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Request IR-1:

Please specify all costs included in the Application which are related to compensation for any Emera or Emera-related employees.

a) Please name each employee and job title, and provide a breakdown of those costs for each employee.
b) Please specify any compensation for the President and CEO of Emera that is included in the Application.

Response IR-1:

(a) There are no direct compensation costs for Emera employees in NS Power's revenue requirement. The forecasts include shared services among affiliates, such as tax and internal audit, which are allocated among affiliates in accordance with accepted approaches pursuant to the Code of Conduct for Affiliate Transactions.

(b) None of the compensation for the President and CEO of Emera is funded by NS Power customers and therefore no such amounts are included in the Application.

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Request IR-2:

Please identify the number and percentage of employees who were eligible to receive a bonus, and the number and percentage that actually received a bonus, in any of the previous 5 years.

a) What was the total amount of the bonus in each year?
b) Provide a breakdown of the number and percentage of employees within each bonus category along with the associated bonus amounts.
c) Please provide similar details regarding the Application for 2013 and for 2014.

Response IR-2:

(a-b) NS Power's incentive program is part of the overall total compensation structure for permanent, non-union employees. The figure below shows total count of eligible employees by category and the total incentive expense for each of the past five years.

- Eligibility count is based on employement status at December 31 of each performance year. Employees must be permanent, non-union, with six months active service.

- Incentive amounts shown are 50 percent of the total incentive payroll amount for those employees identified above as eligible. 50 percent of incentive expense is paid by shareholders.

(c) Forecasted incentive expense for 2013 and 2014 is not detailed to the mix of employees by incentive category. The revenue requirement for 2013 and 2014 does not include any amounts for executive incentives.

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Incentive Category		2007	2008	2009	2010	2011
Executive	**Count of Eligible Employees**	12	13	13	12	11
	50% of payroll amount ($000's)	**$262**	**$487**	**$362**	**$209**	**$221**
Director	**Count of Eligible Employees**	19	21	21	16	24
	50% of payroll amount ($000's)	**$238**	**$203**	**$304**	**$126**	**$231**
Manager	**Count of Eligible Employees**	66	66	73	74	80
	50% of payroll amount ($000's)	**$326**	**$409**	**$552**	**$480**	**$470**
Individual Contributor	**Count of Eligible Employees**	186	182	193	232	258
	50% of payroll amount ($000's)	**$725**	**$710**	**$908**	**$915**	**$968**
General Staff	**Count of Eligible Employees**	354	373	382	397	383
	50% of payroll amount ($000's)	**$484**	**$524**	**$641**	**$612**	**$565**
Job not categorized	**Count of Eligible Employees**	75	40	55	79	53
	50% of payroll amount ($000's)	**$335**	**$272**	**$293**	**$346**	**$212**
Total	**Count of Eligible Employees**	712	695	737	810	809
	50% of payroll amount ($000's)	**$2,369**	**$2,604**	**$3,059**	**$2,688**	**$2,668**
	Accrued Incentive Expense Included in Regulated OM&G ($000's)	**$2,436**	**$2,414**	**$3,097**	**$2,578**	**$2,718**

Note: Differences between accrued incentive expense and actual payroll amounts is due to effects of adjustments to scorecard results based on actual year-end results.

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Request IR-3:

Reference DE-03 - DE-04, p. 82, lines 14 - 25,

Please describe the current status of NSPI's collective agreement with its unionized labour force and identify the percent increase and the total amounts included for 2013 and 2014.

Response IR-3:

Please refer to Eckler IR-14 and Liberty IR-69.

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Request IR-4:

Reference Exhibit N-5, NSPI Analysis of Executive Management Expenses 2011:

a) Please confirm NSPI reports its Named Executive Officer compensation through Sedar.

b) Please provide the link to NSPI's Named Executive Officer reporting for 2011.

c) Please explain why NSPI reports 2 executives on their Sedar Named Executives filing that are not included in this Board report. Were these individuals included in the Tower analysis?

Response IR-4:

(a) Confirmed.

(b) Please refer to Attachment 1 for the NS Power Management Information Circular, June 7, 2012.

(c) Management Information Circular filings require that the Chief Financial Officer position is included in the report. There were two incumbents in this role for 2011 (partial years for each incumbent) and both were required to be included in the NS Power Management Information Circular. The Chief Financial Officer position is common between NS Power and Emera and the costs for this position are not included in rates. The Chief Financial Officer position is not included in the NS Power Towers Watson analysis as it is not included in rates.

NOVA SCOTIA POWER INCORPORATED

ANNUAL MEETING
OF COMMON SHAREHOLDERS
JUNE 7, 2012

MANAGEMENT INFORMATION CIRCULAR

MANAGEMENT INFORMATION CIRCULAR

(as at May 4, 2012, unless otherwise specified)

SOLICITATION OF PROXIES

This Management Information Circular (the "Circular") is furnished in connection with the solicitation of proxies by the management of Nova Scotia Power Incorporated (the "Company" or "NSPI") for use at the Annual Meeting of shareholders of the Company (and any adjournment thereof) (the "Meeting") to be held on June 7, 2012 at the time and place and for the purposes set forth in the Notice of Meeting delivered to shareholders. While it is expected that the solicitation will be primarily by mail, proxies may be solicited personally or by telephone by the regular employees of the Company at nominal cost, or by outside parties. All costs of solicitation by management will be borne by the Company.

The contents and the sending of this Circular have been approved by the Directors of the Company.

APPOINTMENT AND REVOCATION OF PROXIES

The individuals named in the accompanying form of proxy (the "Proxy") are officers of the Company. A SHAREHOLDER WISHING TO APPOINT SOME OTHER PERSON (WHO NEED NOT BE A SHAREHOLDER) TO REPRESENT HIM AT THE MEETING HAS THE RIGHT TO DO SO, EITHER BY STRIKING OUT THE NAMES OF THOSE PERSONS NAMED IN THE PROXY AND INSERTING THE DESIRED PERSON'S NAME IN THE BLANK SPACE PROVIDED IN THE PROXY OR BY COMPLETING ANOTHER FORM OF PROXY. A proxy will not be valid unless the completed form of Proxy is received by Stephen Aftanas, the Corporate Secretary of the Company, no later than 48 hours (excluding Saturdays, Sundays and holidays) before the time for holding the Meeting or any adjournment thereof, unless the Chairman of the Meeting elects to exercise his discretion to accept proxies received subsequently.

A shareholder who has given a Proxy may revoke it by an instrument in writing executed by the shareholder or by his or her attorney authorized in writing or, where the shareholder is a corporation, by a duly authorized officer or attorney of the corporation, and delivered to Stephen Aftanas, the Corporate Secretary of the Company, at any time up to and including the last business day preceding the day of the Meeting, or if adjourned, any reconvening thereof, or to the Chairman of the Meeting on the day of the Meeting, prior to the commencement of the Meeting or, if adjourned, any reconvening thereof or in any other manner provided by law. A revocation of a Proxy does not affect any matter on which a vote has been taken prior to the revocation.

VOTING OF PROXIES

The persons named in the Proxy will vote or withhold from voting the common shares ("Common Shares") represented thereby in accordance with your instructions on any ballot that may be called for. If you specify a choice with respect to any matter to be acted upon, your Common Shares will be voted accordingly. The Proxy confers discretionary authority on the persons named therein with respect to:

(i) each matter or group of matters identified therein for which a choice is not specified,

(ii) any amendment to or variation of any matter identified therein, and

(iii) any other matter that properly comes before the Meeting.

In respect of a matter for which a choice is not specified in the Proxy, the persons named in the Proxy will vote the Common Shares represented by the Proxy for the approval of such matter. Management is not currently aware of any other matter that could come before the Meeting.

VOTING SHARES AND PRINCIPAL HOLDERS THEREOF

Authorized Capital:
1. an unlimited number of Common Shares without nominal or par value;
2. an unlimited number of first preferred shares, issuable in series; and
3. an unlimited number of second preferred shares, issuable in series.

Issued and Outstanding[1]: 117.2 million Common Shares without par value
5,400,000 5.90% Series D cumulative redeemable first preferred shares

The date for determining which shareholders are entitled to receive the accompanying Notice of Meeting is May 17, 2012. This is called the "Record Date". Only shareholders of record who hold Common Shares at the close of business on the Record Date will be entitled to vote. Each Common Share owned as of the Record Date entitles the holder to one vote.

On a show of hands, every individual who is present as a shareholder or as a representative of one or more corporate shareholders, or who is holding a Proxy on behalf of a shareholder who is not present at the Meeting, will have one vote, and on a poll every shareholder present in person or represented by a Proxy and every person who is a representative of one or more corporate shareholders, will have one vote for each Common Share registered in his or her name or the name of the corporate shareholder(s) represented by him or her on the list of shareholders, which is available for inspection during normal business hours at the office of the Corporate Secretary of the Company and will be available at the Meeting.

To the best knowledge of the Directors and Executive Officers of the Company, the persons or companies who beneficially own, directly or indirectly or exercise control or direction over shares carrying more than 10% of the voting rights attached to all outstanding Common Shares of the Company are as follows:

Name	Number of Common Shares	Percentage
Emera Incorporated 1223 Lower Water Street Halifax, Nova Scotia B3J 3S8	99,630,548	85.009%
3081922 Nova Scotia Limited	17,567,108	14.989%

Common shares are the only voting shares at this time. Under Nova Scotia legislation that applies to the Company, no shareholder may own or control, directly or indirectly, more than 15% of the outstanding voting shares to elect Directors other than Emera Incorporated ("Emera"). Shareholders who are not residents of Canada may not hold, in total, more than 25% of outstanding voting shares that may ordinarily be cast to elect Directors. These restrictions may be enforced by limiting non-complying shareholders' voting rights, dividend rights and transfer rights. Shareholders may be required, at any time, to furnish a statutory declaration to verify the number of shares held and/or residency in order to ensure compliance with these restrictions. See also the section entitled "Capital Structure" in NSPI's Annual Information Form which is available under the Company's profile on www.sedar.com.

BUSINESS OF THE MEETING

All resolutions placed before the Meeting must be approved by a majority of the votes cast.

1. **Financial Statements:** The audited financial statements of the Company for the fiscal year ended December 31, 2011 and the auditors' report thereon will be placed before the Meeting. These financial statements are available at www.sedar.com under NSPI's profile.

2. **Election of the Board of Directors**: The 10 nominees proposed for election as Directors at the 2012 Meeting are identified under the section of this Circular entitled "Director Nominees". All nominees are

[1] As at ●⅓Rs ¢, 2012.

currently Directors of the Company and have served as Directors from the dates set out under "Director Nominees" below. Each nominee has indicated his or her willingness to serve as a Director. Each Director elected at the Meeting will hold office until the next Annual Meeting of shareholders.

The persons named on the accompanying Proxy intend to vote "For" the 10 nominees unless instructed otherwise by shareholders in their Proxy.

3. Appointment of Auditors: The Audit Committee pre-approves all services to be supplied by auditors and has reviewed the performance of Grant Thornton LLP, Chartered Accountants, including its independence, relating to the audit.

The persons named on the accompanying Proxy intend to vote "For" the re-appointment of Grant Thornton LLP as auditors of the Company to hold office until the close of the next Annual Meeting of shareholders, unless a shareholder specifies their shares be withheld from voting.

Grant Thornton LLP have been auditors of the Company since May, 2003.

4. Auditors' Fee: The Company is incorporated under the Nova Scotia *Companies Act*. Shareholder approval of the authorization of Directors to establish the auditors' fee is required pursuant to the Act. The fees paid to Grant Thornton LLP for services provided to the Company for 2011 were as follows:

Audit Fees:	$428,197
Audit-Related Fees:	$49,400
Tax Fees:	$22,400
Total:	$499,997

Audit-related fees for the Company related to services associated with French translation and tax fees related to tax compliance on corporation income tax returns.

The persons named on the accompanying Proxy intend to vote "For" the authorization of Directors to establish the auditors' fee for 2012, unless a shareholder specifies their shares be voted "Against" such matter.

DIRECTOR NOMINEES

The Board of Directors of the Company (the "Board of Directors") presently consists of 10 Directors and it is intended to elect 10 Directors for the ensuing year.

Directors are elected for a one year term and the term of the office of each of the present directors expires at the Meeting. The persons named below will be presented for election at the Meeting as management's nominees. Management does not contemplate that any of these nominees will be unable to serve as a director. Each Director elected will hold office until the next Annual Meeting of the shareholders of the Company or until his or her successor is elected or appointed, unless his or her office is earlier vacated in accordance with the provisions of the *Companies Act* (Nova Scotia) or the Articles of Association of the Company.

The following table states the name of each nominee for election as a director, the jurisdiction in which he or she is ordinarily resident, all offices of the Company now held by such nominee, his or her principal occupation, the period of time for which he or she has been a Director of the Company, and the number of Common Shares of the Company beneficially owned by him or her, directly or indirectly, or over which he or she exercises control or direction, as at the Record Date.

