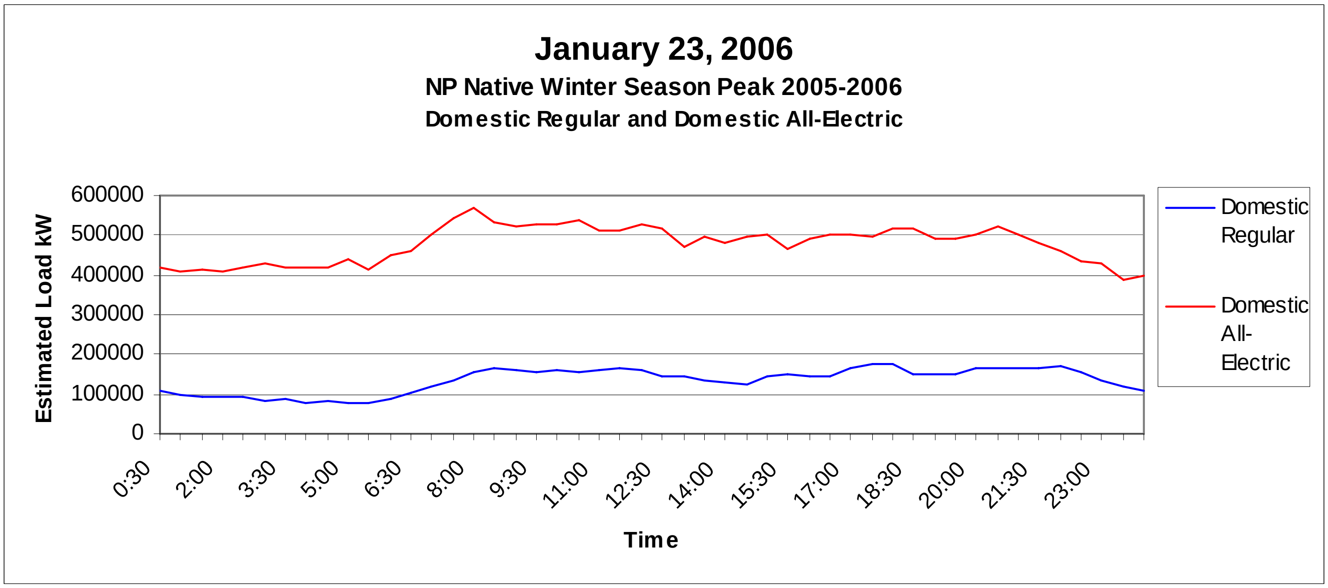
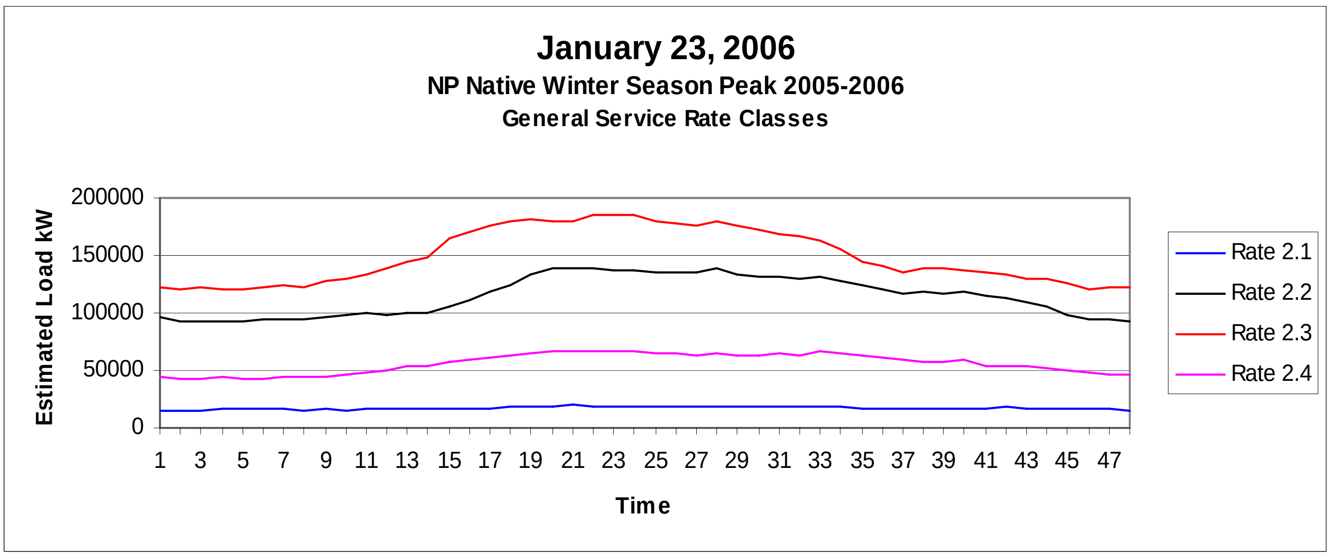
18:30
20:00
21:30
23:00
Time
Rate 2.1
Rate 2.2
Rate 2.3
Rate 2.4


January 23, 2006
NP Native Winter Season Peak 2005-2006
Domestic Regular and Domestic All-Electric
Estimated Load kW
600000
500000
400000
300000
200000
100000
0
0:30
2:00
3:30
5:00
6:30
8:00
9:30
11:00
12:30
14:00
15:30
17:00
18:30
20:00
21:30
23:00
Time
Domestic Regular
Domestic All-Electric


January 23, 2006
NP Native Winter Season Peak 2005-2006
General Service Rate Classes
Estimated Load kW
200000
150000
100000
50000
0
1 3 5 7 9 11 13 15 17 19 21 23 25 27 29 31 33 35 37 39 41 43 45 47
Time
Rate 2.1
Rate 2.2
Rate 2.3
Rate 2.4

Load Profile Data
February 16, 2004
NP Native Winter Season Peak 2003 - 2004

	Domestic Regular	Domestic All-Electric	Rate 2.1	Rate 2.2	Rate 2.3	Rate 2.4	Losses	Streetlights
0:30	77928	317284	13369	80732	107738	37448	38668	8496
1:00	75501	318816	13386	81044	108384	38030	37696	8496
1:30	72445	317607	13460	79827	108693	38481	37317	8496
2:00	69057	322942	13628	80459	108831	38575	37240	8496
2:30	74426	326176	12992	80726	109238	38264	37230	8496
3:00	69493	317940	13696	82933	110626	37515	37496	8496
3:30	70476	340413	13921	83733	113023	38560	37880	8496
4:00	68710	340158	13705	84675	113535	38810	38246	8496
4:30	73382	332377	13942	87744	115855	40058	39742	8496
5:00	75493	347653	14008	89342	116508	40925	40362	8496
5:30	79323	345078	14139	89632	121850	42774	42052	8496
6:00	75260	386292	13984	87231	124456	43244	42964	8496
6:30	83366	383605	13839	93000	131955	47581	47107	0
7:00	108470	391467	14302	93782	134660	52783	51653	0
7:30	131131	430741	15049	98560	146107	56177	58446	0
8:00	147277	453422	16381	103928	153083	58411	64377	0
8:30	135859	451325	16866	113124	159502	62421	68264	0
9:00	130836	459221	17646	117405	162060	65197	70398	0
9:30	151222	499773	19855	122433	163136	65907	72960	0
10:00	166849	488576	19820	125083	163221	66652	73123	0
10:30	158651	479224	21023	125832	164828	66120	72619	0
11:00	149054	465000	20008	126947	163605	65109	72323	0
11:30	158154	466571	19379	125059	161287	68308	71358	0
12:00	136596	455743	18666	122922	160465	68928	72376	0
12:30	136052	469581	18962	124897	156476	67594	69994	0
13:00	140841	479421	18824	121050	155723	67832	69339	0
13:30	127860	475319	18863	119388	158806	68162	66385	0
14:00	143895	500356	18685	117696	157397	67600	66494	0
14:30	162183	485262	18971	117551	159093	67655	66554	0
15:00	134489	446628	19043	116678	156306	66469	66215	0
15:30	132083	466610	18726	119081	157710	64422	66680	0
16:00	128612	436201	19168	118496	152949	63665	68228	0
16:30	141484	465626	19101	114875	152990	63182	70262	0
17:00	157166	501769	17443	112645	148876	62228	72904	0
17:30	160044	517533	17254	110569	144149	62456	74955	0
18:00	172599	500611	16773	107215	141160	60625	76995	8496
18:30	164979	504499	15965	103809	139349	58472	76497	8496
19:00	151401	499009	15773	103469	140608	57133	76554	8496
19:30	172909	537116	15745	106188	138651	56464	76678	8496
20:00	155032	505253	16197	102780	138855	56049	76373	8496
20:30	148253	508223	15844	105019	140900	56667	75073	8496
21:00	157678	461323	15560	102357	138334	55117	73232	8496
21:30	161110	488724	15177	101139	133956	54563	71442	8496
22:00	141635	470439	15660	100445	133136	51776	69455	8496
22:30	140674	460331	15920	95781	129541	49131	64590	8496
23:00	129314	458098	16040	94198	128606	47785	61269	8496
23:30	118747	442660	15503	94261	125333	46221	56587	8496
0:00	106793	411598	14191	93900	125575	43325	52159	8496

Load Profile Data December 6, 2004 NP Native Winter Season Peak 2004 - 2005								
	Domestic Regular	**Domestic All-Electric**	**Rate 2.1**	**Rate 2.2**	**Rate 2.3**	**Rate 2.4**	**Losses**	**Streetlights**
0:30	74930	264045	11929	68213	96069	37430	28484	8496
1:00	65775	237914	12032	64857	97325	38039	27030	8496
1:30	63430	242799	11901	64345	97215	37529	26534	8496
2:00	61431	237545	12297	64754	98856	37403	26366	8496
2:30	64618	254833	12319	66531	98252	37113	26454	8496
3:00	57292	256012	12237	69803	100243	37221	26677	8496
3:30	59464	266333	12190	68759	103510	38166	27166	8496
4:00	59420	264326	12434	68618	104873	38025	27898	8496
4:30	65551	272621	12297	71063	108627	38075	28748	8496
5:00	67209	259750	12457	73248	112746	39738	29837	8496
5:30	62374	259076	12825	77468	116251	43471	31141	8496
6:00	67040	305641	12413	77668	120343	44102	32990	8496
6:30	74387	315589	12865	78975	125800	47791	36507	8496
7:00	93605	353191	13438	82408	132784	50453	41705	8496
7:30	123979	364415	14331	88055	142156	53996	49456	0
8:00	127559	374957	14733	90048	147734	56762	55460	0
8:30	145478	432210	16730	99581	154871	59575	58700	0
9:00	121790	439594	17304	105538	160673	60961	61576	0
9:30	129145	433015	19391	111997	160111	63246	63424	0
10:00	132634	425292	19382	119547	161122	64717	65951	0
10:30	136571	480418	18512	122620	161044	65164	66410	0
11:00	163166	462677	19437	122302	161268	64625	66563	0
11:30	133948	513662	19451	124334	161066	65707	68277	0
12:00	148409	484356	19937	124265	162415	66244	71167	0
12:30	145803	485068	19396	124185	164385	64474	70269	0
13:00	149475	513725	19629	121721	161947	65903	69582	0
13:30	135027	466178	20982	121201	159611	66053	68863	0
14:00	123792	469397	19773	123939	158564	65667	66992	0
14:30	118838	441868	19329	123405	159725	65567	67041	0
15:00	123453	466743	19052	122124	164569	67254	69007	0
15:30	128462	481821	18509	120727	155378	66019	69429	0
16:00	145947	468644	17630	122175	152251	66005	71306	0
16:30	136138	510330	17540	120369	148420	63353	76818	0
17:00	184859	560739	17435	119149	147305	63779	84292	8496
17:30	163410	558552	17185	114448	141885	61998	42242	8496
18:00	164219	573149	15762	107038	135684	59567	83839	8496
18:30	149118	539641	16090	104091	135291	58705	80136	8496
19:00	153065	558683	15535	103465	137344	57740	79602	8496
19:30	159347	524727	15599	102445	130246	57256	79870	8496
20:00	159366	525607	16166	99963	128371	54597	79621	8496
20:30	146628	537062	18346	99368	132723	57042	79759	8496
21:00	140115	504674	17761	98675	138020	58088	77468	8496
21:30	130533	490869	17135	95515	136005	59021	76296	8496
22:00	137087	487425	16437	94265	132779	57120	73325	8496
22:30	128733	501856	16998	89802	130123	52890	68424	8496
23:00	117136	476676	16467	87914	128696	51473	64299	8496
23:30	117269	446379	15819	85727	126439	49630	58023	8496
0:00	109162	430190	16371	89794	127789	48019	53471	8496

Load Profile Data January 23, 2006 NP Native Winter Season Peak 2005 - 2006								
	Domestic Regular	**Domestic All-Electric**	**Rate 2.1**	**Rate 2.2**	**Rate 2.3**	**Rate 2.4**	**Losses**	**Streetlights**
0:30	106515	421277	15659	95514	121925	43563	47936	8538
1:00	97412	408018	15348	92843	120742	43241	45737	8538
1:30	91117	414771	15491	93218	121798	42761	45298	8538
2:00	92982	408940	16579	93065	121149	43712	45063	8538
2:30	90889	419562	16502	92513	120888	42932	45175	8538
3:00	84297	428865	16065	95050	121606	43415	45336	8538
3:30	85657	418537	15851	93984	124676	43904	45650	8538
4:00	79963	417640	15705	93564	123051	44658	46511	8538
4:30	84328	417447	15870	95994	127477	44084	47512	8538
5:00	78652	439564	15592	98012	129710	45689	48096	8538
5:30	79389	412967	16183	100340	133649	47688	50495	8538
6:00	90227	448626	16046	98487	137968	49600	52291	8538
6:30	105237	460078	15808	99599	144058	53622	56440	8538
7:00	119859	500672	16336	100224	148964	53355	61641	8538
7:30	136160	543463	16154	105602	163916	57643	70758	0
8:00	155796	569629	16984	111632	170560	59224	75158	0
8:30	163103	533809	17158	118726	176804	61721	77116	0
9:00	159733	523841	18289	123256	179699	62726	77496	0
9:30	156238	528031	18661	133210	182101	64678	79669	0
10:00	160985	525867	18971	138614	179850	65952	79615	0
10:30	157442	537968	19613	138658	180233	66348	77579	0
11:00	161154	510403	18765	138979	184736	65939	77045	0
11:30	167902	514325	18918	137760	184640	65972	77292	0
12:00	161384	528691	19374	137838	184962	66581	79756	0
12:30	144382	519767	18571	135028	179296	64886	76387	0
13:00	142921	472102	18835	135277	177547	65079	73704	0
13:30	131947	497358	18241	135893	176753	62351	72460	0
14:00	128936	479688	17919	138172	179028	64509	72482	0
14:30	124548	495372	18513	133668	175116	63100	69173	0
15:00	142672	502309	18349	131312	172621	63059	68967	0
15:30	147806	466835	18053	131932	168746	63931	69352	0
16:00	142585	490279	18580	130396	167577	63708	70253	0
16:30	146908	500282	18590	132177	163568	67447	73091	0
17:00	163439	503191	17806	127843	155052	64947	77183	8538
17:30	175197	498843	17540	124121	145313	62257	79796	8538
18:00	175535	516636	16750	120112	140877	61695	79862	8538
18:30	151624	514684	16759	117197	135227	58428	75126	8538
19:00	149810	490884	16931	119048	138067	57812	76032	8538
19:30	148770	493489	16758	117172	138733	57747	74072	8538
20:00	167751	502828	16759	117694	136664	59126	73968	8538
20:30	165951	521908	16778	113967	134530	54128	73384	8538
21:00	163286	501351	17802	112968	133519	54498	71726	8538
21:30	163039	481592	17040	109922	130106	53032	69118	8538
22:00	168379	459317	16546	105466	128952	51621	66143	8538
22:30	155880	434971	16117	98922	125392	49125	61964	8538
23:00	136074	429277	15790	95053	120871	48362	57935	8538
23:30	120369	386767	15975	93649	122157	47060	53467	8538
0:00	107752	396494	15385	93272	121900	46258	49404	8538

Newfoundland Power
Marginal Cost of Electricity Service Study

Newfoundland Power
Marginal Cost of Electricity Service Study

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TABLE OF CONTENTS

SCHEDULES

Newfoundland Power
Marginal Costs of Electricity Service Study

I. INTRODUCTION

Newfoundland Power (NP) retained NERA Economic Consulting (NERA) to prepare estimates of its marginal costs of providing electricity service to its customers. NP is a regulated investor-owned electric utility that serves approximately 227,000 customers throughout the island portion of the province of Newfoundland and Labrador.

