2007 NSUARB-P-886

NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF: The *Public Utilities Act,* R.S.N.S. 1989, c.380 as amended

IN THE MATTER OF: An Application by Nova Scotia Power Incorporated for Approval of Certain Revisions to its Rates, Charges and Regulations

RESPONSE TO INFORMATION REQUEST

TO: NSPI

FROM: UARB **REDACTED**

Question IR-77: **Please file the NSPI (Regulated) 2005 Annual Report.**

Response IR-77: Please refer to Confidential Attachment 1.

NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF: The *Public Utilities Act,* R.S.N.S. 1989, c.380 as amended

IN THE MATTER OF: An Application by Nova Scotia Power Incorporated for Approval of Certain Revisions to its Rates, Charges and Regulations

RESPONSE TO INFORMATION REQUEST

TO: NSPI

FROM: UARB

Question IR-78: **Please file the NSPI (Legal Entity) 2005 Annual Report.**

Response IR-78: Please refer to Attachments 1 and 2.

NOVA SCOTIA POWER INC.

FINANCIAL STATEMENTS

DECEMBER 31, 2005 AND 2004

MANAGEMENT REPORT

Management's Responsibility for Financial Reporting

The accompanying financial statements of Nova Scotia Power Inc. ("Nova Scotia Power" or "NSPI") and the information in this annual report are the responsibility of management and have been approved by the Board of Directors ("Board").

The financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles. When alternative accounting methods exist, management has chosen those it deems most appropriate in the circumstances. Nova Scotia Power Inc. is regulated by the Nova Scotia Utility and Review Board, which also examines and approves NSPI's accounting policies and practices. In preparation of these financial statements, estimates are sometimes necessary when transactions affecting the current accounting period cannot be finalized with certainty until future periods. Management believes that such estimates, which have been properly reflected in the accompanying financial statements, are based on careful judgments and are within reasonable limits of materiality. Management has determined such amounts on a reasonable basis in order to ensure that the financial statements are presented fairly in all material respects. Management has prepared the financial information presented elsewhere in the annual report and has ensured that it is consistent with that in the financial statements.

Nova Scotia Power Inc. maintains effective systems of internal accounting and administrative controls. These systems are designed to provide reasonable assurance that the financial information is relevant, reliable and accurate and that Nova Scotia Power Inc.'s assets are appropriately accounted for and adequately safeguarded.

The Board is responsible for ensuring that management fulfils its responsibilities for financial reporting and is ultimately responsible for reviewing and approving the financial statements. The Board carries out this responsibility principally through its Audit Committee.

The Audit Committee is appointed by the Board, and its members are directors who are not officers or employees of Nova Scotia Power Inc. The Committee meets periodically with management, as well as with the internal auditors and with the external auditors, to discuss internal controls over the financial reporting process, auditing matters and financial reporting issues, to satisfy itself that each party is properly discharging its responsibilities, and to review the annual report, the financial statements and the external auditors' report. The Audit Committee reports its findings to the Board for consideration when approving the financial statements for issuance to the shareholders. The Committee also considers, for review by the Board and approval by the shareholders, the appointment of the external auditors.

The financial statements have been audited by Grant Thornton LLP, the external auditors, in accordance with Canadian generally accepted auditing standards. Grant Thornton LLP has full and free access to the Audit Committee.

January 27, 2006

"Chris Huskilson"
President and Chief Executive Officer

"Nancy Tower, FCA"
Chief Financial Officer

AUDITORS' REPORT

To the Shareholders of Nova Scotia Power Inc.

We have audited the balance sheets of Nova Scotia Power Inc. as at December 31, 2005 and 2004 and the statements of earnings, retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2005 and 2004 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Halifax, Canada
January 27, 2006

"Grant Thornton LLP"
Chartered Accountants

NOVA SCOTIA POWER INC.
STATEMENTS OF EARNINGS

Year Ended December 31
(millions of dollars)

	2005	2004
Revenue		
Electric	**$955.0**	$926.9
Other	**8.0**	7.2
	963.0	934.1
Cost of operations		
Fuel for generation and purchased power	**373.8**	303.1
Operating, maintenance and general	**188.8**	177.5
Provincial grants and taxes	**40.4**	39.5
Provincial grants and taxes deferral (*note 10*)	**(4.5)**	-
Depreciation	**119.5**	116.0
Regulatory amortization	**6.2**	6.2
Allowance for funds used during construction	**(2.1)**	(3.2)
	722.1	639.1
Earnings from operations	**240.9**	295.0
Interest (*note 4*)	**97.9**	100.1
Other Income (*note 5*)	**(8.0)**	-
Amortization of defeasance costs	**13.2**	15.1
Earnings before income taxes	**137.8**	179.8
Income taxes (*note 6*)	**45.5**	59.2
Income taxes deferral (*note 10*)	**(12.2)**	-
Net earnings before preferred dividends	**104.5**	120.6
Preferred dividends (*note 6*)	**13.3**	13.3
Net earnings applicable to common shares	**$91.2**	$107.3

See accompanying notes to the financial statements.

STATEMENTS OF RETAINED EARNINGS

Year Ended December 31
(millions of dollars)

	2005	2004
Retained earnings, beginning of year	**$222.4**	$268.2
Net earnings applicable to common shares	**91.2**	107.3
	313.6	375.5
Dividends	**91.0**	153.1
Retained earnings, end of year	**$222.6**	$222.4

See accompanying notes to the financial statements.

NOVA SCOTIA POWER INC.
BALANCE SHEETS

As at December 31
(millions of dollars)

	2005	2004
Assets		
Current assets		
Restricted cash (*note 7*)	**$3.5**	$ -
Accounts receivable (*note 8*)	**76.8**	68.9
Due from associated companies (*note 9*)	**23.3**	13.9
Income taxes receivable	**7.2**	0.2
Fuel inventory	**45.5**	41.6
Materials and supplies inventory	**26.1**	25.4
Prepaid expenses	**4.5**	4.5
	186.9	154.5
Deferred charges (*note 10*)	**398.5**	390.0
Long-term receivable (*note 11*)	**48.4**	4.9
Property, plant & equipment (*note 12*)	**2,406.7**	2,385.5
Construction work in progress	**21.0**	57.9
	2,427.7	2,443.4
	$3,061.5	$2,992.8
Liabilities & Shareholders' Equity		
Current liabilities		
Current portion of long-term debt (*note 15*)	**$40.2**	$100.0
Short-term debt (*note 14*)	**5.4**	4.7
Accounts payable and accrued charges	**135.8**	141.3
Dividends payable	**3.2**	3.2
	184.6	249.2
Asset retirement obligations (*note 13*)	**71.4**	67.8
Deferred credits (*note 10*)	**4.6**	5.8
Long-term debt (*note 15*)	**1,487.7**	1,357.0
Preferred shares (*note 16*)	**260.0**	260.0
Shareholders' equity		
Common shares (*note 17*)	**830.6**	830.6
Retained earnings	**222.6**	222.4
	1,053.2	1,053.0
	$3,061.5	$2,992.8

See accompanying notes to the financial statements.

Contingency *(note 18)*
Commitments *(note 21)*
Guarantees *(note 22)*

Approved on behalf of the Board of Directors

"Derek Oland"

Derek Oland,
Chairman

"Chris Huskilson"

Chris Huskilson,
President and Chief Executive Officer

NOVA SCOTIA POWER INC.
STATEMENTS OF CASH FLOW

Year Ended December 31
(millions of dollars)

	2005	2004
Operating Activities		
Net earnings applicable to common shares	**$91.2**	$107.3
Non cash items:		
Depreciation	**119.5**	116.0
Deferral of provincial grants and taxes and income taxes	**(16.7)**	-
Regulatory amortization	**6.2**	6.2
Allowance for funds used during construction	**(2.1)**	(3.2)
Amortization of defeasance costs	**13.2**	15.1
Amortization of deferred charges	**2.4**	3.9
Other non-cash operating items	**14.2**	21.5
Other cash operating items	**(24.5)**	(30.0)
	203.4	236.8
Change in non-cash operating working capital	**(73.5)**	(7.9)
Net cash provided by operating activities	**129.9**	228.9
Financing Activities		
Increase (reduction) in short-term debt	**(79.3)**	178.6
Retirements of long-term debt	**(100.0)**	(140.0)
Issuance of long-term debt	**250.0**	
Dividends paid on common shares	**(91.0)**	(153.1)
Accounts receivable securitization	**-**	30.0
Other financing costs	**(1.8)**	-
Net cash used in financing activities	**(22.1)**	(84.5)
Investing Activities		
Property, plant and equipment	**(100.4)**	(142.5)
Cost of removal, net of salvage	**(3.9)**	(1.9)
Increase in restricted cash	**(3.5)**	-
Net cash used in investing activities	**(107.8)**	(144.4)
Change in cash and cash equivalents	**-**	-
Cash and cash equivalents, beginning of period	**-**	-
Cash and cash equivalents, end of period	**$ -**	$ -
Supplemental disclosure of cash paid:		
Interest	**$97.8**	$104.1
Income and capital taxes	**$60.0**	$69.0

See accompanying notes to the financial statements.

NOVA SCOTIA POWER INC.
NOTES TO THE FINANCIAL STATEMENTS

December 31, 2005 and 2004

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nova Scotia Power ("NSPI") is the primary electricity supplier in Nova Scotia providing over 95% of electricity generation, transmission and distribution in the province. NSPI is a public utility as defined under the Public Utilities Act of Nova Scotia ("Act") and is subject to regulation under the Act by the Utility and Review Board ("UARB"). The Act gives the UARB certain authority over NSPI's operations and expenditures. Electricity rates for NSPI's customers are subject to UARB approval. NSPI is not subject to an annual rate review process, but rather participates in hearings from time to time at NSPI's or the regulator's request.

NSPI is regulated under a cost of service model, with rates set to cover prudently incurred costs of providing electricity service to customers, and provide an opportunity to earn an appropriate return to investors. NSPI's allowed regulated rate of return on common equity ("ROE") range is 9.3% to 9.8%, with common equity allowed to grow to 40% of the capital structure. Rates were last set using 9.55% ROE with a common equity component of 37.5% of total capitalization.

NSPI's accounting policies are subject to examination and approval by the UARB.

a. Regulated Accounting

The financial statements of the company are prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). The accounting policies approved by the regulators of NSPI may differ from GAAP for non rate-regulated companies in that the timing of recognition of certain revenues and expenses in these operations may differ from that otherwise expected under generally accepted accounting principles. Where these differences are considered significant, disclosure of the policy has been made in these notes to the financial statements.

b. Measurement Uncertainty

The preparation of financial statements in accordance with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods.

At the end of each month, amounts of energy delivered to customers since the date of their last meter reading are estimated along with the associated unbilled revenues. This estimate is based on several different factors including generation, estimated usage by customer class, weather and line losses.

Actual results may differ from these estimates.

c. Revenue Recognition

The Company's revenue recognition policy is as follows:

- Electric: Revenues are recognized on the accrual basis, which includes an estimate of electricity consumed by customers in the year but billed subsequent to year-end.
- Other: Revenues are recognized on the accrual basis, which includes an estimate for services performed and goods delivered during the year but billed subsequent to year-end.

- Unearned revenue is recorded as a deferred credit.

Accounting for the impact of rate regulation:

Electric revenues generated by NSPI are recognized at rates set by UARB. The Company is unable to determine the effect on electric revenue in the absence of regulation.

d. Allowance for Funds Used during Construction

Accounting for the impact of rate regulation:

In accordance with accounting policies determined by UARB, NSPI provides for the cost of financing construction work in progress by including an allowance for funds used during construction ("AFUDC") as an addition to the cost of property constructed, using a weighted average cost-of-capital. AFUDC is included in property, plant and equipment and construction work in progress for financial reporting purposes and is charged to operations through depreciation over the service life of the related assets and recovered through future revenues. Since AFUDC includes not only an interest component, but also an equity component, it exceeds the amount that could be capitalized in the absence of the regulated accounting policies.

e. Regulatory Amortization

Accounting for the impact of rate regulation:

In accordance with the regulations of the UARB, significant assets of NSPI, which are not currently being used and are not expected to provide service to customers in the foreseeable future are amortized over five years. In 2000 the UARB approved NSPI's request to amortize the Glace Bay generating station over five years. The UARB had allowed Nova Scotia Power flexibility in determining the annual amount to be written off in order to support rate stability. On July 28, 2003 the UARB approved the Company's request to extend the write-off period through 2008, if necessary, with an annual minimum amortization of $6.2 million. The unamortized portion of the generation station is included in property, plant and equipment. In the absence of the UARB's approved accounting policies, the generation station would have been written off in the year when NSPI determined that the unamortized cost of the generation station would not be recoverable. More details are provided in note 12.

f. Property, Plant and Equipment

Property, plant and equipment are recorded at original cost net of contributions in aid of construction.

Depreciation is determined on a straight-line method over the estimated service lives of the assets. The service lives of regulated assets are determined based on formal depreciation studies which require UARB approval.

When indicators of impairment exist, NSPI determines whether the net carrying amount of property, plant and equipment is recoverable from future undiscounted cash flows. Factors which could indicate impairment include significant changes in regulation, a change in the Company's strategy or underperformance relative to projected future operating results.

Accounting for the impact of rate regulation:

During 2003, following completion of a depreciation study, and a negotiated agreement with stakeholders, NSPI's regulator approved new depreciation rates which will be phased in over four years beginning in 2004. Depreciation is now computed on the straight-line basis based on the phase-in rates contained within the settlement agreement. In the March 31, 2005 decision on NSPI's 2005 rate application, the UARB delayed the phase-in of year two rates for one year. Absent consideration of growth in plant-in-service, the phase-in of new depreciation rates will increase depreciation expense by approximately $5 million per year for a cumulative increase of $20 million over the four-year period. In the absence of the UARB's approval of depreciation rates, NSPI would be required to set rates based on management's best estimates of useful lives. The average rates for the major categories of plant in service are summarized as follows:

Function	**2005**	2004
Generation		
Thermal	**2.38%**	2.38%
Gas turbines	**2.18%**	2.18%
Combustion turbines	**3.33%**	5.00%
Hydroelectric	**1.26%**	1.26%
Wind turbines	**5.00%**	5.00%
Transmission	**2.68%**	2.68%
Distribution	**3.96%**	3.96%
General plant	**5.62%**	6.21%
General plant under capital lease	**9.50%**	-
Weighted average depreciation rate	**2.93%**	3.07%

In accordance with regulator approved accounting policies, when depreciable property, plant and equipment are replaced or retired, the original cost plus any removal costs incurred (net of salvage) are charged to accumulated depreciation, with no gain or loss reflected in results of operations. Gains and losses will be charged to results of operations in the future through depreciation expense. In the absence of regulator approved accounting policies, gains and losses on the disposition of property, plant and equipment are charged to net earnings as incurred.

g. Capitalization policy

Capital assets include labour, inventories and other non-labour costs directly attributable to the capital activity. In addition, in order to ensure the full cost approach, overhead costs that contribute to the capital program are allocated to capital projects. These costs include corporate costs such a finance, information technology, executive and other support functions, and employee benefits, insurance, inventory costs, and fleet operating and maintenance costs. Nova Scotia Power calculates a rate depending on the type of capital project and only eligible operating expenditures are used in the calculation. NSPI applies overhead costs based on direct labour costs.

h. Leases

Leases that substantially transfer all the benefits and risks of ownership of property, plant and equipment to the Company, or otherwise meet the criteria for capitalizing a lease under GAAP, are accounted for as capital leases. An asset is recognized at the time a capital lease is entered into together with its related long-term obligation. Property, plant and equipment recognized under capital leases are depreciated on the same basis as described in Note 1(f). Payments on operating leases are expensed as incurred.

i. Income Taxes and Investment Tax Credits

Investment tax credits arising as a result of incurring qualifying scientific research and development expenditures are recorded in the year as a reduction from the related expenditures where there is reasonable assurance of collection.

Accounting for the impact of rate regulation:

In accordance with ratemaking regulations established by the UARB, NSPI uses the taxes payable method of accounting for income taxes. Accordingly, NSPI does not provide for future income taxes. NSPI would be required to recognize all future income tax assets and liabilities in the absence of their regulator approved accounting policies. More details are provided in Note 6.

j. Employee Future Benefits

Pension obligations, and obligations associated with non-pension post-retirement benefits such as health benefits to retirees and retirement awards, are actuarially determined using the projected benefit method prorated on services and management's best estimate assumptions. The accrued benefit obligation is valued based on market interest rates at the valuation date.

Pension fund asset values are calculated using market values at year-end. The expected return on pension assets is determined based on market-related values. The market-related values are determined in a rational and systematic manner so as to recognize investment gains and losses, relative to the assumed rate of return over a five-year period.

Adjustments to the accrued benefit obligation arising from plan amendments are amortized on a straight-line basis over the expected years of future service to the full eligibility date for active employees.

For any given year, when NSPI's net actuarial gain (loss), less the actuarial gain (loss) not yet included in the market-related value of plan assets, exceeds 10% of the greater of the accrued benefit obligation and the market-related value of the plan assets, an amount equal to the excess divided by the average remaining service period ("ARSP") is amortized on a straight-line basis. The ARSP of the active employees is 10 years as at December 31, 2005 (2004 – 10 years).

On January 1, 2000, NSPI adopted the new accounting standard on employee future benefits using the prospective application method. The transitional obligation (asset) resulting from the initial application is amortized linearly over 13 years, which was the expected ARSP of active employees at the transition date.

The difference between benefit cost and pension funding is recorded as a deferred asset on the balance sheet.

k. Inventory

Inventories of materials and supplies are valued at the lower of average cost and market. Fuel inventory is valued at the lower of cost, using the first-in, first-out method, and net realizable value.

l. Debt Financing and Defeasance Costs

Financing costs pertaining to debt issues are amortized over the life of the related debt.

Upon privatization in 1992, NSPI became responsible for managing a portfolio of approximately $1.1 billion of defeasance securities held in trust. The excess of the cost of defeasance investments over the face value of the related debt is deferred on the balance sheet and amortized over the life of the defeased debt.

m. Derivative Financial Instruments

The Company uses various derivative financial instruments to hedge its exposure to foreign exchange, interest rate, and commodity price risks. If documentation and effectiveness requirements are met, gains and losses on these instruments are deferred and recognized in earnings in the same period the related hedged risk is realized (settlement accounting). Where documentation and effectiveness requirements are not met, the instruments are marked-to-market in the period of ineffectiveness with an adjustment to earnings.

If a hedging relationship is terminated, gains and losses on the instruments up until the date of termination are deferred and recognized in the same period the related hedged risk is realized. The instruments, if retained, would then be marked-to-market from the termination date on.

Amounts received or paid related to instruments used to hedge foreign exchange and commodity price risks, including any gains and losses, are recognized in the cost of the fuel purchases. Amounts received or paid, including any gains and losses on instruments used to hedge interest rate risks, are recognized over the term of the hedged item in interest expense. The derivatives are not recorded on the balance sheet.

n. Foreign Currency Translation

Monetary assets and liabilities denominated in foreign currencies are translated to Canadian dollars at rates of exchange prevailing at the balance sheet date. The resulting gains and losses between the translation at the original transaction date and the balance sheet date are charged to earnings.

o. Research & Development Costs

All research and development costs are expensed in the year incurred unless they qualify for deferral as part of the cost of capital assets.

2. CHANGE IN ACCOUNTING POLICIES

Disclosure by Entities Subject to Rate Regulation

In May 2005, the CICA issued Accounting Guideline 19 Disclosure by Entities Subject to Rate Regulation. The guideline applies to fiscal years ending on or after December 31, 2005. The guideline requires entities subject to rate regulation to disclose general information about the rate setting process and discuss how rate regulation has affected its financial statements. NSPI's financial statements and supporting notes reflect the new requirements

Variable Interest Entities

In June 2003, the Canadian Institute of Chartered Accountants issued Accounting Guideline 15 Consolidation of Variable Interest Entities. This guideline applies to annual and interim periods beginning on or after November 1, 2004. A variable interest entity ("VIE") is any type of legal structure in which control is determined through contractual or other financial arrangements as opposed to traditional voting rights, if certain conditions exist. The guideline requires the enterprise which absorbs the majority of a VIE's expected losses or receives the majority of a VIE's expected residual returns, the primary beneficiary, to consolidate the VIE.

NSPI has variable interests in VIEs that are not consolidated because NSPI is not considered the primary beneficiary. These VIEs consist of purchase power agreements for renewable energy with independent power producers. NSPI's only obligation under these agreements is to purchase all of the energy produced, which currently is expected to approximate 145 GWh annually.

3. EMPLOYEE FUTURE BENEFITS

NSPI maintains contributory defined-benefit and defined-contribution pension plans, which cover substantially all of its employees, and plans providing non-pension benefits for its retirees.

Defined benefit pension plans are based on the years of service and average salary at the time the employee terminates employment and provide annual post-retirement indexing equal to the change in the Consumer Price Index up to a maximum increase of 6% per year.

Other retirement benefit plans include; unfunded pension arrangements (with same indexing formula as the funded pension arrangements), unfunded long service award (which is impacted by expected future salary levels) and contributory health care plan.

The measurement date for the assets and obligations of each benefit plan is December 31, 2005.

Valuation date for defined-benefit plans

NSPI has a December 31 valuation date for accounting purposes. The most recent and the next required actuarial valuation dates for funding purposes are as follows:

	Most recent actuarial valuation	Next required actuarial valuation
Employee pension plan	December 31, 2005	December 31, 2006
Acquired companies pension plan	December 31, 2005	December 31, 2006

Total cash amount

Total cash amount for 2005, made up of NSPI contributions to its funded defined-benefit pension plans, contributions to its defined-contribution pension plan, employer paid premiums for its post-retirement health care plan, and amounts paid directly to retirees and beneficiaries in other plans, was $29.9 million (2004 – 34.2 million).

Accrued benefit asset components

millions of dollars	2005		2004	
	Defined-benefit pension plans	**Non-pension benefits plans**	Defined-benefit pension plans	Non-pension benefits plans
Assumptions (weighted-average)				
Accrued benefit obligation, December 31				
Discount rate	**5.25%**	**5.25%**	**6.0%**	**6.0%**
Rate of compensation increase	**3.0% to 5.5%**	**3.0% to 5.5%**	**3.0% to 5.5%**	**3.0% to 5.5%**
Health care trend				
- initial	**-**	**9.0%**	**-**	**10.0%**
- ultimate	**-**	**4.0%**	**-**	**4.0%**
- year ultimate reached	**-**	**2011**	**-**	**2010**
Benefit cost for year ending, December 31				
Discount rate	**6.0%**	**6.0%**	**6.0%**	**6.0%**
Expected long-term return on plan assets	**7.5%**	**-**	**7.5%**	**-**
Rate of compensation increase	**3.0% to 5.5%**	**3.0% to 5.5%**	**3.0% to 5.5%**	**3.0% to 5.5%**
Health care trend				
- initial	**-**	**10.0%**	**-**	**11.0%**
- ultimate	**-**	**4.0%**	**-**	**4.0%**
- year ultimate reached	**-**	**2011**	**-**	**2010**
Accrued benefit obligations reconciliation				
Balance, January 1	**$640.3**	**$31.1**	**$624.0**	**$31.2**
Employer current service cost	**9.6**	**1.2**	**10.0**	**1.2**
Employee contributions	**4.7**	**-**	**5.0**	**-**
Interest cost	**38.1**	**1.8**	**36.8**	**1.9**
Past service amendments	**-**	**-**	**(7.3)**	**-**
Actuarial losses (gains)	**114.3**	**3.2**	**1.3**	**(1.4)**
Benefits paid	**(30.2)**	**(2.5)**	**(29.5)**	**(1.8)**
Other	**0.7**	**-**	**-**	**-**
Balance, December 31	**$777.5**	**$34.8**	**$640.3**	**$31.1**
Fair value of plan assets reconciliation				
Balance, January 1	**$516.0**	**$-**	**$471.3**	**$-**
Contributions by NSPI	**26.7**	**2.5**	**31.6**	**1.8**
Employee contributions	**4.7**	**-**	**5.0**	**-**
Actual investment income	**64.0**	**-**	**37.6**	**-**
Benefits paid	**(30.2)**	**(2.5)**	**(29.5)**	**(1.8)**
Balance, December 31	**581.2**	**$-**	**$516.0**	**$-**

Reconciliation of financial status to accrued benefit asset, December 31				
Fair value of plan assets	**$581.2**	**$-**	**$516.0**	**$-**
Accrued benefit obligations	**777.5**	**34.8**	**640.3**	**31.1**
Plan deficit	**(196.3)**	**(34.8)**	**(124.3)**	**(31.1)**
Unamortized past service costs (gains)	**(0.6)**	**-**	**(0.6)**	**-**
Unamortized actuarial losses (gains)	**273.5**	**(1.6)**	**191.3**	**(5.2)**
Unamortized transitional obligation	**0.1**	**15.7**	**0.2**	**17.9**
Accrued benefit asset	**$76.7**	**$(20.7)**	**$66.6**	**$(18.4)**

The expected return on plan assets is determined based on the market-related value of plan assets of $550.9 million at January 1, 2005 (January 1, 2004 - $519.8 million) adjusted for interest on certain cash flows during the year.

Defined-benefit plans asset allocation

	2005		2004	
(in % of plan assets)	**Employee pension plan**	**Acquired companies pension plan**	Employee pension plan	Acquired companies pension plan
Equity securities	**66%**	**60%**	**67%**	**56%**
Debt securities	**33%**	**37%**	**31%**	**41%**
Cash	**1%**	**3%**	**2%**	**3%**
Total	**100%**	**100%**	**100%**	**100%**

As at December 31, 2005, the pension funds do not hold directly any material investments in Emera Inc. or NSPI securities. Any such investment would primarily be held indirectly through pooled investment funds.

Plans with accrued benefit obligation in excess of assets

As at December 31, 2005, all post-retirement benefit plans have accrued benefit obligations in excess of assets.

Benefit cost components

millions of dollars	2005		2004	
	Defined-benefit pension plans	**Non-pension benefits plans**	Defined-benefit pension plans	Non-pension benefits plans
Costs arising from events in period				
Current service costs	**$9.6**	**$1.2**	$10.0	$1.2
Interest on accrued benefits	**38.1**	**1.8**	36.8	1.9
Less: actual return on plan assets	**(64.0)**	**-**	(37.6)	-
Actuarial losses (gains) on accrued benefit obligations	**114.3**	**3.2**	1.3	(1.4)
Past service gains	**-**	**-**	(7.3)	-
Other	**0.7**	**-**	-	-
Future benefit costs before adjustments	**98.7**	**6.2**	3.2	1.7
Adjustments to recognize long-term nature of costs				
Difference between expected return on assets and actual return	**23.0**	**-**	(1.1)	-
Amortization of transitional obligation	**-**	**2.2**	-	2.2
Difference between amortization of actuarial losses (gains) and actual actuarial losses (gains) on accrued benefit obligations	**(105.1)**	**(3.6)**	6.5	1.1
Difference between amortization of past service costs and past service costs for the year	**-**	**-**	7.6	-
Total defined benefit cost	**$16.6**	**$4.8**	$16.2	$5.0
Defined-contribution plan				
Employer expense	**$0.7**	**$-**	$0.8	$-

Sensitivity analysis for non-pension benefits plans

The health care cost trend significantly influences the amounts presented for health care plans. An increase or decrease of one percentage-point of the assumed health care cost trend would have the following impact in 2005:

millions of dollars	**Increase**	**Decrease**
Current service cost and interest cost	$0.2	$(0.1)
Accrued benefit obligation, December 31	$1.9	$(1.6)

4. INTEREST

Interest expense consists of the following:

millions of dollars	**2005**	**2004**
Interest on long-term debt	**$86.1**	**$89.1**
Interest on short-term debt	**7.9**	**9.3**
Amortization of debt financing	**1.6**	**1.3**
Foreign exchange losses	**2.3**	**0.5**
Defeasance earnings	**-**	**(0.1)**
	$97.9	**$100.1**

5. OTHER INCOME

During 2005, Nova Scotia Power received a payment of $10.5 million, less $2.5 million of associated costs, from a gas supplier as part of renegotiation of certain contractual matters.