Name & Municipality of Residence(1)	Director Since	Principal Occupations During Past Five Years	Number of Voting Shares(2)
Wesley G. Armour(3)(4) Moncton, New Brunswick Canada	2005	President and Chief Executive Officer of Armour Transportation Systems, which provides trucking, warehousing, and courier	Nil

Name & Municipality of Residence[1]	Director Since	Principal Occupations During Past Five Years	Number of Voting Shares[2]
		services in Atlantic Canada.	
Robert R. Bennett Halifax, Nova Scotia Canada	2008	President and Chief Executive Officer since June 2008. From September 2007 to June 2008, Executive Vice-President, Revenue and Sustainability of NSPI. From September 2005 to June 2007, President and Chief Operating Officer of Bangor Hydro. From January 2005 to September 2005, Vice President and General Manager of Bangor Hydro. From June 3, 2002 to January 2005, General Manager Transmission & Distribution Asset Management of Bangor Hydro.	Nil
J. Lee Bragg[(3)(4)] Fall River, Nova Scotia Canada	2010	Chief Executive Officer of Eastlink, a cable and communication company, and its associated communications companies since 1999. Prior to 1999, held various management positions with the Bragg Group of Companies.	Nil
R. Irene d'Entremont, C.M.[(3)(4)(6)] Yarmouth, Nova Scotia Canada	1995	President of ITG Information Management Inc., business and management services consultants.	Nil
James D. Eisenhauer[(3)(5)] Lunenburg, Nova Scotia Canada	2008	President and Chief Executive Officer of ABCO Group Limited, which has holdings in manufacturing and distribution activities.	Nil
Christopher G. Huskilson Wellington, Nova Scotia Canada	2004	President and Chief Executive Officer of Emera since November 2004. Chair of Bangor Hydro, a Director of NSPI and Chair or Director of a number of other Emera affiliated companies. Since 1980 held a number of positions within NSPI and its predecessor, Nova Scotia Power Corporation.	Nil
Raymond E. Ivany [(3)(4)] Wolfville, Nova Scotia Canada	2011	President and Vice Chancellor of Acadia University since April 2009. From 2007 to 2009 Chair of the Worker's Compensation Board of Nova Scotia. Former principal of Ivany and Associates, a consulting firm, from 2005 to 2009.	Nil
John T. McLennan[(3)(4)] Mahone Bay, Nova Scotia Canada	2005	Chair of the Board of Emera since May 2009. Former Chair of the Board of NSPI from May 2006 to May 6, 2009. Director of Chorus Aviation Inc. and Amdocs Ltd. Former Vice-Chair and Chief Executive Officer of Allstream Inc. (formerly AT&T Canada).	Nil

Marie C. Rounding(3)(4)(7) Toronto, Ontario Canada	2007	Counsel to Gowling Lafleur Henderson LLP, and member of the National Energy and Infrastructure Industry Group. Former President and Chief Executive Officer of the Canadian Gas Association from 1998 to 2003. Former Chair of the Ontario Energy Board from 1992 to 1998.	Nil
Elaine S. Sibson(3)(4) Halifax, Nova Scotia Canada	2010	Currently Chair of the Workers' Compensation Board of Nova Scotia. Fellow of the Institute of Chartered Accountants and a Tax Partner in PricewaterhouseCoopers LLP and its predecessor Coopers & Lybrand until 2007. Served on the Board of PricewaterhouseCoopers LLP from 2004 through 2006.	Nil

Notes:
(1) The information as to municipality of residence and principal occupation has been furnished by the respective nominees.
(2) All voting shares of the Company are beneficially owned by Emera, 3081922 Nova Scotia Limited and 3240384 Nova Scotia Limited.
(3) Member of the Audit, Nominating and Corporate Governance Committee.
(4) Member of the Management's Resources, Compensation and Corporate Responsibility Committee.
(5) Chairman of the Board since May 2, 2011.
(6) Chair of the Management's Resources, Compensation and Corporate Responsibility Committee.
(7) Chair of the Audit, Nominating and Corporate Governance Committee.

Corporate Cease Trade Orders or Bankruptcies

No Director or proposed director of the Company is, as at the date of this Circular, or was within 10 years before the date of this Circular, a director, chief Executive Officer or chief financial officer of any company (including the Company), that:

(a) was subject to a cease trade order, an order similar to a cease trade order or an order that denied the relevant company access to any exemption under securities legislation, for a period of more than 30 consecutive days, that was issued while the proposed director was acting in the capacity as director, chief Executive Officer or chief financial officer; or

(b) was subject to a cease trade order, an order similar to a cease trade order or an order that denied the relevant company access to any exemption under securities legislation, for a period of more than 30 consecutive days, that was issued after the proposed director ceased to be a director, chief Executive Officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief Executive Officer or chief financial officer,

No Director or proposed director of the Company:

(a) is, as at the date of this Circular, or has been within the 10 years before the date of this Circular, a director or Executive Officer of any company (including the Company) that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; or

(b) has, with the exception of Mr. MacLennan as set forth below, within 10 years before the date of this Circular, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the proposed director:

John T. McLennan was the Chief Executive Officer of AT&T Canada when AT&T Canada filed for protection under the *Companies' Creditors Arrangement Act* (Canada) on October 15, 2002.

No Director or proposed director of the Company has been subject to:

(a) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority; or

(b) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable securityholder in deciding whether to vote for a proposed director.

STATEMENT OF EXECUTIVE COMPENSATION

The Management Resources, Compensation and Corporate Responsibility Committee ("MRCCR") determines the compensation for NSPI's Executive Officers and makes a recommendation for approval to the Emera Management Resources Compensation Committee ("Emera MRCC"). The MRCCR, in coordination with the Emera MRCC, oversees the administration of all NSPI executive compensation plans and programs. On the recommendation of the MRCCR, the Emera MRCC approves the compensation for NSPI executives. The MRCCR currently consists of R. Irene d'Entremont (Chair), Wesley G. Armour, J. Lee Bragg, Raymond E. Ivany, John T. MacLennan, Marie C. Rounding, and Elaine S. Sibson. All members of the MRCCR are independent Directors. See also the section in this Circular entitled "Corporate Governance Practices – Compensation".

Compensation Advisors

The MRCC and MRCCR retains the services of independent advisors as needed in order to assist in discharging its duties and to assist the MRCC in determining the compensation payable to the President and Chief Executive Officer and the senior officers.

Since 2007, the MRCC has engaged Hugessen Consulting Inc. ("Hugessen") as its principal advisor to provide independent advice, compensation analysis and other information for compensation recommendations. Hugessen provides advice on the competitiveness and appropriateness of compensation practices and comparator groups for Emera and its affiliates

In addition to the MRCC's compensation advisor in 2011, Emera engaged the services of Towers Watson, Morneau Shepell, and Mercer (Canada) Limited ("Mercer") to assist in compiling market information on senior management compensation for Emera relating to base salary, and short-term and long-term incentives. This included competitive reviews of executive compensation levels and information on industry trends.

In 2011, Morneau Shepell completed actuarial analysis on Emera's long-term incentive plan and provided current data on the Executive Pension Plan.

The MRCC reviews information and recommendations provided by Hugessen, Towers Watson, Mercer, and Morneau Shepell, as it considers its decisions relevant to the objectives of the compensation program. The table below summarizes the fees paid to all external compensation advisors in 2010 and 2011.

	2011		2010	
Advisor	MRCC Work	Other Work	MRCC Work	Other Work

Hugessen Consulting Inc. (1)	$59,795	$nil	$96,654	$11,965 (2)
Morneau Shepell	Nil	$58,315	Nil	$69,517
Towers Watson	Nil	$16,142	Nil	$49,679
Mercer (Canada) Limited	Nil	$69,349	Nil	$14,162

Notes:

(1) Hugessen Consulting Inc. did not provide any professional services to Management in 2010 and 2011.

(2) Hugessen Consulting Inc. was retained by the Nominating and Corporate Governance Committee in 2010 to review Directors compensation.

Risk Management and Compensation

The MRCCR also has a role in the risk oversight of compensation policies and practices. The Company has compensation policies and practices in place to ensure a named Executive Officer or individual at a principal business unit does not take inappropriate or excessive risk, such as:

-
- Short-term incentive plans include caps on payouts;
- The Performance Share Unit Plan ("PSU Plan") includes caps on payouts;
- Termination and severance provisions include a double trigger(1) and do not provide enhanced benefits for change of control;
  Executive share ownership requirements align the interests of senior officers with interests of shareholders;
- Inclusion of non-financial performance measures in incentive compensation programs; and
- The Board has discretion to amend the final payout of the incentive compensation programs.

Note:

(1) A doupble trigger is a change in the ownership restriction and more than firty (50) percent of the voiting shares of the Company accrue to a single party ('change of control')_ and within three (3) months of such change of control, there is a substantial reduction in duties of the Executive.

In 2011, the Emera MRCC conducted a risk assessment of its compensation programs. To assist with this risk assessment, the Emera MRCC engaged the services of Mercer which reviewed the design of Emera's executive compensation programs. Based on this assessment, the Emera MRCC and MRCCR concluded that:

- The mix of base salary, short and long-term incentive for senior officers, did not create an incentive to take inappropriate risk to the detriment of NSPI's shareholders;
- The annual incentive plan focused on growth of annual earnings and cash flow, but capped incentive payouts in a manner consistent with market practice, thereby reducing risk;
- Any risk associated with long-term incentive plans was mitigated by annual grants, in the case of performance share unit ("PSU") grants and stock options grants, and also by caps on payouts in the case of PSU grants under the PSU Plan;
- Emera's executive share ownership requirements decreased risk in the compensation program by encouraging alignment between the interests of senior officers and shareholders; and
- The inclusion in employment contracts for senior officers of double trigger provisions and the absence of enhanced benefits for change of control mitigated risk arising from termination.

In summary, the MRCCR concluded Emera's compensation programs did not create inordinate risk to the shareholders of NSPI because an appropriate system of checks and balances was in place to mitigate the level of risk undertaken by management.

As part of the Board and its MRCCR's oversight of the design and administration of the Company's executive compensation programs, the MRCCR identifies and discusses design features or processes that may potentially represent conflicts of interest and/or inducements for unnecessary or excessive risk-taking by senior executives. This includes annual reviews of the amount of total incentive relative to base salaries, the mix of short and long-term incentives, the performance metrics and whether the goals are realistic or encourage excessive risk taking, and the use of other policies designed to mitigate risk such as vesting requirements, caps on payouts, deferral periods, and stock ownership guidelines. In addition, the MRCCR utilizes various technical analyses including "stress testing" and scenario analysis to evaluate the inherent risk and reward outcomes in the incentive compensation plans.

The MRCCR also satisfies itself as to the adequacy of the information it receives, the independence of the review and reporting of financial results on which certain important compensation decisions (e.g. the amount of annual incentive to be paid) are based.

These existing safeguards notwithstanding in 2011, the MRCCR and Board will continue to review the relationship between enterprise risk and the Company's executive compensation plans and policies to confirm they continue to be optimally aligned with shareholder interests while maintaining an acceptable level of risk exposure.

Compensation Discussion and Analysis

This section discusses the elements of compensation for the Named Executive Officers ("NEOs") of NSPI in 2011, namely:

- Robert R. Bennett, the President and Chief Executive Officer (sometimes called the "CEO" below);
- Judy A. Steele, the Chief Financial Officer from May 16, 2011 to December 31, 2011 ("NSPI's CFO");
- Nancy G. Tower, former NSPI Chief Financial Officer from January 1, 2011 to May 16, 2011, and Emera's Executive Vice President, Business Development since May 1, 2011 (the "EVP Business Development, Emera");
- Robin B. McAdam, Executive Vice President, Strategic Business & Customer Services (the "EVP Strategic Business");
- Mark W. Savory, Vice President, Technical and Construction Services (the "VP Technical"); and
- Alan C. Richardson, Vice President, Integrated Customer Services (the "VP Customer").

In 2011, due to Nancy Tower's change in position, there are six NEOs being reported. Judy A. Steele and Nancy G. Tower are collectively referred to as the "CFO" where applicable.

Objective of Compensation Program

The purpose of NSPI's executive compensation program is to reward NSPI's executives for achieving corporate objectives focused on customer safety, employee, operational and financial aspects of the business that seek to ensure the Company delivers on its commitments to customers and shareholders; and to attract, retain and motivate highly qualified and high-performing executives in a competitive national market.

Compensation Program Design

NSPI's compensation program is designed to be competitive in relevant labour markets, include both short-term and long-term performance goals, and link compensation to NSPI's performance as measured by specific business and financial results.

Market Competitiveness. NSPI's executive compensation program is designed to provide Total Target Compensation on average at the median or 50th percentile of compensation paid by similar industries and similarly-sized companies and allows for 75th percentile rewards for top quartile performance. "Total Target Compensation" for senior management, including the NEOs, for these purposes, is comprised of:

- base salary,
- target annual incentive, and
- target long-term incentives linked to total shareholder value.

Pay for Performance. NSPI's executive compensation philosophy is that a significant portion of executive compensation must be at risk. The at-risk components depend on achieving company, business unit and individual performance objectives. These objectives are set forth in "Scorecards" that establish measurable financial, customer, asset and employee objectives that, if achieved, add value to NSPI. The NEOs' performances against their "Scorecard" is measured and rated.

The NEOs must achieve a threshold level of performance for any payment against a particular objective, failing which there is no payment against such objective. Accordingly, incentive compensation plans and programs are designed to pay larger amounts for superior performance, and smaller amounts if target performance is not achieved. Generally, the higher the level of the responsibility, the greater the at risk compensation. In 2011, at least 44% of the Total Target Compensation was at risk for the NEOs

Management considers many factors when developing annual incentive and long term incentive plans, including: current compensation trends; plan costs at payout; expected value to be delivered to participants; maximum payout values and causal analysis of minimum, target and maximum payouts.

Both annual incentive and long-term incentive plan designs are modelled using historical and prospective performance scenarios. This stress testing provides the MRCC with reasonable assurance that the plan payouts will be appropriate and aligned with shareholder and Company objectives. Analysis is done every year to determine how actual payouts compare to expected payouts and whether the plan components require any changes.

Benchmarking Data

NSPI engaged the services of Towers Watson, Morneau Shepell, and Stephanie Milliken to assist in compiling market information on senior management compensation, including the NEOs, relating to base salary, and short-term and long-term incentives. A complete benchmarking review takes place on an annual basis for NSPI. This scope of services includes competitive market reviews of senior executive compensation levels, review and observation of current executive compensation philosophy, policies and practices, and a review of pay and performance comparators. The MRCCR undertakes periodic reviews of compensation design and total compensation opportunities for some of the NEOs to ensure the programs are current and that they fairly compare for particular roles, recognizing varying responsibility and scope of executive positions within NSPI.

The MRCCR reviews compensation data based on a comparator group of companies, primarily regulated utilities and other energy industry enterprises that approximate the size and scope of NSPI. While the intention is to use a consistent list of comparators from year to year, the comparators used for compensation review are subject to some change each year due to (a) the availability of relevant pay data, (b) mergers and acquisitions, and (c) relevance of new comparators based on updated financial metrics.

Based on the benchmark data, NSPI's CEO recommends Total Target Compensation to the MRCCR for each NEO, excluding himself, the CFO, and the EVP Business Development, Emera. The MRCCR reviews benchmark data and other information regarding industry trends for positions of similar scope. Following this process, the MRCCR makes recommendations for approval of Total Target Compensation to the Emera MRCC for NSPI NEOs other than the CEO, CFO, and the EVP Business Development, Emera. With respect to NSPI's CEO, NSPI's CFO, and the EVP Business Development, Emera, Emera's President and Chief Executive Officer recommends for approval the Total Target Compensation to the Emera MRCC.

The following sources were used to gather benchmark market information about executive compensation for NSPI, excluding NSPI's CFO and EVP Business Development, Emera:

Survey Data - Towers Watson's 2010 Executive Survey was used to benchmark compensation of the NEOs and other senior management using a broad comparator group that contained both a regulated sample (regulated utilities) and a select sample (energy industry companies) of survey participants where data was available.