NP's marginal source of generation (and transmission) is the Crown corporation Newfoundland and Labrador Hydro (NLH). NP purchases about 90 percent of its electricity requirements from NLH under a regulated wholesale tariff, and generates the balance from its own hydro electric stations. NP requested that for purposes of this study, NERA uses estimates of NLH's marginal costs of generation and transmission, rather than using NP's financial marginal costs that are dependent on the structure of NLH's wholesale tariff, which is currently under review.

NLH manages and expands, as required, all transmission at the 230-kV level, including 230-kV transformers. NLH also manages the rural 138-kV and 66-kV transmission system that was developed as part of the rural electrification program. NP is responsible for managing and expanding the remaining 33-, 66-, and 138-kV facilities; these facilities are included in our analysis of NP's "distribution" marginal costs.[1]

This report describes the methods used to estimate NP's distribution marginal costs, and summarizes the results of the analysis. In addition, it presents the results of the average 2007-2011 NLH marginal generation and transmission cost Base Case scenario, as estimated by NERA in its May 2006 study,[2] with a brief explanation of the methods and assumptions used in the computation. Using the average 2007-11 estimates of marginal generation and transmission costs developed in that study, the marginal distribution costs arising from the current analysis, and estimated billing determinants for 2007, we computed marginal cost revenues for all the customer classes served by NP, as illustrated in Section IX of this report. All marginal costs and revenues shown in this report are expressed in 2007 Canadian dollars.

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[1] However, there is zero marginal cost related to these lines because there was no growth-related NP investment on 33-, 66-, or 138-kV lines in the last five years and no budget for these components for the next five years.

[2] "Newfoundland and Labrador Hydro Marginal Costs of Generation and Transmission. Final Report", May 2006

Why estimate marginal costs? There are several reasons. First, economic theory indicates that prices that reflect marginal costs lead to the most efficient allocation of society's scarce resources. Many economists believe that efficient resource allocation should be one of the goals of price setting in a regulated industry. Second, in the increasingly competitive electric utility environment, it is very important to know the marginal costs of providing a wide range of services so a utility can ensure that its own promotional efforts and strategic plans are prudent. Finally, accurate estimates of marginal costs are essential for determining the benefits of load management, distributed generation and conservation programs, for the design of special contracts for individual customers, and for engineering studies such as acceptable loss levels in transformer specifications.

Marginal cost is defined as the change in total cost with respect to a small change in output. To quantify the marginal costs of electricity service one must ask and answer the question: What are *all* the additional costs that would be incurred with changes in kilowatt-hours of energy, kilowatts of demand, and number of customers of various types? Given the characteristics of electricity supply and demand, the cost of additional consumption may differ depending upon the time of the change in output. As a result, it is important to estimate time-differentiated marginal costs of electricity service. NERA determines the marginal cost of electricity by examining the system planners' and operators' response to load changes at different times of the day and year. Our method is not a formula, but a series of guidelines outlining what should be measured and how the measurement can be made.

II. SELECTION OF COSTING/PRICING PERIODS

In the May 2006 study for NLH, NERA developed hourly marginal cost estimates for generation capacity, energy and transmission. In this study for NP, NERA developed time-differentiated hourly costs of distribution substations and trunkline feeders. These hourly estimates can be aggregated by daily and seasonal periods to meet the requirements of any marginal cost application, including recommendations for improving the cost-reflectiveness of NP's rates.

NERA develops costing/pricing periods that are efficient (by grouping hours of similar cost), administratively feasible, and likely to be appropriate for a significant number of years. The initial process used to develop the recommended costing/pricing periods was to sum all the time-varying marginal costs (generation capacity and energy, transmission, and distribution substation and trunkline feeder) for each hour, and to use regression analysis to determine a set of seasons and periods within seasons that minimizes the squared differences between the individual hourly costs and the average for the period. After several tests, NERA and NP agreed to use the same periods that NERA had previously developed for NLH. There were other period choices with slightly better R-square, e.g., with three diurnal periods in winter. Those alternatives were capturing variation introduced by NP's marginal distribution substation costs. However, NP decided that giving up some efficiency was justified by the convenience and simplicity of using periods developed for NLH's wholesale customers. The resulting costing periods (Newfoundland time) are described below.

Table 1. Costing Periods[3]

Winter: January – March and December
Peak: Weekdays, 7:00 am to 12:00 pm & 4:00 pm to 8:00 pm.
Off-Peak: All remaining hours.
Non-Winter: April - November
No time-of-day differentiation.

[3] Holidays are treated as the day of the week on which they fall. The costing periods analysis developed for both NLH and NP showed better statistical results when holidays were treated as normal days as opposed to being treated as Sundays.

III. MARGINAL DISTRIBUTION COSTS

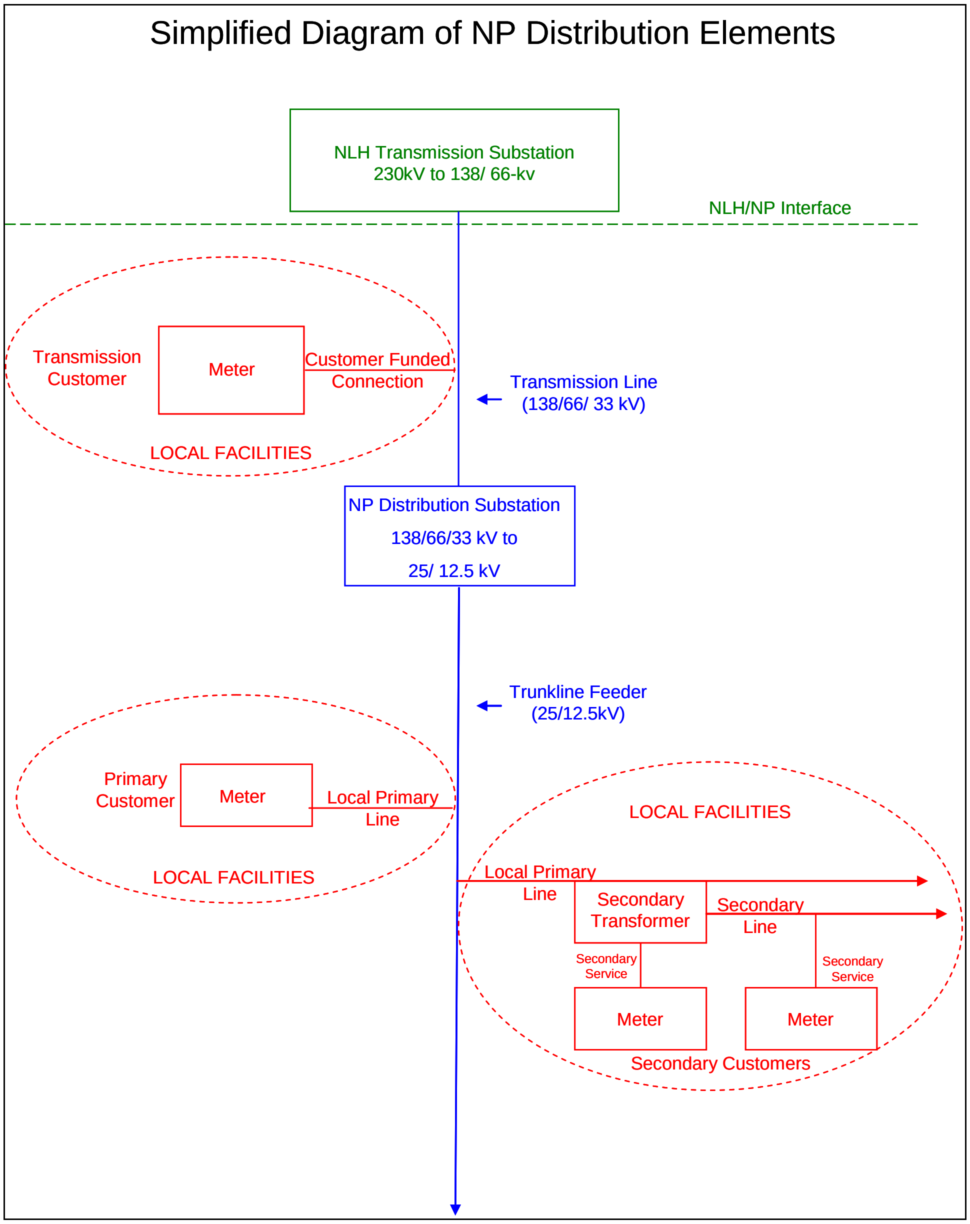
Conceptually, most costing practitioners agree that the design of the distribution system is determined by two major factors: (1) the number and location of customers and (2) their demands. Marginal cost studies have traditionally attempted to identify a portion of distribution costs as customer-related and the remaining portion as demand-related. This has led to semantics arguments about the definition of the customer-related and demand-related components. In fact, for most distribution systems, this two-part segmentation of distribution equipment is not consistent with the cost drivers, because it ignores the fact that there are two types of demand that determine distribution capacity requirements for a particular customer – design (or contract) demand and near-term demand at time of likely neighborhood peaks.

The distribution planning process at Newfoundland Power is typical of that at most Canadian and U.S. utilities. As the load increases, capacity or voltage constraints become apparent and distribution investment is made to provide the extra capacity required. This may include adding extra phases of primary lines, larger conductor sizes or regulator banks. Large increases in load may require adding a new trunk feeder or substation transformer capacity. Generally NP identifies weak areas by peak load measurements, especially at the substation transformer and substation feeder level.[4] At the substation level, load is forecasted by using past peak demands to establish baseline peak, with adjustment for worse than normal weather conditions that may occur, and by using energy growth associated within that area to extend peak growth into future years. Known large points of growth also play roles in establishing loads associated with some feeders.

The various components of NP distribution, illustrated in the figure below, are categorized as:

- higher voltage distribution components: distribution substations (i.e., substation transformers from 138/66/33 kV to 25/12.5 kV and feeders within the substation) and 25 kV /12.5 kV and 4.16 kV trunkline feeders;
- local distribution facilities, e.g., primary lines remote from substation and close to distribution transformers, primary-to-secondary transformers and switchgear and secondary lines; and
- customer-related: service drops and meters (with CTs and PTs as required).

[4] Weak areas are also identified through outages caused by overload, especially the operation of protective equipment as a result of overload, unbalance or similar occurrences.



NP is not currently adding 138-, 66-, or 33-kV lines, so there are no marginal costs associated with these elements of NP's system. NP does add or expand substations and invest in additional primary trunkline feeders as load grows. Because these higher voltage distribution components are more extensively shared, the costs do vary as customer loads change. Therefore they are computed as time-differentiated costs per kWh delivered (or per kW of metered demand).

Local distribution facilities are designed using engineering design standards that take into consideration the number of customers and the *maximum expected* loads (or "design demands") of customers who will eventually use those facilities, over the life of the facilities. Local distribution facilities for commercial and industrial customers are generally designed on a case-by-case basis, given the expected long-term peak demand by the customer. There are minimum conductor sizes specified for primary, with larger sizes specified as required. If a new load is very large, it might require its own feeder. However, in most cases there would be adequate capacity within the trunk feeder system to accommodate the increased load.

Because the marginal cost of local distribution facilities is incurred based on design demand, and does not vary with a customer's actual peak load from month to month, these costs are computed as a fixed monthly cost per kW of design (or contract) demand. Design demand can be represented by some proxy, such as transformer capacity, contract capacity or actual peak in the past twelve months, in the case where the billing system does not have a record of design demand. Meters and service drops in most cases serve a single customer. The service drop, along with the meter and associated equipment is treated as part of the marginal customer cost for each class.

A. Distribution Substation and Trunk-line Feeder Costs

To estimate the marginal cost of typical substation and trunkline feeder expansion per kW of non-coincident substation peak load growth, we asked NP's engineers to provide information on the load growth-related projects of this type (excluding any replacement projects that do not add capacity). NP initially provided its capital budget for the six-year period 2006-2011. Using only forecast information is a more strictly marginal approach, but in this case may be misleading because of the short budget period.

Using a combination of historical and budget information may better align expenditures with load growth causing them. We reviewed projects during the historical period as well (2001-2005) and found that growth-related substation and trunk-line feeder investment was made in 2003, 2004 and 2005.

We divided the sum of growth-related investment (in 2007$) over the period 2003-2011 by the growth in the sum of NP's forecast non-coincident distribution substation peaks for the same period. The marginal investment per kW is shown on Schedule 1.

Schedule 1. Distribution Substation and Trunk-line Feeder Investment

(1)	Investment in Growth-Related Additions to Distribution Substation Plant, 2003-2011 (Thousands of 2007 Dollars)	$9,227
(2)	Estimated Distribution Substation Non-coincident Peak Load Growth, 2003-2011 (MVA)	188.11
(3)	Marginal Investment in Growth-Related Distribution Substation Facilities per Non-Coincident Kilowatt (2007 Dollars) (1) / (2)	$49.05

Additions to the higher voltage distribution system are triggered by marginal load growth only in hours when capacity is strained. We analyzed hourly loads on a sample of five NP distribution substations for the years 2001-2005, and estimated the relative probability of a given hour's being the peak hour on that substation.[5] The resulting distribution probabilities of peak, aggregated by costing periods, are shown on Schedule 2.

Schedule 2. Probability of Peak for Distribution Substation by Costing Period

			Relative Probability of System Peak
			(1)
	Winter Season		
(1)		Peak	50.5%
(2)		Off-Peak	48.9%
(3)		Subtotal	99.4%
	Non-Winter Season		
(4)		Subtotal	0.6%
(5)	**Total**		100%

[5] The analysis includes an adjustment for the higher capability of these facilities in cold weather.

B. Local Distribution Facility Investment

NP provided estimates of the typical investment in secondary lines, transformers, and local primary lines for various types and sizes of customers, by looking at recent distribution work orders for each rate class. The rate classes and categories within classes considered in this study are:

(1) Rate 1.1 - Residential (with customer-related cost differentiated for customers with services ≤ 200 Amps and customers with services > 200 Amps, as requested by NP)

(2) Rate 2.1 - General Service 0-10 kW

(3) Rate 2.2 - General Service 10-100 kW (110 kVA)

(4) Rate 2.3 - General Service 110-1000 kVA (transmission, secondary and primary)

(5) Rate 2.4 - General Service 1000 kVA and over (transmission, secondary and primary).

NP provided separate weights for each of the categories within the class, e.g., facilities with single versus three-phase service, as well as rural versus urban facilities. NP also provided costs and weights for specific residential customer types, e.g., apartments and single-family houses. Each sample distribution customer addition identified the size of the transformer and the number of customers expected to be accommodated. We used the average transformer kVA per customer as a measure of the customer's design demand. With this information it was possible to develop a weighted average distribution facility cost per customer as well as per kVA of design demand, by category within each class.

The distribution facilities investments for residential and non-residential customer categories, stated in 2007 dollars, are shown on Schedule 3. NP's Primary customers (under rate 2.3 and 2.4) always provide their own step-down transformer (distribution primary voltage to usage voltage) and any necessary secondary equipment, including service drops. Generally NP's transmission customers provide the facilities they use to tap into NP's transmission system. Therefore, this study includes no estimate of marginal local facilities costs for them.