6. INCOME TAXES

Income Taxes

The income tax provision differs from that computed using the statutory rates for the following reasons:

millions of dollars	2005		2004	
	$	%	$	%
Earnings before income taxes	**$137.8**		**$179.8**	
Income taxes, at statutory rates	**52.5**	**38.1%**	**68.5**	**38.1%**
Unrecorded future income taxes	**(11.0)**	**(8.0)**	**(13.5)**	**(7.5)**
Large corporations tax	**4.0**	**2.9**	**4.2**	**2.3**
Income taxes	**$45.5**	**33.0%**	**$59.2**	**32.9%**

At December 31, 2005 the unrecorded future income tax assets of NSPI are approximately $21 million (2004 - $39 million), consisting of deductible temporary differences of $55 million (2004 - $103 million). In the absence of the UARB's approval of NSPI's taxes payable accounting policy, NSPI would have had a future income tax expense of $11.0 million in 2005 (2004 - $13.5 million).

Preferred Share Dividends

Preferred share dividends consist of preferred dividends less a recovery of income tax expense of $0.8 million (2004 - $0.8 million). The income tax recovery of $6.4 million in 2005 (2004 - $6.4 million) is reflected as a reduction of preferred share dividends with an offsetting increase in income tax expense.

Millions of dollars	**2005**	2004
Preferred share dividend	**$14.1**	**$14.1**
Part VI.1 tax on preferred share dividends	**5.6**	**5.6**
Part I tax recovery related to the Part VI.1 tax deduction	**(6.4)**	**(6.4)**
	$13.3	**$13.3**

7. RESTRICTED CASH

In NSPI's fuel hedging activities, a counterparty can exceed its established credit limit due to increased forward positions and market changes on its positions. The counterparty can either provide a Line of Credit or provide cash to NSPI in the form of Posted Margin for the value in excess of the credit limit. One of NSPI's fuel hedging counterparties exceeded its credit limit and posted cash with NSPI. This restricted cash will be used for payment as positions settle and /or repaid to the counterparty if the forward positions decrease due to market changes.

8. ACCOUNTS RECEIVABLE

In May 2004, NSPI renewed a revolving non-recourse securitization agreement with an independent trust administered by a major Canadian bank. Under the securitization agreement the Company sells an undivided co-ownership interest in certain current and future accounts receivables generated in the normal course of business. The amount of the accounts receivable sold is removed from the balance sheet with each revolving securitization. The Company also retains an undivided co-ownership of approximately 10% in the receivables sold to the trust. The retained interest is accounted for at carrying value in deferred charges. Fees related to securitization are expensed as incurred.

At December 31, 2005, net accounts receivable sold amounted to $80 million (2004 - $80 million). This agreement is in place until 2009 with the intention that it will be renewed at that time.

At December 31, 2005, the Company had unbilled revenue included in accounts receivable in the amount of $63.8 million (2004 - $65.8 million). The unbilled revenue is an estimate of the amount of revenue related to energy delivered to customers since the date their meter was last read. Actual results may differ from this estimate.

9. RELATED PARTY TRANSACTIONS

The company enters into various transactions with its affiliates in the normal course of operations. All transactions are recorded subject to terms in the Code of Conduct, approved by the UARB, at the exchange value generally based on commercial rates or as agreed to by the parties.

Due from associated companies represents the total carrying amounts of trade receivables, which are owed to NSPI by NSPI's parent company, Emera Inc. and companies wholly-owned by Emera Inc. The terms of repayments are the same as those for non-affiliate trade receivables. During the year NSPI had sales and purchases from companies under common control of Emera Inc. as follows:

		(millions of dollars)	
Affiliate	Purpose of Transaction	**2005**	**2004**
Sales:			
Emera Fuels	Net sale of bunker C oil	**$0.6**	**$9.4**
Emera Energy Services	Net sale of gas and electricity	**195.4**	**156.5**
Emera Inc.	Allocation of common costs	**$6.0**	**$5.8**
Various	Other services provided	**$2.5**	**$2.7**
Purchases:			
Emera Utility Services	Purchase and maintenance of transformers	**2.4**	**4.6**
Cablecom	Purchase of line extension work	**3.8**	**2.3**
Emera Inc.	Purchase of LM6000 gas turbine	**0**	**22.1**
Various	Other services purchased	**$3.9**	**$4.6**

During the year, in the ordinary course of business, the Company purchased transportation capacity totaling $16.7 million (2004 - $16.4 million) from the Maritimes and Northeast Pipeline, an investment under significant influence of Emera Inc. The amount is recognized as an expense in fuel for generation and purchased power and is measured at the fair market value. At December 31, 2005 the amount payable to this related party is $1.4 million (2004 - $1.4 million).

10. DEFERRED CHARGES AND CREDITS

Deferred charges and credits comprise the following:

millions of dollars	**2005**	2004
Deferred charges		
Regulatory assets		
Pre-2003 income tax liability and related interest	**$146.7**	**$150.0**
Deferred restructuring costs	**0.1**	**2.0**
Deferral of taxes not included in Q1, 2005 rates	**16.7**	
	$163.5	**$152.0**
Non-regulatory assets		
Unamortized debt financing and defeasance costs	**169.6**	**181.9**
Accrued pension and non-pension benefit asset *(note 3)*	**56.0**	**48.2**
Deferred hedging premiums	**0.3**	**0.1**
Retained interest in accounts receivable securitized (*note 8)*	**7.6**	**7.5**
Other	**1.5**	**0.3**
	235.0	**238.0**
Total Deferred charges	**$398.5**	**$390.0**
Deferred credits		
Non-regulatory liabilities		
Unearned revenue	**$3.9**	**$4.5**
Other	**0.7**	**1.3**
	$4.6	**$5.8**

Regulatory assets consist of:

Pre-2003 Income Tax Liability and Related Interest

NSPI has a $146.7 million regulatory asset related to pre-2003 income taxes that have been paid, but not yet recovered from customers. This circumstance arose when NSPI claimed capital cost allowance (CCA) deductions in its income tax returns that were ultimately disallowed by a decision of the Supreme Court of Canada. NSPI applied to the regulator to include recovery of these costs in customer rates. In its decision on NSPI's 2005 rate application, the UARB approved the amortization and recovery of this regulatory asset over eight years, commencing in 2007. In the absence of UARB approved recovery, the liability would have been expensed when incurred.

Deferral of taxes not included in Q1, 2005 rates

The UARB agreed to allow NSPI to defer taxes not reflected in rates for the period January 1, 2005 until April 1, 2005, the date when new rates became effective. In 2005, NSPI deferred $16.7 million consisting of $4.5 million of provincial and federal grants and $12.2 million in income taxes reflecting increases in taxes since rates were last set in 2002. The amortization period is pending approval by the UARB. In the absence of the UARB's approval, these taxes would not have been deferred and net earnings would have been $16.7 million lower in 2005.

Deferred Restructuring Costs

In order to provide rate stability, the UARB allows NSPI to defer the cost of large early retirement and severance programs, and amortize the resulting deferred charges on a straight-line basis over a three-year period, commencing in the period in which the program is initiated. In the absence of regulator approval, those costs would have been expensed as incurred and 2005 net earnings would be $1.9 million higher (2004 - $3.5 million).

11. LONG-TERM RECEIVABLE

NSPI's existing long term natural gas purchase agreement, includes a price adjustment clause covering three years of natural gas purchases. The clause states that NSPI will pay for all gas purchases at the agreed contract price, but will be entitled to a price rebate on a portion of the volumes, to be settled in November 2007. Management's best estimate of the price rebate, based on the contract specifications using actual and forward market pricing, of $48.4 million (2004 - $4.9 million) is reflected in long-term receivables.

12. PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment is comprised of the following:

millions of dollars	2005		
	Cost	Accumulated Depreciation	Net Book Value
Generation			
Thermal	$1,719.1	$634.1	$1,085.0
Gas turbines	31.1	21.5	9.6
Combustion turbines	71.4	5.4	66.0
Hydroelectric	369.9	122.7	247.2
Wind turbines	2.0	0.3	1.7
Transmission	576.2	280.9	295.3
Distribution	1,009.8	491.8	518.0
General plant	283.9	101.0	182.9
General plant under capital lease	1.0	-	1.0
	$4,064.4	$1,657.7	$2,406.7

millions of dollars	2004		
	Cost	Accumulated Depreciation	Net Book Value
Generation			
Thermal	$1,651.8	$604.0	$1,047.8
Gas turbines	30.8	21.0	9.8
Combustion turbines	76.0	3.0	73.0
Hydroelectric	364.9	118.6	246.3
Wind turbines	2.0	0.2	1.8
Transmission	572.5	269.3	303.2
Distribution	984.0	458.6	525.4
General plant	270.2	92.0	178.2
	$3,952.2	$1,566.7	$2,385.5

Accounting for the impact of rate regulation:

At December 31, 2005, the Glace Bay generating station had a net book value of $12.9 million (2004 - $17.8 million). During the year NSPI amortized $6.2 million (2004 - $6.2 million) related to the plant, and capitalized $1.3 million in AFUDC (2004 - $1.5 million) to the plant value. In the absence of the UARB's approved accounting policies, the generation station would have been written off in the year when NSPI determined that the unamortized cost of the generating station would not be recoverable.

13. ASSET RETIREMENT OBLIGATIONS

The change in asset retirement obligations is due to the following:

millions of dollars	2005	2004
Balance, beginning of year	**$67.8**	**$64.4**
Accretion included in depreciation expense	**0.9**	**0.8**
Accretion deferred to regulated asset	**2.7**	**2.6**
Balance, end of year	**$71.4**	**$67.8**

The key assumptions used to determine the asset retirement obligations are as follows:

Asset	Credit-adjusted risk-free rate	Estimated undiscounted future obligation *(millions of dollars)*	Expected settlement date *(years)*
Steam	5.3%	$242.3	15 – 34
Hydro	5.3%	60.8	26 – 56
Combustion turbines	5.3%	5.1	2 -18
		$308.2	

Some of the company's transmission and distribution assets may also have asset retirement obligations. As the company expects to use the majority of its installed assets for an indefinite period, no removal date can be determined and consequently a reasonable estimate of fair value of any related asset retirement obligation cannot be made at this time.

Accounting for the impact of rate regulation:

Any difference between the amount approved by the regulated depreciation expense and the amount that would have been calculated under the accounting for asset retirement obligations is recognized as a regulatory asset. In the absence of this deferral, net earnings for 2005 would be $2.7 million lower (2004 – 2.6 million).

14. SHORT-TERM DEBT

Short-term debt consists of advances from the operating line of credit of $5.4 million (2004 - $4.7 million). The operating line of credit bears interest at the prime rate, which on December 31, 2005, was 5.00% (2004 – 4.25%). Short-term debt is unsecured.

15. LONG-TERM DEBT

Long-term debt includes the issues detailed below. All long-term debt instruments are issued under trust indentures at fixed interest rates, and are unsecured. Also included is certain commercial paper where the Company has the intention and the unencumbered ability to refinance the obligation for a period greater than one year.

	Effective average interest rate (%)		Years of maturity	Amount Outstanding	
millions of dollars	**2005**	2004		**2005**	2004
Medium term notes	**6.608**	7.114	**2006 - 2097**	**$1,250.0**	$1,100.0
Debentures	**9.750**	9.750	**2019**	**95.0**	95.0
Commercial paper	**3.020**	2.557	**One Year Renewable**	**182.0**	262.0
Capital lease obligations	**4.410**	-	**2011**	**0.9**	-
				$1,527.9	$1,457.0
Less: amount due within one year				**40.2**	100.0
				$1,487.7	$1,357.0

A Medium term note ("MTN") of $40.0 million bearing interest at 5.20%, maturing in 2029, is redeemable at the option of the holder in 2006. If not redeemed the interest rate on the MTN increases to 6.28% until maturity. Another MTN of $40.0 million, maturing in 2026, is extendable until 2056 at the option of the holder.

As at December 31, 2005, long-term debt and obligations under a capital lease are due as follows:

millions of dollars	**2005**
One year renewable	**$182.0**
2005	**-**
2006	**40.2**
2007	**0.2**
2008	**115.2**
2009	**125.2**
2010	**100.1**
Greater than 5 years	**965.0**
	$1,527.9

16. PREFERRED SHARES

Authorized:

Unlimited number of First Preferred Shares, issuable in series.
Unlimited number of Second Preferred Shares, issuable in series.

Issued and outstanding:

millions of dollars	Millions of Shares	Preferred Share Capital
January 1, 2004	**10.4**	**$260.0**
December 31, 2004	**10.4**	**$260.0**
December 31, 2005	**10.4**	**$260.0**

Series C First Preferred Shares

Each Series C First Preferred Share is entitled to a $1.225 per share per annum fixed cumulative preferential dividend, as and when declared by the Board of Directors, accruing from the date of issue and payable quarterly on the first day of January, April, July and October of each year. On or after April 1, 2009, NSPI may redeem for cash the Series C First Preferred Shares, in whole at any time or in part from time to time at $25 per share plus accrued and unpaid dividends. The Series C First Preferred Shares will be exchangeable into Emera Inc. common shares on April 1, 2009.

Series D First Preferred Shares

Each Series D First Preferred Share is entitled to a fixed cumulative preferential cash dividend of $1.475 per share per annum, as and when declared by the Board of Directors. These dividends will accrue from the date of issue and will be payable quarterly on the fifteenth day of January, April, July, and October of each year. On or after October 15, 2015, NSPI may redeem for cash the Series D First Preferred Shares, in whole at any time, at $25 per share plus accrued and unpaid dividends. The Series D First Preferred Shares will be exchangeable into Emera Inc. common shares on October 15, 2015.

17. COMMON SHARES

Authorized:

Unlimited number of non-par value Common Shares.

Issued and outstanding:

millions of dollars	Millions of shares	Common share capital
January 1, 2004	**96.8**	**$830.6**
December 31, 2004	**96.8**	**$830.6**
December 31, 2005	**96.8**	**$830.6**

SHARE-BASED COMPENSATION

Employee Common Share Purchase Plan

Employees may participate in an Employee Common Share Purchase Plan whereby the Company and employees can make cash contributions for the purpose of purchasing common shares of the parent company, Emera Inc. ("Emera"). The plan also allows for the reinvestment of dividends.

Deferred Share Units Plan and Restricted Share Units Plan

The Company has deferred share units ("DSU") and restricted share units ("RSU") plans.

Under the DSU plan Directors of the Company who are resident in Canada may elect to receive all or any portion of their compensation in DSU in lieu of cash compensation. Directors' fees are paid on a quarterly basis and at the time of each payment of fees, the applicable amount is converted to DSUs. A DSU has a value equal to one Emera common share. When a dividend is paid on Emera's common shares, the Director's DSU account is credited with additional DSUs. DSUs cannot be redeemed for cash until the Director retires, resigns, or otherwise leaves the Board. The cash redemption value of a DSU equals the market value of an Emera common share at the time of redemption, pursuant to the plan.

Under the DSU plan for executive and senior management, each participant may elect to defer all or a percentage of the annual incentive award in the form of DSUs with the proviso that for participants who are subject to executive share ownership guidelines, a minimum of 50% of the value of their actual annual incentive award (25% in the first year of the program) will be payable in DSUs until the applicable guidelines are met.

When incentive awards are determined, the amount elected is converted to DSUs, which have value equal to the market price of an Emera common share. When a dividend is paid on Emera's common shares, each participant's DSU account is allocated additional DSUs equal in value to the dividends paid on an equivalent number of Emera common shares. Following termination of employment or retirement, and by December 15 of the calendar year after termination or retirement, the value of the DSUs credited to the participant's account is calculated by multiplying the number of DSUs in the participant's account by the then market value of an Emera common share.

In addition, special DSU awards may be made from time to time by the Management Resources and Compensation ("MRCC") Committee to selected executives and senior management to recognize singular achievements or to achieve certain corporate objectives.

RSUs are granted annually for three-year overlapping performance cycles. The first cycle runs from January 1, 2003 through December 31, 2005. RSUs are granted at fair value on the grant date and dividend equivalents are awarded and are used to purchase additional RSUs. The RSU value varies according to Emera's common share market price, and corporate performance.

RSUs vest at the end of the three-year cycle and will be calculated and approved by the MRC Committee early in the following year. The value of the payout considers actual service over the performance cycle and will be pro-rated in the case of retirement, involuntary termination, disability or death.

	Employee DSUs Outstanding	Employee RSUs Outstanding	Director DSUs Outstanding
Balance at January 1, 2004	-	97,660	13,226
Granted	137,032	143,652	18,796
Balance at December 31, 2004	137,032	241,312	32,022
Granted	18,880	89,922	14,381
Retirement, termination, disability, death	(43,307)	(47,971)	(6,967)
Balance at December 31, 2005	112,605	283,263	39,436

The Company is using the fair value based method to measure the compensation expense related to its share-based compensation and recognizes the expense over the vesting period on a straight-line basis. The DSU and RSU liabilities are marked to market at the end of each period based on the common share price at the end of the period. For the year ended December 31, 2005 $3.6 million

(2004 - $2.3 million) of net compensation expense was recognized in operating, maintenance and general expense.

18. CONTINGENCY

The Company may, from time to time, be involved in legal proceedings, claims and litigation that arise in the ordinary course of business which the Company believes would not reasonably be expected to have a material adverse effect on the financial condition of the Company.

As part of an ongoing litigation against a coal supplier, NSPI was required to post a $11.5 million bond. The bond may be called if NSPI does not prosecute the claim without delay, or if the claim is not successful. It is not determinable whether NSPI will be successful with its claim, accordingly, an estimate of the potential contingent loss cannot be made.

19. OPERATING LEASES

The Company has entered into operating lease agreements for office space and telecommunication services, which expire in March 2011 and March 2010 respectively. Future minimum annual lease payments under the leases are as follows:

millions of dollars	
2006	**$5.6**
2007	**5.6**
2008	**5.7**
2009	**5.2**
2010	**4.1**
Greater than 5 years	**1.0**
	$27.2

For the year ended December 31, 2005 the Company recognized $5.6 million (2004 - $5.4 million) in operating, maintenance and general expense.

20. FINANCIAL INSTRUMENTS

The Company manages its exposure to foreign exchange, interest rate, and commodity risks in accordance with established risk management policies and procedures using derivative instruments consisting mainly of foreign exchange forward contracts, interest options and swaps, and oil and gas options and swaps.

Derivative financial instruments involve credit and market risks. Credit risk arises from the possibility that a counterparty will default on its contractual obligations and is limited to those contracts where the Company would incur a loss in replacing the instrument.

Financial instruments include the following:

millions of dollars	2005		2004	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
Financial liabilities				
Long-term debt	**$1,527.9**	**$1,794.8**	$1,457.0	$1,666.1
Short-term debt	**5.4**	**5.4**	4.7	4.7
Derivative financial instruments *receivable (payable)*				
Interest rate swaps	**(0.1)**	**(0.2)**	(1.1)	(2.8)
Interest rate caps and collars	**0.3**	**0.3**	0.1	(0.9)
Natural gas swaps	**4.0**	**13.4**	-	(1.1)
Natural gas caps and collars	**-**	**-**	-	-
Oil swaps	**3.5**	**16.1**	-	0.1
Foreign exchange contracts	**-**	**(33.9)**	-	(27.4)

Long-term Debt and Short-term Debt

The fair value of NSPI's long-term and short-term debt is estimated based on the quoted market prices for the same or similar issues, or on the current rates offered to NSPI, for debt of the same remaining maturities.

Derivative Financial Instruments

The fair value of derivative financial instruments is estimated by obtaining prevailing market rates from investment dealers.

Interest rates

The Company enters into interest rate hedging contracts to convert the interest characteristics of a portion of its outstanding short-term debt from a floating to a fixed rate basis. As of December 31, 2005 there were no interest rate swap contracts outstanding. In 2004, interest rate swap contracts converting floating interest on $50.0 million over 2005 to a weighted average fixed interest rate of 6.81% were outstanding at December 31, 2004.

Interest rate caps are used to limit exposure to movements of interest rates on floating debt. Interest rate cap contract covering $150.0 million over 2006 at a fixed rate of 4.10% was outstanding at December 31, 2005.

Interest rate collars are used to partially hedge reinvestment risk on long-term fixed-rate debt. As of December 31, 2005, there were no interest rate collars outstanding. In 2004, interest rate collar contracts covering $25.0 million at average fixed interest rates in a range from 4.89% to 5.30% were outstanding at December 31, 2004.

Commodity prices

The Company purchased natural gas swap contracts in 2005 to limit exposure to fluctuations in natural gas prices. As at December 31, 2005, the Company had hedged approximately 80% of all natural gas purchases and sales for 2006.

The Company enters into oil swap contracts to limit exposure to fluctuations in world prices of heavy fuel oil. As at December 31, 2005, the Company had entered into oil swap contracts that fixed the price of approximately 90% of 2006 requirements and 23% of 2007 requirements.

Foreign exchange

The Company enters into foreign exchange forward, option, and swap contracts to limit exposure to currency rate fluctuations. Currency forwards are used to fix the Canadian dollar cost to acquire U.S. dollars, reducing exposure to currency rate fluctuations. Forward contracts to buy U.S. $531 million over 2006 to 2009 at a weighted average rate of CAD $1.2188 were outstanding at December 31, 2005.

Risk Management

Commodity price and foreign exchange risk

A substantial amount of NSPI's fuel supply comes from international suppliers, and is subject to commodity price and foreign exchange risk. The Company manages exposure to commodity price risk utilizing a combination of physical fixed-price fuel contracts and financial instruments providing fixed or maximum prices. Foreign exchange risk is managed through forward and option contracts. The risk inherent in the Canadian dollar cost of fuel is measured and managed on a portfolio basis. The ability to switch fuel provides a dynamic, operational and effective option in managing commodity price and supply risk.

Interest rate risk

The Company makes use of various financial instruments to hedge against interest rate risk, as discussed above. Additionally, the Company uses diversification as a strategy. It maintains a portfolio of debt instruments which includes short-term instruments and long-term instruments with staggered maturities. The Company also deals with several counterparties so as to mitigate interest rate concentration risk.

Credit risk

The Company is exposed to credit risk with respect to amounts receivable from customers. Credit assessments are conducted on all new customers and deposits are requested on any high risk accounts. The Company also maintains provisions for potential credit losses, which are assessed on a regular basis. With the exception of in-province electricity customers, counterparty creditworthiness is assessed through reports of credit rating agencies or other available financial information.

21. COMMITMENTS

NSPI had the following significant commitments at December 31, 2005:

- An annual requirement to purchase approximately 282 GWh of electricity from independent power producers over varying contract lengths ranging from nine to twenty years.
- A requirement to purchase approximately 61.6 million cubic feet of natural gas per day for the next five years (subject to offshore gas production), and an additional 4 million cubic feet per day, at the option of the supplier, for five years.
- Commitments to purchase approximately 65,000 mmbtu per day of transportation capacity on the Maritimes and Northeast Pipeline, a related party, for the next five years, with renewal rights at the Company's option for an indefinite period of time, at an approximate cost of $16 million per year.
- Responsibility for managing a portfolio of approximately $1.1 billion of defeasance securities held in trust. The defeasance securities must provide the principal and interest streams of the related defeased debt. Approximately 70%, or $735 million, of the

defeasance portfolio consists of investments in the related debt, eliminating all risk associated with this portion of the portfolio.

- Commitment to a third party for the transportation of coal to the Lingan and Point Aconi generation stations for ten years beginning in late 2002 at an approximate cost of $15 million per year.
- Commitment to a third party beginning in early 2004 for seven years to outsource the management of the Company's computer infrastructure at an annual cost ranging from $3.8 to $5.6 million.
- Commitment to third parties for 2006 to 2009, to purchase 2.42 million metric tons ("mts") of import coal, 1.598 million mts of petroleum coke, 360,000 mts of domestic coal and 4.4 million mts of marine freight.
- Commitment of approximately 30,000 mmbtu's per day of US transportation on the Maritimes and Northeast Pipeline US pipeline. The cost of this commitment to purchase over the five year term of the contract is approximately $12.million annually.
- Commitment to a third party beginning in 2005 for 10 years to operate the Point Tupper Marine Terminal at an annual cost of $3.4 million per year.

22. GUARANTEES

The Company had the following guarantees at December 31, 2005:

- As of December 31, 2005 there were letters of credit issued against the Company's operating facility totaling $9.6 million (2004 - $12.7 million). The Company's letters of credit extend to 2006 or are renewed annually and secure payments to various vendors.

23. COMPARATIVE INFORMATION

Certain of the comparative figures have been reclassified to conform to the financial statement presentation adopted for 2005.

OPERATING STATISTICS

Five-Year Summary

	2005	2004	2003	2002	2001
Electric energy sales (*GWh*)					
Residential	**3,999.5**	4,038.7	3,818.9	3,835.0	3,756.7
Commercial	**3,003.9**	2,964.6	3,000.9	2,818.3	2,724.9
Industrial	**4,196.9**	4,196.5	4,091.3	3,786.2	3,831.6
Other	**436.4**	473.4	586.0	766.2	574.6
Total electric energy sales	**11,636.7**	11,673.2	11,497.1	11,205.7	10,887.8
Sources of energy *(GWh)*					
Thermal - coal	**9,116.3**	9,490.2	9,218.7	8,862.2	8,854.8
- oil	**1,580.5**	1,698.2	1,535.8	287.7	690.7
- natural gas	**194.3**	97.0	119.5	1,578.7	1,129.1
Hydro	**1,060.6**	886.2	1,077.0	1,024.3	692.2
Wind	**1.8**	2.4	2.6	0.3	-
Purchases	**529.3**	390.9	375.2	277.6	279.4
Total generation and purchases	**12,482.8**	12,564.9	12,328.8	12,030.8	11,646.2
Losses and internal use	**846.1**	891.7	831.7	825.1	758.4
Total electric energy sold	**11,636.7**	11,673.2	11,497.1	11,205.7	10,887.8
Customers					
Residential	**423,517**	419,832	415,254	411,571	403,767
Commercial	**33,797**	33,107	32,873	32,743	32,159
Industrial	**2,475**	2,419	2,347	2,280	2,246
Other	**9,092**	8,682	8,339	7,917	7,332
Total customers	**468,881**	464,040	458,813	454,511	445,504
Generating nameplate capacity (MW)					
Coal fired	**1,243**	1,243	1,243	1,243	1,243
Dual fired	**350**	350	350	350	350
Gas turbines	**304**	304	254	204	204
Hydroelectric	**395**	395	395	395	395
Wind turbines	**1**	1	1	1	-
Independent power producers	**57**	25	25	25	25
Total capacity	**2,350**	2,318	2,268	2,218	2,217
Total number of employees	**1,623**	1,638	1,750	1,833	1,970
Thousands of kms of transmission lines (69 kV and over)	**5**	5	5	5	5
Thousands of kms of distribution lines (25 kV and under)	**25**	25	25	25	25

FINANCIAL INFORMATION

Five-Year Summary

For the year ended December 31 *(millions of dollars)*	2005	2004	2003	2002	2001
Statements of Earnings Information					
Revenue	**$963.0**	$934.1	$904.6	$876.5	$838.6
Cost of operations					
Fuel for generation and purchased power	**373.8**	303.1	277.8	335.6	301.0
Operating, maintenance and general	**188.8**	177.5	186.0	176.4	156.8
Provincial grants and taxes	**40.4**	39.5	33.4	22.0	20.2
Provincial grants and taxes deferral	**(4.5)**				
Depreciation	**119.5**	116.0	101.7	103.9	99.6
Regulatory amortization	**6.2**	6.2	6.2	1.0	3.0
Allowance for funds used during construction	**(2.1)**	(3.2)	(4.5)	(3.4)	(5.1)
	722.1	639.1	600.6	635.5	575.5
Earnings from operations	**240.9**	295.0	304.0	241.0	263.1
Interest	**97.9**	100.1	104.3	109.6	112.3
Other Income	**(8.0)**	-	-	-	-
Amortization of defeasance costs	**13.2**	15.1	16.7	19.4	19.8
Earnings before income taxes	**137.8**	179.8	183.0	112.0	131.0
Income taxes	**45.5**	59.2	57.8	15.7	13.9
Income taxes deferral	**(12.2)**				
Net earnings before preferred dividends	**104.5**	120.6	125.2	96.3	117.1
Preferred dividends	**13.3**	13.3	13.1	10.2	12.0
Net earnings applicable to common shares	**91.2**	107.3	112.1	86.1	105.1
Common dividends	**91.0**	153.1	70.0	84.4	161.2
Earnings retained for use in Company	**$0.2**	$(45.8)	$42.1	$1.7	($56.1)
Cost of fuel for generation - coal	**$260.9**	$209.1	$211.8	$229.6	$202.9
- oil	**100.2**	91.2	91.4	20.6	40.7
- natural gas	**(35.4)**	(30.6)	(58.4)	62.5	35.8
Purchased power	**48.1**	33.4	33.0	22.9	21.6
Total cost	**$373.8**	$303.1	$277.8	$335.6	$301.0
Balance Sheets Information					
Current assets	**$186.9**	$154.5	$189.6	$242.5	$250.9
Deferred charges	**398.5**	390.0	399.0	256.3	272.2
Long-term Receivable	**48.4**	4.9			
Property, plant and equipment	**2,427.7**	2,443.4	2,416.2	2,384.5	2,381.8
Total assets	**$3,061.5**	$2,992.8	$3,004.8	$2,883.3	$2,904.9
Current liabilities	**$184.6**	$249.2	$296.3	$390.6	$457.8
Deferred credits	**4.6**	5.8	9.3	33.1	25.2
Asset retirement obligations*	**71.4**	67.8	64.4	-	-
Long-term debt	**1,487.7**	1,357.0	1,276.0	1,146.0	1,185.0
Preferred shares	**260.0**	260.0	260.0	260.0	260.0
Common shares	**830.6**	830.6	830.6	827.5	752.5
Retained earnings	**222.6**	222.4	268.2	226.1	224.4
Total equity and liabilities	**$3,061.5**	$2,992.8	$3,004.8	$2,883.3	$2,904.9
Statements of Cash Flow Information					
Cash provided by operating activities	**$129.9**	$228.9	$177.6	$218.3	$145.4
Cash used in investing activities	**$107.8**	$144.4	$94.9	$104.6	$111.8

**Asset retirement obligations restated to December 31, 2003 only.*

2005 Nova Scotia Power Inc. Management's Discussion & Analysis

As at February 17, 2006

Management's Discussion and Analysis ("MD&A") provides a review of the results of operations of Nova Scotia Power Inc. ("Nova Scotia Power" or "NSPI") during the fourth quarter of 2005 relative to 2004, the full year 2005 relative to 2004 and to 2003 and its financial position at December 31, 2005 relative to 2004. Certain factors that may affect future operations are also discussed. Such comments will be affected by, and may involve, known and unknown risks and uncertainties that may cause the actual results of the company to be materially different from those expressed or implied. Those risks and uncertainties include, but are not limited to, weather, commodity prices, interest rates, foreign exchange, regulatory requirements and general economic conditions. To enhance shareholders' understanding, certain multi-year historical financial and statistical information is presented.