Broad Comparator Group:

Alcoa Canada Primary Metals
ARC Resources Ltd.
ATCO Ltd. and Canadian Utilities Ltd.
BC Hydro
BP Canada Energy Company
Bruce Power
Canadian Oil Sands Limited
Canfor Corporation
Capital Power Corporation
CCS Corporation
Chevron Canada Resources
Devon Canada Corporation
ENMAX Corporation
EPCOR Utilities Inc.
Finning International Inc.
Fluor Canada Ltd.
Fort Chicago Energy Partners L.P.
Gaz Metropolitan
GLV Inc.
Husky Injection Molding Systems Ltd.
Hydro One
IAMGOLD Corporation
Irving Oil Limited
Kinross Gold Corporation
Lafarge Canada Inc.
Manitoba Hydro Electric
Marathon Oil Canada Corp.
Methanex Corporation
NOVA Chemicals
Pembina Pipeline Corporation
Pengrowth Corporation
Penn West Energy Trust
SaskEnergy
SaskPower
Spectra Energy Transmission
TAQA NORTH LTD.
Tembec Inc.
Terasen Gas
Toromont Industries Ltd.
Toronto Hydro Electric Systems Ltd.
TransAlta Corporation
The Woodbridge Group

The sources used to establish benchmark data for the CFO are as follows:

Publicly-Disclosed Compensation Data – In 2011, Hugessen Consulting Inc. was retained by Emera's MRCC to advise on the competitiveness and appropriateness of compensation programs (salary, annual and long term incentives, and pension) for the offices of President and Chief Executive Officer of Emera and the CFO, who was also the Chief Financial Officer at Emera, using the pre-agreed proxy comparator group.

The following publicly-traded organizations were used as the primary comparator group for the purposes of the compensation benchmarking review as described above.

S&P / TSX Capped Utilities Index:

ATCO Ltd.
Brookfield Renewable Power Fund
Fortis Inc.
TransAlta Corp.

The following publicly-traded organizations were also used for the purposes of Emera's President and Chief Executive Officer and Chief Financial Officer compensation benchmarking as described above.
Energy Industry Comparables:

AltaGas Income Trust
Enerplus Resources Fund
Ensign Energy Services Inc.
Inter Pipeline Fund
Keyera Facilities Income Fund
Pembina Pipeline Corporation
Pengrowth Energy Trust
Precision Drilling Corporation
Provident Energy Trust
ShawCor Ltd.

The rationale for incorporating the energy industry is that senior talent can migrate between similar organizations (i.e. industry, scale, complexity) and the fact that Emera's strategic objectives include expansion into various energy-related sectors.

Compensation Process

Benchmarking data and other information regarding industry trends for positions of similar scope and responsibility are used to establish a base salary range for each position and a range for annual incentive and long-term incentive target compensation for each position.

Elements of Compensation

Base Salary - Base salaries for each NEO are benchmarked against the median of the salaries paid for positions with similar responsibilities by comparator companies. The base salary for each NEO is reviewed annually and reflects the degree of special skill and knowledge required for the position and the performance and contribution of the individual. Base salary is designed to be a component of Total Target Compensation and provides a threshold level of cash compensation for job performance that is not at risk in the same way as annual incentive compensation.

Annual Incentive – "Annual Incentive" compensation is intended to link a portion of an employee's compensation to the achievement of predetermined levels of performance in support of corporate and business unit objectives. Those objectives are set forth in the NEO's "Scorecard" and designed to focus attention on short term goals that are intended to deliver sustained improvements in business performance and deliver on commitments to customers and shareholders. NSPI and Emera have adopted the Scorecard approach to translate corporate strategies into measurable incentive plan goals. Target payouts under the Scorecards are generally set as a percentage of salary and are benchmarked against the median for positions with similar responsibilities in comparator companies.

NSPI's 2011 Scorecard

The 2011 NSPI Scorecard set out corporate objectives and related threshold, target and stretch performance levels for 2011, on which the Annual Incentives for each of NSPI's CEO, the EVP Strategic Business, the VP Technical, and the VP Customer were based. The Annual Incentive for NSPI's CFO and EVP Business Development, Emera was determined based on the Emera 2011 Scorecard. Payouts can range from 0% to 200% of target.

The NSPI Scorecard is developed and recommended by NSPI management for approval by the MRCCR and the Board, which in turn recommends the NSPI Scorecard for final approval at the beginning of each year by the Emera MRCC. Objectives on the 2011 NSPI Scorecard included a 7.5% weighting for continued safety improvement and 7.5% for development of people. Reliability and reputation with the customer received a 30% weighting, and asset management was weighted at 15%. A 40% weighting for strengthening NSPI's financial positioning by generating growth as measured by financial earnings and cash from operations made up the balance of the scorecard. On the recommendation of the MRCCR, the Emera MRCC determined that the CEO, the EVP Strategic Business, the VP Technical, and the VP Customer of NSPI achieved an aggregate of 95.3% of target on all the objectives measured in the NSPI Scorecard in 2011.

The following table shows the objectives of the NSPI Scorecard for 2011:

Nova Scotia Power Inc. Corporate Objective	Weighting	Target	Actual Result	Percentage Payout
Safety	7.5%	Best Ever Lost Time Frequency (LTF)=<0.18 (approximately 3 or 4 events based per hours) PLUS 95% of critical task reviews are completed by	Threshold	3.75

Nova Scotia Power Inc. Corporate Objective	Weighting	Target	Actual Result	Percentage Payout
		senior management team; PLUS an annual audit on the Safety Program scores 90% with no one element below 85% PLUS annual audit on Safety Program scores 90% with no one element below 85% PLUS Best Ever All Injury Frequency (AIF)=<[0.88]		
People – Attract, Retain and Develop the talent required	7.5%	70% of leaders and high potentials participate in a focused leadership development program; AND statistically significant improvement on health screen body mass index results; AND we achieve 80% Employee Commitment Index on 2011 Annual Employee Survey	Threshold	3.75
Customer – Advancement and cost effectiveness of 5 year reliability plan; Reliability statistics; performance during extreme storm events	10%	25% less tree/equip failure outages versus 2009 actuals OR 70% customer satisfaction with NSPI response to extreme storm events; PLUS 5% improvement in the effectiveness of reliability investment plan	Target	10.0
Customer - Customer Satisfaction with service interactions; cost recovery secured in rates; and overall satisfaction	20%	5% improvement over 2010 with more outstanding scores (9-10) and few very low scores (1-4) on transactional research PLUS cost recovery secured in rates in alignment with the Strategic Plan	Target	20.0
Asset Management - Progress on Greener Cleaner Strategy	15%	90% of projects > $5M are executive in 2011 within plus or minus 5% of the project budget PLUS develop 2012 Capital Work Orders for next wind sites AND achieve 2011 RES compliance	Stretch	30.0
Financial - Earnings (1)	30%	$127 million	$123.5 million	22.5
Financial - Cash From Operations (1)	10%	$297 million (Operating Free Cash Flow)	$270.5 million	5.3
	100.0%		Total	95.3%

Note:

(1) Actual results, below or above target, will be prorated on a scale between each level of performance. Percentage payouts, below or above target for financial measures, are prorated on a scale between each level of performance (50% for threshold, 100% for target and 200% for stretch) The targets for Earnings were $120 million at threshold, $127 million at target and $242 million EBIT (Earnings before Interest and Taxes) for stretch. The EBIT target focused on controlling operating costs as well as capital project spending. The Operating Free Cash Flow objective at threshold was $250 million, $297 million at target, and $300 million Cash from Operations at

stretch. "Operating Free Cash Flow" is a measurement of both "Cash from Operations" and changes in "Working Capital" (e.g. accounts receivable, accounts payable, inventory etc.) while "Cash from Operations" *excludes* changes in "Working Capital".

Emera's 2011 Scorecard

The 2011 Emera Scorecard is developed and recommended by management for approval by the MRCC and the Emera Board of Directors at the beginning of each year. It is used to determine the Annual Incentive for the EVP Business Development, Emera and a portion of the Annual Incentive for NSPI's CFO.

The objectives of the Emera corporate scorecard are based on Emera's business plan for the year and establish threshold, target, and stretch performance standards for each objective. Objectives of the 2011 Emera Scorecard included a 90% weighting for strengthening the financial position of Emera through generating growth as measured by:

- earnings per share; and
- cash flow per share.

The corporate objective of maintaining and enhancing employee commitment and wellness received a 10% weighting on the 2011 Emera Scorecard.

The MRCC determined that the CFO, and the EVP Business Development, Emera achieved 106% of target performance pursuant to the 2011 Emera Scorecard. The following table shows the elements of the 2011 Emera Scorecard:

Emera Inc. Corporate Objective	Weighting	Target	Actual Result	Percentage Payout(1)
Earnings Per Share (2)	60%	$1.81	$1.77 (2)	36
Cash Flow Per Share (3)	30%	$3.14	$3.63	60
Employee Commitment and Wellness as Measured by the Annual Employee Survey(4)	10%	Leadership development and mentoring continues and improvement on 2010 Health Assessment baseline levels.	Target	10
	100%			Total = 106%

Notes:

(1) (1) Percentage payouts, below or above target for financial measures, are prorated on a scale between each level of performance. (50% for threshold, 100% for target and 200% for stretch) The objectives for EPS were $1.76 at threshold, $1.81 at target and $1.91 for stretch. The Cash Flow objectives were $2.96 at threshold, $3.14 at target, and $3.51 at stretch.

(2) Earnings per share for Emera were $1.99, or $2.00 excluding mark to market. The mark-to-market accounting adjustment arises as a result of a contract between Brookfield Power and Bear Swamp Power Company (of which each of Emera and Brookfield each hold a 50% interest). The contract fixes the price of power between Brookfield and Bear Swamp Power Company but it does not fall within the strict hedge accounting rules and therefore gets mark-to-market treatment. The MRCC determined that EPS results for incentive calculation purposes should exclude the gain on the acquisition of Light & Power Holdings Ltd., , and removing this gain adjusted EPS is $1.77 for 2011.

(3) Cash Flow Per Share is calculated Net Cash Provided by Operations Before Working Capital divided by the weighted average number of shares outstanding for the same period..

(4) Based on completing these objectives, Emera would expect a statistically significant increase on the annual employee survey relating to these areas.

Long-Term Incentive - There are two components of long-term incentive compensation for the NEOs; namely, Emera's PSU Plan and Emera's Stock Option Plan. In 2011, the PSU Plan makes up 75% of the target long-term incentive compensatory value for all NEOs, except NSPI's CFO. NSPI's CFO received 100% of her long term incentive in PSUs in 2011. The Stock Option Plan makes up 25% of the target long-term compensatory value for all NEOs except NSPI's CFO. NSPI's CFO did not participate in the Stock Option Plan in 2011.

The number of PSUs and stock options granted to the NEOs is determined based on competitive benchmarking data and the level of responsibility within NSPI. Generally, the level of grant increases with the level of responsibility. On the recommendation of the MRCCR, the Emera MRCC is responsible for granting PSUs and stock options to the NSPI NEOs. The PSUs and the stock options increase or decrease in value in proportion to the increase or decrease in the market price of Emera's common shares over the term of a particular grant. The options granted to senior management are determined as a percentage of base salary in each year. The value of stock option grants are based on the Black-Scholes valuation methodology. The Black-Scholes value was determined to be equal to 12.9% of the closing share price of $32.06 as of February 15, 2011.

Previous grants of stock options and PSUs to senior management are taken into account when recommending new grants by considering a three year history on total compensation, which also includes long-term incentive (stock options and PSUs) and is reviewed for NEOs each year to ensure reasonable progression within the market.

Performance Share Unit Plan

The PSU Plan adopted by Emera is designed to retain and incent employee participants by allowing senior management to participate in the long-term success of the Company. Under the PSU Plan, participants receive annual grants of PSUs. The PSU Plan pays monetary rewards based on a combination of financial measurements over a three-year performance period as established by the MRCC pursuant to the PSU Plan.

The number of PSUs granted to each employee participant is intended to pay 100% of the PSU target based incentive at the end of the three-year performance period if Emera achieves its financial objectives measured by the performance factors.

Performance Factor 1

Performance Factor 1 is based on Emera's average three-year total stock return in excess of the average three year return of the S&P/TSX Capped Utilities Total Return Index as illustrated in the table below:

Relative Annual Return to S&P/TSX Capped Utilities Total Return Index	**Performance Factor**
Less than -5%	0.00
-5%	0.50
0%	1.00
5% or more	1.50

Performance Factor 2

Performance Factor 2 is based on Emera's average annual growth in earnings per share. As well, dividends must be maintained at or higher than the December 31, 2010 levels. If dividends are reduced, Factor 2 will be deemed to be zero regardless of the earnings per share growth as illustrated in the table below:

Emera Average Three-Year Absolute Earnings per Share Growth (Compound Annual Growth Rate)	**Performance Factor**
Less than 4%	0.00
4%	0.50
6%	1.00
8% or more	1.50

The value of each performance factor will be interpolated on the basis of the actual relative returns. In addition, all annual average returns or percent over the three-year performance period will be determined on a compounded basis. If targets are not met, there is the potential for no payouts. If targets are exceeded, payouts may be as much as, but not more than, two times the initial grant value.

The amount payable to senior management, including NEOs, at the end of the three-year performance period is determined by:

1. the number of PSUs held;
2. the average 50 trading-day share price as at the end of the three-year performance period; and
3. Emera's financial performance against the two equally-weighted performance factors over the three-year performance period.

Entitlements if Participant Leaves Employment prior to Payout Date		
If a participant leaves Emera's employment prior to the payout date and is under the age of 55 at the date of termination, the participant is not entitled to a payout for that particular grant of PSUs. An exception to this would be in the event of the death of a participant.	If, prior to the payout date a participant: 1. leaves Emera's employment between age 55 and 65 and does not work for, or on behalf of, one of Emera's competitors; or 2. retires on or after age 65, s/he will be eligible to receive a pro-rated portion of the payout for that particular grant based on the period during which they were employed by Emera during the three-year performance period. The payout will be made after the end of the three-year performance period.	If a participant dies prior to the payout date, their named beneficiary will be eligible to receive a pro-rated portion of the payout based on the period during which they were employed during the three-year performance period for that particular grant. The payout will be made after the end of the three-year performance period.

In 2011, the performance factor applied to PSUs vesting was1.49, reflecting the Company's strong performance over the three year period from 2009 to 2011, and resulted in a total payout of $4.9 million. This payout was 1.95 times the original grant value in 2009.