Schedule 3. Local Distribution Facilities Investment per kVA of Transformer Capacity

	Rate	Customer Class	Average Investment per kVa (2007 Dollars)
			(1)
(1)	1.1	Domestic Service	$167.26
(2)	2.1	General Service 0-10 kW	$173.62
(3)	2.2	General Service 10-100 kW (110 kVa)	$118.77
(4)	2.3	General Service 110 kVa-1000 kVa	
		Transmission	-
		Primary	$16.27
		Secondary	$78.10
(5)	2.4	General Service 1000 kVa and over	
		Transmission	-
		Primary	$5.42
		Secondary	$33.50

C. Meter and Service Drop Investment

The distribution facilities cost samples provided by NP included the installed cost of service drop and meter, including labor and materials. The meter (and associated equipment, including CT and PT when required) and service drop (secondary wiring at 600V or below) costs were weighted by customer numbers of each type whenever aggregation was required. As mentioned before, NP's Primary and Transmission customers are required to supply and own their service drops and associated equipment.

The meter and service drop marginal investments, stated in 2007 dollars, are shown on Schedule 4.

Schedule 4. Investment per Customer in Meters and Services

Rate	Description	Meter Investment	Service Investment
		(2007$ per Customer)	
		(1)	(2)
1.1	Domestic Service (average)	$58.47	$262.22
	200 Amps and below	$55.71	$261.95
	>200 Amp	$757.50	$330.79
2.1	General Service 0-10 kW	$81.10	$267.54
2.2	General Service 10-100 kW (110 kVa)	$423.61	$278.30
2.3	General Service 110-1000 kVa		
	Transmission	$19,383.34	-
	Primary	$10,355.44	-
	Secondary	$2,545.19	221.07
2.4	General Service 1000 kVa and over		
	Transmission	$19,383.34	-
	Primary	$11,370.25	-
	Secondary	$5,578.82	-

D. Distribution Operation and Maintenance Expenses

Distribution O&M expenses depend on the amount of plant in service. The addition of distribution equipment to meet increments in customers or design load or peak substation load gives rise to increased O&M expenses as well. Distribution O&M expenses are, therefore, marginal costs. NP provided a forecast of 2006 and 2007 distribution O&M expenses and we reviewed historical expense for the period 2003-2005.

The average distribution substation and trunkline feeder O&M expenses[6] for the years 2003 to 2007 were divided by the sum of NP's weather-normalized non-coincident peak demands at the substations.[7] We used the average of these annual values for 2005-2007 as our estimate of marginal expenses because there was a substantial drop after 2004. This approach is based on the assumption that average distribution O&M in 2005-2007 is a reasonable estimate of the marginal level of these expenses.

[6] These expenses include distribution substation O&M, SCADA expenses, a share of maintenance of lines/poles/fits expenses, and a share of overhead expenses (vegetation management and pre-issue of materials).

[7] NERA estimated the historical weather-normalized NCPs based on the 2005 forecast NCP (provided by NP) and the average annual growth rate assumed in the 2005-2010 forecasts provided by NP.

Schedule 5. Distribution Substation O&M Expense per kW

	Year	Total Distribution Substation Expenses	Estimated Substation Noncoincident Peak Loads	Substation Expenses Per kW of Substation Noncoincident Peak Loads	Weighted Labor and Materials Cost Index	Substation Expenses Per kW of Substation Noncoincident Peak Loads
		(000 Dollars)	(MW)	(Dollars)	(2007=1.00)	(2007 Dollars)
				(1) / (2)		(3) / (4)
		(1)	(2)	(3)	(4)	(5)
(1)	2003	3,387.90	1,272.4	2.66	0.89	2.98
(2)	2004	3,851.59	1,292.4	2.98	0.92	3.24
(3)	2005	3,498.59	1,312.6	2.67	0.95	2.82
(4)	2006	3,484.99	1,334.8	2.61	0.97	2.69
(5)	2007	3,455.06	1,356.8	2.55	1.00	2.55
(6)	Estimated Annual Substation O&M Expenses for the Planning Period (Average 2005-2007)					2.68

Schedule 6 below shows distribution facilities O&M estimates by voltage level. The annual line transformer maintenance expenses were directly assigned to secondary facilities, since primary customers are responsible for maintaining their own transformer. The remaining local distribution facilities O&M expenses,[8] excluding streetlighting expenses, were assigned to primary and secondary levels on the basis of relative shares of primary and secondary plant in service. The resulting weights were 80 percent for primary and 20 percent for secondary.

The expenses assigned to primary and secondary facilities were divided by estimates of total customer design demand at each voltage level. Total design demand was the product of forecast 2007 customer numbers and the per-customer design demand estimates discussed in Section III.B.

An adjustment for secondary demand losses of 1.018 was applied to total secondary design demand. The adjusted secondary design demand was added to primary customers' design demand in order to estimate total design demand at primary level (shown in column 4). The average of the 2004 to 2007 distribution facilities O&M per kW of design demand was

[8] These O&M expenses consist of a share of maintenance of poles/lines/fits, a share of repeater sites and mobile radio, and a share of overhead expenses (vegetation management and pre-issue of materials).

assumed to be a reasonable estimate of the marginal level of these expenses by voltage level. The marginal distribution facilities O&M expense for a customer served at secondary voltage is calculated as the sum of loss-adjusted primary line O&M expense and secondary line O&M expense.

Schedule 6. Distribution Facilities O&M Expense per kW of Design Demand

		Distribution Line O&M Expenses	Line Transformer O&M	Total Estimated Design Demand At Secondary	Total Estimated Design Demand At Primary	Dist. Facilities O&M Expense Per kW of Design Demand Secondary	Dist. Facilities O&M Expense Per kW of Design Demand Primary
		('000 Dollars)	('000 Dollars)	(MW)		(2007$)	
						[(1) x 0.20 +(2)/ (3)]	[(1) x 0.80/ (4)]
		(1)	(2)	(3)	(4)	(5)	(6)
(1)	2003	2,603.28	336.59	2,641.20	2,800.19	$0.32	$0.74
(2)	2004	2,922.30	265.19	2,676.64	2,834.77	$0.32	$0.82
(3)	2005	2,880.57	250.24	2,717.00	2,873.85	$0.30	$0.80
(4)	2006	3,162.55	283.74	2,744.15	2,903.49	$0.33	$0.87
(5)	2007	3,088.50	280.00	2,769.69	2,929.98	$0.32	$0.84

(6)	Estimated Distribution Facilities O&M for a Primary Customer Col. (6), average Years 2004 to 2007 O&M	**$0.84**
(7)	Loss Adjustment Factor for Use of Primary Lines by Secondary Customers	1.018
(8)	Loss Adjusted Estimated Primary Lines O&M Expenses for Secondary Customers Line (6) * Line (7)	$0.85
(9)	Estimated Secondary Distribution Facilities O&M per kW Col. (5) Average Years 2004 to 2007 O&M	$0.32
(10)	Total Estimated Distribution Facilities Line O&M for a Secondary Customer. Line (8) + Line (9)	**$1.17**

The annual meter O&M was divided by weighted number of customers, with the weights consisting of the relative cost of the typical meter for each class. The average of the 2005 to 2007 O&M per weighted customer was assumed to be a reasonable estimate of the marginal level of these expenses. Multiplying meter O&M per weighted customer by the class weights gives the annual per-meter O&M estimate for each class. Schedules 7 and 8 illustrate these calculations.

Schedule 7. Meter O&M Expense per Weighted Customer

	Year	Total Meter Operation & Maintenance Expenses	Average Number of Customers	Weighted Average Number of Customers	Meter Expense Per Weighted Customer	Weighted Labor and Materials Cost Index	Meter Expense Per Weighted Customer
		(000's Dollars)			(Dollars)	(2007 = 1.00)	(2007 Dollars)
				(2) x 1.77	[(1) x 1000]/(3)		(4)/(5)
		(1)	(2)	(3)	(4)	(5)	(6)
(1)	2003	516.53	212,129	375,468	1.38	0.89	1.545
(2)	2004	560.13	214,885	380,346	1.47	0.92	1.609
(3)	2005	479.69	217,664	385,265	1.25	0.94	1.321
(4)	2006	474.00	219,970	389,347	1.22	0.97	1.257
(5)	2007	508.00	222,028	392,990	1.29	1.00	1.293
(5)	Estimated Annual Weighted Meter O&M Expense for the Planning Period (Average 2005-2007)						1.290

Schedule 8. Annual Meter O&M Expense by Customer Class

	Class		Weighting Factor	Annual Meter Expense Per Customer
				(2007 Dollars)
				(1) x $1.29
			(1)	(2)
(1)	Domestic Service		1.00	$1.29
	(a) services of 200 Amps and below		0.95	$1.23
	(b) services >200 Amp		12.96	$16.72
(2)	General Service 0-10 kW		1.39	$1.79
(3)	General Service 10-100 kW (110 kVa)		7.24	$9.35
(4)	General Service 110 -1000 kVa			
		Tranmission	331.51	$427.77
		Primary	177.11	$228.53
		Secondary	43.53	$56.17
(5)	General Service 1000 kVa and over			
		Tranmission	331.51	$427.77
		Primary	194.46	$250.93
		Secondary	95.41	$123.12

NP provided historic and forecast data for service drop O&M. The annual service O&M was divided by weighted number of customers, with the weights consisting of the relative cost of the typical service for each class. The service O&M per weighted customer was then averaged for the forecast period 2006 and 2007. Multiplying service drop O&M per weighted customer by the class weights gives the annual per-service O&M estimate for each class.

Schedule 9. Service O&M Expense per Weighted Customer

	Year	Total Service Drop Operation & Maintenance Expenses	Average Number of Customers	Weighted Average Number of Customers	Service O&M Per Weighted Customer	Weighted Labor and Materials Cost Index	Service O&M Per Weighted Customer
		(000's Dollars)			(Dollars)	(2007 = 1.00)	(2007 Dollars)
				(2) x 1.01	[(1) x 1000]/(3)		(4)/(5)
		(1)	(2)	(3)	(4)	(5)	(6)
(1)	2003	1,110.63	212,129	214,250	5.18	0.89	5.82
(2)	2004	1,253.54	214,885	217,034	5.78	0.92	6.31
(3)	2005	1,195.26	217,664	219,841	5.44	0.94	5.77
(4)	2006	1,068.00	219,970	222,170	4.81	0.97	4.96
(5)	2007	1,075.00	222,028	224,248	4.79	1.00	4.79
(6)	Estimated Annual Weighted Service O&M Expense for the Planning Period (Average 2006-2007)						4.88

Schedule 10. Annual Service O&M Expense by Customer Class

	Class	Weighting Factor	Annual Service Expense Per Customer
			(2007 Dollars)
			(1) x $4.88
		(1)	(2)
(1)	Domestic Service	1.00	$4.88
	(a) services of 200 Amps and below	1.00	$4.87
	(b) services >200 Amp	1.26	$6.15
(2)	General Service 0-10 kW	1.02	4.98
(3)	General Service 10-100 kW (110 kVa)	1.06	5.18
(4)	General Service 110 -1000 kVa		
	Tranmission	0.00	0.00
	Primary	0.00	0.00
	Secondary	0.84	4.11

IV. MARGINAL CUSTOMER-RELATED EXPENSES

A. Customer Accounts Expenses

NP provided a forecast of 2006 and 2007 customer accounts expenses. Customer accounts expenses, composed mainly of meter-reading and billing expenses, are costs that are directly attributable to the existence of customers on the system. As shown on Schedule 11, the average annual expenses for 2003 to 2007 were divided by weighted customers to obtain customer accounts expense per weighted customer. The weighted number of customers was derived by multiplying the number of customers in each class by a factor reflecting the relative cost responsibility of each class for each sub-account, as measured by allocators such as number of customers, or revenue. These factors were developed by NP. We used the average over the period 2006-2007 as our estimate of marginal customer accounts expense for weighted customer.

Schedule 11. Customer Accounts Expense per Weighted Customer

		2003	2004	2005	2006	2007
		(1)	(2)	(3)	(4)	(5)
(1)	Customer Accounts Expenses (Thousand Dollars)	$6,722.56	$6,564.33	$7,193.81	$6,992.00	$6,985.00
(2)	Number of Customers	212,129	214,885	217,664	219,970	222,028
(3)	Weighted Customers (2) x 1.09	231,221	234,225	237,254	239,767	242,011
(4)	Expense per Weighted Customer (Dollars) [(1) / (3)] x 1000	$29.07	$28.03	$30.32	$29.16	$28.86
(5)	Labor Cost Index (2007=1.00)	0.88	0.91	0.93	0.96	1.00
(6)	Expense Per Weighted Customer in 2007 Dollars (4) / (5)	$33.04	$30.92	$32.48	$30.33	$28.86
(7)	Estimated Annual Expense Per Weighted Customer For the Planning Period (2007 Dollars) (Average 2006 to 2007)	-------------------	-------------------	$29.60	---------------------	---------------------

We developed the customer accounts expense for each category by multiplying the class weighting factor by the expense per weighted customer calculated on Schedule 11.

Schedule 12. Customer Accounts Expense by Customer Class

	Class	Weighting Factor	Annual Customer Accounts Expense Per Customer
			(2007 Dollars)
			(1) x $29.60
		(1)	(2)
(1)	Domestic Service	1.00	$29.60
(2)	General Service 0-10 kW	1.28	37.84
(3)	General Service 10-100 kW	2.73	80.89
(4)	General Service 110 -1000 kVa	2.73	80.89
(5)	General Service 1000 kVa and over	2.73	80.89

B. Customer Service and Informational Expenses

Customer service and informational expenses, which include the costs of administering inquiries and energy management expenses,[9] vary with the number of customers on the system and are, therefore, marginal. The same procedure used for customer accounts expenses was followed to generate an estimated annual expense per weighted customer (on Schedule 13) and per customer by class (Schedule 14), using the class weights developed by NP. NP provided a forecast of 2006 and 2007 customer service expenses. We used the average of 2006 to 2007 expense per weighted customer as an estimate of the marginal expense.

[9] Accounts 609 and 626 respectively.

Schedule 13. Customer Service and Informational Expense per Weighted Customer

		2003	2004	2005	2006	2007
		(1)	(2)	(3)	(4)	(5)
(1)	Customer Service and Informational Expenses (Thousand Dollars)	$2,796.26	$2,996.72	$2,983.17	$3,030.00	$2,833.00
(2)	Customers	212,129	214,885	217,664	219,970	222,028
(3)	Weighted Number of Customers (2) x 1.00	212,129	214,885	217,664	219,970	222,028
(4)	Expense Per Weighted Customer (Dollars) [(1) / (3)] x 1000	$13.18	$13.95	$13.71	$13.77	$12.76
(5)	Labor Cost Index (2007 = 1.00)	0.88	0.91	0.93	0.96	1.00
(6)	Expense Per Weighted Customer in 2007 Dollars (4) / (5)	$14.98	$15.39	$14.68	$14.33	$12.76
(7)	Estimated Annual Expense Per Weighted Customer For the Planning Period (2007 Dollars) (Average 2006 to 2007)	-------------------	-------------------	$13.54	-------------------	-------------------

Schedule 14. Customer Service and Informational Expense by Customer Class

	Class	Weighting Factor	Annual Customer Service and Informational Expense Per Customer (2007 Dollars)
			(1) x $13.54
		(1)	(2)
(1)	Domestic Service	1.00	$13.54
(2)	General Service 0-10 kW	1.00	13.54
(3)	General Service 10-100 kW	1.00	13.54
(4)	General Service 110-1000 kVa	1.67	22.57
(5)	General Service 1000 kVa and over	2.50	33.86

V. OTHER MARGINAL COST ELEMENTS

A. Administrative and General Expenses

When a utility adds plant and incurs additional O&M expenses, it typically incurs additional overhead expenses as well. Certain administrative and general (A&G) expenses can grow either with plant or with O&M expenses. General plant typically grows with other types of plant. Our marginal cost study includes plant-related and non-plant-related A&G and general plant loaders to capture these elements of marginal cost. Based on our understanding of NP's classification of costs for administrative and general (A&G) expenses, we divided these expenses into two categories: (1) those associated with other types of expenses and (2) those associated with plant. We excluded accounts not likely to be marginal with respect to other expenses or plant.[10]

We used a regression analysis of the identified plant-related A&G expenses[11] (excluding property insurance) on cumulative gross additions to total plant, all in constant dollars, for the period 1994 to 2005. The coefficient of the explanatory variable represented the additional A&G expenses required per dollar of investment in new plant. A property insurance component of the loader was estimated based on NP's estimate of the cost of insuring substation plant at replacement cost (7.5 cents of property insurance per $100 of replacement value). Combining the regression result with the property insurance factor yields a plant-related A&G loader applicable to distribution substations of 0.8 percent. The plant-related loader applicable to wires is 0.7 percent.