This discussion and analysis should be read in conjunction with the Nova Scotia Power Inc. 2005 annual audited financial statements and supporting notes. NSPI's accounting policies are subject to examination and approval by the Nova Scotia Utility and Review Board ("UARB"). As a result, the rate-regulated accounting policies may differ from Canadian Generally Accepted Accounting Principles ("GAAP") for non rate-regulated companies.

All amounts are in Canadian dollars.

Additional information related to Nova Scotia Power Inc. including the company's Annual Information Form is available on SEDAR at www.sedar.com.

INTRODUCTION

Nova Scotia Power Inc., a wholly-owned subsidiary of Emera Inc., is a vertically integrated, regulated electric utility, with $3 billion of assets, serving 470,000 customers. NSPI is the primary electricity supplier in Nova Scotia, providing the vast majority of the generation, transmission and distribution of electricity in the province. The company is regulated by the Nova Scotia Utility and Review Board ("UARB").

NSPI is a cost of service utility. As such, regulated electricity rates are set to enable the company to recover all prudently incurred costs, with an opportunity to earn a prescribed return on equity.

Structure of MD&A

This annual MD&A has been prepared in accordance with the Canadian Securities Administrators National Instrument 51-102 Management's Discussion & Analysis.

This Management's Discussion and Analysis begins with an overview of the company's annual results then presents significant changes in the balance sheets, liquidity and capital resources, financial and commodity instruments, transactions with related parties, critical accounting estimates, changes in accounting policies, business risk and enterprise risks management and selected quarterly trend information.

Overview

NSPI is the primary electricity supplier in Nova Scotia, providing over 95% of the electricity generation, transmission and distribution in the province. The company owns 2,293 megawatts ("MW") of generating capacity. Approximately 55% is coal-fired; oil and natural gas together comprise another 30% of capacity; and hydro and wind production provide the remainder. NSPI has 122 MW of renewable energy, substantially wind energy, under contract with independent power producers, of which 57 MW are in service and the remainder expected to be in operation in the next 18 months. NSPI also owns approximately 5,000 kilometres of transmission facilities, and 25,000 kilometres of distribution facilities. The company has a workforce of approximately 1,600 people.

NSPI is a public utility as defined in the Public Utilities Act (Nova Scotia) and is subject to regulation under the Act by the UARB. The Act gives the UARB supervisory powers over NSPI's operations and expenditures. Electricity rates for NSPI's customers are also subject to UARB approval. The company is not subject to an annual rate review process, but rather participates in hearings from time to time at the company's or the regulator's request.

Nova Scotia Power is regulated under a cost of service model, with rates set to cover prudently incurred costs of providing electricity service to customers, and provide an appropriate return to investors. NSPI's allowed regulated return on common equity ("ROE") range is 9.3% to 9.8%, with common equity allowed to grow to 40% of the capital structure. Rates were last set using 9.55% ROE with a common equity component of 37.5% of total capitalization.

2005 Electricity Rate Increase

On March 31, 2005, the UARB granted NSPI an average rate increase of approximately 5.3%, effective April 1, 2005. The rate decision increased NSPI's electric revenues by approximately $25.0 million in 2005 compared to 2004. The decision also provided for full recovery of a $146.7 million Section 21 income tax deposit over eight years, commencing in 2007. In the 2005 decision, the UARB expressed dissatisfaction with certain past fuel procurement practices, resulting in a disallowance of $18 million of NSPI's forecasted 2005 fuel costs. The UARB also rejected NSPI's settlement proposal to defer an additional $13 million of fuel costs to 2006.

The UARB specified certain findings and directives concerning NSPI's fuel procurement in its decision. On September 30, 2005, Nova Scotia Power filed a report with the UARB outlining changes it has made to fuel procurement to comply with the UARB's findings.

2006 Rate Application

In July 2005, Nova Scotia Power filed a general rate application requesting an average 15% increase in electricity prices for 2006, primarily a result of rising fuel commodity prices. In November, as a result of benefits associated with the re-negotiated natural gas supply contract, NSPI reduced its rate request to an average 13%.

The rate application also proposes increases to operating costs of approximately $19 million to improve customer service, strengthen network reliability and to implement new conservation and energy efficiency measures.

Hearings concluded in early December with a decision anticipated in Q1, 2006.

Significant Items

2005

Natural gas supply contract

In Q4, 2005, Nova Scotia Power reached an agreement with its supplier on pricing for natural gas under an existing long-term natural gas purchase agreement. The contract - which began in 2000 and runs until 2010 - calls for up to approximately 61,000 MMBtus of natural gas per day to be supplied to Nova Scotia Power, and was subject to a price re-determination as of November 1, 2004. With both parties unable to agree on terms, the matter was referred to arbitration. The two companies reached agreement prior to the rendering of a decision by the arbitration panel. Throughout most of 2005, while the initial contract discussions and later, the arbitration hearing unfolded, NSPI recorded its gas purchases at its best estimate of the new contract price. The pricing ultimately agreed to was more favourable than NSPI's estimate. This resulted in a $23.8 million ($14.7 million after tax) adjustment to fuel expense for the year, all of which was recorded in Q4. In addition, in a separate agreement, NSPI was provided a net payment of $8.0 million ($5.0 million after tax) by its gas supplier, which has been recorded as other income in Q4.

Deferral of Q1 Income and Capital Taxes

The UARB agreed to allow Nova Scotia Power to defer taxes not reflected in rates for the period January 1, 2005 until April 1, 2005, the date when new rates became effective. In 2005, NSPI deferred $16.7 million consisting of $4.5 million of provincial and federal grants and $12.2 million in income taxes reflecting increases in these taxes since rates were last set in 2002.

2004

There were no significant items in 2004.

2003

Unbilled revenue adjustment

The company recognizes electric revenues on the accrual basis, which includes an estimate of electricity consumed by customers in the period but billed subsequently ("unbilled revenue"). In Q2 2003, the company improved its process for estimating its unbilled revenue. The change resulted in a $10.0 million ($6.5 million after tax) reduction in the unbilled revenue accrual, with a corresponding charge against revenues.

Hurricane Juan

In Q3, 2003 Nova Scotia was struck by Hurricane Juan, a Category Two hurricane causing extensive damage to Nova Scotia Power's transmission and distribution system. The total cost of the hurricane to the company was $12.6 million, specifically $4.0 million of net after-tax operating costs that were recorded in Q3 2003, and $8.6 million in capital costs.

Site restoration costs

Prior to 2003, Nova Scotia Power estimated and accrued site restoration costs for the Glace Bay generating station. The costs to complete the restoration were expected to be $3.8 million lower than estimated. Nova Scotia Power reduced its provision accordingly, with a corresponding reduction in depreciation expense in Q4, 2003.

Review of 2005

Net Earnings

(millions of dollars)	Three months ended December 31		Year ended December 31		
	2005	2004	**2005**	2004	2003
Electric revenue	**$243.0**	$237.8	**$955.0**	$926.9	$895.6
Fuel for generation and purchased power	**79.5**	86.9	**373.8**	303.1	277.8
Operating, maintenance and general	**48.8**	46.4	**188.8**	177.5	186.0
Provincial grants and taxes	**10.2**	9.9	**40.4**	39.5	33.4
Provincial grants and taxes deferral	**0.4**	-	**(4.5)**	-	
Depreciation	**30.1**	28.2	**119.5**	116.0	101.7
Regulatory amortization	**1.5**	1.5	**6.2**	6.2	6.2
Other	**(2.6)**	(2.5)	**(10.1)**	(10.4)	(13.5)
Earnings before the following	**75.1**	67.4	**240.9**	295.0	304.0
Interest	**25.8**	24.6	**97.9**	100.1	104.3
Other income	**(8.0)**	-	**(8.0)**	-	
Amortization of defeasance costs	**3.3**	3.8	**13.2**	15.1	16.7
Earnings before income taxes	**54.0**	39.0	**137.8**	179.8	183.0
Income taxes	**18.5**	10.7	**45.5**	59.2	57.8
Income taxes deferral	**(1.8)**	-	**(12.2)**	-	-
Earnings before preferred dividends	**37.3**	28.3	**104.5**	120.6	125.2
Preferred dividends	**3.3**	3.3	**13.3**	13.3	13.1
Net earnings applicable to common shares	**$34.0**	$25.0	**$91.2**	$107.3	$112.1

NSPI's net earnings were $34.0 million in Q4, 2005, compared to $25.0 million in Q4, 2004. The earnings increase was substantially due to the finalization of pricing terms of NSPI's natural gas supply contract in the quarter at better than previously estimated pricing. Also contributing to the quarter over quarter increase was a separate agreement with NSPI's gas supplier that resulted in a net payment of $8.0 million. Annual net earnings were $91.2 million in 2005, compared to $107.3 million in 2004 and $112.1 million in 2003. Highlights of the earnings changes are summarized in the following table:

(millions of dollars)	Three months ended December 31	**Year ended December 31**
Net earnings, December 31, 2003		$112.1
Increased electric revenues, largely reflecting load growth		21.3
Increased fuel expenses, due to reduced gas sales margin and higher coal costs in Q4		(25.3)
Increased depreciation, reflecting updated rates, and capital investment		(14.3)
Increased provincial grants and taxes		(6.1)
Adjustment to the company's unbilled revenues in 2003		10.0
Hurricane Juan operating expenses in 2003		6.0
All other		3.6
Net earnings, December 31, 2004	**$25.0**	$107.3
Increased electric revenue due to the 5.3% rate increase effective April 1, 2005 partially offset by a of 36 GWh decrease in sales volume for the year	5.2	28.1
Increased fuel expenses due to higher commodity prices, and changes in generation mix partially offset by increased hydro production	(20.8)	(84.3)
Decrease in fuel expenses due to finalization of pricing terms of NSPI's natural gas supply contract	23.8	-
Decrease in fuel expense due to increased gas resale margin	4.3	13.6
Increased operating expenses due to increased planned plant maintenance, storm-related costs and regulatory costs	(2.4)	(11.3)
Increased depreciation due to capital investment	(1.9)	(3.5)
In Q4, increased interest due to foreign exchange losses; year ended December 31, decreased interest due to lower rates	(1.2)	2.2
Net payment from gas supplier	8.0	8.0
(Increased) decreased income taxes resulting from (higher) lower earnings	(7.8)	13.7
Deferral of Q1 2005 taxes	1.4	16.7
All other	0.4	0.7
Net earnings, December 31, 2005	**$34.0**	**$91.2**

Electric Revenue

Q4 Electric Sales Volume
Gigawatt hours("GWh")

	2005	2004	2003
Residential	**999**	1,052	1,049
Commercial	**728**	754	744
Industrial	**1,020**	1,068	1,037
Other	**144**	153	119
Total	**2,891**	3,027	2,949

Q4 Electric Sales Revenues
(millions of dollars)

	2005	2004	2003
Residential	**$104.2**	$103.4	$102.8
Commercial	**65.3**	66.3	64.6
Industrial	**58.6**	55.3	53.5
Other	**14.9**	12.8	10.3
Total	**$243.0**	$237.8	$231.2

YTD Electric Sales Volume
(GWh)

	2005	2004	2003
Residential	**4,000**	4,039	3,819
Commercial	**3,004**	2,965	3,001
Industrial	**4,197**	4,196	4,091
Other	**436**	473	586
Total	**11,637**	11,673	11,497

YTD Electric Sales Revenues
(millions of dollars)

	2005	2004	2003
Residential	**$411.4**	$402.9	$375.8
Commercial	**263.6**	258.3	253.4
Industrial	**235.1**	222.5	218.5
Other	**44.9**	43.2	47.9
Total	**$955.0**	$926.9	$895.6

Q4 Average Revenue /Megawatt hours (" MWh")

	2005	2004	2003
Dollars per MWh	**$84**	$79	$78

YTD Average Revenue / MWh

	2005	2004	2003
Dollars per MWh	**$82**	$79	$78

Electric sales *volume* is primarily driven by general economic conditions, population and weather. Electricity *pricing* in Nova Scotia is regulated and therefore only changes when new regulatory decisions are implemented. The exceptions are Annually Adjusted Rates, subscribed to by certain larger industrial customers, which apply to approximately 20% of NSPI sales volume; and export sales, which in recent years comprised less than 2% of NSPI sales volume, and are priced at market. Residential and commercial electricity sales are seasonal in Nova Scotia, with Q1 and Q4 the strongest periods, reflecting colder weather, and fewer daylight hours in the winter season.

NSPI's residential load generally comprises individual homes, apartments and condominiums. Commercial customers include everything from small retail operations to large office and commercial complexes, and the province's universities and hospitals. Industrial customers include manufacturing facilities and other large volume operations. Other consists of export sales, sales to municipal electric utilities and load from street lighting.

Electric revenues increased by $5.2 million to $243.0 million in Q4, 2005 from $237.8 million for the same period in 2004. Revenue increases are substantially due to the April 1 2005 rate increase partially offset by reduced sales volume due to warmer weather in Q4, customer conservation efforts and the temporary shut down of a large industrial customer for a portion of December 2005.

For the year ended December 31, 2005, electric revenues increased $28.1 million to $955.0 million in comparison to $926.9 million in 2004. The revenue increase is due to the reasons noted above.

For the year ended December 31, 2004, electric revenues increased $31.3 million to $926.9 million from $895.6 million in 2003. Of the difference, $10.0 million relates to a charge against revenue in the 2003 comparative amounts, due to an adjustment to the company's unbilled revenue accrual. In addition to normal growth, a cold Q1, 2004 increased sales volumes. Export sales volumes were lower, as available capacity was used to service in-province load.

Fuel for Generation and Purchased Power

Capacity

To ensure reliability of service, NSPI maintains a generating capacity greater than firm peak demand. The total company-owned generation capacity to 2,293 MW, which is supplemented by 57 megawatts in service contracted with independent power producers. NSPI meets the planning criteria for reserve capacity established by the Maritime Control Area and therefore meets the Northeast Power Coordinating Council criteria.

Management of capacity / capacity utilization is a critical element of operating efficiency. The provision of sufficient generating capacity to meet peak demand inevitably results in excess capacity in non-peak periods. NSPI's daily load is highest in the early evening; its seasonal load is highest through the winter months. Summer cooling load is not a significant factor. Maximizing capacity utilization has a positive affect on earnings, and helps defer significant investment in additional generation capacity. Maximizing capacity utilization primarily depends on:

- Ensuring generating plants are consistently available to service demand - NSPI conducts ongoing planned maintenance programs, and has sustained high availability over the past several years. NSPI continues to maintain unplanned outage rates below 3%.

- Moving demand from peak to non-peak periods - NSPI encourages customers to move some electricity demand from high cost to lower cost periods by offering customers various pricing alternatives. NSPI currently controls over 300 MW of interruptible electric load, including 200 MW of which is economically interruptible.

- Export sales – Increasing export sales when margins are satisfactory allows excess capacity to be sold when not required in province. NSPI operates a 24-hour energy marketing desk to optimize commercial opportunities.

NSPI's generating capacity utilization was 78% in 2005 compared to 82% in 2004. The change is largely due to the completion of two planned turbine inspections as part of NSPI's maintenance and life cycle management program for generation assets.

NSPI Thermal Capacity Utilization

2005	2004	2003	2002	2001	2000
78%	82%	78%	77%	77%	74%

NSPI facilities continue to perform highly among the top ten units in Canada for capacity related performance indicators. In the most recent Canadian Electrical Association Rankings, NSPI units hold five of the top ten positions in Canada including Trenton 6 in first place in 2004. Point Tupper ranked Number 1 in the previous year.

NSPI Generating Capacity Availability

2005	2004	2003	2002	2001	2000
90%	92%	91%	91%	91%	88%

Fuel Expense

Q4 Production Volume
(GWh)

	2005	2004	2003
Coal and petcoke	**2,280**	2,471	2,398
Natural gas	**32**	26	65
Oil	**442**	433	288
Renewable	**308**	265	276
Purchased power	**126**	91	111
Total	**3,188**	3,286	3,138

Purchased power included 29 GWh of wind power in Q4, 2005.

YTD Production Volume
(GWh)

	2005	2004	2003
Coal and petcoke	**9,116**	9,490	9,219
Natural gas	**194**	97	119
Oil	**1,581**	1,698	1,536
Renewable	**1,063**	889	1,080
Purchased power	**529**	391	375
Total	**12,483**	12,565	12,329

Purchased power includes 83 GWh of wind power in 2005.

Q4 Average Unit Fuel Costs

	2005	2004	2003
Dollars per MWh	**$25**	$26	$20

YTD Average Unit Fuel Costs

	2005	2004	2003
Dollars per MWh	**$30**	$24	$23

Coal is NSPI's dominant fuel source, supplying approximately 50% of the company's annual generation. Petroleum coke ("petcoke") fuels approximately 25% of generation. These solid fuels have the lowest per unit fuel cost, after hydro and wind production which have no fuel cost component. Oil and natural gas are next, depending on the relative pricing of each. Purchased power is generally the most expensive option. Economic dispatch of the generating fleet brings the lowest cost options on stream first with the result that the incremental cost of production increases as sales volume increases.

A substantial amount of NSPI's fuel supply comes from international suppliers, and is subject to commodity price and foreign exchange risk. The company manages exposure to commodity price risk utilizing a portfolio strategy, combining physical fixed-price fuel contracts and financial instruments providing fixed or maximum prices. Foreign exchange risk is managed through forward and option

contracts. Further details on the company's fuel cost risk management strategies are included in the Business Risks and Enterprise Risk Management section.

For the three months ended December 31, 2005, fuel for generation and purchased power was $79.5 million, compared to $86.9 million in Q4, 2004. For the year ended December 31, 2005 fuel for generation and purchased power was $373.8 million, compared to $303.1 million in 2004, and $277.8 million in 2003. Highlights of the year over year changes are summarized in the following table:

(millions of dollars)	Three Months ended December 31	Year ended December 31
Fuel for generation and purchased power, December 31, 2003		**$277.8**
Lower net proceeds from resale of natural gas		32.0
Decreased export volumes		(11.4)
Decreased renewable production volumes		11.9
Increased production		16.9
Commodity pricing, including favourable exchange rates		(16.7)
All other		(7.4)
Fuel for generation and purchased power, December 31, 2004	**$86.9**	**$303.1**
Commodity pricing increase	29.5	91.1
Higher net proceeds from resale of natural gas	(4.3)	(13.6)
Finalization of pricing terms of NSPI's natural gas supply contract	(23.8)	-
Changes is generation mix	5.8	12.2
Increase in hydro production volumes	(2.2)	(11.7)
All other	(12.4)	(7.3)
Fuel for generation and purchased power, December 31, 2005	**$79.5**	**$373.8**

In Q4, 2005, Nova Scotia Power reached an agreement with its supplier on pricing for natural gas under an existing long-term natural gas purchase agreement. The contract - which began in 2000 and runs until 2010 - calls for up to approximately 61,000 MMBtus of natural gas per day to be supplied to Nova Scotia Power, and was subject to a price re-determination as of November 1, 2004. With both parties unable to agree on terms , the matter was referred to arbitration. The two companies reached agreement prior to the rendering of a decision by the arbitration panel. Throughout most of 2005, while the initial contract discussions and later the arbitration hearing unfolded, NSPI recorded its gas purchases at its best estimate of the new contract price. The pricing ultimately agreed to was more favourable than NSPI's estimate. This resulted in a $23.8 million ($14.7 million after tax) adjustment to fuel expense for the year, all of which was recorded in Q4. In addition, in a separate agreement, NSPI was provided a net payment of $8.0 million ($5.0 million after tax) by its gas supplier, which has been recorded as other income in Q4.

Operating, Maintenance and General Expenses

NSPI's operating, maintenance and general expenditures ("OM&G") were $48.8 million in Q4, 2005 compared to $46.4 million in Q4, 2004. The increase of $2.4 million is primarily a result of adjustments to allowance for doubtful accounts and increased regulatory costs.

For the year ended December 31, 2005, NSPI's OM&G expenditures were $188.8 million, compared to $177.5 million for 2004 and $186.0 million in 2003. OM&G costs increased $11.3 million in 2005 over 2004 due to increased planned plant maintenance, storm-related costs and higher regulatory costs. OM&G expenditures decreased $8.5 million in 2004 from 2003 levels primarily as a result of lower labour and material costs.

Provincial Grants and Taxes

NSPI pays annual grants to the Province of Nova Scotia, in lieu of all municipal taxation other than deed transfer tax.

Provincial grants and taxes increased $0.3 million in Q4, 2005 and $0.9 million for the year ended December 31, 2005, reflecting inflationary adjustments. For the year ended December 31, 2004, provincial grants and taxes increased $6.1 million over 2003, reflecting a $4.6 million increase in NSPI's annual provincial grants and an increase in provincial capital tax rate from 0.25% to 0.3% effective April 1, 2004.

In Q1, 2005 the UARB agreed to allow NSPI to defer taxes not reflected in rates for the period from January 1, 2005 until April 1, 2005, the date when new rates became effective. As a result, NSPI deferred $4.5 million of provincial grants and taxes to March 31, 2005. The amortization period is pending approval by the UARB.

Depreciation

NSPI's depreciation expense increased $1.9 million in Q4, 2005 to $30.1 million compared to $28.2 million in Q4, 2005, primarily due to increased plant-in-service.

For the year ended December 31, 2005 depreciation expense increased $3.5 million to $119.5 million compared to $116.0 million in 2004, for the reason noted above. The 2004 amount is $14.3 million higher than 2003, reflecting the change in depreciation rates approved by the UARB in its 2003 depreciation order, and increased plant-in-service.

Regulatory Amortization

The Glace Bay generating station has been demolished and returned to an industrial Greenfield site, and is being amortized at an annual minimum rate of $6.2 million. The amount remaining to be written off is $12.9 million.

Interest

Interest expense increased $1.2 million, to $25.8 million in Q4, 2005, compared to $24.6 million in Q4, 2004 due to foreign exchange losses on US denominated working capital offset by a gain on an interest rate derivative.

For the year ended December 31, 2005, interest expense decreased $2.2 million, to $97.9 million from $100.1 million for 2004 largely due to the refinancing in May 2005 of a $100 million 8.38% medium-term note with a $100 million 4.22% medium-term note.

For the year ended December 31, 2004, interest expense decreased $4.2 million, to $100.1 million compared to $104.3 million in 2003. This decrease is due to the refinancing of a $140 million mid-term note with short-term debt in 2004.

The company manages exposure to interest rate risk through a combination of fixed and floating borrowing, and hedging. Interest rate swaps are the principal instrument used to hedge interest rate risk

Other Income

During 2005, Nova Scotia Power received a payment of $10.5 million, less $2.5 million of associated costs, from a gas supplier as part of renegotiation of certain contractual matters.

Income Taxes

In accordance with ratemaking regulations established by the UARB, NSPI uses the taxes-payable method of accounting for income taxes.

NSPI is subject to provincial capital tax (0.288%), large corporations tax (0.175%), corporate income tax (38.12%) and Part VI.1 tax relating to preferred dividends (40%).

NSPI has a $146.7 million regulatory asset related to pre-2003 income taxes that have been paid, but not yet recovered from customers. This circumstance arose when NSPI claimed deductions that were ultimately disallowed by a decision of the Supreme Court of Canada. The UARB has approved the amortization and recovery of this regulatory asset over eight years, commencing in 2007.

In Q1, 2005 the UARB agreed to allow NSPI to defer taxes not reflected in rates for the period January 1, 2005 until April 1, 2005, the date when new rates became effective. As a result, NSPI deferred $12.2 million of federal capital taxes and income taxes reflecting increases in these taxes since rates were last set in 2002. The amortization period is pending approval by the UARB.

Outlook

NSPI's earnings outlook for 2006 is substantially dependant on the outcome of the 2006 rate decision, expected in Q1, 2006. The magnitude of any approved increase, as well as timing of the implementation will affect revenues and could have a material impact on earnings.

Electricity sales volume (load) is expected to be lower in 2006 than in 2005, due to warmer weather in Q1, the temporary shut-down of a large industrial customer and customer conservation effects. Fuel costs are expected to increase primarily due to higher commodity prices and an increase in the amount of higher cost, lower sulphur coal in the fuel mix to meet provincial environmental regulations. These higher costs will be partially offset by the expected reduction in load noted above.

Other costs of NSPI are generally expected to remain consistent with normalized 2005 levels, with additional investments expected to be made in vegetation management, storm response initiatives and energy conservation management. NSPI has also requested an increase in depreciation expense in its 2006 rate application, to implement approved increases flowing from its recent depreciation study.

Debt Management

In Q4, 2005, NSPI issued a $150 million medium-term note at a coupon rate of 5.67% maturing November 14, 2035. Proceeds were used to pay down short-term debt.

Earlier in 2005, NSPI issued a $100 million medium-term note at a coupon rate of 4.22% maturing May 17, 2010. The proceeds were used to refinance $100 million 8.38% medium-term notes that matured on that date.

In 2004, a $140.0 million 7.3% mid-term note matured and was refinanced with short-term debt.

The weighted-average coupon rate on NSPI's outstanding medium-term and debenture notes at December 31, 2005, was 6.83% (2004 - 7.32%). Approximately 41% of the debt matures over the next ten years; 55% matures between 2016 and 2036; and $50.0 million, or 4% matures in 2097. The quoted market-weighted-average interest rate for the same or similar issues of the same remaining maturities was 4.96% as of December 31, 2005 (2004 – 5.14%).