The following are the actual performance factor results for the 3 year period from 2009 to 2011:

	Emera Total Return	Factor 1: S&P/TSX Capped Utilities Total Return Index	Factor 2: Earnings per Share Growth	Overall Factor
2009	18.5%	19.1%	16.5%	-
2010	30.8%	18.4%	11.0%	-
2011	9.8%	6.5%	2.9%	-
Average Annual Compounded Return	**19.4%**	**14.5%**	**10.0%**	-
Emera's Relative Return	-	4.9%	-	-

Resulting Performance Factor	-	1.488	1.500	1.494

The performance targets for the PSU awards are used for compensation purposes only and are not suitable for any other purpose. There is no assurance that any performance level will be met. The targets may also constitute forward-looking information. Forward-looking statements are based upon a number of assumptions and are subject to a number of known and unknown risks and uncertainties, any of which are beyond Emera's control, which could cause actual results to differ materially from the performance targets. Please see the cautionary statement in the 2011 Annual Report respecting risks and assumptions relevant to Emera's determination of performance targets for compensation purposes.

Stock Option Plan

The administration of Emera's Stock Option Plan has been delegated to the MRCC by the Board of Directors. Under the Stock Option Plan, the MRCC is responsible for designating, based on Management's recommendation, which employees of Emera and its affiliates will be eligible to participate. All of the NEOs, except NSPI's CFO, participated in the Stock Option Plan and have received stock options in 2011 as a part of their long-term incentive.

Options are currently designed to deliver a percentage of the long-term incentive opportunity for senior management, including the NEO, and have been retained to recognize their importance as a component of competitive executive compensation and to preserve a long-term focus. The level of grant increases with the level of responsibility.

Options are granted to selected employees of Emera and its affiliates and may be exercised for up to a maximum of ten years. All options granted to date are exercisable on a graduated basis with up to 25% of the options exercisable on the first anniversary date and in further 25% increments on each of the second, third, and fourth anniversaries of the grant. If an option is not exercised within ten years, it expires and the employee loses all rights thereunder. The holder of an option has no rights as a shareholder until the option is exercised and shares have been issued. The price at which stock options may be exercised is the closing market price of the Company's common shares on the TSX on the last business day on which such shares were traded immediately preceding the effective date of the grant of an option.

Unless the term of an option has expired, vested options may be exercised within the 24 months following the date of retirement or termination for other than just cause, and within six months following the date of termination for just cause, resignation, or death. If options are not exercised within such time, they expire.

The maximum percentage of shares under all security-based compensation (including the Stock Option Plan) issuable to insiders of Emera at any time is 10% of the issued and outstanding shares of Emera. The maximum number of shares to be optioned to any one person under the Stock Option Plan is 5% of the issued and outstanding shares of Emera at the date of the grant of the option. The number of shares issued to insiders, within any one-year period, under all security-based compensation arrangements, will not exceed 10% of the issued and outstanding shares of Emera.

Other Executive Benefits - NSPI provided executives with additional benefits in accordance with the compensation program objectives, and for the purpose of retention and motivation. As part of their compensation, the NEOs are eligible to receive (i) life and accidental death and dismemberment insurance coverage of five times annual base salary to a maximum of $1,000,000, (ii) supplementary retirement plan contributions for amounts beyond the allowable CRA pension limits, (iii) annual income tax return preparation in conjunction with retirement planning, (iv) monthly parking, (v) monthly car allowance plus mileage, as applicable, and (vi) an annual wellness/fitness allowance for a recreational and/or social club. Some of these items are considered taxable benefits and are reported in the Summary Compensation Table for the NEOs. All retired employees may be eligible to continue basic life and accident insurance as well as extended health coverage.

Summary Compensation Table

The following table contains information relating to the compensation paid to the NEOs for each of NSPI's three most recently completed financial years:

Name and Principal Position	Year	Salary (1) ($)	Share Based Awards (2) ($)	Option Based Awards (3) ($)	Non-equity Incentive Plan Compensation	Pension Value (7) ($)	All Other Compen-sation (8) ($)	Total Compen-sation (9) ($)
					Annual Incentive Plans (4) (5) (6)			
Robert R. Bennett, President and Chief Executive Officer	2011	398,846	179,966	60,030	190,600	304,000	19,339	1,152,781
	2010	349,519	157,480	52,521	168,720	187,000	18,972	934,212
	2009	336,692	146,309	48,694	195,240	286,000	24,260	1,037,195
Judy A. Steele, Chief Financial Officer	2011	222,800	39,020	0	190,547	276,000	6,000	734,367
	2010	151,876	39,020	0	88,000	32,000	6,000	316,896
	2009	145,688	36,250	0	88,000	73,000	6,000	348,938
Nancy G. Tower, Executive Vice President, Business Development, Emera	2011	398,851	260,033	69,966	254,400	385,000	39,407	1,407,657
	2010	349,231	183,878	61,131	287,700	187,000	15,355	1,084,295
	2009	321,385	162,795	54,216	316,600	85,000	16,866	956,862
Robin B. McAdam Executive Vice President, Strategic Business & Customer Services	2011	209,723	78,910	26,082	73,039	60,000	10,958	458,712
	2010	198,000	74,324	24,682	60,371	40,000	14,140	411,517
	2009	196,738	74,249	49,698	90,071	61,000	8,331	480,087
Mark W. Savory, Vice President, Technical & Construction Services	2011	200,000	60,134	19,872	57,180	(30,000)	16,373	323,559
	2010	199,808	59,907	20,090	50,880	208,000	14,446	553,131
	2009	197,308	56,929	19,076	76,836	171,000	16,509	537,658
Alan C. Richardson, Vice	2011	189,885	71,394	23,598	67,321	20,000	9,989	382,187

Name and Principal Position	Year	Salary [1] ($)	Share Based Awards [2] ($)	Option Based Awards [3] ($)	Non-equity Incentive Plan Compensation Annual Incentive Plans [4] [5] [6]	Pension Value [7] ($)	All Other Compen-sation [8] ($)	Total Compen-sation [9] ($)
President, Integrated Customer Services	2010	188,000	69,258	23,247	47,064	170,000	9,977	507,546
	2009	171,346	61,952	20,582	66,726	84,000	9,442	414,048

Notes:

(1) Salary information is based on actual earnings.

(2) Includes DSU special awards and PSU grants. It does not reflect DSUs received in lieu of cash bonuses. See 'Deferred Share Unit Plan' for further details. The initial value of a PSU was based on the average 50 trading-day share price on December 31, 2010 of $31.19. In 2011 the Share Based awards for the EVP Business Development, Emera included a special DSU grant with an intended award value of $50,000 for project milestones related to Emera Newfoundland & Labrador.

(3) The value of stock option grants is based on the Black-Scholes valuation methodology. Stock options granted to the NEOs in 2011 were based on the Black-Scholes value which was determined to be equal to 12.9% of the closing share price of $32.06 as of February 15, 2011 or $4.14 per option. The value of stock option grants is based on Emera's common share closing price on the last trading day prior to the grant date multiplied by a Black-Scholes factor of 10.5%, multiplied by the number of options granted. The Black-Scholes value ratio was determined using the following assumptions: an estimated volatility of 17.5% (based on daily historical share price for the three-year period ending on January 28, 2011), estimated dividend yield of 4.53%, risk-free interest rate of 3.08%, and an expected life of seven years of the ten-year option term. The Company has chosen to use Black-Scholes as the methodology for determining the fair value of options granted as it is an appropriate and commonly used methodology to value stock options.In 2011, NSPI's CFO was not a participant in the Senior Management Stock Option Plan.

(4) In 2011 the CEO, the EVP Strategic Business, the VP Technical, and the VP Customer participated in the Nova Scotia Power Inc. Corporate Scorecard which included specific financial targets of financial earnings and free cash flow (40%), service reliability and customer satisfaction (30%), asset management (15%), safety excellence (7.5%), and leadership of people (7.5%). Based on year-end results, it was determined by the MRCCR that these NEOs achieved 95.3% of target on the NSPI Corporate Scorecard. In 2011, the EVP Business Development, Emera participated in the Emera Corporate Scorecard which achieved 106% of target, while the Short Term Equity Incentive for the CFO was based on a combination of results achieved in Emera and Emera Energy.

(5) The non-equity incentive plan compensation reflects amounts earned within the 2011 performance year and paid in 2012. The CEO elected to receive 50% of his 2011 annual incentive ($95,300) in DSUs. The EVP Business Development, Emera elected to receive 50% of her 2011 annual incentive ($127,200) in DSUs. The EVP Strategic Business elected to receive 50% of his 2011 annual incentive ($30,019) in DSUs. The VP Technical elected to receive 50% of his 2011 annual incentive ($27,160). The VP Customer elected to receive 50% of his 2011 annual incentive ($27,160) in DSUs.

(6) The 2011 non-equity plan compensation for the EVP Strategic Business, and the VP Customer includes a bonus amount of $13,000 for outstanding contributions to settlements reached with key stakeholders. The 2011 non-equity incentive plan compensation for the CFO includes a bonus amount of $53,480 in lieu of additional Long-Term Incentive received during her assignment.

(7) Further information concerning pension values can be found in the section entitled "Pension Plan Benefits".

(8) As part of their compensation, the NEOs are eligible to receive Life and Accidental Death and Dismemberment (ADD) Insurance coverage of five times annual base salary to a maximum of $1,000,000; supplementary retirement plan contributions for amounts beyond the allowable Canada Revenue Agency pension limits; annual income tax return preparation in conjunction with retirement planning; monthly parking; monthly car allowance plus mileage, as applicable; and an annual wellness/fitness allowance. These items are included in the All Other Compensation column and some of these items are considered taxable benefits.

(9) All compensation for the CEO, the EVP Strategic Business, the VP Technical, and the VP Customer was paid by NSPI, although only their base salary and 50% of their annual incentive was included in NSPI rates, and no portion of their long-term incentive was included in NSPI rates. All compensation for the EVP Business Development, Emera and the CFO was paid by Emera or Emera Energy Inc.

Outstanding Share-Based Awards and Option-Based Awards

The following table describes all option-based and share-based awards outstanding as of December 31, 2011 for each NEO:

	Option-based Awards [1] (Stock Options)	Share-based Awards (Performance Share Units (PSUs) and Deferred Share Units (DSUs))

Name	Number of Securities Underlying Unexercised Options (#)	Option Exercise Price ($)	Option Expiration Date	Value of Unexercised in-the-money Options ($) [2]	Number of Shares or Units of Shares That Have Not Vested (#) [3]	Market or Payout Value of Share-Based Awards That Have Not Vested	Market or Payout Value of Vested share based awards that have not been paid out($) [4][5]
R.R. Bennett							
	14,500	32.06	February 15, 2021	14,210	20,491	677,038	589,665
	13,725	23.94	February 16, 2020	124,897			
	9,700	21.99	February 12, 2019	107,185			
	2,500	21.58	February 14, 2018	28,650			
J.A. Steele [6]	N/A	N/A	N/A	N/A	2,616	86,433	0
N.G. Tower							
	16,900	32.06	February 15, 2021	16,562	13,198	436,062	1,214,286
	21,300	23.94	February 16, 2020	193,830			
	21,600	21.99	February 12, 2019	238,680			
	21,500	21.58	February 14, 2018	246,390			
	42,100	20.42	March 8, 2017	531,302			
	30,500	19.88	March 16, 2016	401,380			
	19,600	19.50	February 9, 2015	265,384			
	14,400	17.79	February 5, 2014	219,600			
	9,000	15.73	February 5, 2013	155,790			
	4,750	17.55	October 27, 2012	73,577			
R.B. McAdam							
	6,300	32.06	February 15, 2021	6,174	5,135	169,660	305,983
	6,450	23.94	February 16, 2020	58,695			
	9,900	21.99	February 12, 2019	109,395			
M.W. Savory	4,800	32.06	February 15, 2021	4,704			
	5,250	23.94	February 16, 2020	47,775	4,023	132,920	57,291
	3,800	21.99	February 12, 2019	41,990			
A.C. Richardson	5,700	32.06	February 15, 2021	5,586	4,713	155,718	59,439
	8,100	23.94	February 16, 2020	73,710			
	8,200	21.99	February 12, 2019	90,610			
	3,850	21.58	February 14, 2018	44,121			
	3,050	20.42	March 8, 2017	38,491			

Notes:

(1) Option-based awards include both vested and unvested options.

(2) The value of all unexercised option-based awards was calculated using a December 31, 2011 closing share price of $33.04.

(3) Unvested share-based awards include initial Performance Share Units (PSUs) and Deferred Share Units (DSUs) grants and any additional PSUs and DSUs from dividend reinvestment as of December 31, 2011.

(4) The market or payout value of share-based awards were calculated based on an assumed performance factor of 1 and a December 31, 2011 closing share price of $33.04.

(5) Value vested share based awards represent Deferred Share Units (DSUs).

(6) In 2011, Ms. Steele was not a participant in the Senior Management Stock Option Plan.

Incentive Plan Awards – Value Vested or Earned During the Year

The following table describes the value of all option-based awards, share-based awards, and non-equity incentives that vested or were earned during 2011 for each NEO:

Name	Option-based awards Value vested during 2011 (1) ($)	Share-based awards (Performance Share Units (PSUs) and Deferred Share Units (DSUs)) Value vested during 2011 (2)(3) ($)	Non-equity incentive plan compensation - Value earned during the year (4) ($)
R.R. Bennett	N/A (5)	382,276	190,600
J.A. Steele	N/A (6)	70,708	190,547
N.G. Tower	263,236	368,272	254,400
R.B. McAdam	N/A (5)	144,803	73.039
M.W. Savory	N/A (5)	111,026	57,180
A.C. Richardson	88,454	120,770	67,321

Notes:

(1) Represents the aggregate dollar value that would have been realized if the options under the option-based award had been exercised on the vesting (eligibility) date in 2011.

(2) This dollar amount represents the payout of 2009 PSU grants based on the performance factors established in 2009. In 2011, the value of share-based awards vested during the year reflects performance factors based on Emera's relative performance versus the S&P/TSX Capped Utilities Total Return Index and Emera's average annual growth in Earnings per Share. The payout at the end of the three-year performance period is calculated based on vested PSUs x Performance Factors x Period Ended Share Price. The overall performance factor was 1.49. The average share price during the last fifty trading days of 2011 was $32.54.

(3) This dollar amount includes the value of DSUs vested in 2011, including additional DSUs from dividend equivalents,, and calculated at a December 31, 2011 closing share price of $33.04. In 2011 for the CEO this amount equalled $96,939.

(4) This dollar amount represents the 2011 incentive payout as previously discussed in the Summary Compensation Table.

(5) All 2011 vested option-based awards were exercised in 2011.

(6) In 2011, Ms. Steele was not a participant in the Senior Management Stock Option Plan.