To estimate the marginal level of non-plant-related A&G expense (e.g., tools and equipment repairs, training and education costs, telephone systems, etc.), we ran a regression of A&G expenses identified as non-plant related and likely to be marginal on total O&M expenses (excluding fuel and purchased power) from 1995 to 2005. The non-plant-related A&G loader was estimated at 69.8 percent. Both plant and non-plant loaders are shown on Schedule 15.

[10] We excluded accounts for corporate communications, strategic planning and rates, environmental accounts (PCB phase out, inspection of PCB storage and environmental policy), which are not marginal. We also considered as non-marginal certain accounts not likely to recur, such as preparation for year 2000 and deferred DSM costs.

[11] Environmental spills, WAN, vehicle expenses, planning & maintenance, public liability, insurance, property management as well as total miscellaneous technical and operating costs.

B. General Plant

General plant consists of items such as office buildings, warehouses, cars, trucks and other equipment. The need for general plant increases with additions to production, transmission and distribution plant. We used a regression analysis on 15 years of historical and forecast company data (1994 - 2008) to estimate a marginal general plant loader. Cumulative net additions to general plant in service were regressed on cumulative net additions to total plant (less general plant) in service over the period 1994 to 2008, all in constant dollars. The coefficient for the explanatory variable, shown on Schedule 15, is the loader applicable to marginal distribution plant.

Schedule 15. Plant and Non-Plant A&G Loaders and General Plant Loader

		Estimate of Loading Factor
	Administrative and General Expenses and Social Security and Unemployment Taxes	
(1)	Applicable to Non-Plant-Related Expenses	69.81%
(2)	Applicable to Plant-Related Expenses (substations)	0.78%
(3)	Applicable to Plant-Related Expenses (wires and poles)	0.70%
(4)	General Plant & the Electric Share of Common Plant	7.96%

C. Marginal Losses

The marginal demand-related distribution loss calculations in this study are based on variable and fixed distribution losses at time of system peak at each voltage level of service. Marginal capacity losses reflect the fact that, to accommodate a kW of additional peak load at the customer's meter, facilities must be expanded by successively more than a kW as you move upstream to accommodate the fixed and variable losses on the system in the peak hour. Peak capacity loss factors were developed from NP's most recent available loss study.[12] The demand-related losses on the distribution system are applied to distribution costs above local facilities as well as to transmission and generation capacity costs stated at the interface between NP and NLH. The latter application is required because these losses are multiplicative; for

[12] NP provided the file "System Loss Study 2005", which contains a detailed breakdown of energy and demand loss factors at various loads for year 2005.

example, providing a marginal kW at a secondary meter costs more than the marginal cost of a kW of capacity at the interface because of additional losses incurred on the distribution system.

Marginal energy losses reflect the additional losses incurred to move an added kWh through the fixed system at a particular level of system load. Fixed losses are, by definition, not affected in these circumstances. Only variable losses come into these calculations. Marginal energy losses increase in proportion to the square of the load. We calculated hourly marginal distribution energy losses by means of an approximation of quadratic losses based on variable losses at system peak load and hourly loads. In this case the loads were taken from a forecast of NP year 2007 hourly loads for typical days by month, provided by Newfoundland and Labrador Hydro. These marginal distribution energy loss factors are applied to NLH's marginal energy costs, stated at the interface between NLH and NP.

VI. ECONOMIC CARRYING CHARGES

Section III above describes the development of estimates of marginal investment in categories of distribution plant. To be useful in ratemaking and other marginal cost applications, the investment must be converted into annual costs using an economic carrying charge. The annual charge reflects the elements of NP's year-by-year revenue requirement associated with a particular type of incremental plant: return to stockholders and bondholders, depreciation, and taxes.

For use in a marginal cost study, the appropriate stream of annual charges is a stream that rises at the rate of inflation net of technical progress and yields the total present value of all costs over the life of the investment. In such a stream, the first year's charge represents the cost in today's dollars of owning the plant or equipment for a year. It also represents the rental rate for such an investment in a competitive market.

Key inputs to the economic carrying charge calculation include: (1) the utility's incremental cost of capital (mix of debt and equity and their respective long-term market costs), (2) the expected inflation rate for that type of plant, net of technical progress, and (3) the average service life and patterns of failure ("Iowa curve") for that type of plant.

NP provided the following incremental cost equity and debt and capital structure for 2006:[13]

[13] In the absence of a longer-term forecast, we used the 2006 incremental cost of debt and equity.

	Share %	Cost %
Common Equity	45.00	9.24
Debt	55.00	5.44
Average Incremental Cost of Capital		7.15

Another integral part of the economic carrying charge calculation is the estimation of the rate of inflation net of technical progress applicable over the life of the investment. We used 2.07 percent as the estimate of this rate, based on the geometric mean of a 2006 to 2025 price index forecast.[14] The rate of technological progress is assumed to be incorporated in the inflation rate.

Finally, an adjustment is required for the fact that not all plant and equipment will last its estimated service life. Some components will require early replacement, causing added costs, while some will last longer than expected and produce savings. The pattern of expected required replacement for each type of plant is defined by an Iowa curve. An adjustment for this dispersed pattern of replacements using Iowa curves was included in the derivation of the economic carrying charges, as shown on line (2) of Schedule 16.

Schedule 16. Economic Carrying Charges

		Substation	Distribution Facilities	Meters	Services
		(1)	(2)	(3)	(4)
(1)	Present Value of Revenue Requirements Related to Incremental $1,000 Investment	$1,270.85	$1,059.68	$1,273.21	$1,292.22
(2)	Present Value Cost of Replacing Dispersed Retirements Related to Incremental $1,000 Investment	$52.35	$49.03	$37.01	$29.67
(3)	Total Present Value Cost Related to Incremental $1,000 Investment (1)+(2)	$1,323.19	$1,108.72	$1,310.22	$1,321.89
(4)	First-Year Annual Economic Charge Related to Incremental $1,000 Investment	$64.82	$56.29	$76.07	$72.08
(5)	First-Year Annual Economic Charge Related to Incremental Investment [(4)/$1,000]	6.48%	5.63%	7.61%	7.21%

14 Specific inflation forecasts for Transmission and Distribution plant (2006-2025) were available from NLH's Economic Analysis Section, System Planning Department.

VII. ANNUAL DISTRIBUTION MARGINAL COSTS

To convert marginal investment for each component of service to annual marginal costs, we adjusted upwards the investment per unit by the general plant loading factor. We multiplied the resulting figures by the annual economic carrying charge percentage plus the plant-related A&G loading factor to yield the annualized plant costs. To these costs we added the associated O&M and A&G expenses and the revenue requirements for working capital.

The computation of working capital includes components for cash, materials, supplies and prepayments. The working capital needs were estimated based on recent historical amounts. The revenue requirement for this working capital is NP's weighted average cost of capital plus an income tax component that recognizes that the equity portion of return on capital is taxable.

The schedules below present the annual marginal cost for higher voltage distribution, local distribution facilities, meters and services, respectively.

Schedule 17. Derivation of Annual Distribution Substation and Trunkline Feeder Costs

		2007 Dollars per kW
(1)	Marginal Investment per kW	$49.05
(2)	With General Plant Loading (1) x 1.0796	52.95
(3)	Annual Economic Carrying Charge Related to Capital Investment	6.48%
(4)	A&G Loading (plant related)	0.78%
(5)	Total Annual Carrying Charge (3) + (4)	7.26%
(6)	Annualized Costs (2) x (5)	3.84
(7)	O&M Expenses	2.68
(8)	With A&G Loading (7) x 1.6981 (Non-plant)	4.56
(9)	Subtotal (6) + (8)	8.40
	Working Capital	
(10)	Material and Supplies (2) x 0.39%	0.21
(11)	Prepayments (2) x 0.12%	0.06
(12)	Cash Working Capital Allowance (8) x 6.21%	0.28
(13)	Total Working Capital (10) + (11) + (12)	0.55
(14)	Revenue Requirement for Working Capital (13) x 9.50%	0.05
(15)	Total Distribution Substation Costs (9) + (14)	8.45

Schedule 18. Derivation of Annual Distribution Facilities Costs

		Rate 1.1	Rate 2.1	Rate 2.2
		Domestic Service	General Service 0-10 kW	General Service 10-100 kW (110 kVa)
		------ (2007 Dollars per kVa) ----------		
		(1)	(2)	(3)
(1)	Marginal Investment per kW	$167.26	$173.62	$118.77
(2)	With General Plant Loading (1) x 1.0796	180.57	187.43	128.22
(3)	Annual Economic Carrying Charge Related to Capital Investment	5.63%	5.63%	5.63%
(4)	A&G Loading (plant-related)	0.70%	0.70%	0.70%
(5)	Total Annual Carrying Charge (3) + (4)	6.33%	6.33%	6.33%
(6)	Annualized Costs (2) x (5)	11.43	11.87	8.12
(7)	O&M Expense per kW	1.17	1.17	1.17
(8)	With A&G Loading (7) x 1.6981 (non-plant related)	1.99	1.99	1.99
(9)	Distribution Facilities Related Costs (6) + (8)	13.42	13.86	10.11
	Working Capital			
(10)	Material and Supplies (2) x 0.39%	0.70	0.73	0.50
(11)	Prepayments (2) x 0.12%	0.22	0.22	0.15
(12)	Cash Working Capital Allowance (8) x 6.21%	0.12	0.12	0.12
(13)	Total Working Capital (10) + (11) + (12)	1.04	1.08	0.78
(14)	Revenue Requirement for Working Capital (13) x 9.50%	0.10	0.10	0.07
(15)	Total Annual Marginal Distribution Facilities Related Costs (9) + (14)	13.52	13.96	10.18

Schedule 18 (II). Derivation of Annual Distribution Facilities Costs

		Rate 2.3 - GS 110-1000 kVa		Rate 2.4 - GS 1000 kVa and over	
		Primary	Secondary	Primary	Secondary
		------ (2007 Dollars per kVa) ----------			
		(1)	(2)	(3)	(4)
(1)	Marginal Investment per kW	$16.27	$78.10	$5.42	$33.50
(2)	With General Plant Loading (1) x 1.0796	17.57	84.31	5.86	36.16
(3)	Annual Economic Carrying Charge Related to Capital Investment	5.63%	5.63%	5.63%	5.63%
(4)	A&G Loading (plant-related)	0.70%	0.70%	0.70%	0.70%
(5)	Total Annual Carrying Charge (3) + (4)	6.33%	6.33%	6.33%	6.33%
(6)	Annualized Costs (2) x (5)	1.11	5.34	0.37	2.29
(7)	O&M Expense per Weighted Customer	0.83	1.17	0.83	1.17
(8)	With A&G Loading (7) x 1.6981 (non-plant related)	1.40	1.99	1.40	1.99
(9)	Distribution Facilities Related Costs (6) + (8)	2.51	7.33	1.77	4.28
	Working Capital				
(10)	Material and Supplies (2) x 0.39%	0.07	0.33	0.02	0.14
(11)	Prepayments (2) x 0.12%	0.02	0.10	0.01	0.04
(12)	Cash Working Capital Allowance (8) x 6.21%	0.09	0.12	0.09	0.12
(13)	Total Working Capital (10) + (11) + (12)	0.18	0.55	0.12	0.31
(14)	Revenue Requirement for Working Capital (13) x 9.50%	0.02	0.05	0.01	0.03
(15)	Total Annual Marginal Distribution Facilities Related Costs (9) + (14)	2.53	7.38	1.78	4.31

Schedule 19. Derivation of Annual Meter, Service and Customer-Related Costs

		Rate 1.1 Domestic Class (Combined)	Rate 1.1 Domestic (Services <200A)	Rate 1.1 Domestic (Services >200A)	Rate 2.1 General Service 0-10 kW
		--------- (2007 Dollars per Customer) --------			
a) Investment - Meter & Services		(1)	(2)	(3)	(4)
(1)	Meter Investment per Customer	$58.47	$55.71	$757.50	$81.10
(2)	With General Plant Loading (1) x 1.0796	63.12	60.15	817.76	87.55
(3)	Annual Economic Charge Related to Capital Investment	7.61%	7.61%	7.61%	7.61%
(4)	Service Investment per Customer	$262.22	$261.95	$330.79	$267.54
(5)	With General Plant Loading (1) x 1.0796	283.08	282.79	357.10	288.82
(6)	Annual Economic Charge Related to Capital Investment	7.21%	7.21%	7.21%	7.21%
(7)	A&G Loading (Plant Related)	0.70%	0.70%	0.70%	0.70%
(8)	Total Carrying Charge Meters (3) + (7)	8.31%	8.31%	8.31%	8.31%
(9)	Total Carrying Charge Services (6) + (7)	7.91%	7.91%	7.91%	7.91%
(10)	Annualized Meter Costs (2) x (8)	5.25	5.00	67.96	7.28
(11)	Annualized Service Costs (5) x (9)	22.40	22.37	28.25	22.85
(12)	Total Annualized Meter & Service Costs (10)+(11)	27.64	27.37	96.21	30.13
b) O&M - Meter, Customer Accounts Expenses, Customer Service					
(13)	Meter O&M Expenses	1.29	1.23	16.72	1.79
(14)	Service O&M Expenses	4.88	4.87	6.15	4.98
(15)	Customer Accounts Expenses	29.60	29.60	29.60	37.84
(16)	Customer Service and Informational Expenses	13.54	13.54	13.54	13.54
(17)	With A&G Loading [(13)+(14)+(15)+(16)] x 1.6981 (Non-plant Related)	83.73	83.61	112.09	98.74
(18)	Customer-Related Costs (12) + (17)	111.37	110.99	208.30	128.87
	Working Capital				
(19)	Materials and Supplies [(2) + (5)] x 0.39%	1.35	1.34	4.58	1.47
(20)	Prepayments [(2) + (5)] x 0.120%	0.42	0.41	1.41	0.45
(21)	Cash Working Capital (17) x 6.21%	5.20	5.19	6.96	6.13
(22)	Revenue Requirement for Working Capital [(19)+(20)+(21)] x 9.50%	0.66	0.66	1.23	0.76
(23)	Total Annual Marginal Customer-Related Costs (18) + (22)	112.04	111.64	209.53	129.63