NSPI has established the following available credit facilities:

(millions of dollars)	**Maturity**	**Maximum Amount**
Short-term		
Commercial paper, with 100% backup line of credit	1 year revolving	$400.0
Operating credit facility	3 year revolving	$100.0

NSPI has the following available credit ratings:

	DBRS		**S&P**		**Moodys**	
	2005	2004	**2005**	2004	**2005**	2004
Long term corporate	**A (low)**	A (low)	**BBB+**	BBB+	**n/a**	n/a
Senior unsecured debt	**A (low)**	A (low)	**BBB+**	BBB+	**Baa1**	Baa1
Preferred stock	**Pfd-2 (low)**	Pfd-2 (low)	**P-2 (Low)**	P-2 (Low)	**n/a**	n/a
Commercial paper	**R-1 (low)**	R-1 (low)	**A-1 (Low)**	A-1 (Low)	**P-2 (Baa)**	P-2 (Baa)

On July 5, 2005, Standard & Poor's Rating Services revised its outlook on NSPI to negative from stable citing fuel cost recovery concerns. On July 6, 2005, the Dominion Bond Rating Service confirmed NSPI's ratings as A(low) and the commercial paper rating as R-1(low). On October 11, 2005, Moody's Investors Services revised its outlook on Nova Scotia Power from stable to negative citing fuel cost recovery and regulatory uncertainty.

Outlook

An NSPI medium-term note ("MTN") of $40 million bearing interest of 5.20%, maturing in 2029 is redeemable at the option of the holder in April 2006. If not redeemed, the interest rate on the MTN increases to 6.28% until maturity.

Based on the company's available credit and credit ratings, and past experience in public financing since privatization, NSPI expects to have access to capital when needed.

Balance Sheets

Balance Sheets
(millions of dollars)

	2005	2004	2003
Assets			
Current assets	**$ 186.9**	$ 154.5	$ 189.6
Deferred charges	**398.5**	390.0	399.0
Long-term receivable	**48.4**	4.9	-
Property, plant & equipment	**2,427.7**	2,443.4	2,416.2
	$3,061.5	$2,992.8	$3,004.8
Liabilities and Shareholders' Equity			
Current liabilities	**$ 184.6**	$ 249.2	$ 296.3
Asset retirement obligations and deferred credits	**76.0**	73.6	73.7
Long-term debt	**1,487.7**	1,357.0	1,276.0
Preferred shares	**260.0**	260.0	260.0
Shareholders' equity	**1,053.2**	1,053.0	1,098.8
	$3,061.5	$2,992.8	$3,004.8

Significant changes in the balance sheets between December 31, 2004 and December 31, 2005 include:

- $32.4 million increase in current assets due to $7.9 million increase in trade accounts receivable as a result of the rate increase, $9.4 million timing increase due to associated companies, $7.0 million increase in income tax receivables and $4.5 million increase in inventory due to an increase in coal inventory.
- $8.5 million increase in deferred charges mainly due to Q1 2005 tax deferral.
- $43.5 increase in long-term receivable reflecting the increased estimated natural gas price adjustment.
- $15.7 million decrease in property, plant and equipment due to accumulated depreciation outpacing additions net of retirements for 2005
- $64.6 million decrease in current liabilities due to a decrease in long-term debt due within one year of $59.8 million
- $130.7 million increase in long-term debt due to a bond issuance in 2005

Significant changes in the balance sheets between December 31, 2003 and December 31, 2004 include:

- $35.1 million decrease in current assets due mostly to a $19.1 million decrease in accounts receivable, reflecting an increase in the amount of accounts receivable securitized, offset by an increase in sales and a $16.8 million decrease in inventory, reflecting a reduction in coal inventory levels.
- $9.0 million decrease in deferred charges, reflecting the amortization of defeasance costs and a decrease in deferred hedging premiums offset by an increase in pension contributions.
- $27.2 million increase in property, plant and equipment due to the addition of a 50 MW gas turbine generating unit and construction of a marine terminal offset by increased depreciation.
- $81.0 million increase in long-term debt is offset by the $40 million decrease in the current portion of long-term debt included in current liabilities. Overall debt level has increased due to increased capital spending.
- $45.8 million decrease in shareholders' equity due to increased dividend payments to bring the capital structure in line with approved levels.

Liquidity and Capital Resources

The company generates funds primarily through its operation as a regulated utility involving the generation, transmission and distribution of electricity. Circumstances that could affect the company's ability to generate funds include fuel commodity price changes, general economic downturns in Nova Scotia and regulatory decisions affecting customer rates. In addition to internally generated funds, the company has access to debt capital markets, through operating lines of credit, an accounts receivable securitization program and a commercial paper program. The company's financing facilities are expected to provide sufficient access to money markets and capital markets necessary to maintain acceptable levels of liquidity relative to current cash forecasts. In Q1, 2005 Nova Scotia Power established a debt shelf prospectus in the amount of $400 million that provides the company with access to long-term debt. The prospectus expires in April 2007.

In July, 2005 NSPI's Board of Directors approved an increase to the size of its commercial paper program from $350 million to $400 million. The company's banking syndicate provides 100% backup facility for this program.

Cash Flow Highlights

(millions of dollars)	Three months ended December 31		Year ended December 31		
	2005	2004	**2005**	2004	2003
Net cash provided by operating activities	**$(13.7)**	$35.5	**$129.9**	$228.9	$177.6
Net cash provided by (used in) financing activities	**30.0**	1.2	**(22.1)**	(84.5)	(96.0)
Net cash used in investing activities	**(16.3)**	(36.7)	**(107.8)**	(144.4)	(94.9)
Decrease in cash and short-term investments	**$-**	$-	**$-**	$-	$(13.3)

Net cash provided by operating activities was $(13.7) million in Q4, 2005, compared to $35.5 million in Q4, 2004 and net cash provided by operating activities was $129.9 million in 2005 compared to $228.9 million in 2004. Significant changes in the cash flows are summarized in the following table:

(millions of dollars)	Three months ended December 31	**Year ended December 31**
Net cash provided by operating activities – 2004	**$35.5**	**$228.9**
Increase (decrease) in cash flow from earnings	12.2	(33.4)
Decrease due to higher gas price adjustment receivable as a result of price changes	(16.8)	(38.6)
Increase (decrease) due to timing of coal and heavy fuel oil shipments and commodity price changes	13.8	(21.3)
Decrease due to lower trade accounts payable with the Q4 decrease due to timing of payment to a large fuel contractor.	(70.8)	(6.3)
All other	12.4	0.6
Net cash provided by operating activities – 2005	**$(13.7)**	**$129.9**

Net cash provided by financing activities was $30.0 million in Q4, 2005 compared to $1.2 million Q4, 2004. Net cash used in financing activities was $22.1 million in 2005 compared to $84.5 million in 2004. Highlights of the changes are summarized in the following table:

(millions of dollars)	Three months ended December 31	**Year ended December 31**
Net cash provided by (used in) financing activities – 2004	**$1.2**	**$(84.5)**
Issuance of long-term debt	150.0	250.0
Retirement of long-term debt	-	40.0
Reduction in short-term debt	(176.0)	(257.9)
Accounts receivable securitization	-	(30.0)
Dividends paid in common shares	55.0	62.1
All other	(0.2)	(1.8)
Net cash provided by (used in) financing activities – 2005	**$30.0**	**$(22.1)**

Net cash used in investing activities was $16.3 million in Q4, 2005 compared to $36.7 million in Q4, 2004. Net cash used in investing activities was $107.8 compared to $144.4 million in 2004. Highlights of the changes are summarized in the following table:

(millions of dollars)	Three months ended December 31	**Year ended December 31**
Net cash used in investing activities – 2004	**$(36.7)**	**$(144.4)**
Reduced capital spending	5.3	40.1
Decreased (Increased restricted) cash related to posted margin	14.3	(3.5)
All other	0.8	-
Net cash used in investing activities – 2005	**$(16.3)**	**$(107.8)**

Contractual Obligations

(millions of dollars)

	Payments Due by Period				
	Total	2006	2007-2008	2009-2010	After 2010
Long-term debt	**$1,527.9**	$222.2	$115.4	$225.3	$965.0
Operating leases	**27.2**	5.6	11.3	9.3	1.0
Purchase obligations	**2,103.0**	501.5	703.8	557.3	340.4
Other long-term obligations	**308.7**	-	0.5	-	308.2
Total contractual obligations	**$3,966.8**	$729.3	$831.0	$791.9	$1614.6

Operating lease obligations consist of the company's operating lease agreements for office space, telecommunications services and photocopiers.

Purchase obligations include the company's purchasing commitments for electricity from independent power producers, transportation of coal, outsource management of the company's computer infrastructure, natural gas, transportation capacity on the Maritimes & Northeast Pipeline, purchasing commitments for fuel and physical trading commitments.

Other long-term obligations represent the company's asset retirement obligations.

The company expects to be able to meet its obligations with cash flows generated from operations.

Capital Resources

Capital expenditures amounted to $104.5 million in 2005 (2004 - $145 million), of which approximately $20 million relates to the installation of environmental technology (electrostatic precipitators) at Tufts Cove generating station.

Outlook

NSPI's capital expenditures will be approximately $133.0 million in 2006 which is generally directed to planned and preventative maintenance, productivity-related investments and air emissions upgrades. The company expects to finance its capital expenditures with funds from operations and short-term debt.

In November 2005, NSPI filed a Notice of Application for the construction of capital projects associated with achieving the air emissions requirements contained in the Provincial environmental regulations. These capital projects are for the installation of air emissions abatement equipment at the Lingan generating station. Total investment associated with this equipment is currently projected at approximately $177 million. Of this amount, $16 million is included in the 2006 capital forecast noted above. A hearing on this matter is anticipated in the first half of 2006.

Off- Balance Sheet Arrangements

Upon privatization in 1992, NSPI became responsible for managing a portfolio of approximately $1.1 billion of defeasance securities held in trust. The defeasance securities must provide the principal and interest streams required to service the related defeased debt. Approximately 70%, or $735 million, of the defeasance portfolio consists of investments in the related debt, eliminating all risk associated with this portion of the portfolio, the remaining defeasance portfolio consists of investments with market values higher than the related debt reducing the future risk of this portion of the portfolio.

NSPI has an agreement with an independent trust administered by a Canadian chartered bank whereby it sells accounts receivable to the trust on a revolving non-recourse basis. As of December 31, 2005, the company had sold $80.0 million (2004 - $80.0 million) of net accounts receivable. The net proceeds from the sale were used to repay a portion of the company's debt. The agreement is in place until May 2009, with the intention that it will be renewed at that time. Securitization provides NSPI with an alternative source of short-term funding. For the year ended December 31, 2005, the average all-in cost of this funding was 2.97% (2004 – 2.64%). In the event of termination of this arrangement, NSPI would utilize another liquidity facility to meet the ongoing operations of the business.

Financial Instruments

The company manages its exposure to foreign exchange, interest rate, and commodity risks in accordance with established risk management policies and procedures. The company uses derivative instruments consisting mainly of foreign exchange forward contracts, interest options and swaps, and oil and gas options and swaps.

Instruments that meet stringent documentation requirements, and can be proven to be effective both at the inception and over the term of the instrument qualify for hedge accounting. Specifically, amounts paid or received are deferred and recognized in earnings in the same period the related hedged item is realized. Where the documentation or effectiveness requirements are not met, the non-qualifying hedges are marked-to-market and recognized in earnings in the reporting period.

As at December 31, 2005, the company had deferred payments and receipts on derivative instruments that are designated and effective as hedges and are recognized in the following categories on the balance sheet:

Deferred Hedging Losses (Gains) Recognized on the Balance Sheet
(millions of dollars)

	2005	2004
Inventory	**$0.2**	$1.6
Deferred charges	**-**	0.1
Accounts payable and accrued charges	**-**	(0.3)
Deferred hedging losses	**$0.2**	$1.4

For the three-month period and year ended December 31, 2005 the impacts of effective hedges recognized in earnings were recorded in the following categories:

Hedging Impact Recognized in Earnings
(millions of dollars)

	Three months ended December 31		Year ended December 31	
	2005	2004	**2005**	2004
Fuel and purchased power increase	**$(3.9)**	$(3.7)	**$(20.5)**	$(4.9)
Interest expense increase	**(0.5)**	(1.0)	**(1.9)**	(4.7)
Hedging earnings impact	**(4.4)**	(4.7)	**(22.4)**	(9.6)

In addition, in Q4 2005 the company recognized mark-to-market gains in fuel and purchased power expense of $8.5 million.

In determining the fair value of derivative financial instruments, the company has relied on quoted market prices as of December 31, 2005.

Transactions With Related Parties

The company enters into various transactions with its affiliates in the normal course of operations. All transactions are recorded subject to terms in the Code of Conduct, approved by the UARB, at the exchange value generally based on normal commercial rates or as agreed to by the parties.

Q4 Related Party Transactions
(millions of dollars)

Affiliate	Purpose of Transaction	2005	2004
Emera Fuels	Net sale of bunker C oil	**$0.0**	**$1.1**
Emera Energy Services	Net sale of gas and electricity	**76.2**	**35.8**
Maritimes and Northeast Pipeline	Purchase of transportation capacity	**4.2**	**4.1**
Emera Utility Services	Purchase and maintenance of transformers	**0.3**	**1.2**
Cablecom	Purchase of line extension work	**1.7**	**1.0**
Emera Inc. and affiliate under common control	Dividends paid	**24.0**	**80.0**
Emera Inc.	Allocation of common costs	**$1.4**	**$1.1**

YTD Related Party Transactions
(millions of dollars)

Affiliate	Purpose of Transaction	2005	2004
Emera Fuels	Net sale of bunker C oil	**$0.6**	**$9.4**
Emera Energy Services	Net sale of gas and electricity	**195.4**	**156.5**
Maritimes and Northeast Pipeline	Purchase of transportation capacity	**16.7**	**16.4**
Emera Utility Services	Purchase and maintenance of transformers	**2.4**	**4.6**
Cablecom	Purchase of line extension work	**3.8**	**2.3**
Emera Inc. and affiliate under common control	Dividends paid	**91.0**	**153.1**
Emera Inc.	Purchase of LM6000 gas turbine	**0**	**22.1**
	Allocation of common costs	**$6.0**	**$5.8**

The company also provides services to other various affiliates in the normal course of operations amounting to $2.5 million (2004 - $2.7 million) and receives services from other various affiliates in the normal course of operations amounting to $3.9 million (2004 - $4.6 million).

Disclosure Controls and Procedures

Under the supervision and participation of our management, including the President and Chief Executive Officer and the Chief Financial Officer, we evaluated the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Multilateral Instrument 52-109, Certification of Disclosure in Issuers' Annual and Interim Filings) as of December 31, 2005.

Based on that evaluation, the President and Chief Executive Officer and the Chief Financial Officer concluded that our disclosure controls and procedures are effective in making known to them material information relating to us that is required to be disclosed in our reports filed or submitted under the Multilateral Instrument.

Critical Accounting Estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, related amounts of revenues and expenses, and disclosure of contingent assets and liabilities. Significant areas requiring the use of management estimates relate to rate regulation, the determination of pension and other employee benefits, unbilled revenue, asset retirement obligations, useful lives for depreciable assets and natural gas price adjustment receivable. Actual results may differ from these estimates.

Rate Regulation

NSPI's accounting policies are subject to examination and approval by the UARB. As a result, NSPI's rate-regulated accounting policies may differ from accounting policies for non-rate-regulated companies. These differences occur when regulators render decisions on rate applications or other matters and generally involve the timing of revenue and expense recognition.

The accounting for these items is based on an expectation of the future actions of the regulator. For example, the company does not record future income taxes. The taxes payable method is prescribed by the regulator for rate-making purposes and there is reasonable expectation that the regulator will provide for all such future income taxes to be recovered in rates when they become payable. Similarly, the deferral of differences between the amounts included in rates and actual experience for specified expenses is based on the expectation that the regulator will approve the refund to or recovery from ratepayers of the deferred balance.

If the regulator's future actions are different from the company's expectations, the timing and amount of the recovery of liabilities and refund of assets, recorded or unrecorded, could be significantly different from that reflected in the financial statements.

Pension and Other Post-Retirement Employee Benefits

The company provides post-retirement benefits to employees, including a defined benefit pension plan. The cost of providing these benefits is dependent upon many factors that result from actual plan experience and assumptions of future experience.

The benefit cost and accrued benefit obligation for employee future benefits included in annual compensation expenses are affected by employee demographics, including age, compensation levels, employment periods, contribution levels and earnings on plan assets.

Changes to the provisions of the plan may also affect current and future pension costs. Benefit costs may also be significantly affected by changes in key actuarial assumptions, including anticipated rates of return on plan assets and discount rates used in determining the accrued benefit obligation and benefit costs.

The pension plan assets are comprised primarily of equity and fixed income investments. Fluctuations in actual equity market returns and changes in interest rates may result in increased or decreased pension costs in future periods.

The following table reflects the sensitivities associated with a change in certain actuarial assumptions. If both the expected rate of return on plan assets or the discount rate were increased by 0.5%, the impact on the 2006 benefit cost and accrued benefit asset recorded in the year end financial statements would be as follows:

(millions of dollars)	2006
Impact of increasing the rate of return assumption by 0.5%	
Benefit cost	$(2.9)
Accrued benefit asset	$2.9
Impact of increasing the discount rate assumption by 0.5%	
Benefit cost	$(6.4)
Accrued benefit asset	$6.4

The discount rate used to determine benefit costs is based on "A' grade long-term Canadian corporate bonds. The discount rate is determined with reference to bonds which have the same duration as the accrued benefit obligation, as at January 1st of the fiscal year rounded to the nearest 25 basis points. The rate was 6.0% for 2005 and 2004. The expected rate to be used for 2006 is 5.25%.

The expected return on plan assets is based on management's best estimate of future returns, considering economic and consensus forecasts. The 2004 and 2005 benefit cost calculations assumed that plan assets would earn a rate of return of 7.5%. The 2006 benefit cost calculation is expected to use the same asset return assumption.

Unbilled Revenue

Electric revenues are billed on a systematic basis over a one or two-month period. At the end of each month the company must make an estimate of energy delivered to customers since the date their meter was last read and of related revenues earned but not yet billed. The unbilled revenue is estimated based on several factors including current month's generation, estimated customer usage by class, weather, line losses and applicable customer rates. Based on the extent of the estimates included in the determination of unbilled revenue, actual results may differ from the estimate. As of December 31, 2005, unbilled revenues amount to $63.8 million (2004 - $65.8) on a base of annual electric revenues of approximately $955 million (2004 - $926.9 million).

Natural Gas Price Adjustment Receivable

NSPI's existing long term natural gas purchase agreement includes a price adjustment clause covering three years of natural gas purchases. The clause states that NSPI will pay for all gas purchases at the agreed contract price, but will be entitled to a price rebate on a portion of the volumes, to be settled in November 2007. Management has made a best estimate of the price rebate based on the contract specifications using actual and forward marketing pricing and recorded it in long-term receivables.

Asset Retirement Obligations

The company recognizes asset retirement obligations for property, plant and equipment in the period in which they are incurred if a reasonable estimate of fair value can be determined. The fair value of the liability is described as the amount at which the liability could be settled in a current transaction between willing parties. Expected values are discounted at the risk-free interest rate adjusted to reflect the market's evaluation of the company's credit standing. Determining asset retirement obligations requires estimating the life of the related asset and the costs of activities such as demolition, dismantling, restoration and remedial work based on present day methods and technologies.

As part of the 2003 depreciation settlement, the UARB included the amount of future expenditures associated with the removal of generation facilities. The company believes that it will continue to be able to recover asset retirement obligations through rates. Accordingly, changes to the asset retirement obligations or cost recognition attributable to changes in the factors discussed above, should not impact the results of operations of the company.

At December 31, 2005, the asset retirement obligations recorded on the balance sheet were $71.4 million (2004 - $67.8 million). The company estimates the undiscounted amount of cash flow required to settle the obligations is approximately $308.2 million, which will be incurred between 2007 and 2061. The majority of these costs will be incurred between 2020 and 2039.

Property, Plant and Equipment

Property, plant and equipment represents 80% of total assets recognized on the company's balance sheet. Included in property, plant and equipment are the generation, transmission and distribution and other assets of the company. Due to the size of the company's property, plant and equipment, changes in estimated depreciation rates can have a significant impact on depreciation expense.

Depreciation is calculated on a straight-line basis over the estimated service life of the asset. The estimated useful lives of the assets are based on formal depreciation studies which are conducted from time to time.

In 2002, NSPI commissioned a Depreciation Study by an external consultant. The study was filed with the UARB in 2003. A settlement agreement on the matter was reached with all intervenors, which recommended a four-year phase-in of new depreciation rates, which, based on assets in service in the study would reach an overall increase of $20 million by 2007. The UARB approved the settlement. NSPI began phasing the new rates in 2004. Subsequently, in its 2005 rate decision, the UARB deferred the scheduled phase-in for 2005. NSPI's 2006 rate application includes the phase-in of Year 2 rates as per the settlement agreement.

Change In Accounting Policies

In 2005, the company adopted the new accounting guidelines related to variable interest entities and disclosures by entities subject to rate regulation.

Variable Interest Entities

The Canadian Institute of Chartered Accountants ("CICA") issued Accounting Guideline 15 Consolidation of Variable Interest Entities, which applies to annual and interim periods beginning on or after November 1, 2004. A variable interest entity ("VIE") is any type of legal structure in which control is determined through contractual or other financial arrangements as opposed to traditional voting rights, if certain conditions exist. The guideline requires the enterprise which absorbs the majority of a VIE's expected losses or receives the majority of a VIE's expected residual returns, the primary beneficiary, to consolidate the VIE.

The company has variable interests in VIEs that are not consolidated because the company is not considered the primary beneficiary. These variable interests consist of purchase power agreements for renewable energy with independent power producers. The company's only obligation under these agreements is to purchase all of the energy produced, which currently is expected to approximate 100 GWh annually.

Disclosures by Entities Subject to Rate Regulation

The CICA issued Accounting Guideline 19 Disclosures by Entities Subject to Rate Regulation ("AcG-19"), which is effective for fiscal years ending on or after December 31, 2005. AcG-19 is intended to ensure that financial statement users are better informed about the existence, nature and economic effects of rate regulation, as well as its financial statement effects. NSPI's financial statements and supporting notes reflect the new requirements.

Future Accounting Policy Changes

The company is currently assessing the financial impact of the CICA's Emerging Issue Committee Abstract 159 Conditional Asset Obligations ("EIC-159"). EIC-159 is to be applied retroactively, with restatement of prior periods, to all financial statements for interim and annual reporting periods ending after March 31, 2006. EIC-159 was issued in response to the diverse accounting practices developed with respect to the timing of liability recognition when the timing and/or method of settlement are conditional on a future event.

The company is also assessing the financial impact of CICA Handbook sections 1530 Comprehensive Income, 3855 Financial Instruments – Recognition and Measurement, 3861 Financial Instruments – Disclosure and Presentation, and 3865 Hedges. These new standards apply to interim and annual financial statements beginning on or after October 1, 2006.

Business Risks and Enterprise Risk Management

Risk Management

Significant risk management activities for NSPI are overseen by the Enterprise Risk Management Committee to ensure that risks are appropriately assessed, monitored and controlled within predetermined risk tolerances established through Board approved policies.

The company's risk management activities are focused on those areas that most significantly impact profitability and quality of earnings. These risks include, but are not limited to, exposure to commodity prices, foreign exchange, credit risk, interest rates and regulatory risks.

Commodity Prices

Substantially all of the company's annual fuel requirement is subject to fluctuations in commodity market prices, prior to any commodity risk management activities. NSPI developed and put forth for regulatory approval, a portfolio strategy for fuel procurement. The strategy consists of a combination of long, medium and short term supply agreements. It also provides for supply and supplier diversification with credit worthy counterparties. The strategy is designed to reduce the effects from market volatility through agreements with staggered expiration dates, volume options, and varied pricing mechanisms.

Coal / Petroleum Coke

A substantial portion of the company's coal and petroleum coke supply comes from international suppliers at prevailing market prices. The company has entered into fixed-price contractual arrangements with several suppliers as part of the fuel procurement portfolio strategy. Physical contracts are used to hedge coal price risk due to the lack of liquidity in the financial markets for coal. The approximate percentage of coal and petcoke requirements contracted as at December 31, 2005 is as follows:

- For 2006, 85%
- For 2007, 23%
- For 2008, 17%

Heavy Fuel Oil

NSPI manages exposure to changes in the market price of heavy fuel oil through the use of swaps, options and futures contracts. As at December 31, 2005, the price of heavy fuel oil purchases has been hedged and contracted at approximately as follows:

- For 2006, 90%
- For 2007, 26%

Natural Gas

The company has entered into multi-year contracts to purchase approximately 65 million cubic feet of natural gas per day. Volumes exposed to market prices are managed using financial instruments where the fuel is required for generation; and the balance is sold against floating market prices where available for resale. Fixed price gas volumes not required for generation will be resold into the gas market with the margin managed using financial instruments. As at December 31, 2005, the amounts of natural gas volumes that have been hedged and contracted are approximately as follows:

- For 2006, 80%.
- For 2007, 54%
- For 2008, 54%

Fuel Mix

The risk due to fluctuation of the Canadian dollar against the US dollar for the cost of fuel is measured and managed. The ability to switch fuel provides a dynamic, operational and effective option in managing commodity price and supply risk.

Foreign Exchange

In 2006, the company expects approximately 80% of its anticipated net fuel costs to be denominated in U.S. dollars, $US income from sales of surplus natural gas will provide a natural hedge against a portion of $US denominated fuel costs. Forward contracts are in place for approximately 93% of 2006 anticipated $US net fuel costs.

Interest Rates

Nova Scotia Power manages interest rate risk through a combination of fixed and floating borrowing and a hedging program. Prior to hedging, floating rate debt is estimated to represent approximately 15% of total debt in 2006. Interest forward rate agreements and swaps are used to fix rates on part of the floating rate debt, while interest rate caps are used to limit exposure to movements of interest rates on floating debt. For 2006, interest on approximately 64% of the company's anticipated floating debt is capped through cap contracts at an average rate of 4.10%.

Credit Risk

Credit risk arising as a result of contractual obligations between the corporation and other counterparties is managed by assessing the counterparties' financial creditworthiness prior to assigning credit limits based upon Board of Directors approved credit policies. The corporation frequently uses master agreements to further mitigate credit exposure.

Regulatory Risk

In December 2001, the Nova Scotia government released Nova Scotia's Energy Strategy, *Seizing the Opportunity*. The strategy for the electricity industry is to carefully introduce certain aspects of competition over time. The Electricity Act, passed by the Nova Scotia Legislature in 2004, has not yet been proclaimed. Once proclaimed, wholesale customers may purchase electricity from other competitive supplier. The wholesale market in Nova Scotia is limited to the six municipal distribution utilities, which represent approximately 1.3% of NSPI's revenues.

In May 2005, the Nova Scotia Utility and Review Board (UARB) approved Nova Scotia Power's (NSPI) Open Access Transmission Tariff ("OATT"). The OATT will facilitate competition in the wholesale market. It also ensures that Nova Scotia meets United States and other Canadian market reciprocity requirements, thus facilitating electricity exports.

Further material restructuring of the electricity industry in Nova Scotia is not expected for at least the medium term. The province's geographic location, the limits of inter-provincial transmission links, and the diversity of our customer are key factors.

NSPI faces risk with respect to the timeliness and certainty of full recovery of fuel and other costs. In its 2005 rate decision, the UARB discussed a Fuel Adjustment Mechanism ("FAM") and did not rule out the possibility of a FAM in the future. The Company plans to work with the UARB and other stakeholders to identify and meet the conditions necessary for future approval of a FAM. In the interim, NSPI is addressing UARB concerns with regard to fuel and NSPI expects to undertake general rate cases more frequently to ensure it fully recovers fuels costs.

NSPI has applied for customer rates for 2006 to recover higher fuel expenses. The hearing is complete and UARB's decision is anticipated in Q1, 2006.

Labour

In June 2004, NSPI reached a fifty-two month agreement with 800 unionized employees which expires in late 2007.

Environmental Protection

Corporate Environmental Governance

NSPI is committed to operating in a manner that is respectful and protective of the environment, and in full compliance with legal requirements and company policy. NSPI has implemented this policy through development and application of environmental management systems ("EMS").

Implementation of the EMS has provided a systematic focus on environmental issues such that risks are identified and managed proactively. For example, hydro operations within NSPI developed strategies to identify the potential of and increase protection against, accidental release of oil to water. Other areas of the company also undertook initiatives to reduce potential environmental risks and associated costs.

Conformance with legislative and company requirements is verified through an environmental audit program. The 2005 program maintained an objective to review all NSPI operations within a three-year cycle. Results from 2005 continued to show improved environmental performance.