Pension Plan Benefits

The NEOs are members of NSPI's or Emera's corporate pension plan and may participate on either a defined benefit basis or a defined contribution basis. For 2011, all NEOs participated in the defined benefit plan.

Defined Benefit

The following table shows years of credited service, estimated pension amounts, and changes to accrued obligations from January 1, 2011 to December 31, 2011 for the NEOs who participate in the corporate pension plan on a defined benefit basis:

Name	Number of Years Credited Service (#)	Annual Benefits Payable At Year End(1) ($)	Annual Benefits Payable At Age 65 ($)	Accrued Obligation at Start of Year ($)	Compensatory Change(2) ($)	Non-Compensatory Change ($)	Accrued Obligation at Year End ($)
R.R. Bennett	23.67	178,000	263,000	2,626,000	304,000	510,000	3,440,000
J.A. Steele	12.33	44,000	90,000	595,000	276,000	101,000	972,000
N.G. Tower	14.33	118,000	218,000	1,635,000	385,000	220,000	2,240,000
R.B. McAdam	13.17	55,000	98,000	817,000	60,000	116,000	993,000
M.W. Savory	29.58	111,000	131,000	2,003,000	(30,000)	270,000	2,243,000
A.C. Richardson	25.67	88,000	120,000	1,400,000	20,000	264,000	1,684,000

Notes:

(1) Not eligible for immediate pension at year-end, amount shown is the amount payable starting at age 65 if NEO terminated employment at December 31, 2011.

(2) Reflects change in accrued benefit obligation related to a) the employer cost of the additional pension service earned during 2011 and b) changes in pensionable earnings different than what was assumed.

The defined benefit component of the plan entitles members to pension benefits based on 2% of the average of the four highest years' earnings (base salary plus up to 50% of target short term incentive) multiplied by each year of credited service to a maximum of 35 years credited service. Upon reaching age 65, pension benefits under the pension plan are reduced to reflect commencement of payments under the Canada Pension Plan. In addition, the NEOs are eligible to have portions of their annual incentive included in pensionable earnings. The pension is payable upon the earlier of age 60 or age 55, provided that age and years of service add up to at least 85. A member may also retire on a reduced formula if the member has attained age 55, but does not qualify for the rule of 85. Members of the defined benefit component of the plan contribute 5.4 percent of eligible earnings up to the year's maximum pensionable earnings under the Canada Pension Plan, and 7% of earnings between the year's maximum pensionable earnings and the amount on which pension benefits may be earned under a registered pension plan as permitted by the Income Tax Act (Canada).

Spousal benefits are paid on the death of a member at the rate of 60% of regular pension benefits. The pension plan is indexed to the Consumer Price Index to a maximum of 6% per annum.

Deferred Share Unit Plan

Emera has a Deferred Share Unit Plan ("DSU Plan") for executives and senior management and the NEOs are participants.

A DSU is a bookkeeping entry that has a value based upon the value of one common share of Emera. Each DSU earns dividend equivalents in the form of additional DSUs. DSUs are not paid out until such time as the participant is no longer employed by Emera or any of its affiliates. When redeemed, the value of a participant's DSUs is equivalent to the fair market value of an equal number of common shares of Emera.

Prior to the start of each financial year, the NEOs provide elections respecting the portion of their upcoming Annual Incentive, if any, which is to be allocated to DSUs. When the Annual Incentive is paid to the NEOs, the amount elected is allocated to DSUs rather than paid in cash. Each DSU has a value equal to the market price of an Emera common share.

The table below identifies the amount of annual incentive for 2011 which each NEO elected to receive as DSUs:

	Percentage of 2011 Annual Incentive Elected to Deferred Share Units	Dollar Amount of 2011 Annual Incentive Elected to Deferred Share Units
R.R. Bennett	50	95,300
J.A. Steele (1)	N/A	0
N. G. Tower	50	127,200
R.B. MacAdam	50	30,019
M.W. Savory	50	28,590
A.C. Richardson	50	27,160

Note:

(1) In 2011, Ms. Steele was not a participant in the DSU Plan.

Termination and Change of Control Benefits

Employment contracts, agreements or arrangements are in place between NSPI and some of the NEOs.

Robert R. Bennett, President and Chief Executive Officer

Resignation	Entitled to all compensation and benefits up to the effective date of resignation.
Terminated for Cause	Will not be entitled to compensation upon or following such termination.
Terminated without Cause	Entitled to 12 months' compensation based upon annual salary, annual incentive at target, and car allowance in effect at the time, salary to termination date, any accrued but unused vacation time, health, dental and other such benefits for 12 months.
Change in Control	If there is a change of control of the ownership of the Company, such that any one party acquires 50 percent or more of voting securities and there is a substantial reduction in responsibilities or scope of authority, Mr. Bennett may elect within three months following such substantial reduction in responsibilities or scope of authority to terminate employment and receive 12 months' compensation calculated on his annual salary and target bonus then in effect.
Retirement	Mr. Bennett is eligible to retire with an unreduced pension on October 31, 2017. Information regarding pension entitlement is contained in the section entitled "Pension Plan Benefits".
PSUs/DSUs	Any unvested PSUs held at the date of termination without cause will be prorated. Under all scenarios, unless otherwise noted, Mr. Bennett shall be entitled to payments associated with PSUs, DSUs, and Stock Options according to the terms and conditions of the plans.
Other	If Mr. Bennett is terminated without cause any special Deferred Share Unit grants received in 2008 will vest immediately.

Judy A. Steele, Chief Financial Officer

Resignation	Entitled to all compensation and benefits up to the effective date of resignation.
Terminated for Cause	Will not be entitled to compensation upon or following such termination.
Terminated without Cause	Would be paid in accordance with common law.
Change in Control	Ms, Steele's employment contract does not contain change of control provisions.
Retirement	Ms. Steele becomes eligible to retire with an unreduced pension on October 31, 2019. Information regarding pension entitlement is contained in the section entitled "Pension Plan Benefits".
PSUs/DSUs	Under all scenarios, unless otherwise noted, Ms. Steele shall be entitled to payments associated with PSUs according to the terms and conditions of the plans.
Other	No other conditions.

Nancy G. Tower, Executive Vice-President, , Emera and Chief Executive Officer Emera Newfoundland & Labrador Inc.

Resignation	Entitled to all compensation and benefits up to the effective date of resignation.
Terminated for Cause	Will not be entitled to compensation upon or following such termination.
Terminated without Cause	Entitled to a lump sum equal to 12 months' compensation based upon annual salary, annual incentive at target, and car allowance in effect at the time, salary to termination date, any accrued but unused vacation time, health, dental and other such benefits for 12 months or until she obtains new employment benefit coverage.
Change in Control	If there is a change of control of the ownership of the Company, such that any one party acquires 50 percent or more of voting securities and there is a substantial reduction in responsibilities or scope of authority, Ms. Tower may elect, within three months following such substantial reduction in responsibilities

	or scope of authority, to terminate employment and receive 12 months' compensation calculated on the basis of her annual salary and target bonus then in effect.
Retirement	Ms. Tower becomes eligible to retire with an unreduced pension on March 31, 2019. Information regarding pension entitlement is contained in the section entitled "Pension Plan Benefits".
PSUs/DSUs	Any unvested PSUs held at the date of termination without cause will be prorated. Under all scenarios, unless otherwise noted, Ms. Tower shall be entitled to payments associated with PSUs, DSUs, and Stock Options according to the terms and conditions of the plans.
Other	No other conditions.

Robin B. McAdam, Executive Vice President, Strategic Business & Customer Services

Resignation	Entitled to all compensation and benefits up to the effective date of resignation.
Terminated for Cause	Will not be entitled to compensation upon or following such termination.
Terminated without Cause	Would be paid in accordance with common law.
Change in Control	Mr. McAdam's employment contract does not contain change of control provisions.
Retirement	Mr. McAdam becomes eligible to retire with an unreduced pension on May 31, 2017. Information regarding pension entitlement is contained in the section entitled "Pension Plan Benefits".
PSUs/DSUs	Under all scenarios, unless otherwise noted, Mr. McAdam shall be entitled to payments associated with PSUs, DSUs, and Stock Options according to the terms and conditions of the plans.
Other	No other conditions.

Mark W. Savory, Vice President, Technical and Construction Services

Resignation	Entitled to all compensation and benefits up to the effective date of resignation.
Terminated for Cause	Will not be entitled to compensation upon or following such termination.
Terminated without Cause	Would be paid in accordance with common law.
Change in Control	Mr. Savory's employment contract does not contain change of control provisions.
Retirement	Mr. Savory becomes eligible to retire with an unreduced pension on June 30, 2020. Information regarding pension entitlement is contained in the section entitled "Pension Plan Benefits".
PSUs/DSUs	Under all scenarios, unless otherwise noted, Mr. Savory shall be entitled to payments associated with PSUs, DSUs, and Stock Options according to the terms and conditions of the plans.
Other	No other conditions.

Alan C. Richardson, Vice President, Integrated Customer Services

Resignation	Entitled to all compensation and benefits up to the effective date of resignation.
Terminated for Cause	Will not be entitled to compensation upon or following such termination.
Terminated without Cause	Would be paid in accordance with common law.
Change in Control	Mr. Richardson's employment contract does not contain change of control provisions.
Retirement	Mr. Richardson becomes eligible to retire with an unreduced pension on January 31, 2018. Information regarding pension entitlement is contained in the section entitled "Pension Plan Benefits".

PSUs/DSUs	Under all scenarios, unless otherwise noted, Mr. Richardson shall be entitled to payments associated with PSUs, DSUs, and Stock Options according to the terms and conditions of the plans.
Other	No other conditions.

The following table provides the estimated amounts of incremental payments, payables and benefits to which certain NEOs, where applicable under their current contracts, would be entitled under various plans and arrangements, assuming retirement, resignation, termination without cause, termination for cause, and separation from the Company in circumstances of a change of control, assuming the triggering event took place on December 31, 2011:

Termination and Change of Control Benefits

Name[1]	Termination Scenario[2]	Cash Severance ($)	Short Term Incentive ($)	Performance Share Units (PSUs) ($)	Deferred Share Units (DSUs) ($)	Stock Options ($)	Continuation of Benefits (Present Value) [3] ($)	Total ($)
R.R. Bennett	Retirement/Resignation Termination for Cause							
	Not for Cause	400,000	200,000	182,744	303,472		18,700	1,104,917
	Change of Control	400,000	200,000	373,517	303,472			1,276,990
N.G. Tower	Retirement/Resignation Termination for Cause							
	Not for Cause	400,000	240,000	213,361			19,900	873,261
	Change of Control	400,000	240,000	436,062				1,076,062

Notes:

(1) Ms. J.A. Steele, Mr. R.B. McAdam, Mr. M.W. Savory, and Mr. A.C. Richardson have no incremental payments, payables or benefits due to them under the various scenarios outlined above.

(2) Change of control scenarios assume all unvested PSUs would become payable in full and are valued based on an assumed performance factor of 1 and a year end closing share price of $33.04. Change of control scenarios also assume that all unvested DSUs would become payable and are valued based on a year end closing share price of $33.04.

(3) Continuation of benefits reflects a lump sum amount for car allowance and health and dental benefits.

Compensation of Directors

Directors who are not full time employees of NSPI receive compensation for their services as Directors.

Listed below are the annual compensation rates for independent Directors during 2011. These rates are not applicable to CEO Robert R. Bennett, who was an employee of NSPI, nor to James D. Eisenhauser, who received an annual all-inclusive retainer as Chair of NSPI's Board. NSPI does not offer option-based awards, non-equity incentive plan participation, or participation in any pension plan to its Directors. Directors have the ability to elect to receive some or all of their cash compensation in the form of DSUs.

The Chair's annual retainer is an all-inclusive fee, meaning the Chair of the Board of NSPI receives no meeting fees or any other retainer. As of December 31, 2011, the all-inclusive retainer of the Chair of the NSPI Board was $130,000. The Chair also receives $25,000 payable in DSUs for participation on Emera's Board of Directors.

Annual Retainers and Meeting Fees	Cash Amount	DSUs [1]	Total
Chair Retainer	$130,000	$25,000	$155,000
Directors' Retainer	45,000		
In-person Meeting Fee	1,750		
Telephone Attendance Meeting Fee	1,250		
Travel Fee (if one-way travel is longer than 5 hours)	1,750		
Travel Fee (if one-way travel is between 3 to 5 hours)	875		
Audit, Nominating and Corporate Governance Committee Member Retainer	5,000		
Chair of Audit, Nominating and Corporate Governance Committee Retainer	15,000		

MRCCR Member Retainer	3,000
Chair of MRCCR Retainer	15,000

Note: (1) $25,000 in DSUs is on account of the Chair's participation on Emera's Board of Directors.

In September, 2011, the annual retainer for NSPI Directors was increased by $12,000, effective January 1, 2012. Therefore, from January 1, 2012 on, the annual retainer for each Director was $57,000.

Total Director Compensation in 2011

The following table sets out the total compensation earned by the Directors who served on NSPI's Board during 2011 for attendance at Board and committee meetings for which a Director attended as a member or guest, briefing meetings, education sessions, and travel fees. Robert R. Bennett is not included in the table as his compensation for service as NSPI's CEO is disclosed in the Statement of Executive Compensation above. Mr. Bennett does not receive any additional compensation for his services as a Director of NSPI. Further Christopher G. Huskilson, the President and Chief Executive Officer of Emera, is not included in the table because he is compensated by Emera and does not receive any additional compensation as a Director of NSPI.

Director	Fees Earned in 2011 (1)	All Other Compensation	Total	Share Based Compensation(2)
Wesley G. Armour	83,374	N/A	83,374	113,112
J. Lee Bragg	83,749	N/A	83,749	46,652
R. Irene d'Entremont	116,750	N/A	116,750	0
James D. Eisenhauer	140,694(3)	N/A	140,694	157,506
John T. McLennan	N/A	219,999 (4)	219,999	278,338
Marie C. Rounding	114,500	N/A	114,500	56,958
Elaine S. Sibson	89,999	N/A	89,999	0
Raymond E. Ivany(5)	19,915	N/A	19,915	0

Notes:
(1) The "fees earned" column is the amount of Directors' fees and includes the value of that portion of their retainer only paid in DSUs. All Directors are paid in Canadian dollars.
(2) This column shows the value obtained when the number of DSUs awarded to each Director in 2011 in lieu of cash compensation, plus dividends earned on the DSUs in the form of additional DSUs, is multiplied by the December 31, 2011 Emera share closing price of $33.04.
(3) Earned as the annual retainer for acting as the Chair of the Board of NSPI.
(4) Earned for sitting on the Board of Directors of Emera.
(5) Mr. Ivany joined the Board of Directors in September, 2011.