Schedule 19 (II). Derivation of Annual Meter, Service and Customer-Related Costs

		Rate 2.2	Rate 2.3 - General Service 110-1000 kVa		
		GS 10-100 kW	Transmission	Primary	Secondary
		--------- (2007 Dollars per Customer) --------			
a) Investment - Meter & Services		(1)	(2)	(3)	(4)
(1)	Meter Investment per Customer	$423.61	$19,383.34	$10,355.44	$2,545.19
(2)	With General Plant Loading (1) x 1.0796	457.31	20,937.48	11,185.73	2,749.26
(3)	Annual Economic Charge Related to Capital Investment	7.61%	7.61%	7.61%	7.61%
(4)	Service Investment per Customer	$278.30	$0.00	$0.00	$221.07
(5)	With General Plant Loading (1) x 1.0796	300.44	0.00	0.00	238.80
(6)	Annual Economic Charge Related to Capital Investment	7.21%	7.21%	7.21%	7.21%
(7)	A&G Loading (Plant Related)	0.70%	0.78%	0.78%	0.78%
(8)	Total Carrying Charge Meters (3) + (7)	8.31%	8.39%	8.39%	8.39%
(9)	Total Carrying Charge Services (6) + (7)	7.91%	7.99%	7.99%	7.99%
(10)	Annualized Meter Costs (2) x (8)	38.00	1,755.73	937.99	230.54
(11)	Annualized Service Costs (5) x (9)	23.77	0.00	0.00	19.07
(12)	Total Annualized Meter & Service Costs (10)+(11)	61.77	1,755.73	937.99	249.61
b) O&M - Meter, Customer Accounts Expenses, Customer Service					
(13)	Meter O&M Expenses	9.35	427.77	228.53	56.17
(14)	Service O&M Expenses	5.18	0.00	0.00	4.11
(15)	Customer Accounts Expenses	80.89	80.89	80.89	80.89
(16)	Customer Service and Informational Expenses	13.54	22.57	22.57	22.57
(17)	With A&G Loading [(13)+(14)+(15)+(16)] x 1.698 (Non-plant Related)	185.02	902.08	563.75	278.05
(18)	Customer-Related Costs (12) + (17)	246.80	2,657.81	1,501.74	527.66
	Working Capital				
(19)	Materials and Supplies [(2) + (5)] x 0.39%	2.96	81.66	43.62	11.65
(20)	Prepayments [(2) + (5)] x 0.120%	0.91	25.12	13.42	3.59
(21)	Cash Working Capital (17) x 6.21%	11.49	56.02	35.01	17.27
(22)	Revenue Requirement for Working Capital [(19)+(20)+(21)] x 9.50%	1.46	15.47	8.75	3.09
(23)	Total Annual Marginal Customer-Related Costs (18) + (22)	248.26	2,673.28	1,510.48	530.75

Schedule 19 (III). Derivation of Annual Meter, Service and Customer-Related Costs

		Rate 2.4 - General Service 1000 kVa and over		
		Transmission	Primary	Secondary
		--------- (2007 Dollars per Customer) --------		
a) Investment - Meter & Services		(1)	(2)	(3)
(1)	Meter Investment per Customer	$19,383.34	$11,370.25	$5,578.82
(2)	With General Plant Loading (1) x 1.0796	20,937.48	12,281.91	6,026.12
(3)	Annual Economic Charge Related to Capital Investment	7.61%	7.61%	7.61%
(4)	Service Investment per Customer	$0.00	$0.00	$0.00
(5)	With General Plant Loading (1) x 1.0796	0.00	0.00	0.00
(6)	Annual Economic Charge Related to Capital Investment	7.21%	7.21%	7.21%
(7)	A&G Loading (Plant Related)	0.78%	0.78%	0.78%
(8)	Total Carrying Charge Meters (3) + (7)	8.39%	8.39%	8.39%
(9)	Total Carrying Charge Services (6) + (7)	7.99%	7.99%	7.99%
(10)	Annualized Meter Costs (2) x (8)	1,755.73	1,029.91	505.33
(11)	Annualized Service Costs (5) x (9)	0.00	0.00	0.00
(12)	Total Annualized Meter & Service Costs (10)+(11)	1,755.73	1,029.91	505.33
b) O&M - Meter, Customer Accounts Expenses, Customer Service				
(13)	Meter O&M Expenses	427.77	250.93	123.12
(14)	Service O&M Expenses	0.00	0.00	0.00
(15)	Customer Accounts Expenses	80.89	80.89	80.89
(16)	Customer Service and Informational Expenses	33.86	33.86	33.86
(17)	With A&G Loading [(13)+(14)+(15)+(16)] x 1.6981 (Non-plant Related)	921.25	620.96	403.92
(18)	Customer-Related Costs (12) + (17)	2,676.98	1,650.87	909.25
	Working Capital			
(19)	Materials and Supplies [(2) + (5)] x 0.39%	81.66	47.90	23.50
(20)	Prepayments [(2) + (5)] x 0.120%	25.12	14.74	7.23
(21)	Cash Working Capital (17) x 6.21%	57.21	38.56	25.08
(22)	Revenue Requirement for Working Capital [(19)+(20)+(21)] x 9.50%	15.58	9.61	5.30
(23)	Total Annual Marginal Customer-Related Costs (18) + (22)	2,692.56	1,660.48	914.55

VIII. MARGINAL GENERATION AND TRANSMISSION COSTS

A. Marginal Generation Costs

The Island interconnected system is planned and operated by NLH to minimize costs and provide reliable service under a full range of hydrological conditions. Marginal energy cost is a function of the dispatch of generating resources. In years when additional load triggers a capacity addition, the annualized cost of adding capacity, net of any fuel savings the added capacity would provide in other hours by displacing resources with higher operating costs, represents the marginal generation capacity cost. As a result, the marginal generation cost depends upon NLH's generation expansion plans, and the forecast of system reliability that results from that plan.

While NLH develops its plans using a range of assumptions about hydrological conditions, NERA used the results based on expected water availability. The marginal cost study is a forward-looking exercise intended to provide cost estimates many years into the future. Obviously in real time, hydrological conditions might be better or worse than average, and total short-run marginal demand or energy costs correspondingly lower or higher.

NP's marginal source of generation is NLH. For purposes of this study for NP, we used estimates of NHL's marginal generation costs, computed using NLH's base-case fuel price forecast, and averaged over the period 2007-11.

1. Marginal Energy Costs

NLH dispatches its hydro resources in order to:

- Obtain the most energy from hydro production across the year (by minimizing the probability of spill and the need to operate thermal units, while maintaining the firm energy target);
- Keep thermal units as close to their efficient operating levels as possible; and
- Assist with system frequency and voltage control.

An additional kWh of energy consumed in a given hour generally leads to an additional kWh of hydro production in that hour (plus marginal energy losses), which is then replaced by thermal generation at Holyrood at a later time. Under most hydrological conditions, this replacement energy is produced at times when the thermal units are operating at high levels (when heat rates are the most efficient). As a consequence, NLH marginal energy costs exhibit no daily, weekly or seasonal variation. These estimates include fuel, variable O&M, expense-related overheads (administrative and general or "A&G" expenses), revenue requirement for fuel stock and cash working capital, and marginal energy losses to the NLH/NP interface. NERA's average marginal energy cost analysis for 2007-2011 are shown in Schedule 20 below, adjusted for losses of the NP system down to the various voltage levels of service.

Schedule 20: Average Marginal Energy Cost Forecast for 2007-2011, by Voltage Level (cents per kWh)

		NP Marginal Energy Cost by Voltage Level (2007 cents per kWh)
(1)	NLH	8.474
(2)	Transmission	8.652
(3)	Distribution Substation	8.713
(4)	Primary	8.971
(5)	Secondary	9.257

2. Marginal Generation Capacity Costs

If load grows in hours when capacity is tight, there is a reduction in reliability, which is a marginal shortage cost imposed on consumers. When the shortage cost is sufficiently high, it is cost-effective to add capacity to restore reliability to the acceptable level. In years when an increment of load would not trigger a capacity addition, there is still a marginal capacity cost – the cost to consumers of the reduced reliability that results when load grows but capacity remains the same.

The type of capacity added solely to restore reserves to the required level in response to load growth is generally a peaking unit, such as a combustion turbine. Generating units designed to run more often than peakers have higher fixed costs, which are only justified when their variable costs are low enough to warrant their dispatch in many hours, not just in peak hours. The fixed costs of baseload or intermediate units are thus incurred for both capacity and energy reasons.

NLH's current base case expansion plan includes three 25-MW wind purchase contracts, construction of three small hydro projects, and a combined cycle combustion turbine (CCCT) unit. Because of the intermittent nature of wind generation and its non-dispatchability, NLH does not count on these wind projects to provide capacity in particular hours. As a result, NERA did not consider these wind projects as a marginal source of capacity in calculating NLH's marginal generation capacity cost.

We computed the annualized cost of each non-wind resource in the base case expansion plan. The per-kW investment costs of the hydro units and CCCT were adjusted for general plant, and annualized using an economic carrying charge that included an allowance for plant-related A&G. Fixed O&M, including non-plant-related A&G, and an allowance for working capital were added. The working capital factor includes cash, materials and supplies.

To yield a pure capacity cost, the annual costs per kW must be reduced by the annual average operating cost savings expected to be provided by a marginal kW of these non-peaking resources over their lives. The annual operating cost savings were computed, for each resource, by multiplying the expected hours of operation in each full year of operation, by the difference between the expected Holyrood marginal running costs per kWh[15] and the running cost per kWh of the capacity addition in that year.[16] These annual operating cost savings were then averaged over the expected service life of the unit.[17] This crediting of the annual fixed costs of the marginal kW for the average annual operating cost savings recognizes that the last kW added to the system is required to meet marginal load only in a single (or very few) hours of the year.[18] If the unit runs in other hours, that is because it displaces a resource with higher running costs.

As an estimate of the net capacity of cost of a generic hydro unit, NERA averaged the results for the three hydro additions, weighting them by installed capacity. In the case of the CCCT, the unit is expected to operate at the margin (in the years included in the study) and thus generates no fuel savings. The cost estimate was adjusted to incorporate marginal demand losses through NLH's system.

The annual costs must then be time-differentiated. NLH's system planning model produces estimates of LOLH for each month. NERA used the relative LOLH in each month, aggregated to seasons and averaged over the period 2007-2011, to compute generation capacity costs by the seasonal costing periods.[19] Within a month, capacity costs were assigned to hours based on each hour type's relative probability of being the peak hour of the month.[20] These results were also aggregated over the months in a season. Schedule 21 shows the resulting NLH marginal

[15] NLH estimates that the Holyrood efficiency in these particular hours is between the average value of 630 kWh/BBL and the marginal value of 688 kWh/BBL. The marginal fuel cost is then fuel cost per BBL divided by efficiency. Variable O&M and working capital were also included in the operating cost savings calculations.

[16] The running costs of the hydro units were assumed be to zero.

[17] When necessary the 2006 fuel price forecasts and hours run were used in subsequent years.

[18] The annual fixed cost is calculated on a real-levelized basis. All calculations are done in 2007 Canadian dollars.

[19] The seasonal relative LOLH values are essentially unchanged for the entire period, 2007-2025.

[20] The hour types are the 24 hours in weekdays, Saturdays, and Sundays.

generation capacity cost estimate averaged for 2007-2011, using NP costing periods and adjusted for losses on the NP system down to the various voltage levels of service.

Schedule 21. Average Marginal Capacity Cost Forecast for 2007-2011 by Costing Period and Voltage Level ($ per kW-Mo.)

		Winter (Dec - Mar)		Non-Winter
		Peak	Off-Peak	
		(2007 $ per kW-mo.)		
		(1)	(2)	(3)
(1)	NLH	0.400	0.053	0.001
(2)	Transmission	0.407	0.054	0.001
(3)	Substation	0.410	0.055	0.001
(4)	Primary	0.420	0.056	0.001
(5)	Secondary	0.433	0.058	0.001

B. Marginal Transmission Costs

For most utilities the long-term marginal cost of transmission can be estimated from the typical investment per kW of transmission added to meet load growth. Transmission investment is somewhat lumpy, so the addition of capacity in a given year does not necessarily reflect load growth in that year. NERA normally relies on the cost of budgeted growth-related transmission projects over the budget period as the basis for our marginal cost estimates. Projects considered to be growth-related include the following categories:

- Projects related to growth in system or area loads; and
- Projects related to increased interconnection capability to provide for added reliability.

Transmission expenditures that replace existing facilities without adding capacity would be undertaken even in the absence of load growth and, therefore, are not marginal. Projects that connect generation to the network are generation-related and not functionally transmission. Transmission projects that facilitate economy purchases or economy interchange, but do not add significantly to system reliability, are energy-related, rather than transmission-related. Projects that bring the system to a new target level of reliability (rather than returning the system to an unchanged target in response to load growth) are also not marginal.

NLH provided its capital budget for the period 2006-2009. There was only one growth-related transmission project during that period. Therefore, the load-related transmission investment per kW of load growth in the budget period might not be representative. We decided that using a combination of historical and budget information better align expenditures with load growth causing them. Therefore we reviewed projects during the historical period as well (2001-2005) and found that growth-related investment was made in 2002 and 2003.[21] We estimated the investment in growth-related transmission per kW of load growth over the period 2002-2009. We assumed that this value is representative of marginal transmission investment over the full forecast period, 2006-2025.

When load growth requires transmission investment, marginal transmission O&M expenses are also incurred. Because the growth-related projects involve substations rather than lines, we began with an analysis of NLH's average level of transmission substation O&M expenses in the recent past as a guide for estimating marginal O&M costs. O&M expenses for 2000 to 2004 were first converted into 2007 dollars. These constant dollar values were then divided by kilowatts of weather-normalized peak load at the transmission level. The expenses per kW have declined significantly in recent years, so we used the 2003-2004 average as our estimate of marginal transmission O&M expenses.

Transmission capacity is sized to handle annual peak demands on the transmission system. NERA used the estimated relative probability of annual transmission system peak, based on five years of historical hourly transmission loads,[22] to time-differentiate transmission marginal costs. The reduced carrying capability of transmission facilities in periods of high ambient temperature is taken into account in these calculations. Schedule 22, line (1) shows marginal transmission costs by NP costing periods and adjusted for distribution losses through the NP system.

[21] The bulk of the projects were not growth-related. On the interconnected Island grid, growth-related projects are very limited because work on the 230 kV bulk system, which was constructed in the late 1960s, is now typically driven by issues other than load growth.

[22] From years 2000 to 2004.

Schedule 22. Time-Differentiated Marginal Transmission Costs by Costing Period and Voltage Level ($ per kW)

		Winter (Dec - Mar)		Non-Winter
		Peak	Off-Peak	
		(2007 $ per kW-mo.)		
		(1)	(2)	(3)
(1)	NLH	1.386	0.331	0.001
(2)	Transmission	1.413	0.337	0.001
(3)	Distribution Substation	1.424	0.340	0.001
(4)	Primary	1.458	0.348	0.001
(5)	Secondary	1.502	0.374	0.001

Schedule 23 summarizes average 2007-2011 marginal energy, generation capacity, transmission and distribution substation costs, with the generation capacity, transmission and distribution substation costs stated in dollars per kW and all costs stated in 2007 dollars. Schedule 24 shows all the time-differentiated costs (including energy) stated in cents per-kWh.

Schedule 23. Summary of Marginal Energy Cost ($ per kWh) and Time-Differentiated Marginal Demand-related Costs by Voltage of Service ($ per kW)

		Winter Peak	Winter Off-Peak	Non-Winter All hours
		---------- (2007$)	----------	----------
		(1)	(2)	(3)
	Secondary Customer			
(1)	Energy ($/kWh)	0.0970	0.0950	0.0912
(2)	Generation Capacity ($/kW-mo.)	0.4329	0.0109	0.0002
(3)	Transmission ($/kW-mo.)	1.5021	0.3736	0.0011
(4)	Distribution Substation ($/kW-mo.)	1.1353	1.0984	0.0124
(5)	Total Demand-Related Cost ($/kW- mo.)	3.0703	1.4829	0.0137
	Primary Customer			
(6)	Energy ($/kWh)	0.0924	0.0913	0.0889
(7)	Generation Capacity ($/kW-mo.)	0.4201	0.0562	0.0014
(8)	Transmission ($/kW-mo.)	1.4577	0.3480	0.0011
(9)	Distribution Substation ($/kW-mo.)	1.1017	1.0659	0.0120
(10)	Total Demand-Related Cost ($/kW-mo.)	2.9795	1.4701	0.0145
	Transmission Customer			
(11)	Energy ($/kWh)	0.0875	0.0871	0.0863
(12)	Generation Capacity ($/kW-mo.)	0.4073	0.0544	0.0014
(13)	Transmission ($/kW-mo.)	1.4133	0.3374	0.0011
(14)	Distribution Substation ($/kW-mo.)			
(15)	Total Demand-Related Cost ($/kW-mo.)	1.8206	0.3918	0.0024

Schedule 24. Summary of Marginal Generation, Transmission and Distribution Substation Costs by Voltage of Service (cents per kWh)

		Winter		Non-Winter
		Peak	Off-Peak	All hours
		(2007 cents per kWh)		
		(1)	(2)	(3)
(1)	Secondary Customer			
	Energy	9.700	9.504	9.122
	Generation Capacity	0.223	0.011	0.000
	Transmission	0.773	0.070	0.000
	Distribution Substation	0.584	0.207	0.002
	Total (cent/kWh)	11.279	9.792	9.124
(2)	Primary Customer			
	Energy	9.243	9.126	8.891
	Generation Capacity	0.216	0.011	0.000
	Transmission	0.750	0.065	0.000
	Distribution Substation	0.567	0.201	0.002
	Total (cent/kWh)	10.776	9.402	8.893
(3)	Transmission Customer			
	Energy	8.748	8.709	8.629
	Generation Capacity	0.210	0.010	0.000
	Transmission	0.727	0.063	0.000
	Total (cent/kWh)	9.684	8.783	8.630

Schedules 25 and 26 summarize the monthly marginal local distribution facilities cost and monthly marginal customer cost for each customer class.