The Emera Board of Directors' Environmental, Safety and Security Committee met several times throughout 2005 and continued to carry out its oversight role in ensuring focus is placed on environmental protection. Environmental performance is also regularly reviewed by the Emera Executive and NSPI Leadership Team. In addition, an Environmental Council, made up of senior Emera employees, including NSPI staff, with working accountability for environment, continues to guide the implementation of programs that address key environmental issues.

Atmospheric Emissions

Beginning in 2005 and continuing through the end of the decade, Air Quality Regulations under the Nova Scotia Environment Act require reductions of sulphur dioxide (SO2), oxides of nitrogen (NOx) and mercury emitted from Nova Scotia Power (NSPI) facilities. In addition, the Canadian government is a signatory to the Kyoto Protocol. NSPI continues to work with the federal and provincial governments to develop an implementation plan that considers the potential cost and benefits to the company and its customers

NSPI met its 2005 Air Quality Regulations annual emissions limits. Plans have been developed to achieve the objectives in NSPI's Air Emissions Strategy which addresses the entire suite of air emissions, including those linked to greenhouse gases. In 2005 NSPI:

- invested approximately $20 million on electrostatic precipitator upgrades to control particulate emissions at the Tufts Cove plant.
- filed an application with the Utilities and Review Board recommending an investment of approximately $177 million for a wet flue gas desulphurization unit that will reduce sulphur dioxide emissions at Lingan and to install low NOx burners at Lingan, to reduce emissions of oxides of nitrogen.
- signed contracts with several independent power producers (IPPs) for renewable energy that will increase NSPI's renewable energy supply by 25% over 2002 levels. These contracts represent an addition of approximately 100 MW of supply, almost entirely from wind with some biomass and

- addressed customer feedback in the 2004 Customer Energy Forum indicating that customers want NSPI to play a stronger role in educating consumers on energy efficiency and conservation. As part of its 2006 Rate Case filing, NSPI has proposed to invest $5 million annually towards new energy conservation and efficiency measures aimed at customers. The UARB Decision is anticipated in Q1, 2006.

Summary of Quarterly Results

For the quarter ended
(millions of dollars)

	Total Revenues	Net earnings applicable to common shares
December 31, 2005	$245.1	$34.0
September 30, 2005	$223.8	$2.7
June 30, 2005	$232.3	$13.7
March 31, 2005	$261.8	$40.8
December 31, 2004	$239.0	$25.0
September 30, 2004	$213.4	$18.5
June 30, 2004	$222.3	$25.0
March 31, 2004	$259.4	$38.8

Quarterly revenues and quarterly net earnings applicable to common shares are affected by seasonality, with Q1 and Q4 the strongest periods, reflecting colder weather and fewer daylight hours at those times of the year.

NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF: The *Public Utilities Act,* R.S.N.S. 1989, c.380 as amended

IN THE MATTER OF: An Application by Nova Scotia Power Incorporated for Approval of Certain Revisions to its Rates, Charges and Regulations

RESPONSE TO INFORMATION REQUEST

TO: NSPI

FROM: UARB

Question IR-79: **Please file the Emera third quarter 2006 Financial Statements.**

Response IR-79: Please refer to Attachment 1.

Financial Statements

Consolidated Statements of Earnings (Unaudited)

For the millions of dollars (except earnings per common share)	Three months ended September 30		Nine months ended September 30	
	2006	2005	**2006**	2005
Revenue				
Electric	**$261.1**	$268.0	**$830.4**	$838.6
Other	**11.3**	13.1	**28.6**	32.3
	272.4	281.1	**859.0**	870.9
Cost of operations				
Fuel for generation and purchased power	**81.2**	113.7	**245.4**	335.3
Operating, maintenance, and general	**66.2**	63.1	**190.6**	186.3
Provincial, state, and municipal taxes	**12.2**	12.2	**36.3**	36.6
Provincial tax deferral (note 10)	**-**	-	**-**	(4.9)
Depreciation	**36.1**	34.1	**108.3**	101.9
Regulatory amortization	**6.4**	5.7	**16.6**	16.5
Allowance for funds used during construction	**(1.4)**	(1.4)	**(3.7)**	(3.4)
	200.7	227.4	**593.5**	668.3
Earnings from operations	**71.7**	53.7	**265.5**	202.6
Equity earnings (note 8)	**1.2**	1.5	**3.7**	4.8
Earnings before interest and income taxes	**72.9**	55.2	**269.2**	207.4
Interest (note 9)	**32.2**	22.6	**92.9**	79.0
Amortization of defeasance costs	**3.2**	3.3	**9.5**	9.9
Earnings before income taxes	**37.5**	29.3	**166.8**	118.5
Income taxes	**14.7**	7.9	**64.5**	34.5
Income taxes deferral (note 10)	**-**	-	**-**	(10.4)
Net earnings before non-controlling interest	**22.8**	21.4	**102.3**	94.4
Non-controlling interest	**3.3**	3.3	**10.0**	10.0
Net earnings from continuing operations	**19.5**	18.1	**92.3**	84.4
Loss from discontinued operations, net of tax (note 5)	**-**	(2.2)	**-**	(0.9)
Net earnings applicable to common shares	**$19.5**	$15.9	**$92.3**	$83.5
Earnings per common share – basic				
Continuing operations	**$0.18**	$0.16	**$0.84**	$0.77
Discontinued operations	**-**	(0.02)	**-**	(0.01)
	$0.18	$0.14	**$0.84**	$0.76
Earnings per common share – diluted				
Continuing operations	**$0.18**	$0.16	**$0.82**	$0.77
Discontinued operations	**-**	(0.02)	**-**	(0.01)
	$0.18	$0.14	**$0.82**	$0.76

See accompanying notes to the unaudited consolidated financial statements.

Weighted average number of common shares outstanding (millions)				
– basic	110.6	109.7	110.4	109.4
– diluted	110.6	109.7	116.8	109.4

Consolidated Statements of Retained Earnings (Unaudited)

For the nine months ended September 30 millions of dollars	2006	2005
Retained earnings, beginning of year	**$423.4**	$399.6
Net earnings applicable to common shares	**92.3**	83.5
	515.7	483.1
Dividends	**73.6**	72.9
Retained earnings, end of period	**$442.1**	$410.2

See accompanying notes to the unaudited consolidated financial statements.

Consolidated Balance Sheets (Unaudited)

As at millions of dollars	September 30 2006	December 31 2005 Restated (note 3)
Assets		
Current assets		
Cash and cash equivalents	**$4.5**	$21.5
Restricted cash	**14.3**	5.8
Accounts receivable	**183.8**	231.8
Income tax receivable	**-**	15.1
Inventory (note 3)	**121.3**	76.1
Prepaid expenses	**46.0**	15.9
Future income tax assets	**14.9**	9.3
Energy marketing assets	**19.4**	16.0
	404.2	391.5
Long-term receivables	**62.6**	48.4
Energy marketing assets	**3.2**	4.1
Deferred charges	**468.7**	508.3
Future income tax assets	**10.9**	19.0
Goodwill	**93.0**	97.1
Investments (note 11)	**99.3**	101.0
Property, plant and equipment	**2,732.1**	2,789.2
Construction work in progress	**85.5**	40.0
	2,817.6	2,829.2
	$3,959.5	$3,998.6
Liabilities and Shareholders' Equity		
Current liabilities		
Current portion of long-term debt	**$3.6**	$152.9
Short-term debt	**184.3**	88.1
Accounts payable and accrued charges	**217.0**	248.6
Income tax payable	**20.4**	1.5
Dividends payable	**3.2**	3.2
Energy marketing liabilities	**17.7**	12.1
	446.2	506.4
Energy marketing liabilities	**3.7**	2.9
Future income tax liabilities	**78.9**	78.9
Asset retirement obligations (note 3 and note 12)	**77.1**	74.1
Deferred credits	**66.5**	77.5
Long-term debt (note 13)	**1,646.7**	1,631.8
Non-controlling interest	**260.8**	260.8
Shareholders' equity		
Common shares (note 14)	**1,052.0**	1,039.2
Contributed surplus (note 15)	**2.0**	1.8
Foreign exchange translation adjustment	**(116.5)**	(98.2)
Retained earnings	**442.1**	423.4
	1,379.6	1,366.2
	$3,959.5	$3,998.6

Contingencies (Note 17)
See accompanying notes to the unaudited consolidated financial statements.

Approved on behalf of the Board of Directors

"Derek Oland"
Derek Oland
Chairman

"Christopher Huskilson"
Christopher Huskilson
President and Chief Executive Officer

Consolidated Statements of Cash Flow (Unaudited)

For the millions of dollars	Three months ended September 30		Nine months ended September 30	
	2006	2005	**2006**	2005
Operating activities				
Net earnings before non-controlling interest	**$22.8**	$21.4	**$102.3**	$94.4
Non-cash items:				
Depreciation	**36.1**	34.1	**108.3**	101.9
Deferral of provincial taxes and income taxes	**-**	-	**-**	(15.3)
Amortization of deferred charges	**3.6**	3.8	**10.4**	11.8
Equity earnings	**(1.2)**	(1.5)	**(3.7)**	(4.8)
Regulatory amortization	**6.4**	5.7	**16.6**	16.5
Allowance for funds used during construction	**(1.4)**	(1.4)	**(3.7)**	(3.4)
Future income taxes	**2.8**	4.7	**6.0**	9.8
Other non-cash operating items	**7.0**	2.7	**25.4**	11.4
Discontinued operations	**-**	0.3	**-**	2.1
Other cash operating items	**(11.1)**	(8.6)	**(20.5)**	(16.9)
	65.0	61.2	**241.1**	207.5
Change in non-cash operating working capital	**33.8**	55.5	**(2.0)**	(6.9)
Net cash provided by operating activities	**98.8**	116.7	**239.1**	200.6
Investing activities				
Property, plant and equipment	**(52.9)**	(39.3)	**(109.7)**	(92.9)
Proceeds on disposition (note 5)	**-**	0.1	**-**	0.1
Acquisition (note 4)	**-**	-	**-**	(52.6)
Retirement spending net of salvage	**(0.6)**	(1.2)	**(2.2)**	(2.9)
Increase in restricted cash	**(4.3)**	(43.3)	**(8.5)**	(25.9)
Other investing activities	**0.4**	-	**0.4**	(1.5)
Net cash used in investing activities	**(57.4)**	(83.7)	**(120.0)**	(175.7)
Financing activities				
Retirement of long-term debt	**-**	-	**(150.8)**	(102.3)
Issuance of long-term debt	**-**	-	**40.0**	100.0
(Decrease) increase in short-term debt	**(41.8)**	(5.5)	**76.5**	51.1
Issuance of common shares	**6.0**	4.0	**12.1**	16.9
Dividends on common shares	**(24.5)**	(24.4)	**(73.6)**	(72.9)
Dividends paid by subsidiaries to non-controlling interest	**(3.3)**	(3.3)	**(10.0)**	(10.0)
Accounts receivable securitization	**-**	(20.0)	**(30.0)**	(30.0)
Other financing	**0.3**	2.7	**(0.3)**	(1.2)
Net cash used in financing activities	**(63.3)**	(46.5)	**(136.1)**	(48.4)
Decrease in cash and cash equivalents	**(21.9)**	(13.5)	**(17.0)**	(23.5)
Cash and cash equivalents, beginning of period	**26.4**	32.7	**21.5**	42.7
Cash and cash equivalents, end of period	**$4.5**	$19.2	**$4.5**	$19.2
Cash and cash equivalents consists of:				
Cash	**$3.0**	$18.4	**$3.0**	$18.4
Cash equivalents	**1.5**	0.8	**1.5**	0.8
Cash and cash equivalents, end of period	**$4.5**	$19.2	**$4.5**	$19.2
Supplemental disclosure of cash paid:				
Interest	**$17.8**	$36.3	**$96.4**	$97.4
Income and capital taxes	**$7.5**	$15.8	**$33.8**	$48.9

See accompanying notes to the unaudited consolidated financial statements.

Notes to the Interim Unaudited Consolidated Financial Statements

September 30, 2006

1. Basis of Presentation

The disclosures in these unaudited interim consolidated financial statements do not conform in all respects to the requirements of Canadian Generally Accepted Accounting Principles for annual audited financial statements and should be read in conjunction with Emera Inc.'s annual consolidated financial statements as at and for the year ended December 31, 2005.

These consolidated financial statements follow the same accounting policies and methods of computation as Emera Inc.'s annual audited consolidated financial statements as at and for the year ended December 31, 2005 with the exception of the accounting policy changes disclosed in note 3.

2. Seasonal Nature of Operations

Interim results are not necessarily indicative of results for the full year due primarily to seasonal factors. Sales and related production vary significantly over the year, with Q1 and Q4, the strongest periods, reflecting colder weather and fewer daylight hours in the winter season.

3. Changes in Accounting Policy

Conditional Asset Retirement Obligations

In December 2005, the Canadian Institute of Chartered Accountants ("CICA") issued Emerging Issues Committee Abstract 159 Conditional Asset Retirement Obligations ("EIC-159"). EIC-159 is to be applied retroactively, with restatement of prior periods, to financial statements for interim and annual reporting periods ending after March 31, 2006. EIC-159 was issued in response to the diverse accounting practices that have developed under CICA Handbook Section 3110 Asset Retirement Obligations ("Section 3110") with respect to the timing of liability recognition when the timing and/or method of settlement are conditional on a future event.

As a result of adopting EIC-159, the Company has determined that it has conditional asset retirement obligations related to the disposal of polychlorinated biphenyls ("PCBs"). As at September 30, 2006, property, plant and equipment has increased by $0.6 million (December 31, 2005 - $0.6 million), accumulated depreciation has decreased by $1.9 million (December 31, 2005 - $1.8 million), and asset retirement obligations have increased by $2.5 million (December 31, 2005 - $2.4 million). There is no impact to net earnings in 2006 and 2005.

Accounting for the impact of rate regulation:

Any difference between the amount of depreciation and accretion expense approved by the regulator of Nova Scotia Power and the amount that would have been calculated under EIC-159 is recognized as a regulatory asset in accumulated depreciation. In the absence of this deferral, year to date net earnings for 2006 would be $0.1 million lower.

Inventory

In August 2006, Nova Scotia Power changed its method of costing fuel inventory from the first-in, first-out method to the weighted average cost method to provide more appropriate information. The change in accounting policy has been approved by the UARB.

The CICA Handbook Section 1506 Accounting Changes requires that changes in accounting policies be applied retroactively to all prior periods presented for comparative purposes. Nova Scotia Power applied the change in accounting policy retroactively but did not restate prior periods as the necessary adjustments were considered immaterial. The change in accounting policy resulted in a cumulative adjustment to the opening balance of fuel inventory in Q3 2006 of $1.0 million. As a result, NSPI decreased inventory by $1.0 million and increased fuel expense by $1.0 million in Q3 2006.

4. Acquisition

On May 24, 2005 Emera and Brookfield Power Corporation, in a 50/50 joint venture, acquired Bear Swamp, a 600 megawatt ("MW") pumped storage hydro-electric facility in northern Massachusetts. Emera's share of the purchase price was $61.2 million. The facility sells energy, capacity and ancillary products into the New England Power Pool. Also included in the acquisition is the nearby 10 MW Fife Brook run-of-river hydro-electric facility.

The acquisition has been accounted for under the purchase method of accounting using proportionate consolidation, and accordingly, Emera's pro-rata share of the results since acquisition have been included in the consolidated statements of earnings.

Emera's share of the transaction is as follows:

millions of dollars	
Net assets acquired at fair value	
Inventory	$0.2
Property, plant and equipment	61.8
Deferred charges	0.2
Accrued liabilities	(0.1)
Deferred credits	(0.9)
Total cash consideration	$61.2

5. Discontinued Operations

Effective September 30, 2005 Emera Fuels, a subsidiary of Emera, sold its heating oil distribution business. Emera Fuels is included in the segment "Other" in Note 6 Segment Information.

Emera Fuels has been accounted for as a discontinued operation. Accordingly, prior periods have been reclassified to reflect this change. The following provides additional information with respect to amounts included in earnings from discontinued operations on the consolidated statements of earnings:

For the millions of dollars	Three months ended September 30		Nine months ended September 30	
	2006	2005	**2006**	2005
Revenue	-	$19.1	-	$69.7
Earnings before income taxes	-	(0.9)	-	0.3
Loss on disposition, net of tax	-	(1.6)	-	(1.6)

The following summarizes the transaction:

millions of dollars	
Proceeds on disposition	$18.6
Disposition costs	0.2
Net proceeds on disposition	18.4
Net assets included in disposition	19.3
Loss on disposition	0.9
Income taxes	0.7
Loss on disposition, net of tax	$1.6

Proceeds were received in Q4 2005.

6. Segment Information

Segmented financial information for the three months ended and as at September 30, 2006:

millions of dollars	NSPI	Bangor Hydro	Other*	Total
Revenues from external customers	$222.7	$34.2	$15.5	$272.4
Depreciation	32.0	3.5	0.6	36.1
Cost of operations, including depreciation	164.8	23.3	12.6	200.7
Net inter-segment operating revenues/(expenses)	32.9	(0.8)	(32.1)	-
Equity earnings	-	-	1.2	1.2
Interest expense	27.0	2.7	2.5	32.2
Income taxes	11.6	3.1	-	14.7
Net earnings applicable to common shares	12.7	5.1	1.7	19.5
Assets	3,066.7	581.9	310.9	3,959.5
Goodwill	-	93.0	-	93.0
Capital expenditures	28.1	21.4	3.4	52.9

* Other consists of items related to corporate activities and other subsidiaries.

Segmented financial information for the three months ended and as at September 30, 2005:

millions of dollars	NSPI	Bangor Hydro	Other*	Total
Revenues from external customers	$223.9	$36.6	$20.6	$281.1
Depreciation	30.0	3.6	0.5	34.1
Cost of operations, including depreciation	186.5	26.3	14.6	227.4
Net inter-segment operating revenues/(expenses)	51.9	(0.6)	(51.3)	-
Equity earnings	-	-	1.5	1.5
Interest expense	23.1	2.9	(3.4)	22.6
Income taxes	4.9	2.8	0.2	7.9
Net earnings from continuing operations	2.7	4.4	11.0	18.1
Net earnings applicable to common shares	2.7	4.4	8.8	15.9
Assets	3,082.4	593.6	443.1	4,119.1
Goodwill	-	96.7	-	96.7
Goodwill included in loss on disposition	-	-	7.4	7.4
Capital expenditures	30.8	8.4	0.1	39.3

* Other consists of items related to corporate activities and other subsidiaries.

Segmented financial information for the nine months ended and as at September 30, 2006:

millions of dollars	NSPI	Bangor Hydro	Other*	Total
Revenues from external customers	$717.2	$101.1	$40.7	$859.0
Depreciation	95.7	10.9	1.7	108.3
Cost of operations, including depreciation	485.6	74.0	33.9	593.5
Net inter-segment operating revenues/(expenses)	122.0	(2.2)	(119.8)	-
Equity earnings	-	-	3.7	3.7
Interest expense	78.0	8.5	6.4	92.9
Income taxes	59.8	7.1	(2.4)	64.5
Net earnings applicable to common shares	74.4	11.5	6.4	92.3
Assets	3,066.7	581.9	310.9	3,959.5
Goodwill	-	93.0	-	93.0
Capital expenditures	58.3	43.5	7.9	109.7

* Other consists of items related to corporate activities and other subsidiaries.

Segmented financial information for the nine months ended and as at September 30, 2005:

millions of dollars	NSPI	Bangor Hydro	Other*	Total
Revenues from external customers	$717.9	$111.6	$41.4	$870.9
Depreciation	89.3	11.3	1.3	101.9
Cost of operations, including depreciation	552.2	84.7	31.4	668.3
Net inter-segment operating revenues/(expenses)	117.0	(1.9)	(115.1)	-
Equity earnings	-	-	4.8	4.8
Interest expense	72.1	9.0	(2.1)	79.0
Income taxes	27.0	6.8	0.7	34.5
Net earnings from continuing operations	57.2	10.9	16.3	84.4
Net earnings applicable to common shares	57.2	10.9	15.4	83.5
Assets	3,082.4	593.6	443.1	4,119.1
Goodwill	-	96.7	-	96.7
Goodwill included in loss on disposition	-	-	7.4	7.4
Capital expenditures	70.8	23.4	51.3	145.5

* Other consists of items related to corporate activities and other subsidiaries.

7. Employee Future Benefits

Emera maintains contributory defined-benefit and defined-contribution pension plans, which cover substantially all of its employees, and plans that provide non-pension benefits for its retirees. The Company's estimated cost, related to these plans, for the three month period ended September 30, 2006 is $10.7 million (2005 - $7.6 million), and for the nine month period ended September 30, 2006 is $32.2 million (2005 - $22.2 million).

8. Equity Earnings

Equity earnings of $1.2 million (2005 - $1.5 million) for the three months ended September 30, 2006, and $3.7 million (2005 - $4.8 million) for the nine month period ended September 30, 2006 consists of the Company's pro-rata share of after-tax earnings from Maritimes and Northeast Pipeline, an investment under significant influence of the Company.

9. Interest

Interest expense consists of the following:

For the millions of dollars	Three months ended September 30		Nine months ended September 30	
	2006	2005	**2006**	2005
Interest on long-term debt	**$25.6**	$25.7	**$78.8**	$78.9
Interest on short-term debt	**5.4**	5.7	**10.9**	12.4
Amortization of debt financing	**0.5**	0.4	**1.5**	1.4
Foreign exchange losses (gains)	**0.7**	(9.2)	**1.7**	(13.7)
	$32.2	$22.6	**$92.9**	$79.0

10. Provincial Tax Deferral and Income Tax Deferral

The UARB agreed to allow NSPI to defer taxes not reflected in rates for the period January 1, 2005 until April 1, 2005, the date when new rates became effective. In Q1 2005, NSPI deferred a portion of provincial and federal grants and taxes. The amortization period is subject to approval by the UARB.

11. Investments

Investments are comprised of the following:

As at millions of dollars	**September 30 2006**	December 31 2005
Equity accounted investments		
Maritimes & Northeast Pipeline ("M&NP")	**$91.9**	$92.8
Maine Yankee Atomic Power Company	**1.4**	2.4
Maine Electric Power Company Inc.	**1.2**	1.5
Intragas Energy	**1.9**	1.9
Total equity investments	**96.4**	98.6
Long-term portfolio investments	**2.9**	2.4
	$99.3	$101.0

12. Asset Retirement Obligations

In addition to asset retirement obligations recognized under Section 3110 and EIC-159, the Company may have asset retirement obligations associated with some of its transmission and distribution assets. As the Company expects to use the majority of its installed assets for an indefinite period, no removal date can be determined and consequently a reasonable estimate of the fair value of any related asset retirement obligation cannot be made at this time.

13. Long-Term Debt

As at September 30, 2006 long-term debt includes $55.8 million of Bangor Hydro debt, which is secured by first mortgage indentures. As at December 31, 2005, long-term debt included $58.3 million of Bangor Hydro debt, which is secured by first mortgage indentures, and a private placement in Emera in the amount of $10.0 million, which was secured by a letter of credit. The private placement matured on April 24, 2006.

Long-term debt includes $4.3 million (December 31, 2005 - $0.9 million) in capital lease obligations.

14. Common Shares

As of September 30, 2006 there were 110.8 million (December 31, 2005 – 110.1 million) issued and outstanding common shares, 5.0 million (December 31, 2005 – 0.3 million) common shares reserved and available for issuance under the senior management stock option plan, and 1.2 million (December 31, 2005 – 1.3 million) common shares reserved and available for issuance under the employee common share purchase plan.

During the nine months ended September 30, 2006, the Company issued 0.7 million (2005 – 1.0 million) common shares for cash proceeds of $12.1 million (2005 - $16.9 million). Additionally, $0.7 million (2005 - $0.7 million) was recognized as share compensation. Common shares were issued through the employee common share purchase plan, the senior management stock option plan, and the dividend reinvestment plan.

15. Contributed Surplus

millions of dollars	
Balance, December 31, 2005	$1.8
Stock option expense	0.6
Exercise of stock options	(0.4)
Balance, September 30, 2006	$2.0

16. Related Party Transactions

In the ordinary course of business, Emera purchased natural gas transportation capacity totaling $7.4 million (2005 - $5.9 million) during the three months ended September 30, 2006, and $23.1 million (2005 - $16.6 million) during the nine months ended September 30, 2006 from the Maritimes & Northeast Pipeline, an investment under significant influence of the Company. The amount is recognized in fuel for generation and purchased power or netted against energy marketing margin in other revenue, and is measured at the exchange amount. At September 30, 2006 the amount payable to the related party is $5.3 million (December 31, 2005 – $4.5 million), and is under normal interest and credit terms.

17. Contingencies

The Company may, from time to time, be involved in legal proceedings, claims and litigation that arise in the ordinary course of business which the Company believes would not reasonably be expected to have a material adverse effect on the financial condition of the Company.

In late 2005 some of Nova Scotia Power's petroleum coke (petcoke) suppliers were unable to supply the fuel due to hurricanes in the Gulf of Mexico, which seriously affected their operations. As a result, NSPI incurred additional costs for replacement fuel, and other expenses. NSPI has advised its insurers that it intends to seek recovery of applicable costs. The insurers have advised that coverage is available under the policy but at this time NSPI is unable to estimate the total recovery amount.

18. Comparative Information

Certain of the comparative figures have been reclassified to conform to the consolidated financial statement presentation adopted for 2006.

NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF: The *Public Utilities Act,* R.S.N.S. 1989, c.380 as amended

IN THE MATTER OF: An Application by Nova Scotia Power Incorporated for Approval of Certain Revisions to its Rates, Charges and Regulations

RESPONSE TO INFORMATION REQUEST

TO: NSPI

FROM: UARB **REDACTED**

Question IR-80: **Please file the NSPI (Regulated) third quarter 2006 Financial Statements.**

Response IR-80: Please refer to Confidential Attachment 1.