All independent Directors are reimbursed for expenses incurred for attendance at Directors' and committee meetings, and when on NSPI's business.

CORPORATE GOVERNANCE PRACTICES

Set out below is a description of certain corporate governance practices of the Company.

Board of Directors

All Directors are independent from management, except Robert R. Bennett, who is the President and Chief Executive Officer of the Company, and Christopher G. Huskilson, the President and Chief Executive Officer of

Emera. To be considered independent, a Director must be independent as defined under applicable Canadian securities laws and, in particular, must be free of any direct or indirect material relationship which could, in the view of the Board of Directors, be reasonably expected to interfere with the Director's independent judgment. Use of the term "independent" in relation to a Director in this Circular shall refer to the foregoing meaning of that term. None of the independent Directors receive remuneration from the Company other than Directors' retainers, fees or retainers for service as Chair of the Board or Chair of a Committee. Christopher G. Huskilson receives a retainer and fees from Emera.

There were 9 Board and 12 Committee meetings during 2011. At each Board and Committee meeting as a matter of course, an opportunity is provided for an in-camera session at which management is not present.

The Chair of the Board, Mr. James D. Eisenhauser, is an independent Director. The Articles of Association of the Company mandate that the Chair of the Board and the Chief Executive Officer must be separate individuals. The Chair is responsible to lead the Board to fulfill its duties effectively, efficiently and independent of management. The Chair ensures Board and shareholder meetings function effectively, provides leadership of the Board and its Committees and provides advice and counsel to Directors and the Chief Executive Officer. The Chair participates in the recruitment of Directors and the assessment of their performance.

Board Mandate

The Board of Directors adopted a Charter which is attached to this Circular as Appendix "A". Under the Charter, the Board is responsible for overseeing the management of the business of the Company. The Charter emphasizes the duties and responsibilities of the Board in matters of independence and integrity, strategic planning, risk responsibility, leadership and succession, financial reporting, corporate communications and public disclosure, and corporate governance.

Position Descriptions

Committee Chairs

All of the Committees have Charters which set out duties and responsibilities. It is the responsibility of each Committee Chair to ensure that the Committee carries out its duties and responsibilities. The various Committees review their Charters on an annual basis.

Chief Executive Officer

The roles and responsibilities of the President and Chief Executive Officer are contained in his employment contract and in the Articles of Association which provide that he is chief executive for the Company.

Orientation and Continuing Education

The Board and management believe that for new Directors to be effective in their roles they must be knowledgeable about the Company, its strategy, strengths and challenges. As well, effectiveness is enhanced as the new Directors form a collegial working relationship with other members of the Board in order to best bring their skills and knowledge to the operation of the Board.

New Directors receive an orientation to the Company that familiarizes them with the businesses, investments and key personnel of the Company and allows them to effectively integrate with other Board members.

The following are the elements of the orientation process:

Key documents of the business are provided. These include the following:

(a) the most recent annual and interim management's discussion & analysis and financial statements; most recent management information circular and annual information form;
(b) the Board and Committee Charters;

(c) the most recent strategic plan and business plan;
(d) a guide to the Company's management structure;
(e) insider trading guidelines;
(f) the Emera Group of Companies Standards for Business Conduct; and
(g) recent minutes of the meetings of the Board and Committees.

The oversight function of Directors is enhanced when they are well informed about the Company's businesses and its industry. Management continually seeks opportunities to update, educate and inform the Directors in areas they request or that management determines are relevant to issues facing the Company.

The Board and Committees receive briefing reports and material from management in advance of all meetings. Regular communications are provided to the Directors between meetings to provide updates on developments that might affect the Company's business and that of its subsidiaries. The Board is also provided with opportunities to make site visits to operational facilities to assist Directors to more fully understand the business.

Ethical Business Conduct

The Board recognizes the importance of establishing and promoting integrity and ethical business practices throughout the Company. The Board encourages and promotes a culture of ethical business conduct.

Emera has adopted a written code entitled "The Emera Group of Companies Standards for Business Conduct" (the "Standards for Business Conduct") for all Directors, Officers, and employees of the Emera group of companies and a protocol entitled "Procedures for the Reporting of Irregularities and Dishonesty" (otherwise commonly referred to as a whistleblower's policy) which applies to the Emera group of companies. See the section entitled "Statement of Corporate Governance Practices" in Emera's Management Information Circular dated April 16, 2012 which is available under Emera's profile on SEDAR at www.sedar.com.

Under the Company's Articles of Association, Directors are required to declare any interest which they may have in a matter before the Board. In any matter requiring approval of the Board, a Director is prohibited by the Articles from voting in respect of the matter in which the Director is interested.

Nomination of Directors

The Company has an Audit, Nominating and Corporate Governance Committee which is responsible for providing the Company with a list of nominees for election as Directors prior to each annual meeting of shareholders of the Company. The Committee creates and reviews the criteria for selecting Directors by assessing the personal qualities, business experience, and qualifications of current Directors. The Committee also assesses the Company's ongoing needs and circumstances, geographical representation and the overall experience of the Board. The Committee considers the background, skills and experience desired for Directors in view of the Company's strategy and activities, and provides a plan for the recruitment of nominees who can provide those characteristics.

Director nominees must, in the opinion of the Committee, be able to contribute to the broad range of issues with which the Directors must deal and who are able to devote the time necessary to prepare for and attend meetings of the Board and Committees of the Board to which they may be appointed.

Compensation

The Company's MRCCR, which is comprised entirely of independent Directors, determines the compensation for the Company's Executive Officers and makes recommendations to Emera's Board of Directors' Management Resources and Compensation Committee which, in turn, approves the compensation of the Company's executives. Emera's Board of Directors' Nominating and Corporate Governance Committee determines the compensation for the Company's Directors on the recommendation of NSPI's Audit, Nominating and Corporate Governance Committee. See the "Statement of Executive Compensation" above for information regarding compensation of the Company's NEOs and Directors.

Other Board Committees

Other than the Audit, Nominating and Corporate Governance Committee and the MRCCR Committee, the Company does not have any other standing committees.

For information regarding the Company's Audit, Nominating and Corporate Governance Committee, including its Audit Charter, composition, relevant education and experience of its members, oversight, policies and procedures for the approval of non-audit services and auditors' service fees, please refer to the section entitles "Directors and Officers" in the Company's Annual Information Form dated March 29, 2012 available on SEDAR under NSPI's profile at www.sedar.com.

Assessments

The Audit, Nominating and Corporate Governance Committee annually determines the process by which Director performance assessments will be conducted. The process may include the use of questionnaires, one-on-one interviews with Directors by the Board Chair or such other process as the Committee determines appropriate. A report on the assessment is provided to the Board of Directors. Issues arising from the assessment are identified, an action plan developed and progress monitored by the Audit, Nominating and Corporate Governance Committee.

SECURITIES AUTHORIZED FOR ISSUANCE UNDER EQUITY COMPENSATION PLANS

Emera has established equity compensation plans which apply to the Company. See the section entitled "Statement of Executive Compensation" in Emera's Management Information Circular dated April 16, 2012 which is available under Emera's profile on SEDAR at www.sedar.com.

INDEBTEDNESS OF DIRECTORS AND EXECUTIVE OFFICERS

The Company does not have a program that allows for the provision of loans to Directors or Officers, and the Company is not intending to initiate such a program. In addition, there is no program to allow loans or indebtedness under any share purchase program. As of the date of this Circular there was no indebtedness of the Directors to the Company. As of the date of this Circular, except for routine indebtedness, there is no indebtedness of Executive Officers and other employees to the Company[2].

MATERIAL TRANSACTIONS

During the fiscal year ended December 31, 2011, insiders of the Company and its affiliates, including Directors, Executive Officers, proposed nominee Directors or their associates or corporations they controlled, did not have any material interest, direct or indirect, in any transaction or in any proposed transaction that has materially affected or will materially affect the Company.

MANAGEMENT CONTRACTS

There are no functions of management which are performed by a person or company other than the Directors, Executive Officers or other employees of the Company.

OTHER MATTERS

Management of the Company knows of no matters to come before the Meeting other than those referred to in the Notice of Meeting accompanying this Circular. However, if any other matters properly come before the

[2] "Routine indebtedness" includes: (i) loans made on terms no more favourable than loans to employees generally, for which the amount remaining unpaid does not exceed $50,000; (ii) loans to full-time employees, fully secured against their residence and not exceeding their annual salary; and (iii) loans for purchases on usual trade terms, or for ordinary travel or expense advances, or similar reasons, with repayment arrangements in accordance with usual commercial practice.

Meeting, it is the intention of the persons named in the form of proxy accompanying this Circular to vote the same in accordance with their best judgement of such matters.

ADDITIONAL INFORMATION

Additional information relating to the Company is available under the Company's profile on SEDAR at www.sedar.com. Shareholders may contact Stephen Aftanas, the Company's Corporate Secretary, to request copies of the Company's financial statements and management's discussion and analysis ("MD&A") for the fiscal year ended December 31, 2011, and the Company's annual information form dated March 29, 2012. Financial information is provided in the Company's annual financial statements and MD&A.

APPROVAL OF THIS CIRCULAR

The Board of Directors has approved the contents of this Circular and has authorized it to be sent to the shareholders of the Company.

DATED at Halifax, Nova Scotia, this 4th day of May, 2012.

BY ORDER OF THE BOARD OF DIRECTORS

(signed) *"Stephen Aftanas"*

Stephen Aftanas
Corporate Secretary

APPENDIX "A"

CHARTER OF THE BOARD OF DIRECTORS

NOVA SCOTIA POWER INCORPORATED
BOARD OF DIRECTORS CHARTER

The fundamental responsibility of the Board of Directors (the "Board") is to provide stewardship and governance to Nova Scotia Power Incorporated ("NSPI") to ensure the viability of the Company by overseeing management of the business.

In addition to the powers set out in NSPI's Articles of Association, the Board shall have the following duties and responsibilities.

Independence and Integrity

The Board shall be comprised of a majority of "independent directors" as defined from time to time under applicable legislation and the rules of any stock exchange on which NSPI's securities are listed for trading.

The Chair shall be an "independent director" as defined above.

The Board shall review and approve standards for ethical business conduct for employees, officer and directors of NSPI and a procedure for monitoring compliance with such code throughout the Company.

The Board shall satisfy itself as to the integrity of the Chief Executive Officer and executive officers and the creation of an integrity-based culture throughout the Company.

The Board shall, through its oversight of management, continue to foster an organization which operates in an environmentally responsible manner.

Strategic Planning

The Board shall provide oversight and guidance on the strategic issues facing NSPI.

The Board shall oversee a strategic planning process resulting in a strategic plan which shall be approved on an annual basis and will take into account, among other things, the opportunities and risks of the business.

The Board shall regularly consider NSPI's strategy, evaluate progress made in pursuing that strategy, and consider any adjustments to the strategy that may be required from time to time.

The Board shall review and approve the Company's financial objectives, plans and actions, including significant capital allocations and expenditures.

The Board shall review and approve all material acquisitions, dispositions, projects, business plans, and budgets.

Risk Responsibility

The Board shall oversee the implementation by management of appropriate systems to identify, report, and manage the principal risks of NSPI's business.

The Board shall receive regular updates on the status of risk management activities and initiatives.

The Board shall approve and monitor processes that provide reasonable assurance of compliance with applicable legal and regulatory requirements.

The Board shall oversee security procedures and practices for the protection of Company personnel, physical assets, and other corporate assets from physical damage, harm, or interruption of operations including the Company's disaster preparedness.

Leadership and Succession

The Board shall oversee policies and practices to enable the Company to attract, develop and retain the human resources required by the Company to meet its business objectives.

The Board shall appoint executive officers and delegate the necessary authority for the conduct of the business.

The Board shall establish annual performance expectations and corporate goals and objectives for the Chief Executive Officer and monitor progress against those expectations.

The Board shall oversee the succession planning program for the Chief Executive Officer and other key executive positions from time to time.

Financial

The Board shall oversee the financial reporting and disclosure obligations imposed on the Company by laws, regulations, rules, policies and other applicable requirements.

The Board will review the financial performance of the Company and declare dividends as appropriate.

The Board shall approve for release to the public as necessary the Company's financial statements, management's discussion and analysis (MD&A) and earnings releases prepared by management and oversee the Company's compliance with applicable audit, accounting and reporting requirements.

The Board shall review the quality and integrity of NSPI's internal controls and management information systems.

Corporate Communications and Public Disclosure

The Board shall oversee policies and processes for accurate, timely and appropriate public disclosure.

Governance Responsibility

The Board is responsible for overseeing the Company's corporate governance policies and practices.

The Board shall establish appropriate structures and procedures to allow the Board to function independently of management and in the interests of the Company and its shareholders.

The Board, in carrying out its mandate, shall appoint committees of the Board and delegate certain functions to those committees, each of which shall have its own written charter. Notwithstanding such delegation, the Board retains its oversight function and ultimate responsibility for these delegated functions.

The Board shall oversee a process for the selection of qualified individuals for board nomination, and shall approve selection criteria for identifying director candidates taking into account the competencies and skills the Board as a whole should possess.

The Board shall undertake regular evaluation of the Board, the Chair of the Board, the Board committees and individual Directors.

The Board shall undertake regular evaluation of Directors' compensation.

The Board shall review this Charter annually to ensure it appropriately reflects the Board's stewardship responsibilities.

NON-CONFIDENTIAL

Request IR-5:

Reference Exhibit N-5, NSPI Analysis of Executive Management Expenses 2011:

a) What comparisons has NSPI or consultants made to comparable utilities such as NB Power, Canadian Utilities, BC Hydro, Saskatchewan Power for executive compensation?

b) Has NSPI or consultants performed an analysis of their executive compensation compared to that of comparable entities as a % of revenue, # of employees, or other values that would reflect the size and complexity of the entity.

c) What were total salary and compensation of Named Executive Officers when the entity changed from a crown corporation? How has the performance of their duties changed?

Response IR-5:

(a) The Towers Watson Executive Compensation Report includes Canadian utilities such as BC Hydro and Saskatchewan Power. NB Power was not named as a participant in the 2011 survey results as they declined to participate but participation by comparator companies can vary year to year.

The Towers Watson Executive Compensation Report includes analysis based on revenue dollars which is standard for these types of market surveys.

(b) The Towers Watson Executive Compensation Report includes analysis based on revenue dollars which is standard for these types of market surveys.

(c) Please refer to Booth IR-2 Attachment 1.