Schedule 25: Summary of Monthly Marginal Local Distribution Facilities Costs per KW of Design Demand and Per Customer

	Customer Class	Monthly Facility Cost per kW of Design Demand ($/kW) (1)	Typical Design Demand by Customer kW (2)	Monthly Facility Cost per Customer ($/customer/mo.) (1)*(2) (3)
(1)	Domestic Class	$1.13	10	$11
(2)	General Service 0-10 kW	1.16	10	$11
(3)	General Service 10-100 kW (110 kVa)	0.85	35	$30
(4)	General Service 110-1000 kVa			
	Primary	0.21	500	$105
	Secondary	0.61	370	$228
(5)	General Service 1000 kVa and over			
	Primary	0.15	2,000	$297
	Secondary	0.36	1,500	$538

Schedule 26. Summary of Monthly Marginal Customer Costs

	Customer Class	Monthly Marginal Customer Cost per Customer (2007$ /mo.)
(1)	Domestic (Class Average)	$9.34
	(a) services of 200 Amps and below	$9.30
	(b) services >200 Amp	$17.46
(2)	General Service 0-10 kW	$10.80
(3)	General Service 10-100 kW (110 kVa)	$20.69
(4)	General Service 110 -1000 kVa	
	Transmission	$222.77
	Primary	$125.87
	Secondary	$44.23
(5)	General Service 1000 kVa and over	
	Transmission	$224.38
	Primary	$138.37
	Secondary	$76.21

IX. MARGINAL COST REVENUES

Ideally, customers should pay charges that match their marginal costs. However, rates set at marginal costs rarely produce revenue equal to the authorized revenue requirement, which is determined on a different cost basis. We computed the class marginal cost revenues for test year 2007—the revenue that would be produced by charging each class marginal costs as rates—based on our estimates of marginal costs of generation (averaged for 2007-2011), transmission, distribution substation, local distribution facilities and customer costs (all stated in 2007 dollars), and using NP's forecast of 2007 sales. Next, we compared these to the NP's forecast of 2007 revenues by class at current rates.[23] Schedule 27 shows the gap between marginal cost revenues and revenue requirement, in total and by class, as well as the share of the total marginal cost of service being paid by each class at existing rates. Total revenues at current rates cover 81.3 percent of NP's total marginal costs, with class percentages ranging from 72.7 to 99 percent.

Schedule 27. Marginal Cost Revenues Compared to Forecast Revenues at Current Rates

Rate Class	2007 MC Revenues (000$)	2007 Revenues at Current Rates (000$)	MC Revenues less Revenues at Current Rates (000$)	Ratio of Current Revenues to MC Revenues (%)
	(1)	(2)	(1) - (2)	(2)/(1)
1.1 Domestic - Regular	$97,689	$77,723	$19,966	79.6%
1.1 Domestic - All Electric	$244,338	$195,809	$48,529	80.1%
Total Domestic:	$342,028	$273,532	$68,495	80.0%
2.1 GS (0-10 kW)	$12,262	$12,134	$127	99.0%
2.2 GS (10-100 kW)	$63,951	$58,832	$5,119	92.0%
2.3 GS (110-1000 kVA)	$86,591	$69,547	$17,044	80.3%
2.4 GS (1000 kVA and Over)	$39,641	$28,826	$10,815	72.7%
Total General Service:	$202,445	$169,340	$33,105	83.6%
TOTAL REVENUES	**$544,473**	**$442,872**	**$101,601**	**81.3%**

[23] Forecast revenue at current rates includes RSA fuel factor for 2006-2007, but excludes municipal tax revenues.

Jurisdictions that use marginal costs as the basis for allocation of revenue requirement to classes often use the "equi-proportional marginal cost" (EPMC) approach to close the marginal cost revenue gap. This means setting each class' revenue requirement at the same percent of its marginal cost revenues (79 percent in Schedule 27). However, it is sometimes more efficient to deviate from the strict EPMC revenue allocations when customers in some classes are more price-responsive than others. The "inverse elasticity" approach makes larger percentage adjustments to marginal cost revenues for classes that are less price-responsive (i.e., have lower demand elasticity) and smaller percentage adjustments for classes that are more price-responsive.

Rate Design Review

May 2007

NEWFOUNDLAND POWER
A FORTIS COMPANY

Table of Contents

Page

1.0 EXECUTIVE SUMMARY

Newfoundland Power has reviewed its rates to determine what changes should be made to customer rates to recover the 2008 revenue requirement. The following is a summary of the rate design proposals resulting from the rate review.

- With the exception of Rate 2.1, energy charges should increase to better reflect the high marginal cost of energy on the system.
- With the exception of Rate 2.1, no increase is proposed in the basic customer charges so as to accommodate higher percentage increases in energy charges to better reflect the high marginal cost of energy on the system.
- In Rate 2.1, where the current energy charge exceeds both the embedded and the marginal cost, the Company proposes to recover the class increase in revenue requirement through a higher basic customer charge.
- The demand charges during the non-winter season should be reduced to increase the price differential between the winter and non-winter season and better reflect the seasonal cost differences on the system.
- The energy component of the maximum monthly charge within General Service Rates 2.2, 2.3 and 2.4 should be increased to reflect the average increase in costs.
- The street and area lighting rates should continue to be developed based on recovering embedded costs with the price of fixtures, poles and wiring varying in a manner reflective of differences in their fixed costs and variable operating costs.
- The Curtailable Service Option provides operational and planning benefits and should be maintained. It is proposed that the annual credit remain at $29 per kVA and the value of curtailable load on the system continue to be monitored.

Individual rate components within each rate are proposed to change by different percentages, with tail block energy charges receiving the highest increases. Accordingly, customers within each class will experience percent bill impacts that vary according to usage.

The general impacts are as follows:

- Domestic customers with higher energy usage will receive higher percent rate increases.
- General Service customers served under Rate 2.1 will all experience approximately the same dollar increase.
- General Service customers served under Rates 2.2, 2.3 and 2.4 will experience percentage impacts that vary by load factor, with higher load factor customers (high energy use relative to billing demand) experiencing higher percentage increases. Low load factor customers served under Rates 2.2, 2.3 and 2.4 that are charged under the maximum monthly charge, will experience percentage increases approximately equal to the overall proposed average rate increase.

2.0 GENERAL

To recover its forecast 2008 revenue requirement the Company is proposing an average increase in current customer rates of 5.3%. The Company has applied generally accepted rate design principles in determining where to place emphasis in revising customer rates.

To determine what changes should be made to customer rates, the Company has compared customer rates to the results of embedded and marginal cost studies.[1] These comparisons enable general conclusions to be made as to the need to increase or decrease individual charges. The Company has also considered the rate impact on customers of measures required to bring revenue to cost ratios back within an acceptable recovery range and the impact on customers of moving between the different customer rates.[2]

Rate adjustments routinely involve the balancing of various ratemaking principles. For instance, basic customer charges are used to recover customer related costs and to ensure a reasonable cost recovery from customers with low usage.[3] However, basic customer charges provide customers with limited information as to how usage impacts cost. When the marginal cost of energy is high, higher energy charges are often necessary to ensure customers receive a reasonable price signal to reduce consumption. However, when increasing one rate component it is often necessary to decrease or limit increases in other charges to ensure the overall revenue requirement is not exceeded. In this example, an appropriate balance must be sought between the need to provide a reasonable price signal and the need to ensure the level of cost recovery from customers is reasonable.

Newfoundland Power's rate design proposals reflect the balancing of a number of ratemaking principles.

2.1 The Embedded Cost of Service Study

The Company has completed an embedded cost of service study for the purpose of assessing customer rates for the 2008 test year (the "Cost of Service Study"). The Cost of Service Study is based on 2005 results, but reflects current rates and the current depreciation study.

Newfoundland Power designs its customer rates to achieve revenue to cost ratios within the range of 90 per cent to 110 per cent.[4]

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1 Both of these studies provide cost information that can be directly compared to the charges contained in existing rates.

2 General Service customer can transition between rates for small changes in load. The Company reviews these rate transitions to identify and limit any material customer bill impacts from small changes in load.

3 Customer related costs include the cost of providing metering, billing, collections, service drops and portion of the distribution system. If the basic customer charge is set too low, the lack of cost recovery from low usage customers will need to be offset by an over recovery of costs from higher usage customers.

4 This is consistent with the views of the Board as expressed in Order No. P.U. 7 (1996-97), where the Board stated: "The Board agrees with the philosophy that it is not necessary to achieve a 100% revenue to cost ratio for all classes and takes no exception to a variance of up to 10%, …".

Table 1 shows the revenue to cost ratios from the Cost of Service Study.

Table 1
Cost of Service Study Results

Class of Service	Rate Code	Revenue to Cost Ratios %
Domestic	1.1	93.7
General Service 0-10 kW	2.1	119.8
General Service 10-100 kW (110 kVA)	2.2	116.8
General Service 110-1000 kVA	2.3	110.5
General Service 1000 kVA and Over	2.4	103.9
Street and Area Lighting	4.1	101.5

The revenue to cost ratios for the General Service 0-10 kW and 10-100 kW (110 kVA) classes are materially greater than 110 percent, while the rate of the General Service 110-1000 kVA class is slightly above 110 percent. Rates should change to reduce the cost recovery for these classes.[5]

The Company proposes a gradual approach to bring all customer classes back within an acceptable cost recovery range.

Table 2 provides the 2008 proposed relative rate changes by class and the resulting *pro forma* revenue to cost ratios.

Table 2
Proposed Relative Rate Changes by Class

Rate Code	Class of Service	Relative to Average	*Pro forma* Revenue to Cost Ratios
1.1	Domestic	1% above[6]	94.6
2.1	General Service 0-10 kW	4% below	115.0
2.2	General Service 10-100 kW (110 kVA)	3% below	113.3
2.3	General Service 110-1000 kVA	1% below	109.4
2.4	General Service 1000 kVA and Over	Average	103.9
4.1	Street and Area Lighting	Average	101.5

The Cost of Service Study also provides estimates of the embedded cost of service broken down by customer class and by demand, energy, and customer related costs. When expressed on a unit cost basis, the embedded costs are comparable to the energy, demand and customer charges within rates. A comparison of rates to embedded costs is provided in Appendix A to this review.

5 To provide for recovery of total revenue requirement effectively requires that another class, or classes, receive an above average rate increase. Since the Domestic class is the only class with a revenue to cost ratio less than 100 percent, it is practically required that the Domestic class receive an above average increase if the over-recovery in General Service 0-10 kW and 10-100 kW classes is to be addressed.

6 The Domestic class increase relative to average may vary slightly from 1% to ensure matching of revenue from rates to revenue requirement. The Domestic class is used to ensure matching since it is the largest class, and such reconciling adjustments will have the least impact on the Domestic class.

2.2 The Marginal Cost Study

In January 2007, NERA Economic Consulting completed the *Newfoundland Power Marginal Cost of Electricity Study* (the "Marginal Cost Study"). The Marginal Cost Study provides estimates of all the changes in costs that would occur with changes in kilowatt-hours of energy, kilowatts of demand, and the number of customers of various types. The Marginal Cost Study includes both Hydro's marginal costs of generation and transmission and Newfoundland Power's marginal costs related to distribution and customer service. A comparison of rates to marginal cost for all rate classes is provided in Appendix A.

Based on the results of the Marginal Cost Study, the Company has observed that:

1. Marginal costs on the system exceed the average costs recovered in customer rates;
2. Practically all marginal generation demand, transmission demand, and distribution demand costs are related to winter season demand requirements; and
3. Marginal energy costs are substantially the same year-round.

3.0 RATE REVIEW

3.1 Rate 1.1 Domestic

Rate 1.1 consists of the following monthly charges:

Basic Customer Charge	$15.59
Energy Charge	8.935 ¢/kWh

Basic Customer Charge

The basic customer charge is used to recover customer related costs and to ensure a reasonable cost recovery from customers with low usage.

Table 3 provides a comparison of the existing basic customer charge and the embedded and marginal costs for Rate 1.1.

Table 3
Review of Basic Customer Charge for Rate 1.1
($ / customer per month)

Basic Customer Charge	Embedded Customer Cost	Marginal Customer & Distribution Facilities Cost	Maximum Basic Customer Charge[7]
$15.59	$20.88	$20.90	$16.95

The basic customer charge is lower than the total of the marginal customer and distribution facilities costs and the agreed-to maximum basic customer charge. Therefore, an increase in the basic customer charge can be justified on the basis of recovery of the cost of service. However, the degree of emphasis on increasing the basic customer charge is dependant on the reasonableness of the price signal provided by the energy charge.[8]

Energy Charge

The Rate 1.1 energy charge is intended to recover both demand and energy costs. Table 4 provides a comparison of the existing Rate 1.1 energy charge to the blended demand and energy costs from the Cost of Service Study and the Marginal Cost Study.

Table 4
Review of Energy Charge for Rate 1.1
(¢ per kWh)

Energy Charge	Embedded Demand and Energy Cost	Marginal Demand and Energy Cost
8.935	9.18	10.35

The current energy charge of 8.935 ¢/kWh is approximately 3% less than the embedded cost of 9.18 ¢/kWh and approximately 13.6% less than the marginal cost. Therefore, it is reasonable to increase the energy charge.

Summary

7 Based on an agreement reached between the parties at Newfoundland Power's 2003 GRA and incorporated in the Board's decision in Order No. P.U. 19(2003), the Company agreed-to cap the recovery through basic customer charge at 50% the of embedded distribution costs beyond the service drop for Rate 1.1 with the remainder to be recovered through energy charges. On that basis, the maximum basic customer charge is calculated to be $16.95 per month.

8 Since basic customer charges do not vary with customer consumption, it is sometimes necessary to limit changes in basic customer charges to provide a reasonable price signal to customers, through energy and demand charges, of the cost of increasing their consumption.

Increases in both the basic customer charge and the energy charge can be justified. However, the basic customer charge is considered to have less importance in promoting efficiency in rate design than the energy charges. The energy charges are materially lower than marginal costs. As a result, the Company proposes not to increase the basic customer charge and to recover its increased revenue requirement from Domestic by increasing the energy charge. The customer impact of this proposal is that Domestic customers with higher usage will receive a higher percentage increase on their bill.

3.2 General Service Rates

3.2.1 Rate 2.1 General Service 0 – 10 kW

The Rate 2.1 General Service 0 – 10 kW ("Rate 2.1") consists of the following monthly charges:

Basic Customer Charge	$17.88
Energy Charge	11.462 ¢/kWh
Minimum Monthly Charge (Single Phase)	$17.88
Minimum Monthly Charge (Three Phase)	$35.76

Basic Customer Charge and Minimum Monthly Charge

Table 5 provides a comparison of the existing basic customer charge and the embedded and marginal costs for Rate 2.1.