NOVA SCOTIA POWER
An Emera Company

REGULATED STATEMENT OF EARNINGS

Period: September 2006

	Quarter-to-Date Actual September	Quarter-to-Date Budget September	Quarter-to-Date Variance September	Year-to-Date Actual	Year-to-Date Budget	Year-to-Date Variance	Full Year Budget	Prior YTD Actual	Curr/Prior YTD Variance
Revenue									
Electric	219,921,124	260,905,029	(40,983,905)	709,978,861	856,030,403	(146,051,542)	1,158,365,258	712,050,771	(2,071,911)
Other	3,003,154	2,776,893	226,261	7,922,784	8,007,534	(84,750)	10,390,248	6,367,831	1,554,953
	222,924,278	263,681,922	(40,757,644)	717,901,645	864,037,937	(146,136,292)	1,168,755,506	718,418,602	(516,958)
Cost of operations									
Fuel for generation	60,771,048	96,883,427	(36,112,379)	185,521,664	331,144,275	(145,622,611)	453,223,115	260,786,303	(75,264,639)
Power purchased	6,932,792	5,380,300	1,552,492	18,134,061	17,820,900	313,161	25,850,800	35,276,738	(17,142,677)
Fuel deferral	-	-	-	-	-	-	-	-	-
Cost of goods sold (Retail)	311,817	198,839	112,978	705,650	418,576	287,074	801,023	600,021	105,629
Operating, maintenance and general	51,388,697	53,236,368	(1,847,672)	147,127,312	155,359,436	(8,232,124)	206,422,755	137,146,848	9,980,465
Grants in lieu of property taxes	8,207,676	8,182,677	24,999	24,533,725	24,458,727	74,998	32,641,404	24,052,377	481,348
Provincial capital tax	1,918,000	1,779,773	138,227	5,687,373	5,281,283	406,090	7,061,056	6,193,382	(506,009)
Provincial grants & taxes deferred	-	-	-	-	-	-	-	(4,914,125)	4,914,125
Depreciation	31,164,165	31,770,919	(606,754)	93,083,960	94,865,797	(1,781,837)	126,902,201	87,923,499	5,160,461
Accretion	473,970	473,970	-	1,421,910	1,421,910	-	1,895,880	675,105	746,805
	161,168,165	197,906,273	(36,738,109)	476,215,655	630,770,904	(154,555,249)	854,798,234	547,740,148	(71,524,492)
	61,756,113	65,775,649	(4,019,535)	241,685,990	233,267,033	8,418,957	313,957,272	170,678,455	71,007,534
Glace Bay	(1,550,000)	(1,550,001)	1	(4,650,000)	(4,650,003)	3	(6,200,004)	(4,650,000)	-
Allowance for funds used in constr'n	405,793	1,016,984	(611,191)	1,109,174	1,992,396	(883,222)	2,655,642	1,695,451	(586,277)
Income before interest and income taxes	60,611,906	65,242,632	(4,630,725)	238,145,164	230,609,426	7,535,738	310,412,910	167,723,906	70,421,257
Interest	29,687,642	29,199,015	488,627	86,089,981	87,408,344	(1,318,362)	116,893,702	81,275,087	4,814,894
Earnings before income taxes	30,924,265	36,043,617	(5,119,353)	152,055,182	143,201,083	8,854,100	193,519,208	86,448,819	65,606,363
Large corporations tax	-	357,116	(357,116)	(31,010)	1,060,705	(1,091,715)	1,419,481	3,125,383	(3,156,393)
Income taxes, net	12,956,416	14,811,571	(1,855,156)	62,274,639	57,045,141	5,229,498	76,993,069	25,156,986	37,117,653
Income tax deferred	-	-	-	-	-	-	-	(10,415,000)	10,415,000
Net income	17,967,849	20,874,929	(2,907,080)	89,811,554	85,095,236	4,716,317	115,106,658	68,581,450	21,230,103
Preferred Dividends	3,320,100	3,319,850	250	9,956,484	9,959,551	(3,067)	13,279,401	9,958,301	(1,817)
Net Earnings Available To Common Shares	14,647,749	17,555,079	(2,907,330)	79,855,070	75,135,685	4,719,384	101,827,257	58,623,149	21,231,920

NOVA SCOTIA POWER
An Emera Company

REGULATED BALANCE SHEET

Period: September 2006

	September-06	September-05
ASSETS		
Fixed assets		
Property, plant and equipment in service	4,071,358,142	3,997,554,237
Less accumulated depreciation	1,745,295,947	1,643,063,395
	2,326,062,195	2,354,490,842
Construction work in progress	23,363,845	21,050,052
	2,349,426,040	2,375,540,894
Due From Associated Companies	9,746,093	20,621,044
Long-term Receivable	62,622,136	26,616,036
Deferred Charges	371,485,265	394,228,373
Current assets		
Cash	31,589	37,040
Short-term investments	8,213,672	17,782,348
Accounts receivable	87,920,814	91,990,591
Unbilled revenue	52,587,152	48,781,262
Materials inventory	28,515,427	26,809,418
Fuel inventory	87,610,617	57,305,172
Prepaid expenses	15,045,267	15,418,235
	279,924,538	258,124,066
	3,073,204,072	3,075,130,413

	September-06	September-05
SHAREHOLDER'S EQUITY AND LIABILITIES		
Shareholder's equity		
Common Shares	830,606,598	830,606,598
Preferred Shares	259,967,375	259,967,375
Retained earnings	286,626,792	245,725,790
	1,377,200,765	1,336,299,763
Long-term debt	1,349,314,275	1,195,000,000
Debt due within one year	-	40,000,000
	1,349,314,275	1,155,000,000
Deferred credits	88,883,194	92,864,895
Current liabilities		
Bank indebtedness	16,415,271	15,615,249
Short-term notes payable	93,201,595	269,267,022
Accounts payable and accrued charges	96,047,725	153,869,018
Income taxes payable	24,325,135	(12,158,619)
Dividends payable	3,212,352	3,212,352
Accrued interest on long-term debt	24,603,755	21,160,730
Debt due within one year	-	40,000,000
	257,805,833	490,965,752
	3,073,204,067	3,075,130,410

NOVA SCOTIA POWER
An Emera Company

REGULATED ACCRUED & BILLED ELECTRIC REVENUE

Period: September 2006

	Quarter-to-Date Actual September	Quarter-to-Date Budget September	Quarter-to-Date Variance September	Year-to-Date Actual	Year-to-Date Budget	Year-to-Date Variance	Full Year Budget	Prior YTD Actual	Curr/Prior YTD Variance
RESIDENTIAL	90,135,158	99,752,585	(9,617,427)	324,475,574	367,325,491	(42,849,917)	504,340,138	307,196,636	17,278,938
COMMERCIAL									
SMALL GENERAL	6,239,358	6,948,910	(709,552)	20,165,461	23,144,635	(2,979,174)	30,091,590	18,906,939	1,258,522
GENERAL	55,100,359	59,385,383	(4,285,024)	169,087,738	185,624,531	(16,536,793)	249,048,620	157,693,888	11,393,850
LARGE GENERAL	8,660,362	9,266,483	(606,121)	23,900,385	26,293,093	(2,392,708)	35,029,062	21,709,508	2,190,877
TOTAL COMMERCIAL	70,000,079	75,600,776	(5,600,697)	213,153,584	235,062,259	(21,908,675)	314,169,272	198,310,335	14,843,249
INDUSTRIAL									
SMALL INDUSTRIAL	5,851,725	6,083,482	(231,757)	16,211,983	17,813,972	(1,601,989)	23,984,297	14,963,387	1,248,596
MEDIUM INDUSTRIAL	11,827,636	12,807,929	(980,293)	33,339,411	37,111,259	(3,771,848)	50,077,648	30,092,770	3,246,641
LARGE INDUSTRIAL	5,214,977	5,730,440	(515,463)	15,035,782	16,750,901	(1,715,119)	22,291,766	13,464,269	1,571,513
T.O.U. - R.T.P.	(453)	-	(453)	(1,443)	-	(1,443)	-	-	(1,443)
2-P-RTP	1,843,078	3,318,069	(1,474,991)	5,073,473	9,958,675	(4,885,202)	13,233,679	8,291,204	(3,217,731)
LG.INDUST.INTERRUPT.RIDER	12,271,670	12,803,698	(532,028)	33,549,379	35,919,054	(2,369,675)	47,947,197	28,776,698	4,772,681
REPLACEMENT & LOAD FOLLOWIN	310,156	421,133	(110,977)	578,701	980,923	(402,222)	1,210,709	573,323	5,378
EXTRA LG. INDUST. INTERUPT.	3,038,465	28,556,604	(25,518,139)	9,835,567	85,056,663	(75,221,096)	113,570,397	67,244,927	(57,409,360)
MERSEY	4,415,893	4,627,002	(211,109)	12,652,442	13,715,562	(1,063,120)	18,342,563	13,154,253	(501,811)
TOTAL INDUSTRIAL	44,773,147	74,348,357	(29,575,210)	126,275,295	217,307,009	(91,031,714)	290,658,256	176,560,831	(50,285,536)
OTHER									
MUNICIPAL	3,320,331	3,534,094	(213,763)	10,317,950	11,480,086	(1,162,136)	15,502,705	9,439,657	878,293
UNMETERED	6,158,671	5,619,933	538,738	16,767,810	17,865,577	(1,097,767)	25,383,186	15,436,656	1,331,154
OTHER REVENUE	-	-	-	-	-	-	-	-	-
TOTAL OTHER	9,479,002	9,154,027	324,975	27,085,760	29,345,663	(2,259,903)	40,885,891	24,876,313	2,209,447
TOTAL	214,387,386	258,855,745	(44,468,359)	690,990,213	849,040,422	(158,050,209)	1,150,053,557	706,944,115	(15,953,902)
GRID SALES	5,533,737	2,049,286	3,484,451	18,988,648	6,989,982	11,998,666	8,311,702	5,106,655	13,881,993
TOTAL	219,921,123	260,905,031	(40,983,908)	709,978,861	856,030,404	(146,051,543)	1,158,365,259	712,050,770	(2,071,909)

NOVA SCOTIA POWER
An Emera Company

REGULATED OM&G EXPENSE & FUEL FOR THERMAL PLANTS

Period: September 2006

	Quarter-to-Date Actual September	Quarter-to-Date Budget September	Quarter-to-Date Variance September	Year-to-Date Actual	Year-to-Date Budget	Year-to-Date Variance	Full Year Budget	Prior YTD Actual	Curr/Prior YTD Variance
LINGAN									
LABOUR	2,644,407	2,656,734	(12,327)	8,092,616	8,264,343	(171,727)	11,315,116	7,586,575	506,041
NON-LABOUR	2,242,356	2,205,996	36,360	5,814,370	5,570,012	244,358	7,129,206	4,264,095	1,550,275
FUEL	34,754,115	41,804,600	(7,050,485)	112,846,049	121,269,600	(8,423,551)	163,156,300	116,773,842	(3,927,793)
	39,640,878	46,667,330	(7,026,452)	126,753,035	135,103,955	(8,350,920)	181,600,622	128,624,512	(1,871,477)
TUFTS COVE									
LABOUR	1,225,139	1,518,210	(293,071)	3,690,485	4,484,249	(793,764)	6,071,174	3,794,982	(104,497)
NON-LABOUR	1,758,136	1,464,892	293,244	3,307,462	3,362,358	(54,896)	5,350,581	3,147,731	159,731
FUEL	(4,661,323)	15,806,031	(20,467,354)	(23,912,090)	86,732,730	(110,644,820)	124,859,953	53,631,136	(77,543,226)
	(1,678,048)	18,789,133	(20,467,181)	(16,914,143)	94,579,337	(111,493,480)	136,281,708	60,573,849	(77,487,992)
TRENTON									
LABOUR	2,129,505	1,847,374	282,131	5,818,333	5,451,711	366,622	7,402,302	5,727,915	90,418
NON-LABOUR	2,206,846	2,000,660	206,186	4,551,065	3,393,941	1,157,124	4,115,988	4,410,244	140,821
FUEL	13,186,009	14,378,157	(1,192,148)	44,455,328	50,067,795	(5,612,467)	66,749,902	39,712,130	4,743,198
	17,522,360	18,226,191	(703,831)	54,824,726	58,913,447	(4,088,721)	78,268,192	49,850,289	4,974,437
PT. TUPPER									
LABOUR	1,067,079	979,285	87,794	3,091,360	3,089,398	1,962	4,289,747	3,091,296	64
NON-LABOUR	561,645	445,251	116,394	1,078,994	1,262,419	(183,425)	2,170,114	2,166,639	(1,087,645)
FUEL	6,358,490	9,564,822	(3,206,332)	24,621,720	32,111,698	(7,489,978)	42,612,549	23,664,644	957,076
	7,987,214	10,989,358	(3,002,144)	28,792,074	36,463,515	(7,671,441)	49,072,410	28,922,579	(130,505)
PT. ACONI									
LABOUR	1,010,792	976,919	33,873	3,497,580	3,266,768	230,812	4,468,935	3,459,961	37,619
NON-LABOUR	409,848	480,453	(70,605)	1,984,860	2,247,193	(262,333)	2,634,699	1,949,394	35,466
FUEL	9,434,491	8,360,530	1,073,961	23,502,824	22,274,920	1,227,904	30,640,350	17,628,496	5,874,328
	10,855,131	9,817,902	1,037,229	28,985,264	27,788,881	1,196,383	37,743,984	23,037,851	5,947,413
GAS TURBINES									
LABOUR	111,180	149,360	(38,180)	363,350	452,333	(88,983)	620,238	350,542	12,808
NON-LABOUR	99,122	115,326	(16,204)	307,828	294,413	13,415	458,962	238,093	69,735
FUEL	1,715,701	7,208,918	(5,493,217)	3,992,663	19,406,424	(15,413,761)	25,712,584	13,337,456	(9,344,793)
	1,926,003	7,473,604	(5,547,601)	4,663,841	20,153,170	(15,489,329)	26,791,784	13,926,091	(9,262,250)
HYDRO WATER ROYALTIES	211,036	211,036	-	633,109	633,109	-	844,145	633,109	-
FUEL FOR RESALE	-	(450,667)	450,667	-	(1,352,001)	1,352,001	(1,352,668)	-	-
TOTAL PLANTS									
LABOUR	8,188,102	8,127,882	60,220	24,553,724	25,008,802	(455,078)	34,167,512	24,011,271	542,453
NON-LABOUR	7,277,953	6,712,578	565,375	17,044,579	16,130,336	914,243	21,859,550	16,176,196	868,383
FUEL	60,998,519	96,883,427	(35,884,908)	186,139,603	331,144,275	(145,004,672)	453,223,115	265,380,813	(79,241,210)
	76,464,574	111,723,887	(35,259,313)	227,737,906	372,283,413	(144,545,507)	509,250,177	305,568,280	(77,830,374)
HEAD OFFICE	1,722,711	2,639,386	(916,675)	5,417,728	7,667,273	(2,249,545)	9,772,073	5,930,940	(513,212)
FUEL	(227,472)	0	(227,472)	(617,939)	0	(617,939)	0	(4,594,510)	3,976,571
	1,495,239	2,639,386	(1,144,147)	4,799,789	7,667,273	(2,867,484)	9,772,073	1,336,430	3,463,359
DIVISION TOTAL	77,959,813	114,363,273	(36,403,460)	232,537,695	379,950,686	(147,412,991)	519,022,250	306,904,710	(74,367,015)

NOVA SCOTIA POWER
An Emera Company

REGULATED OM&G BY GENERAL MANAGER

Period: September 2006

	Quarter-to-Date Actual September	Quarter-to-Date Budget September	Quarter-to-Date Variance September	Year-to-Date Actual	Year-to-Date Budget	Year-to-Date Variance	Full Year Budget	Prior YTD Actual	Curr/Prior YTD Variance
Office of the C.E.O.									
Executive Management	34,857	216,535	(181,678)	243,111	754,295	(511,184)	1,006,746	1,066,386	(823,275)
Legal Services	88,415	171,140	(82,725)	577,010	534,997	42,013	727,715	713,535	(136,525)
Corporate Secretary	1,165,911	1,201,847	(35,936)	3,806,940	3,933,927	(126,987)	5,158,667	3,698,443	108,497
	1,289,183	1,589,522	(300,339)	4,627,061	5,223,219	(596,158)	6,893,128	5,478,364	(851,303)
VP Gen. Planning & Infracture									
Administration	91,693	88,872	2,821	204,545	224,921	(20,376)	327,596	0	204,545
Procurement, Facilities	2,125,567	2,153,454	(27,887)	6,519,051	6,782,533	(263,482)	9,161,339	6,742,140	(223,089)
Information Technology	1,834,962	1,771,576	63,386	5,328,116	5,317,466	10,650	7,141,092	6,388,111	(1,059,995)
Project Implementation	93,666	96,188	(2,522)	106,344	193,193	(86,849)	278,958	0	106,344
Generation Planning	72,086	88,107	(16,021)	239,685	275,322	(35,637)	371,297	197,734	41,951
Gen Services	284,399	408,565	(124,166)	1,095,315	1,405,963	(310,648)	1,857,015	1,317,706	(222,391)
	4,502,373	4,606,762	(104,389)	13,493,056	14,199,398	(706,342)	19,137,297	14,645,691	(1,152,635)
VP External Relations									
Government Relations	350,700	310,537	40,163	1,361,289	1,437,110	(75,821)	1,778,150	1,406,617	(45,328)
	350,700	310,537	40,163	1,361,289	1,437,110	(75,821)	1,778,150	1,406,617	(45,328)
VP Human resources									
Human resources	880,994	953,347	(72,353)	2,546,345	2,783,833	(237,488)	3,785,037	2,319,572	226,773
Office of the C.O.O.									
Executive Management	243,499	272,922	(29,423)	762,086	713,518	48,568	1,034,539	812,177	(50,091)
Project Management	(2)	46,481	(46,483)	210,004	256,487	(46,483)	310,006	343,402	(133,398)
	243,497	319,403	(75,906)	972,090	970,005	2,085	1,344,545	1,155,579	(183,489)
Environmental Planning & Monitoring									
G.M. Env. Planning & Monitoring	79,374	68,177	11,197	307,685	320,272	(12,586)	398,266	273,371	34,314
Ambient Air	115,683	169,030	(53,347)	329,308	495,449	(166,141)	679,676	303,812	25,497
Environment	193,209	239,925	(46,716)	508,919	640,840	(131,921)	853,445	453,638	55,281
Environment pol. & prog	94,492	103,387	(8,894)	269,260	302,973	(33,713)	407,145	277,041	(7,781)
Renewable Energy	36,418	89,725	(53,307)	135,573	280,802	(145,229)	362,000	144,251	(8,679)
	519,176	670,244	(151,067)	1,550,745	2,040,336	(489,590)	2,700,532	1,452,113	98,632
Operations NSPI									
Plant Operations	233,380	852,039	(618,659)	704,329	1,980,374	(1,276,045)	2,206,914	1,428,529	(724,200)
Lingan	4,886,762	4,862,730	24,032	13,906,985	13,834,355	72,630	18,444,322	11,850,670	2,056,315
Pt. Aconi	1,420,640	1,457,372	(36,732)	5,482,440	5,513,961	(31,521)	7,103,634	5,409,355	73,085
Tufts Cove	2,983,275	2,983,102	173	6,997,947	7,846,607	(848,660)	11,421,755	6,942,713	55,234
Trenton	4,336,352	3,848,034	488,318	10,369,397	8,845,652	1,523,745	11,518,290	10,138,159	231,238
Pt. Tupper	1,628,724	1,424,536	204,188	4,170,355	4,351,818	(181,463)	6,459,861	5,257,935	(1,087,580)
Combustion Turbine	210,302	264,686	(54,384)	671,178	746,745	(75,567)	1,079,200	588,635	82,543
Hydro	1,582,829	1,767,008	(184,179)	4,868,666	5,319,442	(450,776)	6,957,701	4,942,376	(73,710)
NSP Commercial Operations	0	0	0	0	0	0	0	1,423,180	(1,423,180)
Energy, Fuels & Risk Mgmt.	704,618	715,096	(10,478)	2,075,355	2,217,751	(142,396)	3,005,310	357,299	1,718,056
Management Information	39,962	98,448	(58,486)	157,131	331,302	(174,171)	400,150	175,671	(18,540)
	18,026,844	18,273,051	(246,207)	49,403,783	50,988,007	(1,584,224)	68,597,137	48,514,522	889,261

NOVA SCOTIA POWER
An Emera Company

REGULATED OM&G BY GENERAL MANAGER

Period: September 2006

	Quarter-to-Date Actual September	Quarter-to-Date Budget September	Quarter-to-Date Variance September	Year-to-Date Actual	Year-to-Date Budget	Year-to-Date Variance	Full Year Budget	Prior YTD Actual	Curr/Prior YTD Variance
GM Customer Operations									
Metro	1,205,931	1,157,172	48,759	3,663,254	3,588,755	74,499	4,936,702	3,850,622	(187,368)
Northeast	854,779	936,611	(81,832)	2,840,921	2,731,226	109,695	3,680,621	3,512,076	(671,155)
West	1,159,130	967,797	191,333	3,569,973	2,986,557	583,416	4,015,905	3,650,850	(80,877)
Sydney	826,369	807,187	19,182	2,866,176	2,539,205	326,971	3,512,830	2,267,161	599,015
Transmission Ops&Maintenance	1,388,465	1,370,132	18,332	4,448,595	4,726,021	(277,426)	5,784,985	4,316,849	131,747
Regional Administration	(3,383)	0	(3,383)	70	0	70	0	1,254	(1,184)
Subtotal	5,431,291	5,238,899	192,391	17,388,989	16,571,764	817,225	21,931,043	17,598,812	(209,822)
Control Centre	915,233	1,026,065	(110,832)	3,085,924	3,349,488	(263,564)	4,481,861	2,758,894	327,030
T & D Asset	3,296,030	4,837,223	(1,541,193)	11,861,880	14,695,675	(2,833,795)	18,497,820	13,237,495	(1,375,615)
COPS Administration	636,357	1,345,252	(708,895)	1,588,625	4,951,912	(3,363,287)	8,701,000	907,282	681,343
	10,278,911	12,447,439	(2,168,529)	33,925,418	39,568,839	(5,643,421)	53,611,724	34,502,483	(577,064)
Performance & Regulation									
Regulatory Affairs	1,833,238	1,462,444	370,794	2,827,133	4,399,126	(1,571,993)	5,147,362	2,393,687	433,446
	1,833,238	1,462,444	370,794	2,827,133	4,399,126	(1,571,993)	5,147,362	2,393,687	433,446
Total Operations	30,138,993	32,182,934	(2,043,942)	86,156,334	94,955,972	(8,799,638)	127,356,223	85,410,692	745,643
Cust. Service Marketing & Sales									
Administration	630,798	2,127,188	(1,496,390)	1,402,770	5,440,566	(4,037,796)	7,618,136	609,095	793,675
Call Centre	1,681,826	1,952,885	(271,059)	5,122,476	5,554,635	(432,159)	7,478,650	4,619,257	503,219
Storm Casts	42,298	0	42,298	212,453	0	212,453	0	463,986	(251,533)
Revenue Operations	2,693,738	3,614,914	(921,176)	9,693,094	10,675,439	(982,345)	14,378,115	10,650,024	(956,930)
	5,048,660	7,694,987	(2,646,327)	16,430,793	21,670,640	(5,239,847)	29,474,901	16,342,362	88,431
Senior VP & CFO									
Internal Audit	65,599	49,319	16,280	190,555	195,261	(4,706)	266,472	227,395	(36,840)
Investor Relations	46,940	43,300	3,640	291,175	304,900	(13,725)	354,200	305,748	(14,573)
Director Finance	44,363	30,240	14,123	95,885	104,742	(8,857)	149,005	107,488	(11,603)
Treasurer	207,367	238,752	(31,385)	656,091	728,718	(72,627)	988,631	678,955	(22,864)
Tax	60,482	59,915	567	177,559	195,418	(17,859)	271,006	239,144	(61,585)
	424,751	421,526	3,225	1,411,265	1,529,039	(117,774)	2,029,314	1,558,730	(147,465)
G.M. Finance	205,098	274,459	(69,361)	924,890	861,731	63,159	1,158,524	238,512	686,378
Corporate Controller	253,390	273,571	(20,181)	781,873	857,478	(75,605)	1,169,359	957,808	(175,935)
Corp. Performance & Back Office	12,873	27,287	(14,414)	67,495	86,132	(18,637)	117,689	78,807	(11,312)
	471,361	575,317	(103,956)	1,774,258	1,805,341	(31,083)	2,445,572	1,275,127	499,131
Corporate Adjustments	7,519,012	3,911,790	3,607,221	16,804,074	8,744,545	8,059,529	9,478,056	6,102,003	10,702,072
Grand Total	51,388,700	53,236,369	(1,847,670)	147,127,310	155,359,438	(8,232,127)	206,422,755	137,146,850	9,980,462

NOTE: Donations/sponsorships are made throughout the cost centres. For regulated purposes, the total has been removed from Corporate Adjustments.

NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF: The *Public Utilities Act,* R.S.N.S. 1989, c.380 as amended

IN THE MATTER OF: An Application by Nova Scotia Power Incorporated for Approval of Certain Revisions to its Rates, Charges and Regulations

RESPONSE TO INFORMATION REQUEST

TO: NSPI

FROM: UARB

Question IR-81: **Please file the NSPI (Legal Entity) third quarter 2006 Financial Statements.**

Response IR-81: Please refer to Attachment 1.

Financial Statements

Nova Scotia Power Inc.
Statements of Earnings (Unaudited)

For the millions of dollars	Three months ended September 30		Nine months ended September 30	
	2006	2005	**2006**	2005
Revenue				
Electric	**$219.9**	$221.5	**$710.0**	$712.1
Other	**2.7**	2.3	**7.2**	5.8
	222.6	223.8	**717.2**	717.9
Cost of operations				
Fuel for generation and purchased power (note 7)	**68.0**	97.9	**205.1**	294.4
Operating, maintenance, and general	**53.5**	47.6	**151.0**	140.2
Provincial grants and taxes	**10.1**	10.1	**30.2**	30.2
Provincial grants and tax deferral (note 6)	**-**	-	**-**	(4.9)
Depreciation	**32.0**	30.0	**95.7**	89.3
Regulatory amortization	**1.6**	1.6	**4.7**	4.7
Allowance for funds used during construction	**(0.4)**	(0.7)	**(1.1)**	(1.7)
	164.8	186.5	**485.6**	552.2
Earnings from operations	**57.8**	37.3	**231.6**	165.7
Interest (note 5)	**27.0**	23.1	**78.0**	72.1
Amortization of defeasance costs	**3.2**	3.3	**9.5**	9.9
Earnings before income taxes	**27.6**	10.9	**144.1**	83.7
Income taxes	**11.6**	4.9	**59.8**	27.0
Income taxes deferral (note 6)	**-**	-	**-**	(10.4)
Net earnings before preferred dividends	**16.0**	6.0	**84.3**	67.1
Preferred dividends	**3.3**	3.3	**9.9**	9.9
Net earnings applicable to common shares	**$12.7**	$2.7	**$74.4**	$57.2

See accompanying notes to the unaudited financial statements.

Statements of Retained Earnings (Unaudited)

For the nine months ended September 30 millions of dollars	**2006**	2005
Retained earnings, beginning of year	**$222.6**	$222.4
Net earnings applicable to common shares	**74.4**	57.2
	297.0	279.6
Dividends	**50.0**	66.0
Retained earnings, end of period	**$247.0**	$213.6

See accompanying notes to the unaudited financial statements.

Nova Scotia Power Inc.
Balance Sheets (Unaudited)

As at millions of dollars	September 30 2006	December 31 2005 Restated (note 3)
Assets		
Current assets		
Cash and cash equivalents	**$0.3**	$-
Restricted cash	**7.9**	3.5
Accounts receivable	**85.7**	76.8
Due from associated companies (note 7)	**8.7**	23.3
Income tax receivable	**-**	7.2
Fuel inventory (note 3)	**87.6**	45.5
Materials and supplies inventory	**28.5**	26.1
Prepaid expenses	**15.1**	4.5
	233.8	186.9
Long-term receivable	**62.6**	48.4
Deferred charges	**376.3**	398.5
Property, plant and equipment	**2,367.8**	2,409.1
Construction work in progress	**26.2**	21.0
	2,394.0	2,430.1
	$3,066.7	$3,063.9
Liabilities and Shareholders' Equity		
Current liabilities		
Current portion of long-term debt	**$0.7**	$40.2
Short-term debt	**20.8**	5.4
Income taxes payable	**24.3**	-
Accounts payable and accrued charges	**126.1**	135.8
Dividends payable	**3.2**	3.2
	175.1	184.6
Asset retirement obligations (note 3 and note 8)	**76.8**	73.8
Deferred credits	**5.6**	4.6
Long-term debt (note 9)	**1,471.6**	1,487.7
Preferred shares (note 10)	**260.0**	260.0
Shareholders' equity		
Common shares (note 10)	**830.6**	830.6
Retained earnings	**247.0**	222.6
	1,077.6	1,053.2
	$3,066.7	$3,063.9

Contingencies (Note 11)
See accompanying notes to the unaudited financial statements.

Approved on behalf of the Board of Directors

"John McLennan"

John McLennan
Chairman

"Ralph Tedesco"

Ralph Tedesco
President and Chief Executive Officer

Nova Scotia Power Inc.
Statements of Cash Flow (Unaudited)

For the millions of dollars	Three months ended September 30		Nine months ended September 30	
	2006	2005	**2006**	2005
Operating activities				
Net earnings applicable to common shares	**$12.7**	$2.7	**$74.4**	$57.2
Non-cash items:				
Depreciation	**32.0**	30.0	**95.7**	89.3
Deferral of provincial grants and taxes	**-**	-	**-**	(15.3)
Amortization of defeasance costs	**3.2**	3.3	**9.5**	9.9
Amortization of deferred charges	**0.4**	0.5	**0.9**	1.9
Regulatory amortization	**1.6**	1.6	**4.7**	4.7
Allowance for funds used during construction	**(0.4)**	(0.7)	**(1.1)**	(1.7)
Other non-cash operating items	**10.1**	4.6	**25.3**	14.2
Cash operating items	**(4.5)**	(4.5)	**(13.0)**	(15.3)
	55.1	37.5	**196.4**	144.9
Change in non-cash operating working capital	**22.0**	29.5	**(7.9)**	(1.3)
Net cash provided by operating activities	**77.1**	67.0	**188.5**	143.6
Investing activities				
Property, plant and equipment	**(28.1)**	(30.8)	**(58.3)**	(70.8)
Retirement spending net of salvage	**(0.5)**	(1.2)	**(1.9)**	(2.9)
Increase in restricted cash	**(7.2)**	(17.8)	**(4.4)**	(17.8)
Net cash used in investing activities	**(35.8)**	(49.8)	**(64.6)**	(91.5)
Financing activities				
(Decrease) increase in short-term debt	**(41.2)**	2.8	**(43.6)**	45.6
Retirement of long-term debt	**-**	-	**-**	(100.0)
Issuance of long-term debt	**-**	-	**-**	100.0
Dividends on common shares	**-**	-	**(50.0)**	(66.0)
Accounts receivable securitization	**-**	(20.0)	**(30.0)**	(30.0)
Other financing	**-**	-	**-**	(1.7)
Net cash used in financing activities	**(41.2)**	(17.2)	**(123.6)**	(52.1)
Increase in cash and cash equivalents	**0.1**	-	**0.3**	-
Cash and cash equivalents, beginning of period	**0.2**	-	**-**	-
Cash and cash equivalents, end of period	**$0.3**	$-	**$0.3**	$-
Supplemental disclosure of cash paid:				
Interest	**$29.1**	$27.2	**$77.8**	$74.8
Income and capital taxes	**$9.1**	$12.0	**$33.8**	$45.4

See accompanying notes to the unaudited financial statements.