REDACTED

Request IR-6:

With respect to Exhibit N-5, NSPI Analysis of Executive Management Expenses 2011:

NSPI indicates on page 2 of the Introduction to the "Analysis of Executive Management Expenses" document that base salary is designed to result in remuneration at, on average, the median (50^{th} percentile) of the comparator groups. In 2010, the revenue range of the comparator group was increased from a maximum of $2 billion to $5 billion, in response to which the Board commented as follows:

> **The Board is concerned that the increase in the top of the revenue range of the comparator group from $2 billion to $5 billion may not be appropriate. NSPI's reported revenue of $1.1 billion for the past 2 years represented approximately, the mid-point of the range used in prior years. The increase in the range moves NSPI well under the mid-point based on revenue and the executive compensation comparators drop to an average 25^{th} percentile, from 50^{th} percentile under the prior range. This appears to be a reflection of the increase in range of the comparator group. The Board is concerned that use of this report as a basis for establishing future Executive compensation structure, when base salary is designed to meet the median of the comparator companies, may not be appropriate.**

Please indicate whether consideration was given to determining whether the 50^{th} percentile of the revised comparator group remains an appropriate benchmark. If so, how does NSPI support this position?

Response IR-6:

The response to this information request is confidential.

NON-CONFIDENTIAL

Request IR-7:

With respect to Exhibit N-5, NSPI Analysis of Executive Management Expenses 2011:

Please reference the positions in Attachment B “Confidential: Summary of NSPI’s 2011 Executive Compensation, Benefits and Other Expenses” to those positions and compensation reported to Tower for both salary and target total cash as outlined under findings within Attachment A, “Tower Watson 2011 Executive Compensation Review”. Please explain the variances.

Response IR-7:

Please refer to Exhibit N-5 Attachment A, page 3 and 4, for the list of employees. Towers Watson does not always have an exact comparable position, please refer to Attachment A, at page 10, for the list of comparable positions to those reviewed by Towers Watson.

CONFIDENTIAL (Attachment Only)

Request IR-8:

With respect to Exhibit N-5, NSPI Analysis of Executive Management Expenses 2011, Attachment B - "Confidential: Summary of NSPI's 2011 Executive Compensation, Benefits and Other Expenses":

a) Please provide the details supporting travel expenditures outlined in for the President & CEO as well as the EVP Sustainability.
b) Please reconcile and explain the inconsistency for the total compensation of the VP Technical & Construction Services.
c) Please explain why the expense reports for the two Emera/NSPI shared executives are reported in different ways, one at the reduced 32.5% attributable to NSPI and another at 100%.

Response IR-8:

(a) Please refer to Confidential Attachment 1 for the detail of expenses for the President & CEO of NS Power.

Please refer to Confidential Attachment 2 for the detail of expenses for the EVP Sustainability of NS Power.

(b) The Total Compensation amount (Column 12) for the VP Technical & Construction Services is the correct compensation for 2011, however due to an error in the spreadsheet the Car Allowance and Mileage (Column 6) is incorrect. The correct number for Car Allowance was $12,000 and Mileage (Column 6) is $695.

(c) Total expenses for Corporate Secretary were reduced by the 32.5 percent allocation in Column 13 and Column 14 while the expenses for VP Corporate Insurance & Assets had not been reduced in these two columns in error. However, these expenses were reduced in Column 16 and included in Column 18 correctly for both positions.

Request IR-9:

Please explain the approval process capital work orders follow from work order approval through to final costing, including what requirements exist for Board approval at each stage prior to inclusion in Rate Base.

Response IR-9:

Per Section 35 of the *Public Utilities Act* (the Act), NS Power capital expenditures in excess of $250,000 require the Board's approval. Per Section 35A of the Act, NS Power is able to submit a capital budget to the Board for approval.

The Company's capital budget, the Annual Capital Expenditure (ACE) Plan, is submitted to the Board for approval in the autumn of the preceding year. The ACE Plan provides the Company's five-year forecast of capital spending and requests approval of projects to be undertaken in Year 1 of the program. For projects for which the Company is requesting approval, the Company provides full justification in the ACE Plan Application, including cost support and economic and technical analyses.

The Board's review of the ACE Plan is conducted through a public hearing. This process includes registration of interested parties as Intervenors, the submission of information requests to the Company, the filing of evidence by interested parties, cross-examination of the Company's witnesses, and the exchange of closing submissions by the Company and participating parties. The process from application to Board Decision requires approximately six months.

Where the Board has determined the Company has provided sufficient justification of its capital items the Board will approve projects included in the ACE Plan submission. For those projects for which the Board determines sufficient justification has not been provided, it will withhold its approval.

For projects either not included in the ACE Plan or for ACE Plan projects for which the Board has withheld it approval, NS Power makes separate capital filings to the Board. Depending on the cost of the project and strategic significance, the Board may invite interested parties to provide comment as to the process the Board should initiate to undertake its review of the capital application and/or whether the Board should approve the project.

For projects approved by the Board in excess of $1 million, Final Cost submissions are required.

The Final Cost filing confirms the project was completed and provides the Board with the Company's actual cost information for the project. In the circumstances where project costs exceed the amount approved by the Board, NS Power is required to file for Board approval of the additional spending. Depending on the materiality of the over-spend, NS Power may submit the application to over-spend the project, coincident with its Final Cost Application.

Projects included in the Company's capital program are submitted for approval in accordance with the provisions of the Board-approved Capital Expenditure Justification Criteria (CEJC). The CEJC describes the essential elements of the capital program and justification categories and information required by the Board in order to approve NS Power's capital applications.

NS Power capital work-in-progress is included in rate base. For rate-setting purposes, the effect of this on revenue requirement is offset by the application of Allowance For Funds Used During Construction (AFUDC). When an asset is declared in service it moves from work-in-progress to plant in service and the Application of AFUDC ceases and depreciation begins.

The capital process is rigorous and transparent. The Board ensures NS Power's applications are vetted thoroughly and with the active engagement of stakeholders for the ACE Plan and the Company's larger capital applications. In addition, NS Power provides ongoing quarterly reporting to the Board which provides the status and spending of items included in the capital plan and other ad hoc reporting the Board determines appropriate. All of this information is posted to the Board's web-site and is readily accessible to interested parties coincident with NS Power's filings to the Board.

Request IR-10:

Please list all capital items included in the Application which have not yet received UARB work order approval.

a) Identify the included amounts for each project along with the associated amount for ROE and the associated depreciation amounts.
b) Identify when each project will be submitted for Board approval.

Response IR-10:

Please refer to Attachment 1 for a list of projects yet to receive Board approval and their estimated submittal date.

(a) NS Power's asset management accounting system does not calculate depreciation by project, only to the depreciation group detail. NS Power does not track return on equity (ROE) by asset.

(b) The methodology used to develop the capital plans for the test years considered capital as sustaining, or program/ project specific (strategic) investments. The assumptions used for the sustaining and some strategic investments apply historical spending and addition profiles to estimate spend and additions by major location. These have been modelled in the asset management accounting system as funding levels in the appropriate year.

Strategic investment forecasts for projects currently being executed identify the investment levels carried over from previous years. New strategic investments for 2013 and 2014 were modelled based on forecast funding levels and spend profiles per project.

As the estimates are refined and specific projects identified throughout 2013 and 2014, these investments will be brought forward for Board approval for the respective years.

Capital Items to be Submitted for Approval

Project#	Project Name	To be Submitted for Approval	2012 * $	2013 GRA (2013) $	2013 GRA (2014) $
18180	WRC - WAREHOUSE REPLACEMENT	ACE 2013		189,066	-
18448	TUC - Cooling Water System Biofouli	Q2 2012	2,752,964		
27358	CT'S - AC Generator Stator Lcm	ACE 2013		35,739	-
31182	LIN-AIR HEATER DAMPER REFURBISHMENT	ACE 2014		-	90,598
31402	LIN-AIR HEATER GEARBOX	ACE 2014		-	70,000
31582	LIN-GLAND STEAM CONDENSATE	ACE 2014		-	85,000
36782	Forklift Replacement	ACE 2014		-	154,407
37604	Dumper Building A/C	ACE 2014		-	70,930
38823	2013 Protection Upgrades	ACE 2013		2,947,916	-
38868	HYD Marshall Falls Hydro Station	Q4 2012	2,816,988	787,490	1,187,300
39042	HYD -Ten Mile Lake Dam Decommission	Pending Approval	1,018,923		
39265	Transmission Reliablity Replacement	ACE 2013		7,698,545	-
39267	Transmission Replacements	ACE 2013		6,140,942	-
39271	Dist. Reliability Replacements	ACE 2013		11,498,841	-
39274	Distribution Replacements	ACE 2014		-	4,774,218
39306	Radio & Communication Replacements	ACE 2013		5,058,039	5,063,889
39566	LIN2 Steam Turbine Last Stage Blade	Cancelled	567,450		
40224	78W-301 Second Peninsula	Q2 2012	406,674		
40278	OMS Upgrade 2011	TBD	1,871,134		
40299	Field Office Phone System Replaceme	Deferred	833,454		
40310	Circuit Switcher Additions	TBD	681,018		
40314	Main Computer Centre Upgrade	Pending Approval	7,180,164		
40320	LED Street Light Conversion	TBD	5,743,851	11,523,841	17,837,881
40330	LIN2 HT Fastener Replacement	Cancelled	532,899		
40553	Wind Farm #2 (100MW)	ACE 2014		-	28,097,454
40648	Field Mobility System	Q4 2012	1,705,303	-	
41126	HYD-ANN Sluiceway Stop Logs	Q2 2012	1,112,121		
41233	LIN 3 Boiler Refurbishment	Deferred	755,711		
41234	LIN4 Boiler Refurbishment	Q2 2012	494,143		
41235	LIN 1 Boiler Refurbishment	Q2 2012	749,410		
41248	TUC - Lube Oil Storage Building	Q2 2012	240,548		
41403	GIS Enterprise License Agreement	Q2 2012	90,643		
41424	PeopleSoft Self Service Module	Q3 2012	373,859		
41425	Cognos Upgrade	ACE 2013		54,809	-
41516	TRE6 - Stack Breaching Inlet Ductwo	TBD	252,963		
41519	Harbour East 138 kV Tx Line	Q2 2012	2,019,567	6,903,791	-
41520	Harbour East Substation	Q2 2012	905,465	2,544,112	-
41522	138kV Line Terminal at Dart East	Q3 2012	207,792	570,223	-
41534	2012 Reliability Technologies Dist.	Q3 2012	2,424,338		
41536	2012 Reliability Technology Trans.	Q2 2012	878,217		
41537	Amherst 138kV Substation	Q2 2012	2,719,310		
41557	Street Light & Area Management	TBD	809,436		
41595	POT - Sternson PLC Replacement	TBD	597,050		
41766	Commercial AMI Pilot	TBD	2,529,527	2,407,715	2,407,715
41797	Brier Island Crossing	Pending Approval	1,006,642		
41806	HYD - Big Falls Unit #6 Refurbishme	Cancelled	497,566		
41830	Wind - Routine Equipment Replacemen	ACE 2013		99,305	99,305
41845	Residential AMI Pilot	TBD		2,449,992	2,449,992
42152	GRA LIN0 Sustaining Q1 2013	ACE 2013		36,592	-
42153	GRA LIN1&2 Sustaining Q1 2013	ACE 2013		149,075	-
42155	GRA LIN3&4 Sustaining Q1 2013	ACE 2013		827,504	-
42157	GRA POA Sustaining Q1 2013	ACE 2013		149,673	-
42158	GRA POT1 Sustaining Q1 2013	ACE 2013		54,690	-
42159	GRA POT2 Sustaining Q1 2013	ACE 2013		178,864	-
42160	GRA TRE0 Sustaining Q1 2013	ACE 2013		132,134	-
42161	GRA TRE5 Sustaining Q1 2013	ACE 2013		194,656	-

Capital Items to be Submitted for Approval

Project#	Project Name	To be Submitted for Approval	2012 * $	2013 GRA (2013) $	2013 GRA (2014) $
42162	GRA TRE6 Sustaining Q1 2013	ACE 2013		110,809	-
42163	GRA TUC0 Sustaining Q1 2013	ACE 2013		55,474	-
42164	GRA TUC1 Sustaining Q1 2013	ACE 2013		67,978	-
42165	GRA TUC2 Sustaining Q1 2013	ACE 2013		132,460	-
42166	GRA TUC3 Sustaining Q1 2013	ACE 2013		134,842	-
42170	GRA Burnside Sustaining Q1 2013	ACE 2013		-	1,628,926
42173	GRA Annapolis Sustaining Q1 2013	ACE 2013		92,791	-
42174	GRA Avon Sustaining Q1 2013	ACE 2013		51,035	-
42175	GRA Sissiboo Sustaining Q1 2013	ACE 2013		918,161	-
42178	GRA Tusket Sustaining Q1 2013	ACE 2013		378,121	-
42179	GRA Fall River Sustaining Q1 2013	ACE 2013		4,639	-
42180	GRA Harmony Sustaining Q1 2013	ACE 2013		37,116	-
42181	GRA Nict.&Parad Sustaining Q1 2013	ACE 2013		108,100	-
42184	GRA St. Marg's Sustaining Q1 2013	ACE 2013		128,978	-
42185	GRA Sheet Harbor Sustaining Q1 2013	ACE 2013		12,465	-
42186	GRA Bear River Sustaining Q1 2013	ACE 2013		1,160	-
42187	GRA Wreck Cove Sustaining Q1 2013	ACE 2013		16,721	-
42191	GRA Hydro Administration Q1 2013	ACE 2013		121,200	-
42194	GRA LIN0 Sustaining Q2 2013	ACE 2013		278,303	-
42206	GRA LIN1&2 Sustaining Q2 2013	ACE 2013		1,159,840	-
42208	GRA LIN3&4 Sustaining Q2 2013	ACE 2013		4,617,543	-
42210	GRA POA Sustaining Q2 2013	ACE 2013		1,046,263	-
42211	GRA POT1 Sustaining Q2 2013	ACE 2013		379,118	-
42212	GRA POT2 Sustaining Q2 2013	ACE 2013		1,270,673	-
42214	GRA TRE0 Sustaining Q2 2013	ACE 2013		933,141	-
42215	GRA TRE5 Sustaining Q2 2013	ACE 2013		1,353,674	-
42216	GRA TRE6 Sustaining Q2 2013	ACE 2013		780,473	-
42217	GRA TUC0 Sustaining Q2 2013	ACE 2013		391,658	-
42218	GRA TUC1 Sustaining Q2 2013	ACE 2013		491,930	-
42219	GRA TUC2 Sustaining Q2 2013	ACE 2013		882,831	-
42220	GRA TUC3 Sustaining Q2 2013	ACE 2013		958,532	-
42231	GRA Annapolis Sustaining Q2 2013	ACE 2013		654,543	-
42232	GRA Avon Sustaining Q2 2013	ACE 2013		360,000	-
42233	GRA Sissiboo Sustaining Q2 2013	ACE 2013		6,476,703	-
42235	GRA Tusket Sustaining Q2 2013	ACE 2013		2,667,262	-
42236	GRA Fall River Sustaining Q2 2013	ACE 2013		32,727	-
42237	GRA Harmony Sustaining Q2 2013	ACE 2013		261,818	-
42238	GRA Nict.&Parad Sustaining Q2 2013	ACE 2013		762,542	-
42241	GRA St. Marg's Sustaining Q2 2013	ACE 2013		909,814	-
42242	GRA Sheet Harbor Sustaining Q2 2013	ACE 2013		87,935	-
42243	GRA Bear River Sustaining Q1 2013	ACE 2013		8,181	-
42244	GRA Wreck Cove Sustaining Q2 2013	ACE 2013		117,817	-
42246	GRA Hydro Administration Q2 2013	ACE 2013		854,947	-
42247	GRA LIN0 Sustaining Q3 2013	ACE 2013		281,859	-
42249	GRA LIN1&2 Sustaining Q3 2013	ACE 2013		1,179,879	-
42251	GRA LIN3&4 Sustaining Q3 2013	ACE 2013		4,634,432	-
42253	GRA POA Sustaining Q3 2013	ACE 2013		1,057,654	-
42254	GRA POT1 Sustaining Q3 2013	ACE 2013		383,691	-
42255	GRA POT2 Sustaining Q3 2013	ACE 2013		884,108	-
42256	GRA TRE0 Sustaining Q3 2013	ACE 2013		945,070	-
42257	GRA TRE5 Sustaining Q3 2013	ACE 2013		876,653	-
42258	GRA TRE6 Sustaining Q3 2013	ACE 2013		795,489	-
42259	GRA TUC0 Sustaining Q3 2013	ACE 2013		394,685	-
42260	GRA TUC1 Sustaining Q3 2013	ACE 2013		467,469	-
42261	GRA TUC2 Sustaining Q3 2013	ACE 2013		915,692	-
42262	GRA TUC3 Sustaining Q3 2013	ACE 2013		1,106,911	-