Table 5
Review of Basic Customer Charge for Rate 2.1
($ / customer per month)

Basic Customer Charge	Embedded Customer Cost	Marginal Customer & Distribution Facilities Cost	Maximum Basic Customer Charge[9]
$17.88	$23.80	$22.71	$19.85

The customer-related cost from the Cost of Service Study is $23.80 per month. This cost is higher than the customer related cost for Domestic primarily because more expensive demand meters are required on approximately 25% of serviced premises on Rate 2.1.[10]

[9] Based on an agreement reached between the parties at Newfoundland Power's 2003 GRA and incorporated in the Board's decision in Order No. P.U. 19(2003), the Company agreed-to cap the recovery through basic customer charge at 50% the of embedded distribution costs beyond the service drop for Rate 2.1 with the remainder to be recovered through energy charges. On that basis, the maximum basic customer charge is calculated to be $19.85 per month.

The basic customer charge is lower than the total of the marginal customer and distribution facilities costs and the agreed-to maximum basic customer charge. Therefore, an increase in the basic customer charge can be justified on the basis of recovery of the cost of service. However, the degree of emphasis on increasing the basic customer charge is dependant on the reasonableness of the price signal provided by the energy charge.

The minimum monthly charge for three-phase customers is set at 2 times the basic customer charge to ensure a reasonable recovery of the higher cost investment for three-phase customers.

Energy Charge

Table 6 provides a comparison of the existing Rate 2.1 energy charge to the blended demand and energy costs from the Cost of Service Study and the Marginal Cost Study.

Table 6
Review of Energy Charge for Rate 2.1
(¢ per kWh)

Energy Charge	Embedded Demand and Energy Cost	Marginal Demand and Energy Cost
11.462	8.26	10.27

The current energy charge of 11.462 ¢/kWh is approximately 38% greater than the embedded cost of 8.26 ¢/kWh and approximately 12% greater than the marginal cost. The significant difference between the energy charge and embedded cost is due to: (i) a significant portion of the customer related costs being recovered through the energy charge, and (ii) the allocation of demand related costs to the class being reduced as a result of the recent load research study.

Summary

The current energy charge exceeds both the embedded and marginal cost. The basic customer charge is lower than the total of the marginal customer and distribution facilities costs and the agreed-to maximum basic customer charge. Therefore, it is proposed that any increased revenue from the Rate 2.1 class be obtained through an increase in the basic customer charge. Given the lower than average increase proposed to be applied to this customer class, Rate 2.1 customers will receive bill increases that are smaller in magnitude.[11]

3.2.2 Rate 2.2 General Service 10 – 100 kW (110 kVA)

Rate 2.2 consists of the following monthly charges:

[10] Demand meters are installed on Rate 2.1 services to monitor demand to determine the rate that should apply to the customer.

[11] The proposal for a lower than average increase for Rate 2.1 is reviewed in Section 2.1 of this report.

Basic Customer Charge (B.C.C.)	$20.60
Energy Charges	
First 150 kWh per kW of billing demand	9.108 ¢/kWh
All excess kWh	6.102 ¢/kWh
Demand Charge	
Winter Season	$8.63 per kW of billing demand
Non-Winter Season	$7.88 per kW of billing demand
Maximum Monthly Charge	B.C.C. + 15.9 ¢/kWh
Minimum Monthly Charge (Single Phase)	$20.60
Minimum Monthly Charge (Three Phase)	$35.76

Basic Customer Charge and Minimum Monthly Charge

Table 7 provides a comparison of the existing basic customer charge and the embedded and marginal costs for Rate 2.2.

Table 7
Review of Basic Customer Charge for Rate 2.2
($ / customer per month)

Basic Customer Charge	Embedded Customer Cost	Marginal Customer & Distribution Facilities Cost
$20.60	$41.86	$51.61

The basic customer charge is significantly lower than the customer related costs from the Cost of Service Study and the total of the marginal customer and distribution facilities costs. The embedded customer costs are significantly higher than those for Rate 2.1 primarily because more expensive demand metering is required on all Rate 2.2 services. The higher cost also reflects the mixture of single phase and three phase customers supplied under Rate 2.2.[12]

An increase in the basic customer charge can be justified on the basis of recovery of the cost of service. However, the degree of emphasis on increasing the basic customer charge is dependant on the reasonableness of the price signal provided by the energy charge. Also, to minimize the impact on customers of moving between Rate 2.1 and 2.2, the basic customer charge is set slightly above the Rate 2.1 basic customer charge.
The minimum monthly charge for three-phase customers is set at 2 times the basic customer charge to ensure a reasonable recovery of the higher cost investment for three-phase customers.

Energy Charges

[12] Approximately 40% of customers under Rate 2.2 are three phase customers.

Table 8 provides a comparison of the existing Rate 2.2 energy charges to energy costs from the Cost of Service Study and the Marginal Cost Study.

Table 8
Rate 2.2 Energy Charge Review
(¢/kWh)

Energy Charges		Embedded Cost	Marginal Costs
First Block Rate	**Tail Block Rate**	**Total**	**Total**
9.108	6.102	4.66	9.99

This rate contains a two block energy charge. The first block size is determined by the customer's monthly peak demand. Customers with high energy usage relative to their monthly billing demand (i.e., higher load factor) have energy consumption billed on both energy blocks. Approximately 75% of Rate 2.2 customer bills have energy consumption billed on both energy blocks. The marginal energy rate for these customers is the tail block rate.

The tail block energy charge is approximately 1.5¢ per kWh greater than the embedded energy cost. The difference is due to the Company's practice of pricing the tail block energy charges to reflect short-run marginal energy costs. The tail block energy charge is materially less than the marginal energy costs. To improve the pricing signal to customers under Rate 2.2 will require increasing the tail block price. Given the relatively low increase that is proposed for Rate 2.2 (see Table 2), a material increase in the tail block energy price will require decreasing other rate components.

Demand Charges

Table 9 provides a comparison of the existing Rate 2.2 demand charges to the demand costs from the Cost of Service Study and the Marginal Cost Study.

Table 9
Rate 2.2 Demand Charge Review

Demand Charges $/kW Billing Demand Winter / Non-winter	Embedded Cost $/kW Billing Demand	Marginal Costs $/kW Winter / Non-winter
8.63 / 7.88	10.54	4.67 / 0.01

The Rate 2.2 demand charges are significantly below the average embedded cost of demand and significantly above marginal demand costs. The main reasons for demand charges being below embedded demand costs are: (i) some demand costs are recovered in the first block energy charge, and (ii) tail block energy rates are set closer to short run marginal costs to provide more efficient pricing signals to customers.

Rate 2.2 has demand charges that vary by season. The Marginal Cost Study indicates that practically all of the marginal generation demand, transmission demand, and distribution demand costs are related to winter season demand requirements. The Cost of Service Study does not provide a breakdown of embedded costs on a seasonal basis. However, the allocation of demand costs based on system peak, which occurs during the winter season, is consistent with the concept of seasonal costs differentials.

From an efficiency perspective, there is no reason to increase the current demand charges since they are materially higher than current marginal costs. The seasonal price differential is lower than the seasonal marginal cost differential as a result the seasonal price differentials in the demand charges should be increased. This can be accomplished by decreasing summer demand charges. Reducing summer demand charges also permits an increase in tail block charges to better reflect marginal energy costs.

Maximum Monthly Charge

The maximum monthly charge is designed to protect customers with very low monthly load factors from being charged more than the cost to serve. On average, customers with very low load factors (high demand requirements and low energy requirements) have a low probability of requiring their maximum demand during time of system peak. For these customers, the maximum monthly charge allows them to avoid a very high average cost per kWh that would result if they were charged the total of their basic customer charge, demand charges and energy charge in the month.

The maximum monthly charge is currently the basic customer charge plus 15.9¢ per kWh. The same energy charge applies to the maximum monthly charge for General Service Rate 2.2, 2.3 and 2.4. The energy component of the maximum monthly charge was most recently reviewed at the Company's 1996 GRA. Since that time the energy charge component has been subject to overall average rate increases.[13] The Company is proposing to continue that practice.

Rate Transition

An assessment of rate transitions is conducted to identify and avoid the occurrence of material customer bill impacts when slight changes in load cause a customer to move from one rate class to another.

Figure 1 shows the average cost per kWh for a customer with a billing demand of 10 kW at differing kWh usage computed on Rate 2.1 and Rate 2.2. The 10 kW amount is the transition demand level at which customers move from Rate 2.1 to Rate 2.2.

Figure 1: Unit Cost Comparison for Rate 2.1 and 2.2 at 10 kW

[13] Excluding RSA adjustments.

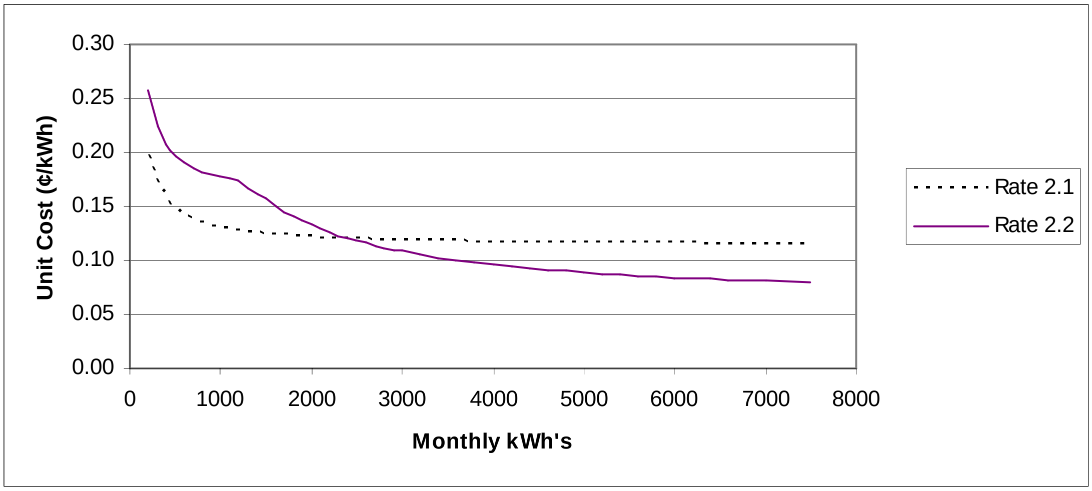

Figure 1 shows there are considerable differences in average prices depending on the customer's kWh consumption. The significant differences in average price are the result of comparing two different billing approaches. Rate 2.2 has demand and energy costs recovered through demand and energy charges, while Rate 2.1 has demand and energy costs recovered through a single energy charge. An average price comparison shows that high load factor customers (i.e., higher energy use and low demand) pay a lower average price on Rate 2.2 and a higher average price on Rate 2.1. Conversely, low load factor customers (i.e., low energy use and high demand) pay a lower average price on Rate 2.1 and a higher average price on Rate 2.2.

Addressing this transitional issue would require charging all small general service customers on a demand and energy rate. This is not recommended due to customer understandability issues, metering costs and the limited ability of small general service customers to respond to demand pricing. Also, making such a change would have a significant impact on customer bills.

While changing rate structures is not recommended, the Company has limited the rate transition impact for customers with low load factors by keeping the basic customer charge for Rate 2.2 only slightly above the basic customer charge for Rate 2.1.

Summary

To improve the pricing signal to customers on Rate 2.2, the Company is proposing to increase the tail block energy price by more than the average increase for the class. Given the relatively low increase that is proposed for Rate 2.2, a material increase in the tail block energy price will require decreasing other rate components. To support the increase in the tail block energy rate, the Company is proposing to decrease the summer demand charge and leave the basic customer charge unchanged. The proposed decrease in the summer demand charge will also better reflect the seasonal demand cost differentials identified in the Marginal Cost Study.

Consistent with past practice, the Company is proposing to increase the energy component of the monthly maximum charge by the average overall increase.

The customer impact of increasing the tail block energy charge by more than average to better reflect marginal costs is that customers with high load factors (higher energy use and low demand) will receive bill increases above the class average. Some adjustment in the first block energy charge may also be required to moderate customer impacts.

3.2.3 Rate 2.3 General Service 110 kVA (100 kW) – 1000 kVA

The Rate 2.3 General Service 110 – 1000 kVA ("Rate 2.3") consists of the following monthly charges:

Basic Customer Charge	$92.73
Energy Charges	
First 150 kWh per kW of billing demand, to a maximum of 30,000 kWh	8.722 ¢/kWh
All excess kWh	5.974 ¢/kWh
Demand Charge	
Winter Season	$7.46 per kVA of billing demand
Non-Winter Season	$6.71 per kVA of billing demand
Maximum Monthly Charge	B.C.C. + 15.9 ¢/kWh

Basic Customer Charge

Table 10 provides a comparison of the existing basic customer charge with embedded and marginal costs for Rate 2.3.

Table 10
Review of Basic Customer Charge for Rate 2.3
($ / customer per month)

Basic Customer Charge	Embedded Customer Cost	Marginal Customer & Distribution Facilities Cost
$92.73	$105.94	$275.53

The basic customer charge is lower than the customer related costs from the Cost of Service Study and the total of the marginal customer and distribution facilities costs. The Rate 2.3 customer costs are materially higher than those for Rate 2.2. The higher customer cost reflects the fact that almost all customers on Rate 2.3 require three phase service. An increase in the basic customer charge can be justified on the basis of recovery of the cost of service. However, the degree of emphasis on increasing the basic customer charge is dependant on the reasonableness of the price signal provided by the energy charge.

Energy Charges

Table 11 provides a comparison of the existing Rate 2.3 energy charges to Rate 2.3 energy costs from the Cost of Service Study and the Marginal Cost Study.

Table 11
Rate 2.3 Energy Charge Review
(¢/kWh)

Energy Charges		Embedded Cost	Marginal Costs
First Block Rate	Tail Block Rate	Total	Total
8.722	5.974	4.66	9.94

Similar to Rate 2.2, Rate 2.3 also contains a two block energy charge. The first block size is determined by the customer's monthly peak demand. The maximum first block size in Rate 2.3 is 30,000 kWh per month. Customers with high energy usage relative to their monthly billing demand (i.e., higher load factor) have energy consumption billed on both energy blocks. Approximately 85% of Rate 2.3 customer bills have energy consumption billed on both energy blocks. The marginal energy rate for these customers is the tail block energy rate.

The tail block energy charge is approximately 1.3¢ per kWh greater than the embedded energy cost. The difference is due to the pricing of the tail block energy charges to reflect short-run marginal energy costs. The tail block energy charge is materially lower than the marginal energy costs. To improve the pricing signal to customers on Rate 2.3 will require increasing the tail block energy price.

Demand Charges

Table 12 provides a comparison of the existing Rate 2.3 demand charges to demand costs from the Cost of Service Study and the Marginal Cost Study.

Table 12
Rate 2.3 Demand Charge Review

Current Charges $/kVA Billing Demand Winter / Non-winter	Embedded Cost $/kVA Billing Demand	Marginal Costs $/kVA Winter / Non-winter
7.46 / 6.71	10.81	5.16 / 0.02

The Rate 2.3 demand charges are significantly below the total average embedded cost of demand and significantly above marginal demand costs. The main reasons for demand charges being below embedded demand are: (i) the first block energy charge recovers some demand costs and (ii) tail block energy rates are set closer to short run marginal costs to provide more efficient pricing signals to customers.

Like Rate 2.2, Rate 2.3 demand charges vary by season. The Marginal Cost Study results support increasing seasonal cost differentials in the demand charges by decreasing summer demand charges. Reducing summer demand charges also permits an increase in tail block energy charges to better reflect marginal energy costs.

Rate Transition

Figure 2 attached shows the average cost per kWh for a customer with a billing demand of 100 kW at differing kWh usage computed on Rate 2.2 and Rate 2.3. The 100 kW amount is the transition demand level at which customers move from Rate 2.2 to Rate 2.3.