Nova Scotia Power Inc.
Notes to the Interim Unaudited Financial Statements
September 30, 2006

1. Basis of Presentation

The disclosures in these unaudited interim financial statements do not conform in all respects to the requirements of Canadian Generally Accepted Accounting Principles for annual audited financial statements and should be read in conjunction with Nova Scotia Power Inc.'s ("NSPI") annual financial statements as at and for the year ended December 31, 2005.

These financial statements follow the same accounting policies and methods of computation as NSPI's annual audited financial statements as at and for the year ended December 31, 2005 with the exception of the accounting policy changes disclosed in note 3.

2. Seasonal Nature of Operations

Interim results are not necessarily indicative of results for the full year due primarily to seasonal factors. Sales and related production vary significantly over the year, with Q1 and Q4, the strongest periods, reflecting colder weather and fewer daylight hours in the winter season.

3. Changes in Accounting Policy

Conditional Asset Retirement Obligations

In December 2005, the Canadian Institute of Chartered Accountants ("CICA") issued Emerging Issues Committee Abstract 159 Conditional Asset Retirement Obligations ("EIC-159"). EIC-159 is to be applied retroactively, with restatement of prior periods, to financial statements for interim and annual reporting periods ending after March 31, 2006. EIC-159 was issued in response to the diverse accounting practices that have developed under CICA Handbook Section 3110 Asset Retirement Obligations ("Section 3110") with respect to the timing of liability recognition when the timing and/or method of settlement are conditional on a future event.

As a result of adopting EIC-159, the Company has determined that it has conditional asset retirement obligations related to the disposal of polychlorinated biphenyls ("PCBs"). As at September 30, 2006, property, plant and equipment has increased by $0.6 million (December 31, 2005 - $0.6 million), accumulated depreciation has decreased by $1.9 million (December 31, 2005 - $1.8 million), and asset retirement obligations have increased by $2.5 million (December 31, 2005 - $2.4 million). There is no impact to net earnings in 2006 and 2005.

Accounting for the impact of rate regulation:

Any difference between the amount of depreciation and accretion expense approved by the regulator of Nova Scotia Power and the amount that would have been calculated under EIC-159 is recognized as a regulatory asset in accumulated depreciation. In the absence of this deferral, year to date net earnings for 2006 would be $0.1 million lower.

Inventory

In August 2006, Nova Scotia Power changed its method of costing fuel inventory from the first-in, first-out method to the weighted average cost method to provide more appropriate information. The change in accounting policy has been approved by the Nova Scotia Utility and Review Board ("UARB").

The CICA Handbook Section 1506 Accounting Changes requires that changes in accounting policies be applied retroactively to all prior periods presented for comparative purposes. Nova Scotia Power applied the change in accounting policy retroactively but did not restate prior periods as the necessary adjustments were considered immaterial. The change in accounting policy resulted in a cumulative adjustment to the opening balance of fuel inventory in Q3 2006 of $1.0 million. As a result, NSPI decreased inventory by $1.0 million and increased fuel expense by $1.0 million in Q3 2006.

4. Employee Future Benefits

NSPI maintains contributory defined-benefit and defined-contribution pension plans, which cover substantially all of its employees, and plans that provide non-pension benefits for its retirees. The Company's estimated cost, related to these plans, for the three month period ended September 30, 2006 is $9.1 million (2005 - $5.4 million), and for the nine month period ended September 30, 2006 is $27.0 million (2005 - $16.0 million).

5. Interest

Interest expense consists of the following:

For the millions of dollars	Three months ended September 30		Nine months ended September 30	
	2006	2005	**2006**	2005
Interest on long-term debt	**$23.1**	$21.3	**$69.1**	$64.5
Interest on short-term debt	**2.7**	2.5	**5.3**	7.2
Amortization of debt financing	**0.4**	0.4	**1.3**	1.2
Foreign exchange losses (gains)	**0.8**	(1.1)	**2.3**	(0.8)
	$27.0	$23.1	**$78.0**	$72.1

6. Provincial Grants and Tax Deferral and Income Tax Deferral

The UARB agreed to allow NSPI to defer taxes not reflected in rates for the period January 1, 2005 until April 1, 2005, the date when new rates became effective. In Q1 2005, NSPI deferred a portion of provincial and federal grants and taxes. The amortization period is subject to approval by the UARB.

7. Related Party Transactions

The Company enters into various transactions with its affiliates in the normal course of operations. All transactions are recorded, subject to terms in the Code of Conduct, at the exchange value, which is generally based on commercial rates or as agreed to by the parties. The Code of Conduct governs transactions between NSPI and its affiliates and is approved by the UARB.

Due from associated companies represents the total carrying amounts of trade receivables, which are owed to NSPI by NSPI's parent company, Emera Inc. and companies wholly owned by Emera Inc. The terms of repayment are the same as those for non-affiliate trade receivables. During the quarter, NSPI had sales and purchases from companies under common control of Emera Inc. as follows:

For the millions of dollars		Three months ended September 30	
Affiliate	Purpose of Transaction	**2006**	2005
Sales:			
Emera Energy Services	Net sales of gas and electricity	**$31.6**	$53.4
Emera Inc.	Allocation of common costs	**1.4**	1.3
Emera Energy Services	Net sale of swaps	**1.2**	-
Various	Other services provided	**0.3**	0.3
Purchases:			
Emera Utility Services	Purchase and maintenance of transformers	**0.3**	0.3
Cablecom	Purchase of line work	**0.9**	0.7
Emera Energy Services	Net purchase of swaps	**-**	1.9
Various	Other services purchased	**0.4**	0.5

In the ordinary course of business, the Company purchased natural gas transportation capacity totaling $4.3 million (2005 - $4.2 million) for the three months ended September 30, 2006 from the Maritimes & Northeast Pipeline, an investment under significant influence of Emera Inc.

Year to date, NSPI had sales and purchases from companies under common control of Emera Inc. as follows:

For the millions of dollars		Nine months ended September 30	
Affiliate	Purpose of Transaction	**2006**	2005
Sales:			
Emera Energy Services	Net sales of gas and electricity	**$122.2**	$ 119.2
Emera Inc.	Allocation of common costs	**4.5**	4.7
Emera Energy Services	Net sale of swaps	**0.3**	-
Various	Other services provided	**1.1**	1.6
Purchases:			
Emera Utility Services	Purchase and maintenance of transformers	**0.9**	2.1
Cablecom	Purchase of line work	**4.2**	2.1
Emera Energy Services	Net purchase of swaps	**-**	3.1
Various	Other services purchased	**1.0**	0.9

In the ordinary course of business, the Company purchased natural gas transportation capacity totaling $12.8 million (2005 - $12.5 million) during the nine months ended September 30, 2006 from the Maritimes & Northeast Pipeline, an investment under significant influence of Emera Inc. The amount is recognized in fuel for generation and purchased power and is measured at the exchange amount. As at September 30, 2006 the amount payable to the related party is $1.4 million (December 31, 2005 - $1.4 million), and is under normal interest and credit terms.

8. Asset Retirement Obligations

In addition to asset retirement obligations recognized under Section 3110 and EIC-159, the Company may have asset retirement obligations associated with some of its transmission and distribution assets. As the Company expects to use the majority of its installed assets for an indefinite period, no removal date can be determined and consequently a reasonable estimate of the fair value of any related asset retirement obligation cannot be made at this time.

9. Long-Term Debt

Long-term debt includes $4.3 million (December 31, 2005 - $0.9 million) in capital lease obligations.

10. Common Shares and Preferred Shares

As of September 30, 2006 and December 31, 2005 there were 96.8 million issued and outstanding common shares all of which are owned by NSPI's parent, Emera Inc., or an affiliate under common control.

As of September 30, 2006 and December 31, 2005 the Company had outstanding the following First Preferred Share Units:

- 5.0 million 4.9% Series C, which if not redeemed, in whole or in part, by NSPI on or after April 1, 2009, will be exchangeable into common shares of Emera Inc.
- 5.4 million 5.9% Series D, which if not redeemed in whole or part, by NSPI on or after October 15, 2015, will be exchangeable into common shares of Emera Inc.

11. Contingencies

The Company may, from time to time, be involved in legal proceedings, claims and litigation that arise in the ordinary course of business which the Company believes would not reasonably be expected to have a material adverse effect on the financial condition of the Company.

In late 2005 some of Nova Scotia Power's petroleum coke (petcoke) suppliers were unable to supply the fuel due to hurricanes in the Gulf of Mexico, which seriously affected their operations. As a result, NSPI incurred additional costs for replacement fuel and other expenses. NSPI has advised its insurers that it intends to seek recovery of applicable costs. The insurers have advised that coverage is available under the policy but at this time NSPI is unable to estimate the total recovery amount.

12. Comparative Information

Certain of the comparative figures have been reclassified to conform to the financial statement presentation adopted for 2006.

NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF: The *Public Utilities Act,* R.S.N.S. 1989, c.380 as amended

IN THE MATTER OF: An Application by Nova Scotia Power Incorporated for Approval of Certain Revisions to its Rates, Charges and Regulations

RESPONSE TO INFORMATION REQUEST

TO: NSPI

FROM: UARB

Question IR-82: **Please provide the Strategist runs used to compute the fuel and purchased power costs for the years 2006 and 2007.**

Response IR-82: Please refer to Confidential Liberty IR-9 Attachment 1 and Attachment 2.

NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF: The *Public Utilities Act,* R.S.N.S. 1989, c.380 as amended

IN THE MATTER OF: An Application by Nova Scotia Power Incorporated for Approval of Certain Revisions to its Rates, Charges and Regulations

RESPONSE TO INFORMATION REQUEST

TO: NSPI

FROM: UARB

Question IR-83: **Please provide the load forecast information used as input to the Strategist run, including monthly peak demand, monthly energy requirements and the typical week used for each month. Provide the week values in both tabular format (Excel spreadsheet, 168 hourly values) and in graphic format.**

Response IR-83: The following table lists the 2007 forecast of monthly energy and peak demand used for the Strategist run.

The 168-hour typical week data is provided in Attachment 1.

The graphs are provided in Attachment 2.

Hourly Loads for a Typical Week - 2007 Forecast

Day-Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Mon 12:00 AM	1557.2	1457.5	1394.4	1355.8	1186.4	1186.6	1159.2	1185.6	1095.2	1187.0	1376.3	1418.4
Mon 1:00 AM	1537.0	1417.3	1378.3	1309.3	1156.5	1097.6	1115.7	1145.5	1017.9	1146.2	1325.8	1338.8
Mon 2:00 AM	1535.1	1398.0	1375.1	1266.8	1125.8	1066.4	1101.2	1127.3	1011.6	1130.9	1306.4	1315.7
Mon 3:00 AM	1535.3	1386.1	1366.8	1280.0	1121.8	1048.1	1091.6	1122.4	998.5	1129.2	1311.0	1316.4
Mon 4:00 AM	1536.7	1411.8	1392.0	1306.0	1152.6	1057.9	1071.2	1115.9	1004.6	1138.1	1315.6	1321.6
Mon 5:00 AM	1550.7	1519.5	1446.3	1372.5	1220.4	1095.3	1105.7	1160.9	1058.4	1168.2	1390.4	1375.2
Mon 6:00 AM	1640.7	1714.1	1612.0	1543.4	1343.4	1227.5	1209.9	1241.5	1144.9	1269.7	1536.9	1546.8
Mon 7:00 AM	1862.3	1868.9	1781.0	1651.8	1508.2	1388.3	1286.7	1332.2	1225.2	1379.0	1687.9	1686.1
Mon 8:00 AM	1908.9	1941.9	1764.9	1795.5	1558.9	1487.2	1445.7	1411.2	1305.6	1550.8	1776.7	1765.3
Mon 9:00 AM	1913.7	1925.2	1738.6	1714.2	1578.7	1495.6	1511.9	1477.6	1345.2	1618.9	1696.6	1752.0
Mon 10:00 AM	1803.5	1849.2	1714.3	1640.2	1521.6	1490.6	1520.1	1571.0	1372.2	1601.1	1652.3	1788.8
Mon 11:00 AM	1741.0	1866.7	1699.3	1655.7	1508.2	1488.9	1560.6	1567.1	1390.5	1492.2	1640.3	1784.3
Mon 12:00 PM	1731.5	1797.4	1666.6	1628.7	1470.0	1472.6	1520.1	1545.1	1431.5	1501.5	1619.0	1760.8
Mon 1:00 PM	1720.1	1723.5	1608.7	1551.6	1449.5	1439.1	1511.9	1572.3	1406.8	1509.6	1579.9	1791.1
Mon 2:00 PM	1687.7	1733.9	1591.5	1504.5	1412.6	1440.9	1466.4	1489.8	1348.5	1427.4	1565.4	1756.4
Mon 3:00 PM	1713.3	1753.9	1635.3	1462.9	1404.4	1457.8	1499.6	1515.9	1345.2	1443.5	1577.7	1725.7
Mon 4:00 PM	1788.8	1770.8	1679.8	1488.9	1440.3	1450.7	1475.6	1514.7	1357.5	1468.8	1680.4	1741.0
Mon 5:00 PM	1958.7	1890.8	1771.6	1546.9	1476.2	1457.8	1498.3	1538.7	1419.7	1560.7	1914.8	2038.2
Mon 6:00 PM	2031.7	2003.0	1880.8	1571.9	1525.8	1410.8	1457.3	1538.7	1388.2	1582.1	1925.1	2033.0
Mon 7:00 PM	1974.2	1937.5	1858.6	1482.3	1459.8	1392.1	1358.4	1493.5	1401.0	1573.5	1762.2	1960.9
Mon 8:00 PM	1806.3	1853.6	1746.4	1504.5	1388.1	1353.6	1304.0	1428.6	1405.6	1520.4	1691.6	1922.7
Mon 9:00 PM	1703.5	1764.5	1700.6	1535.3	1404.4	1352.6	1341.0	1379.3	1337.4	1423.8	1536.9	1810.4
Mon 10:00 PM	1628.2	1655.5	1620.8	1453.3	1332.2	1293.2	1318.4	1314.2	1252.8	1288.9	1465.5	1653.7
Mon 11:00 PM	1577.2	1628.1	1580.0	1426.4	1284.7	1218.7	1266.6	1258.1	1230.3	1265.1	1492.7	1588.2
Tue 12:00 AM	1563.5	1559.5	1543.0	1329.0	1204.4	1132.9	1154.0	1179.3	1129.2	1188.5	1403.0	1504.0
Tue 1:00 AM	1541.7	1494.5	1497.2	1246.6	1142.6	1049.3	1117.3	1146.4	1089.1	1135.7	1304.1	1400.2
Tue 2:00 AM	1536.6	1476.4	1468.8	1239.4	1116.9	1019.7	1100.5	1125.6	1062.6	1111.6	1288.6	1361.8
Tue 3:00 AM	1535.8	1480.2	1469.6	1240.1	1125.8	1022.2	1088.0	1108.0	1051.8	1104.5	1279.9	1346.4
Tue 4:00 AM	1538.5	1488.8	1482.7	1245.9	1136.7	1060.3	1093.8	1116.7	1064.3	1125.7	1286.4	1367.3
Tue 5:00 AM	1555.3	1572.3	1558.7	1292.0	1215.4	1123.6	1116.5	1162.7	1106.7	1167.5	1340.2	1435.2
Tue 6:00 AM	1665.0	1742.3	1767.6	1435.6	1352.5	1277.6	1190.3	1246.4	1207.2	1278.3	1462.6	1582.4
Tue 7:00 AM	1913.7	1856.9	2029.5	1671.4	1513.3	1405.2	1265.6	1370.4	1328.5	1480.4	1577.7	1733.3
Tue 8:00 AM	2026.1	1919.6	1983.4	1729.2	1549.6	1463.9	1342.2	1505.9	1418.5	1612.9	1641.5	1775.3
Tue 9:00 AM	1984.7	1894.1	1946.7	1681.9	1529.9	1479.5	1363.2	1491.1	1435.1	1574.9	1636.7	1736.6
Tue 10:00 AM	1830.0	1849.2	1857.1	1598.7	1445.4	1463.9	1401.7	1552.8	1427.9	1483.0	1578.8	1710.6
Tue 11:00 AM	1786.1	1824.3	1775.6	1532.9	1444.4	1465.6	1415.3	1505.9	1447.0	1421.3	1532.6	1708.4

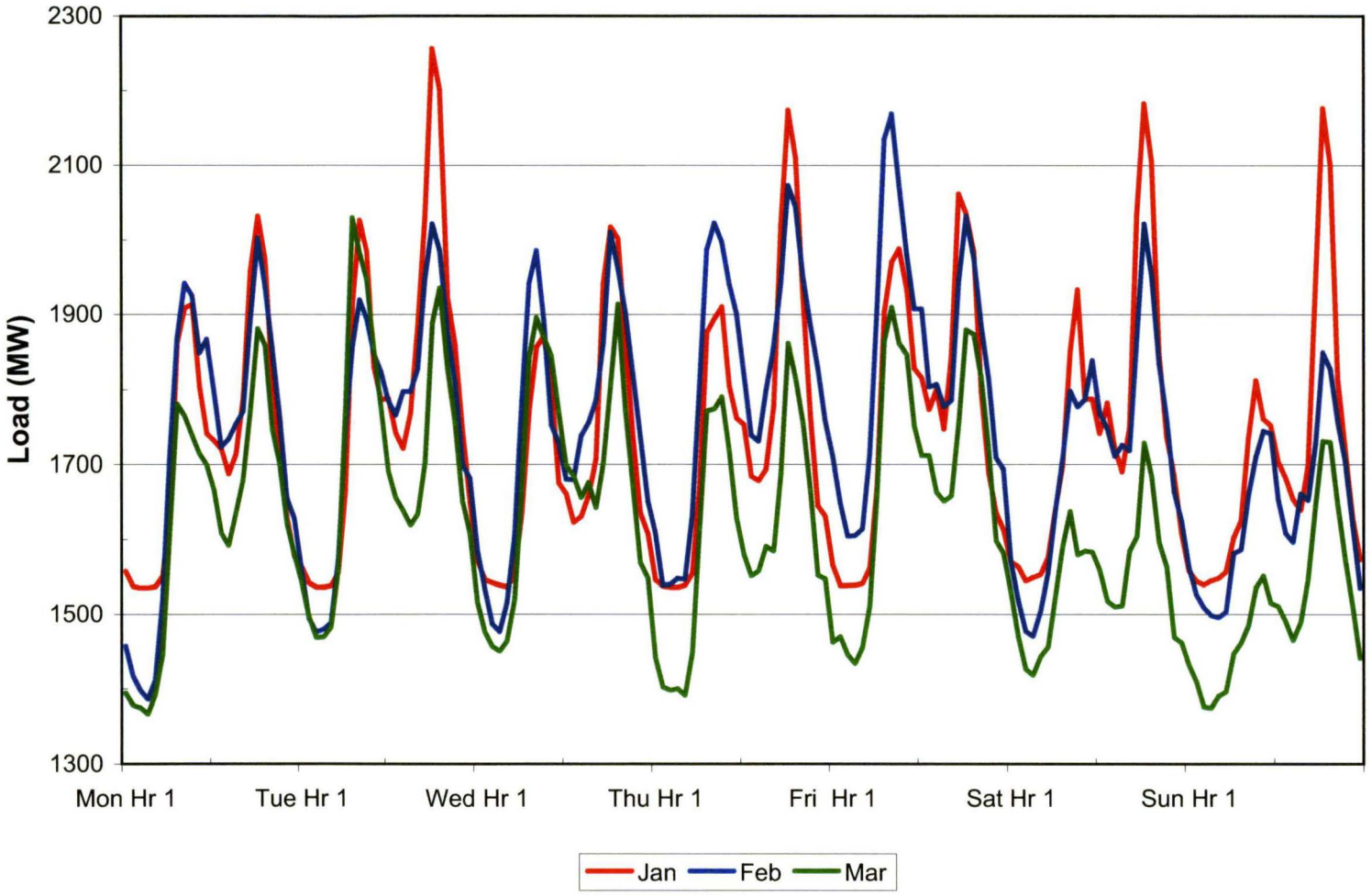
Tue 12:00 PM	1788.8	1785.7	1691.9	1484.5	1401.4	1446.2	1406.6	1549.0	1487.1	1421.3	1526.2	1727.9
Tue 1:00 PM	1742.2	1765.5	1656.0	1444.9	1392.2	1446.2	1411.6	1602.6	1453.0	1421.3	1471.5	1705.2
Tue 2:00 PM	1721.2	1797.4	1638.7	1442.8	1378.9	1444.5	1339.9	1510.9	1443.4	1381.3	1439.3	1687.1
Tue 3:00 PM	1768.0	1797.4	1618.6	1451.2	1403.4	1456.0	1327.4	1521.0	1423.2	1422.6	1495.8	1697.7
Tue 4:00 PM	1883.6	1827.5	1634.2	1470.4	1424.9	1456.0	1351.4	1489.8	1405.6	1442.2	1591.3	1737.7
Tue 5:00 PM	2029.8	1947.5	1703.0	1514.6	1449.5	1432.8	1394.3	1517.2	1484.6	1566.3	1775.4	2033.0
Tue 6:00 PM	2256.3	2021.3	1888.2	1558.7	1463.9	1449.8	1419.0	1546.4	1465.1	1635.4	1835.2	2197.4
Tue 7:00 PM	2201.6	1985.9	1935.7	1542.2	1440.3	1440.0	1377.4	1510.9	1546.0	1681.8	1718.1	2053.8
Tue 8:00 PM	1921.9	1876.5	1828.3	1502.2	1417.7	1367.2	1337.6	1465.5	1511.9	1555.0	1700.4	1942.3
Tue 9:00 PM	1859.3	1810.3	1755.6	1497.8	1395.2	1403.3	1354.9	1469.1	1443.4	1392.8	1565.4	1772.0
Tue 10:00 PM	1744.6	1700.6	1651.4	1399.4	1348.4	1338.8	1274.0	1326.9	1332.9	1287.9	1452.8	1678.7
Tue 11:00 PM	1650.3	1682.1	1607.6	1352.2	1310.9	1252.3	1266.6	1272.0	1304.5	1276.4	1422.3	1665.1
Wed 12:00 AM	1572.0	1585.1	1515.9	1274.5	1228.4	1161.7	1183.9	1231.9	1208.2	1205.6	1364.3	1543.9
Wed 1:00 AM	1545.9	1534.1	1476.1	1235.2	1141.6	1096.4	1109.5	1173.1	1161.7	1144.3	1281.4	1440.4
Wed 2:00 AM	1541.7	1486.9	1456.9	1209.4	1103.0	1071.3	1074.6	1126.5	1131.0	1126.3	1269.4	1404.3
Wed 3:00 AM	1538.9	1476.4	1450.0	1218.7	1100.1	1050.6	1057.9	1122.4	1132.9	1131.5	1268.0	1392.9
Wed 4:00 AM	1536.4	1515.7	1464.0	1243.7	1128.7	1073.7	1068.5	1113.5	1152.3	1138.1	1285.7	1400.2
Wed 5:00 AM	1551.0	1605.0	1519.5	1276.8	1187.4	1127.1	1111.8	1151.5	1218.2	1185.5	1352.5	1466.4
Wed 6:00 AM	1637.3	1785.7	1666.6	1418.3	1330.2	1281.8	1189.4	1222.4	1330.7	1321.2	1471.5	1617.0
Wed 7:00 AM	1773.1	1941.9	1842.6	1603.7	1457.7	1384.5	1295.3	1327.9	1447.0	1494.9	1664.5	1757.5
Wed 8:00 AM	1856.3	1985.9	1895.8	1670.1	1507.1	1460.4	1405.4	1404.3	1589.9	1612.9	1764.8	1906.9
Wed 9:00 AM	1871.3	1891.9	1868.9	1588.9	1495.8	1466.5	1438.0	1394.0	1520.7	1583.6	1647.5	1810.4
Wed 10:00 AM	1804.9	1752.8	1845.5	1582.8	1475.2	1449.8	1506.4	1486.2	1480.9	1530.0	1566.5	1756.4
Wed 11:00 AM	1675.6	1728.7	1770.2	1513.5	1433.1	1435.5	1476.9	1489.8	1498.2	1515.0	1584.5	1769.7
Wed 12:00 PM	1661.2	1681.0	1698.1	1492.2	1428.0	1425.5	1469.0	1498.5	1521.9	1541.0	1597.0	1766.4
Wed 1:00 PM	1622.7	1680.0	1685.8	1466.1	1404.4	1418.2	1459.9	1543.8	1492.0	1505.5	1521.9	1736.6
Wed 2:00 PM	1630.7	1738.1	1656.0	1429.4	1415.7	1439.1	1430.4	1510.9	1466.3	1456.0	1544.5	1744.2
Wed 3:00 PM	1659.4	1756.0	1676.2	1478.0	1442.3	1419.1	1407.8	1526.0	1465.1	1476.5	1576.6	1785.4
Wed 4:00 PM	1706.7	1785.7	1642.2	1490.0	1420.8	1442.7	1396.8	1478.8	1463.9	1531.3	1594.7	1902.1
Wed 5:00 PM	1941.7	1861.2	1701.8	1588.9	1483.4	1448.9	1416.5	1524.7	1493.3	1579.2	1806.3	2146.7
Wed 6:00 PM	2017.0	2009.8	1807.2	1618.6	1511.3	1431.9	1414.0	1465.5	1497.0	1716.9	1885.9	2185.0
Wed 7:00 PM	2002.5	1962.2	1914.0	1586.4	1486.5	1400.5	1415.3	1410.0	1487.1	1618.9	1798.2	2061.6
Wed 8:00 PM	1865.3	1903.0	1772.9	1538.7	1452.6	1414.5	1324.0	1414.6	1547.3	1557.8	1675.5	1977.1
Wed 9:00 PM	1737.4	1822.1	1672.6	1529.5	1457.7	1424.6	1342.2	1408.9	1472.4	1462.4	1593.6	1872.2
Wed 10:00 PM	1635.6	1739.2	1568.8	1467.2	1380.0	1356.5	1292.1	1336.5	1315.4	1344.5	1467.5	1738.8
Wed 11:00 PM	1607.1	1651.4	1547.9	1395.5	1319.0	1290.1	1237.1	1275.1	1277.8	1305.8	1426.9	1709.5
Thu 12:00 AM	1545.9	1609.0	1441.8	1359.5	1223.4	1203.3	1151.5	1194.6	1157.0	1197.7	1349.2	1555.3
Thu 1:00 AM	1537.7	1538.9	1402.3	1287.9	1134.7	1101.2	1096.8	1166.1	1126.5	1154.0	1285.7	1487.7
Thu 2:00 AM	1536.0	1539.9	1398.0	1275.3	1128.7	1070.0	1076.7	1144.7	1084.8	1124.6	1266.6	1429.3