Figure 2: Unit Cost Comparison for Rate 2.2 and 2.3 at 100 kW

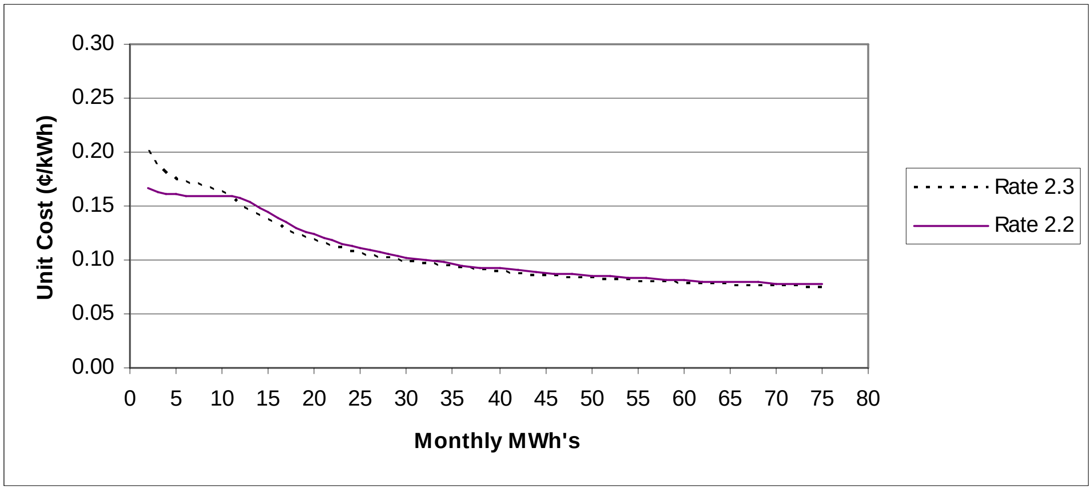

Figure 2 shows the differences in the average price per kWh for customers at the transition demand level between the rate classes are minimal. This is achieved by giving consideration in rate design to the differences between the Rate 2.2 and Rate 2.3 tail block energy rates and demand charges.

To minimize impacts on customer who move between Rate 2.2 and Rate 2.3, it is necessary to maintain the tail block energy price differentials between Rate 2.2 and Rate 2.3 when rates change.

Summary

To improve the pricing signal to customers under Rate 2.3, the Company is proposing to increase the tail block energy price by more than the average increase for the class. A material increase in the tail block energy price will require decreasing other rate components. To support the increase in the tail block energy rate, the Company is proposing to decrease the summer demand charge and to leave the basic customer charge unchanged. The proposed decrease in the summer demand charge will also better reflect the seasonal demand cost differentials identified in the Marginal Cost Study.

Consistent with past practice, the Company is proposing to increase the energy component of the maximum monthly charge by the average overall increase.

The customer impact of increasing the tail block energy charges by more than class average to better reflect marginal costs is that customers with higher energy usage will receive bill increases above the class average. Some adjustments in the first block energy charge may also be required to moderate customer impacts.

3.2.4 Rate 2.4 General Service 1000 kVA and Over

The Rate 2.4 General Service 1000 kVA and Over (Rate 2.4") consists of the following monthly charges:

Basic Customer Charge	$185.46
Energy Charges	
First 100,000 kilowatt-hours	7.334 ¢/kWh
All excess kilowatt-hours	5.866 ¢/kWh
Demand Charge	
Winter Season	$7.05 per kVA of billing demand
Non-Winter Season	$6.30 per kVA of billing demand
Maximum Monthly Charge	B.C.C. + 15.9 ¢/kWh

Basic Customer Charge

Table 13 provides a comparison of the existing basic customer charge with embedded and marginal costs for Rate 2.4.

Table 13
Review of Basic Customer Charge for Rate 2.4
($ / customer per month)

Basic Customer Charge	Embedded Customer Cost	Marginal Customer & Distribution Facilities Cost
$185.46	$190.63	$520.53

The basic customer charge is slightly lower than the customer-related costs from the Cost of Service Study and materially lower than the total of the marginal customer and distribution facilities costs. The cost data indicates an increase in the basic customer charge can be justified. However, the degree of emphasis on increasing customer charges is heavily dependent on the reasonableness of the price signal provided by the energy and demand charges.

Energy Charges

Table 14 provides a comparison of the existing Rate 2.4 energy charges with Rate 2.4 energy costs from the Cost of Service Study and the Marginal Cost Study.

Table 14
Rate 2.4 Energy Charge Review
(¢/kWh)

Current Charges		Embedded Cost	Marginal Cost
First Block Rate	Tail Block Rate	Total	Total
7.334	5.866	4.63	9.73

Rate 2.4 contains a two block energy charge. The size of the first block is 100,000 kWh. Approximately 90% of Rate 2.4 customer bills have energy consumption billed on both energy blocks. The marginal energy rate for these customers is the tail block energy rate. For the remaining customers the first block rate is the marginal energy rate.

The tail block energy charge is approximately 1.2¢ per kWh greater than the embedded energy cost. The difference is due to the pricing of the tail block energy charges to reflect short-run marginal energy costs. The first block and tail block energy charges are materially lower than the marginal energy costs. To improve the pricing signal to customers on Rate 2.4 will require increasing the energy charges with more emphasis on the tail block energy price.

Demand Charges

Table 15 provides a comparison of the existing Rate 2.4 demand charges with demand costs from the Cost of Service Study and the Marginal Cost Study.

Table 15
Rate 2.4 Demand Charge Review

Current Charges $/kVA billing demand Winter / Non-winter	Embedded Cost $/kVA billing demand	Marginal Costs $/kVA Winter / Non-winter
7.05 / 6.30	10.73	5.06 / 0.02

Consistent with Rates 2.2 and 2.3, the Rate 2.4 demand charges are significantly below the average embedded cost of demand and significantly above marginal demand costs. The main reason for demand charges being below embedded demand costs is that rates have been designed to allow tail block energy charges to better reflect short-run marginal energy costs.

The Rate 2.4 demand charges vary by season. The Marginal Cost Study results support increasing seasonal cost differentials in the demand charges by decreasing summer demand charges. Reducing summer demand charges also permits an increase in tail block energy charges to better reflect marginal energy costs.

Rate Transition

Figure 3 shows the average cost per kWh for a customer with a billing demand of 1000 kVA at differing kWh usage computed on Rate 2.3 and Rate 2.4. The 1000 kVA amount is the transition demand level at which customers move from Rate 2.3 to Rate 2.4.

Figure 3: Unit Cost Comparison for Rate 2.3 and 2.4 at 1000 kVA

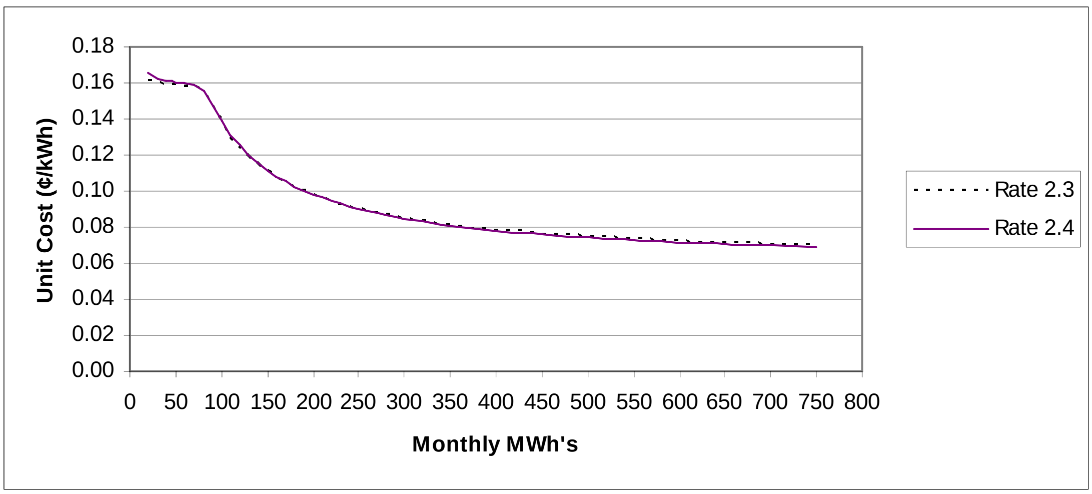

Figure 3 shows there are only minor differences in the average price per kWh for a customer at the transition demand level between the rate classes. This is achieved by giving consideration in rate design to the differences between the Rate 2.3 and Rate 2.4 tail block rates and demand charges.

To minimize impacts on customer who move between Rate 2.3 and Rate 2.4, it is necessary to maintain the tail block energy charge differentials between Rate 2.3 and Rate 2.4 when rates change.

Summary

To improve the pricing signal to customers on Rate 2.4, the Company is proposing to increase the tail block energy price by more than the average increase for the class. A material increase in the tail block energy price will require decreasing other rate components. To support the increase in the tail block rate, the Company is proposing to decrease the summer demand charge and to leave the basic customer charge unchanged. The proposed decrease in the summer demand charge will also better reflect the seasonal demand cost differentials identified in the Marginal Cost Study.

Consistent with past practice, the Company is proposing to increase the energy component of the maximum monthly charge by the average overall increase.

The customer impact of increasing the tail block energy charge by more than average to better reflect marginal costs is that customers with higher energy usage will receive bill increases above the class average. Changes in the first block energy charge may also be required to moderate customer impacts.

3.3 Street and Area Lighting Rates

The Company offers individual customers and municipalities a Street and Area Lighting Service that is based on the Company owning, installing and maintaining street and area lighting. The price for this service includes fixed monthly rates for lighting fixtures, poles (used exclusively for lighting) and underground servicing.

The Company's street and area lighting rates are based on the demand, energy and customer costs as determined from the Cost of Service Study and the average cost of the street and area lighting plant. This approach results in rates that are cost based and the price of each fixture, pole and wiring rate varying in accordance with the difference in their fixed costs and their variable operating costs. The Company proposes to continue its historical rate design approach.

3.4 The Curtailable Service Option

The Company has a Curtailable Service Option available to General Service customers. The Curtailable Service Option provides for credits to be paid to those Rate 2.3 and Rate 2.4 customers that can reduce their demand, upon request, by between 300 kW and 5000 kW for short periods during the winter season. The Curtailable Service Option provides customers with an incentive to reduce their demand during peak periods.

The Company currently has 20 customers on the Option providing peak load reduction of approximately 8 MW.[14] These customers include public sector customers such as health care facilities, and private sector customers from tourism, telecommunications, and manufacturing.

The Company reviewed the value of the curtailable load to the system based on the Marginal Cost Study.[15] The review concluded:

(i) The Option provides operational and planning benefits;
(ii) The demand credit being provided to customers is greater than the marginal cost of demand on the system; and
(iii) The wholesale demand charge provides an incentive to Newfoundland Power to maintain the level of the credit.

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14 For the 2004-2005 winter season, there were 8 customers on the Curtaillable Service Option.
15 The review also considered the Report, *Implications of Marginal Costs results for Class Revenue Allocation and Rate Design*, prepared for Newfoundland and Labrador Hydro by NERA, July 2006.

The current credit of $29 per kVA appears reasonable based on the current demand charge from Hydro of $48 per kW per year ($4 per kW per month). The $29 per kVA is equivalent to approximately $25 per kW (at 90% power factor). The current curtailment credit provides approximately 50% of the demand charge savings to participants on the rate option. The remaining 50% of the savings is provided to the general customer population through lower purchased power costs used in determining test year rates.

The marginal cost of demand on the system is currently low. However, the marginal cost of demand can change significantly depending on the price of fuel to supply the Holyrood thermal generating facility. Because of the relatively small size of General Service customers served by Newfoundland Power, a large number of participants are required for the Option to provide a material load management tool. Eliminating the Option when the marginal cost of capacity is low and trying to re-establish it when the marginal cost of capacity increases will likely result in lost participants and reduced availability and reliability of curtailable load.

Summary

The Curtailable Service Option provides operational and planning benefits and should be maintained. It is proposed that the annual credit remain at $29 per kVA and the value of curtailable load on the system continue to be monitored.

Comparison of Rate Components to Costs

Table 15
Comparison of Basic Customer Charges to Embedded Costs
($ / customer per month)

Rate	Basic Customer Charge[16]	Embedded Costs: Customer Cost	Embedded Costs: Customer Related Distribution System Cost Beyond Service Drop	Embedded Costs: Total[17]	Total including 50% of Costs Beyond Service Drop
Rate 1.1	$ 15.59	13.02	7.86	20.88	16.95
Rate 2.1	$ 17.88	15.90	7.90	23.80	19.85
Rate 2.2	$ 20.60	33.96	7.90	41.86	37.91
Rate 2.3	$ 92.73	98.26	7.68	105.94	102.11
Rate 2.4	$185.46	184.43	6.20	190.63	187.53

Table 16
Comparison of Basic Customer Charges to Marginal Costs
($ / customer per month)

Rate	Basic Customer Charge	Marginal Costs: Marginal Customer Cost	Marginal Costs: Monthly Distribution Facility Cost[18]	Marginal Costs: Total[19]
Rate 1.1	15.59	9.57	11.33	20.90
Rate 2.1	17.88	11.07	11.64	22.71
Rate 2.2	20.60	21.21	30.40	51.61
Rate 2.3	92.73	51.91	223.62	275.53
Rate 2.4	185.46	116.33	404.20	520.53

16 Based upon customer rates effective January 1, 2007.
17 From the 2005 Pro-forma Cost of Service Study.
18 Distribution Facilities Cost can also be expressed in terms of cost per customer design demand.
19 From the Newfoundland Power Marginal Cost Study dated January 29, 2007. Marginal costs weighted on service type (transmission, primary and secondary) and include municipal taxes at 2.5%.

Table 17
Domestic Rate 1.1 and General Service Rate 2.1 Classes
Comparison of Energy Charges to Demand and Energy Costs
(¢/kWh)

Rate	Energy Charges	Embedded Cost Energy	Embedded Cost Demand	Embedded Cost Total	Marginal Cost[20] Total
Rate 1.1	8.935	4.653	4.528	9.181	10.35
Rate 2.1	11.462	4.673	3.586	8.259	10.27

Table 18
Demand and Energy Rates
Comparison of Energy Charges to Energy Costs
(¢/kWh)

Rate	Energy Charges First Block Rate	Energy Charges Tail Block Rate	Embedded Cost Total	Marginal Costs[21] Total
Rate 2.2	9.108	6.102	4.66	9.99
Rate 2.3	8.722	5.974	4.66	9.94
Rate 2.4	7.334	5.866	4.63	9.73

[20] From the Newfoundland Power Marginal Cost Study dated January 29, 2007. Marginal costs are weighted average based on energy sales per period (peak, off-peak, non-winter). Includes RSA at 0.444 ¢/kWh and Municipal Taxes at 2.5%

[21] From the Newfoundland Power Marginal Cost Study dated January 29, 2007. Marginal costs are weighted average based on energy sales per period (peak, off-peak, non-winter) and weighted on service type (transmission, primary, and secondary). Includes RSA at 0.444 ¢/kWh and Municipal Taxes at 2.5%.

Table 19
Demand and Energy Rates
Comparison of Demand Charges to Demand Costs

Rate	Demand Charges[22] Winter / Non-winter	Embedded Cost [23] Total	Marginal Costs[24] Winter / Non-winter
Rate 2.2 ($/kW)	8.63 / 7.88	10.54	4.67 / 0.01
Rate 2.3 ($/kVA)	7.46 / 6.71	10.81	5.16 / 0.02
Rate 2.4 ($/kVA)	7.05 / 6.30	10.73	5.06 / 0.02

[22] Based upon customer rates effective January 1, 2007.
[23] From the 2005 Pro-forma Cost of Service Study.
[24] Determined from the Newfoundland Power Marginal Cost Study dated January 29, 2007. Marginal Demand Costs are weighted on service type and include Municipal Taxes at 2.5%. The $/kW units are based on average kW usage during winter/non-winter period, not peak demand usage during period. $/kVA computed based on a 90% power factor assumption.