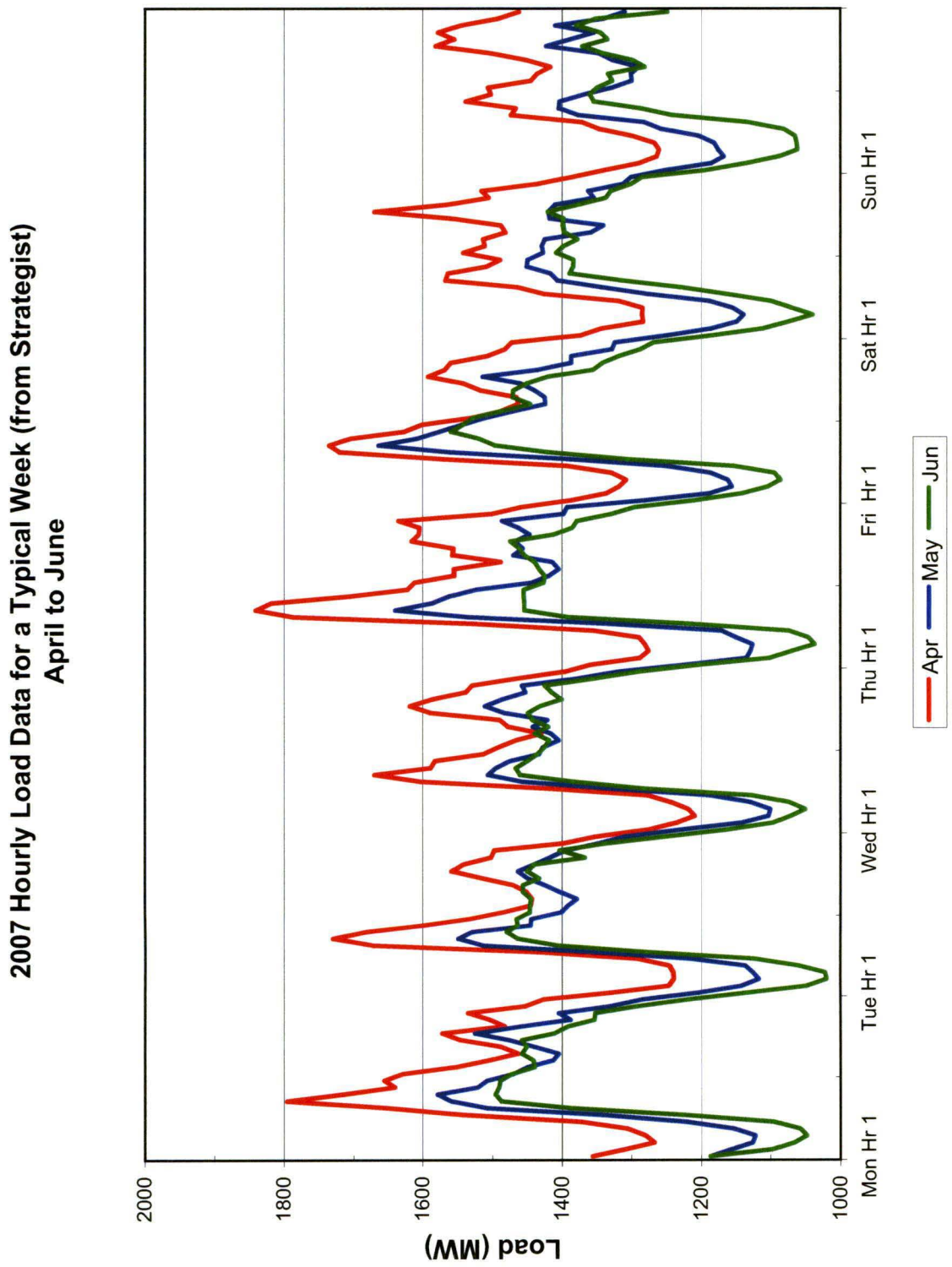
Thu 3:00 AM	1535.4	1547.7	1399.9	1280.8	1125.8	1037.1	1082.3	1137.2	1065.1	1119.6	1254.4	1411.7
Thu 4:00 AM	1538.7	1546.7	1390.8	1288.7	1149.6	1045.7	1094.6	1143.9	1083.9	1123.5	1263.9	1441.2
Thu 5:00 AM	1554.5	1634.2	1448.5	1354.0	1170.5	1073.7	1105.7	1162.7	1135.6	1160.6	1316.4	1473.4
Thu 6:00 AM	1669.8	1806.0	1614.1	1528.3	1334.2	1217.6	1178.5	1228.1	1252.8	1266.0	1464.5	1612.0
Thu 7:00 AM	1875.9	1987.0	1771.6	1786.8	1536.1	1392.1	1277.1	1337.6	1367.7	1444.7	1647.5	1810.4
Thu 8:00 AM	1894.6	2022.4	1774.3	1840.9	1640.2	1454.2	1393.1	1443.9	1451.8	1546.6	1704.1	1906.9
Thu 9:00 AM	1910.5	1998.4	1790.6	1818.7	1587.0	1454.2	1432.9	1440.4	1397.5	1517.7	1674.3	1839.3
Thu 10:00 AM	1804.9	1941.9	1719.4	1706.0	1563.1	1455.1	1476.9	1527.3	1411.4	1473.9	1603.9	1852.2
Thu 11:00 AM	1761.7	1901.9	1628.6	1622.4	1524.7	1455.1	1476.9	1554.1	1420.8	1449.7	1564.3	1767.5
Thu 12:00 PM	1753.1	1822.1	1580.0	1612.4	1443.3	1426.4	1495.6	1600.0	1416.1	1494.9	1547.8	1760.8
Thu 1:00 PM	1684.6	1739.2	1550.8	1555.2	1418.7	1424.6	1486.2	1581.5	1444.6	1468.8	1540.1	1739.9
Thu 2:00 PM	1678.6	1730.8	1557.7	1555.2	1404.4	1432.8	1421.5	1550.2	1418.5	1443.5	1513.5	1776.4
Thu 3:00 PM	1693.9	1798.5	1590.5	1487.8	1413.6	1439.1	1396.8	1519.7	1387.1	1428.6	1520.9	1801.3
Thu 4:00 PM	1777.0	1855.8	1584.2	1557.6	1470.0	1454.2	1401.7	1488.6	1423.2	1397.5	1639.1	1863.9
Thu 5:00 PM	2018.8	1943.1	1688.3	1556.4	1456.7	1461.3	1431.6	1499.7	1495.7	1498.9	1794.2	2039.5
Thu 6:00 PM	2174.0	2073.2	1861.5	1616.1	1468.0	1474.3	1479.6	1481.3	1499.4	1515.0	1776.7	2097.1
Thu 7:00 PM	2110.5	2044.3	1815.6	1606.1	1446.4	1411.7	1398.0	1402.0	1449.4	1549.4	1694.1	1958.4
Thu 8:00 PM	1921.9	1950.9	1755.6	1604.9	1462.8	1385.4	1367.9	1402.0	1427.9	1470.1	1657.2	1893.7
Thu 9:00 PM	1764.2	1886.4	1665.4	1635.1	1486.5	1378.8	1372.6	1387.2	1397.5	1410.5	1633.2	1874.6
Thu 10:00 PM	1645.0	1829.7	1551.8	1501.1	1398.3	1328.8	1336.5	1315.2	1278.9	1320.1	1450.8	1710.6
Thu 11:00 PM	1630.7	1758.1	1546.9	1458.6	1393.2	1295.3	1260.4	1292.3	1229.2	1288.9	1456.7	1602.0
Fri 12:00 AM	1565.3	1712.0	1462.4	1387.7	1281.7	1209.9	1194.9	1177.6	1139.3	1219.4	1356.7	1477.9
Fri 1:00 AM	1537.9	1648.3	1469.6	1336.0	1188.4	1141.0	1152.3	1155.8	1075.3	1154.6	1290.0	1378.4
Fri 2:00 AM	1538.5	1604.0	1445.5	1317.8	1155.5	1103.6	1128.4	1111.9	1069.4	1131.5	1261.2	1340.3
Fri 3:00 AM	1538.7	1605.0	1433.8	1307.6	1161.5	1085.7	1115.7	1094.0	1066.8	1121.8	1253.8	1318.6
Fri 4:00 AM	1540.7	1614.0	1455.4	1329.0	1186.4	1094.1	1132.4	1100.1	1103.2	1135.7	1275.7	1336.5
Fri 5:00 AM	1561.7	1713.1	1511.3	1392.6	1250.5	1152.6	1167.0	1155.8	1162.7	1195.4	1322.6	1407.6
Fri 6:00 AM	1670.7	1907.4	1660.7	1569.5	1388.1	1305.5	1257.3	1247.3	1288.4	1353.2	1464.5	1521.4
Fri 7:00 AM	1904.1	2135.4	1864.5	1719.6	1561.0	1420.0	1339.9	1336.5	1406.8	1497.5	1603.9	1657.8
Fri 8:00 AM	1970.7	2168.7	1909.5	1734.7	1664.3	1496.5	1491.6	1472.7	1520.7	1640.0	1674.3	1739.9
Fri 9:00 AM	1988.2	2073.2	1861.5	1704.7	1608.9	1519.6	1572.0	1521.0	1538.3	1580.7	1673.0	1759.7
Fri 10:00 AM	1933.4	1980.2	1847.0	1627.5	1576.6	1559.3	1586.4	1609.3	1551.1	1573.5	1643.9	1700.9
Fri 11:00 AM	1828.6	1907.4	1751.6	1601.2	1544.4	1542.9	1538.1	1597.3	1528.2	1513.6	1630.8	1694.5
Fri 12:00 PM	1815.9	1907.4	1711.8	1530.6	1511.3	1528.6	1533.9	1541.3	1533.3	1447.2	1600.4	1671.3
Fri 1:00 PM	1773.1	1803.9	1711.8	1487.8	1470.0	1487.2	1482.2	1547.7	1488.3	1457.3	1570.9	1644.4
Fri 2:00 PM	1800.8	1807.1	1663.1	1462.9	1423.9	1445.3	1490.2	1558.0	1468.7	1449.7	1556.5	1632.2
Fri 3:00 PM	1747.0	1777.2	1651.4	1465.0	1424.9	1470.9	1458.6	1519.7	1476.0	1405.7	1579.9	1662.0
Fri 4:00 PM	1844.5	1785.7	1658.4	1516.9	1439.2	1470.0	1434.2	1501.0	1472.4	1406.9	1645.1	1746.4
Fri 5:00 PM	2061.8	1945.3	1755.6	1542.2	1459.8	1450.7	1476.9	1533.6	1530.7	1479.1	1762.2	1975.9

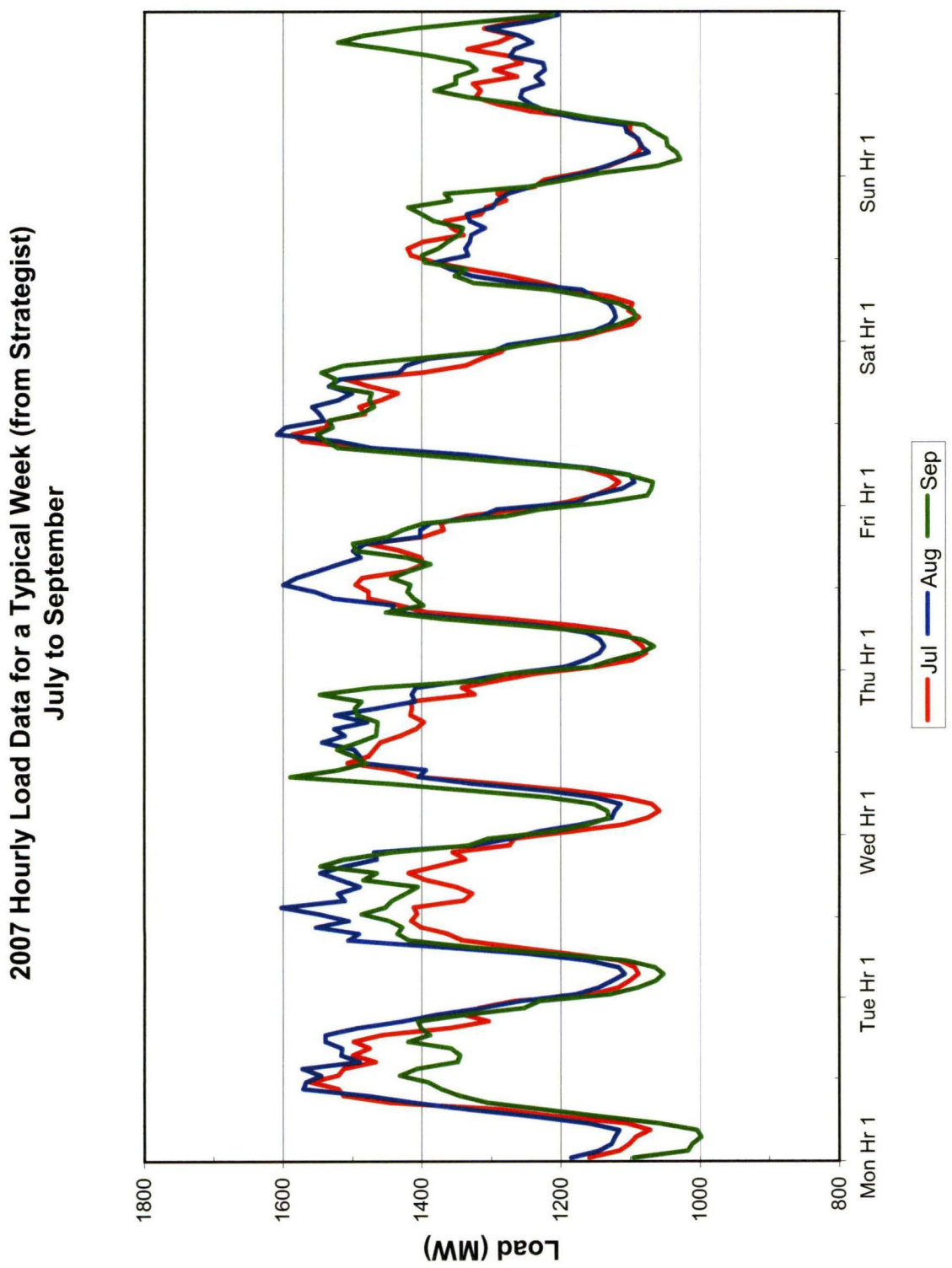
Fri 6:00 PM	2035.4	2031.6	1879.3	1592.6	1514.4	1420.0	1509.1	1518.4	1523.2	1553.6	1821.4	1979.6
Fri 7:00 PM	1984.7	1975.7	1873.3	1568.3	1435.1	1355.6	1398.0	1433.3	1544.7	1532.7	1732.2	1892.5
Fri 8:00 PM	1796.8	1885.3	1815.6	1559.9	1387.1	1341.8	1336.5	1422.8	1511.9	1535.5	1642.7	1865.1
Fri 9:00 PM	1689.8	1814.6	1719.4	1507.8	1387.1	1317.8	1313.9	1390.6	1412.6	1451.0	1578.8	1778.7
Fri 10:00 PM	1635.6	1708.9	1597.9	1482.3	1328.1	1287.0	1285.6	1299.6	1306.7	1334.8	1501.0	1691.3
Fri 11:00 PM	1612.9	1693.4	1581.1	1472.5	1324.1	1268.2	1276.1	1276.1	1253.8	1355.4	1503.1	1678.7
Sat 12:00 AM	1570.0	1570.3	1528.8	1373.5	1248.5	1183.2	1174.9	1207.5	1188.6	1271.6	1364.3	1595.1
Sat 1:00 AM	1563.5	1518.5	1469.6	1344.0	1185.4	1110.7	1139.8	1152.3	1144.9	1171.7	1289.3	1436.9
Sat 2:00 AM	1544.0	1477.4	1426.1	1283.1	1148.6	1074.9	1098.2	1128.9	1116.5	1156.6	1256.4	1385.6
Sat 3:00 AM	1549.1	1470.7	1417.9	1284.7	1138.7	1039.5	1087.3	1120.8	1090.9	1154.0	1244.0	1373.6
Sat 4:00 AM	1552.7	1505.1	1443.3	1283.9	1154.5	1070.0	1102.0	1123.2	1096.1	1152.0	1250.5	1373.6
Sat 5:00 AM	1575.6	1555.5	1456.2	1317.8	1188.4	1098.8	1096.0	1130.6	1116.5	1181.8	1291.5	1405.9
Sat 6:00 AM	1640.7	1639.2	1524.1	1425.4	1276.6	1164.0	1128.4	1153.2	1160.8	1231.2	1324.2	1476.1
Sat 7:00 AM	1699.2	1708.9	1591.5	1463.9	1343.4	1229.6	1188.5	1169.6	1216.2	1292.8	1368.6	1519.6
Sat 8:00 AM	1848.9	1798.5	1637.6	1567.1	1406.5	1313.7	1226.3	1262.1	1325.2	1418.9	1507.2	1634.2
Sat 9:00 AM	1933.4	1777.2	1579.0	1563.5	1416.7	1389.2	1275.0	1327.9	1351.9	1543.8	1535.8	1695.6
Sat 10:00 AM	1787.4	1786.8	1584.2	1509.0	1450.5	1384.5	1331.9	1358.2	1336.3	1550.8	1554.3	1664.0
Sat 11:00 AM	1787.4	1839.5	1583.1	1488.9	1449.5	1383.5	1381.0	1381.6	1395.2	1520.4	1545.6	1654.7
Sat 12:00 PM	1741.0	1768.7	1558.7	1542.2	1426.9	1408.0	1415.3	1333.3	1399.8	1406.9	1543.4	1639.3
Sat 1:00 PM	1782.2	1747.6	1517.7	1511.2	1429.0	1397.7	1420.3	1337.6	1375.6	1418.9	1544.5	1625.1
Sat 2:00 PM	1721.2	1711.0	1509.6	1513.5	1424.9	1377.8	1398.0	1331.1	1362.0	1439.7	1521.9	1625.1
Sat 3:00 PM	1690.8	1725.6	1511.3	1481.2	1358.6	1396.8	1339.9	1329.0	1346.3	1418.9	1492.7	1645.4
Sat 4:00 PM	1748.2	1718.3	1584.2	1487.8	1340.3	1398.7	1356.1	1308.9	1340.7	1422.6	1591.3	1717.0
Sat 5:00 PM	2033.5	1868.9	1603.3	1558.7	1417.7	1397.7	1366.7	1331.1	1382.5	1527.2	1790.1	2001.1
Sat 6:00 PM	2182.4	2021.3	1728.3	1670.1	1419.8	1420.0	1315.1	1335.4	1399.8	1626.4	1780.7	2142.6
Sat 7:00 PM	2106.5	1952.0	1684.6	1564.7	1409.5	1376.9	1307.3	1297.5	1419.7	1587.9	1664.5	2018.9
Sat 8:00 PM	1848.9	1835.1	1595.8	1505.6	1354.5	1336.8	1278.2	1291.3	1357.5	1485.7	1595.8	1904.5
Sat 9:00 PM	1736.2	1760.2	1562.7	1515.8	1362.7	1329.8	1291.0	1276.1	1366.5	1404.6	1506.2	1805.9
Sat 10:00 PM	1685.7	1663.6	1468.8	1435.6	1311.9	1300.4	1237.1	1241.5	1245.6	1311.9	1449.9	1699.9
Sat 11:00 PM	1608.6	1624.1	1461.6	1386.8	1300.8	1284.9	1223.3	1209.3	1191.5	1271.6	1441.2	1678.7
Sun 12:00 AM	1557.6	1562.4	1431.7	1340.5	1252.5	1194.4	1172.3	1165.3	1141.2	1232.0	1358.4	1543.9
Sun 1:00 AM	1544.0	1526.3	1409.3	1289.6	1185.4	1135.2	1130.8	1133.9	1060.1	1170.3	1293.0	1419.2
Sun 2:00 AM	1539.0	1508.9	1376.1	1263.7	1167.5	1088.1	1105.7	1107.2	1028.2	1130.4	1269.4	1370.5
Sun 3:00 AM	1544.5	1498.3	1374.5	1259.9	1175.4	1061.6	1088.7	1072.9	1033.8	1126.3	1253.1	1361.1
Sun 4:00 AM	1547.6	1495.5	1390.2	1266.8	1181.4	1062.8	1083.0	1084.8	1046.0	1139.3	1270.8	1384.8
Sun 5:00 AM	1556.4	1503.1	1396.2	1299.3	1204.4	1065.2	1089.5	1088.6	1047.7	1153.3	1293.7	1410.1
Sun 6:00 AM	1602.3	1581.1	1447.0	1346.7	1257.5	1082.1	1100.5	1104.8	1065.1	1175.3	1322.6	1470.8
Sun 7:00 AM	1625.1	1586.1	1461.6	1371.6	1281.7	1132.9	1099.7	1108.0	1080.5	1215.2	1351.7	1517.7
Sun 8:00 AM	1733.9	1659.5	1485.2	1473.6	1376.9	1241.5	1160.0	1179.3	1156.1	1297.8	1452.8	1645.4

Sun 9:00 AM	1811.8	1710.0	1535.4	1466.1	1404.4	1287.0	1244.1	1219.6	1211.2	1335.9	1506.2	1640.3
Sun 10:00 AM	1760.5	1744.4	1550.8	1538.7	1403.4	1354.6	1289.9	1242.5	1259.0	1411.7	1559.8	1656.8
Sun 11:00 AM	1751.8	1741.3	1515.0	1502.2	1368.8	1360.4	1322.9	1258.1	1332.9	1426.2	1517.7	1644.4
Sun 12:00 PM	1703.5	1653.4	1510.4	1506.7	1328.1	1349.7	1315.1	1255.2	1381.3	1385.9	1482.6	1597.1
Sun 1:00 PM	1682.6	1608.0	1490.3	1444.9	1299.8	1327.8	1326.3	1225.2	1350.7	1389.3	1455.7	1597.1
Sun 2:00 PM	1653.9	1596.0	1464.8	1435.6	1300.8	1333.8	1262.5	1235.7	1350.7	1414.1	1454.7	1563.9
Sun 3:00 PM	1639.0	1661.6	1489.5	1416.3	1289.7	1280.8	1295.3	1222.4	1320.9	1373.3	1435.5	1564.9
Sun 4:00 PM	1699.2	1652.4	1546.9	1451.2	1328.1	1298.4	1256.3	1225.2	1332.9	1428.6	1488.7	1695.6
Sun 5:00 PM	1940.1	1726.6	1644.5	1502.2	1347.4	1341.8	1272.9	1273.1	1383.6	1464.9	1749.0	1985.9
Sun 6:00 PM	2176.1	1849.2	1730.8	1581.6	1422.8	1371.1	1334.2	1266.1	1448.2	1494.9	1836.6	1987.2
Sun 7:00 PM	2100.6	1827.5	1729.6	1555.2	1389.1	1334.8	1289.9	1240.5	1520.7	1532.7	1721.9	1959.7
Sun 8:00 PM	1813.2	1757.1	1646.8	1577.9	1354.5	1344.7	1267.7	1260.1	1484.6	1463.7	1700.4	1930.1
Sun 9:00 PM	1721.2	1704.8	1573.9	1545.8	1409.5	1379.7	1310.6	1305.8	1412.6	1433.6	1623.7	1827.7
Sun 10:00 PM	1629.1	1620.1	1511.3	1492.2	1340.3	1351.6	1260.4	1241.5	1314.3	1320.1	1502.0	1671.3
Sun 11:00 PM	1573.0	1535.0	1441.1	1461.8	1309.9	1248.0	1225.3	1203.8	1212.2	1249.5	1445.0	1585.3

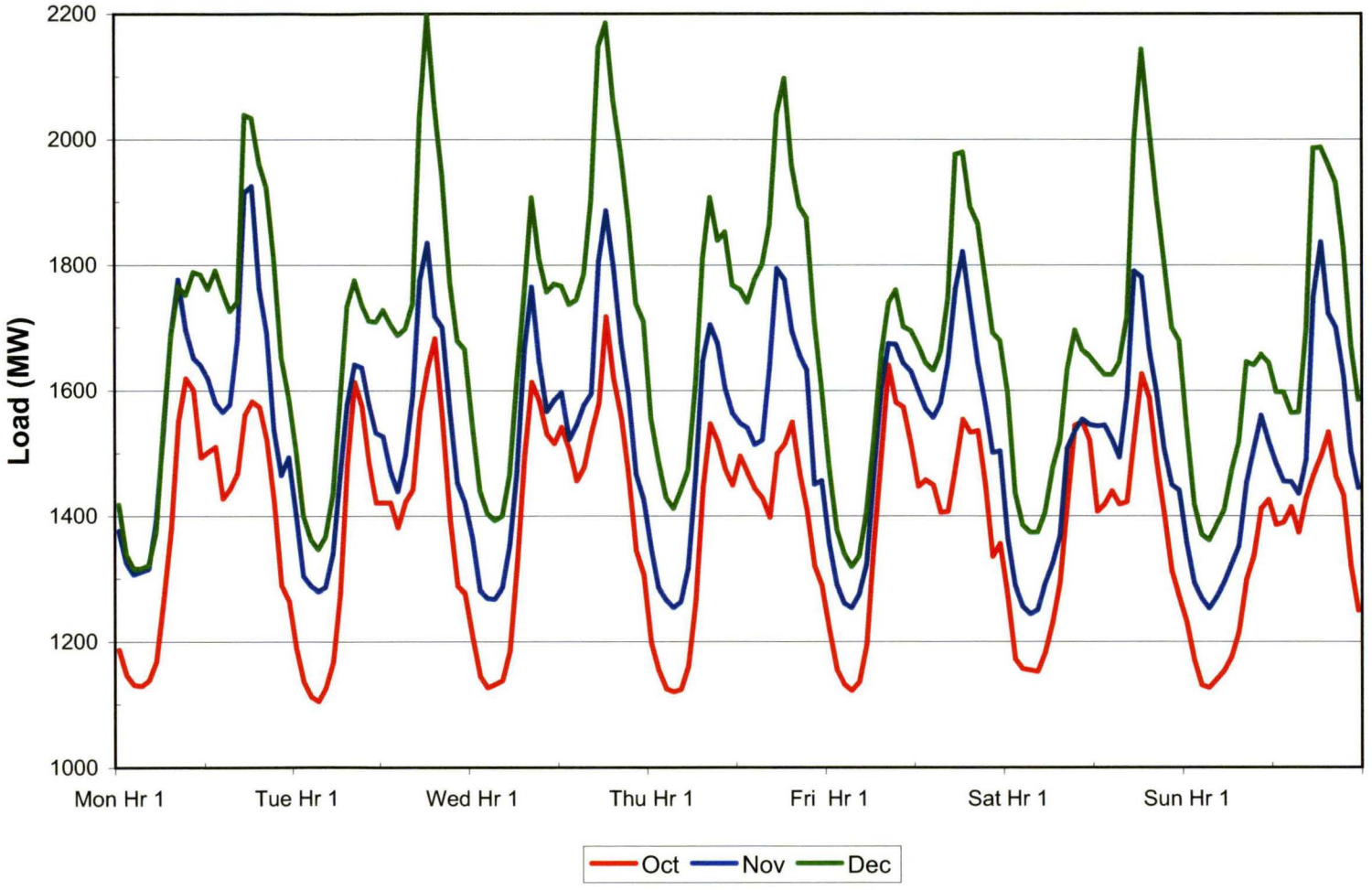
2007 Hourly Load Data for a Typical Week (from Strategist)
January to March




2007 Hourly Load Data for a Typical Week (from Strategist)
April to June
Load (MW)
2000
1800
1600
1400
1200
1000
Mon Hr 1
Tue Hr 1
Wed Hr 1
Thu Hr 1
Fri Hr 1
Sat Hr 1
Sun Hr 1
Apr
May
Jun


2007 Hourly Load Data for a Typical Week (from Strategist)
July to September
Load (MW)
1800
1600
1400
1200
1000
800
Mon Hr 1
Tue Hr 1
Wed Hr 1
Thu Hr 1
Fri Hr 1
Sat Hr 1
Sun Hr 1
Jul
Aug
Sep

2007 Hourly Load Data for a Typical Week (from Strategist)
October to December



NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF: The *Public Utilities Act,* R.S.N.S. 1989, c.380 as amended

IN THE MATTER OF: An Application by Nova Scotia Power Incorporated for Approval of Certain Revisions to its Rates, Charges and Regulations

RESPONSE TO INFORMATION REQUEST

TO: NSPI

FROM: UARB **REDACTED**

Question IR-84: **Please provide the 2007 fuel forecast in the same format and level of detail as the 2005 rate case (P-881) response to UARB IR-49.**

Response IR-84: Please refer to Confidential Attachment 1.