Capital Items to be Submitted for Approval

Project#	Project Name	To be Submitted for Approval	2012 * $	2013 GRA (2013) $	2013 GRA (2014) $
42269	Circuit Switchers Addit's 2013/2014	ACE 2013		492,150	491,811
42270	2014 Protection Upgrades	ACE 2014		-	5,847,535
42272	GRA Annapolis Sustaining Q3 2013	ACE 2013		659,638	-
42273	GRA Avon Sustaining Q3 2013	ACE 2013		362,803	-
42274	GRA Sissiboo Sustaining Q3 2013	ACE 2013		6,527,126	-
42276	GRA Tusket Sustaining Q3 2013	ACE 2013		2,688,027	-
42277	GRA Fall River Sustaining Q3 2013	ACE 2013		32,982	-
42278	GRA Harmony Sustaining Q3 2013	ACE 2013		263,856	-
42279	GRA Nict.&Parad Sustaining Q3 2013	ACE 2013		768,478	-
42282	GRA St. Marg's Sustaining Q3 2013	ACE 2013		916,897	-
42283	GRA Sheet Harbor Sustaining Q3 2013	ACE 2013		88,620	-
42284	GRA Bear River Sustaining Q3 2013	ACE 2013		8,244	-
42285	GRA Wreck Cove Sustaining Q3 2013	ACE 2013		118,735	-
42287	GRA Hydro Administration Q3 2013	ACE 2013		861,603	-
42288	GRA LIN0 Sustaining Q4 2013	ACE 2013		121,103	-
42289	GRA LIN1&2 Sustaining Q4 2013	ACE 2013		506,805	-
42291	GRA LIN3&4 Sustaining Q4 2013	ACE 2013		1,646,828	-
42293	GRA POA Sustaining Q4 2013	ACE 2013		457,004	-
42294	GRA POT1 Sustaining Q4 2013	ACE 2013		167,160	-
42295	GRA POT2 Sustaining Q4 2013	ACE 2013		547,758	-
42296	GRA TRE0 Sustaining Q4 2013	ACE 2013		405,120	-
42297	GRA TRE5 Sustaining Q4 2013	ACE 2013		589,350	-
42298	GRA TRE6 Sustaining Q4 2013	ACE 2013		338,413	-
42299	GRA TUC0 Sustaining Q4 2013	ACE 2013		169,931	-
42300	GRA TUC1 Sustaining Q4 2013	ACE 2013		208,513	-
42301	GRA TUC2 Sustaining Q4 2013	ACE 2013		401,143	-
42302	GRA TUC3 Sustaining Q4 2013	ACE 2013		411,080	-
42309	GRA Annapolis Sustaining Q4 2013	ACE 2013		284,873	-
42310	GRA Avon Sustaining Q4 2013	ACE 2013		156,681	-
42311	GRA Sissiboo Sustaining Q4 2013	ACE 2013		2,818,828	-
42313	GRA Tusket Sustaining Q4 2013	ACE 2013		1,160,862	-
42315	GRA Fall River Sustaining Q4 2013	ACE 2013		14,243	-
42316	GRA Harmony Sustaining Q4 2013	ACE 2013		113,950	-
42317	GRA LIN0 Sustaining Q3 2014	ACE 2014		-	869,946
42318	GRA Nict.&Parad Sustaining Q4 2013	ACE 2013		331,879	-
42319	GRA LIN1&2 Sustaining Q3 2014	ACE 2014		-	445,650
42322	GRA St. Marg's Sustaining Q4 2013	ACE 2013		395,975	-
42324	GRA Sheet Harbor Sustaining Q4 2013	ACE 2013		38,272	-
42325	GRA Bear River Sustaining Q4 2013	ACE 2013		3,560	-
42326	GRA LIN3&4 Sustaining Q3 2014	ACE 2014		-	1,165,431
42327	GRA Wreck Cove Sustaining Q4 2013	ACE 2013		51,278	-
42330	GRA Hydro Administration Q4 2013	ACE 2013		372,095	-
42331	GRA POA Sustaining Q3 2014	ACE 2014		-	4,620,618
42332	2014 Dist Relibability Replacements	ACE 2014		-	9,114,633
42333	GRA LIN0 Sustaining Q1 2014	ACE 2014		-	113,441
42335	GRA LIN1&2 Sustaining Q1 2014	ACE 2014		-	57,422
42336	GRA POT2 Sustaining Q3 2014	ACE 2014		-	416,787
42338	GRA LIN3&4 Sustaining Q1 2014	ACE 2014		-	157,196
42339	GRA TRE0 Sustaining Q3 2014	ACE 2014		-	638,373
42341	GRA TRE5 Sustaining Q3 2014	ACE 2014		-	561,234
42342	GRA POA Sustaining Q1 2014	ACE 2014		-	650,820
42344	GRA POT2 Sustaining Q1 2014	ACE 2014		-	58,734
42345	GRA TRE6 Sustaining Q3 2014	ACE 2014		-	1,990,100
42346	GRA TRE0 Sustaining Q1 2014	ACE 2014		-	89,852
42347	GRA TRE5 Sustaining Q1 2014	ACE 2014		-	80,035
42348	GRA TUC0 Sustaining Q3 2014	ACE 2014		-	530,847

Capital Items to be Submitted for Approval

Project#	Project Name	To be Submitted for Approval	2012 * $	2013 GRA (2013) $	2013 GRA (2014) $
42349	GRA TRE6 Sustaining Q1 2014	ACE 2014		-	280,329
42350	GRA TUC0 Sustaining Q1 2014	ACE 2014		-	74,782
42351	GRA TUC1 Sustaining Q3 2014	ACE 2014		-	1,055,663
42352	GRA TUC1 Sustaining Q1 2014	ACE 2014		-	147,780
42353	GRA TUC2 Sustaining Q1 2014	ACE 2014		-	268,864
42354	GRA TUC2 Sustaining Q3 2014	ACE 2014		-	1,893,467
42355	GRA TUC3 Sustaining Q1 2014	ACE 2014		-	321,966
42359	GRA TUC3 Sustaining Q3 2014	ACE 2014		-	2,283,851
42367	GRA Annapolis Sustaining Q1 2014	ACE 2014		-	97,661
42369	GRA Sissiboo Sustaining Q1 2014	ACE 2014		-	76,259
42370	GRA Black River Sustaining Q1 2014	ACE 2014		-	396,089
42372	GRA Tusket Sustaining Q1 2014	ACE 2014		-	27,061
42374	GRA Fall River Sustaining Q1 2014	ACE 2014		-	36,900
42376	GRA Harmony Sustaining Q1 2014	ACE 2014		-	31,979
42377	GRA Nict.&Parad Sustaining Q1 2014	ACE 2014		-	30,012
42379	GRA Lequille Sustaining Q1 2014	ACE 2014		-	24,600
42380	GRA Annapolis Sustaining Q3 2014	ACE 2014		-	694,264
42381	GRA Roseway Sustaining Q1 2014	ACE 2014		-	39,360
42382	GRA St. Marg's Sustaining Q1 2014	ACE 2014		-	85,229
42385	GRA Bear River Sustaining Q1 2014	ACE 2014		-	14,760
42386	GRA Sissiboo Sustaining Q3 2014	ACE 2014		-	542,121
42387	GRA Wreck Cove Sustaining Q1 2014	ACE 2014		-	386,217
42388	GRA Black River Sustaining Q3 2014	ACE 2014		-	2,722,427
42390	GRA Hydro Administration Q1 2014	ACE 2014		-	737,390
42391	GRA Tusket Sustaining Q3 2014	ACE 2014		-	202,567
42392	GRA Fall River Sustaining Q3 2014	ACE 2014		-	262,316
42393	GRA Harmony Sustaining Q3 2014	ACE 2014		-	227,342
42394	GRA Nict.&Parad Sustaining Q3 2014	ACE 2014		-	213,350
42395	GRA Lequille Sustaining Q3 2014	ACE 2014		-	174,879
42396	2014 Trans Reliability Replacements	ACE 2014		-	5,683,548
42397	2013 Transmission Reinforcements	ACE 2013		40,462,286	-
42398	2014 Transmission Reinforcements	ACE 2014		-	28,920,805
42399	2013 Distribution Replacements	ACE 2013		4,763,626	-
42400	GRA Roseway Sustaining Q3 2014	ACE 2014		-	279,804
42401	GRA St. Marg's Sustaining Q3 2014	ACE 2014		-	605,889
42403	GRA LIN0 Sustaining Q4 2014	ACE 2014		-	375,417
42404	GRA Bear River Sustaining Q3 2014	ACE 2014		-	104,927
42405	GRA Wreck Cove Sustaining Q3 2014	ACE 2014		-	2,745,581
42406	GRA LIN1&2 Sustaining Q4 2014	ACE 2014		-	192,315
42408	GRA Hydro Administration Q3 2014	ACE 2014		-	5,242,037
42410	GRA LIN3&4 Sustaining Q4 2014	ACE 2014		-	502,931
42411	GRA LIN0 Sustaining Q2 2014	ACE 2014		-	863,869
42412	GRA LIN1&2 Sustaining Q2 2014	ACE 2014		-	442,536
42415	GRA POA Sustaining Q4 2014	ACE 2014		-	1,994,033
42416	GRA LIN3&4 Sustaining Q2 2014	ACE 2014		-	1,157,290
42419	GRA POA Sustaining Q2 2014	ACE 2014		-	4,594,095
42420	GRA POT2 Sustaining Q4 2014	ACE 2014		-	179,861
42422	GRA POT2 Sustaining Q2 2014	ACE 2014		-	413,876
42423	GRA TRE0 Sustaining Q4 2014	ACE 2014		-	275,481
42424	GRA TRE0 Sustaining Q2 2014	ACE 2014		-	633,914
42425	GRA TRE5 Sustaining Q4 2014	ACE 2014		-	242,196
42426	GRA TRE5 Sustaining Q2 2014	ACE 2014		-	557,313
42427	GRA TRE6 Sustaining Q2 2014	ACE 2014		-	1,970,129
42428	GRA TRE6 Sustaining Q4 2014	ACE 2014		-	856,099
42429	GRA TUC0 Sustaining Q2 2014	ACE 2014		-	527,139
42430	GRA TUC0 Sustaining Q4 2014	ACE 2014		-	230,690

Capital Items to be Submitted for Approval

Project#	Project Name	To be Submitted for Approval	2012 * $	2013 GRA (2013) $	2013 GRA (2014) $
42431	GRA TUC1 Sustaining Q2 2014	ACE 2014		-	1,043,176
42432	GRA TUC2 Sustaining Q2 2014	ACE 2014		-	1,880,241
42433	GRA TUC1 Sustaining Q4 2014	ACE 2014		-	453,289
42434	GRA TUC3 Sustaining Q2 2014	ACE 2014		-	2,267,897
42436	GRA TUC2 Sustaining Q4 2014	ACE 2014		-	814,242
42438	GRA TUC3 Sustaining Q4 2014	ACE 2014		-	987,935
42446	GRA Annapolis Sustaining Q2 2014	ACE 2014		-	688,901
42449	GRA Sissiboo Sustaining Q2 2014	ACE 2014		-	537,933
42450	GRA Black River Sustaining Q2 2014	ACE 2014		-	2,709,775
42452	GRA Tusket Sustaining Q2 2014	ACE 2014		-	201,002
42454	GRA Fall River Sustaining Q2 2014	ACE 2014		-	260,290
42455	GRA Harmony Sustaining Q2 2014	ACE 2014		-	225,585
42456	GRA Annapolis Sustaining Q4 2014	ACE 2014		-	299,826
42457	GRA Nict.&Parad Sustaining Q2 2014	ACE 2014		-	211,702
42459	GRA Lequille Sustaining Q2 2014	ACE 2014		-	173,528
42460	GRA Roseway Sustaining Q2 2014	ACE 2014		-	277,643
42461	GRA Sissiboo Sustaining Q4 2014	ACE 2014		-	234,121
42462	GRA St. Marg's Sustaining Q2 2014	ACE 2014		-	601,209
42463	GRA Black River Sustaining Q4 2014	ACE 2014		-	59,358
42465	GRA Bear River Sustaining Q2 2014	ACE 2014		-	104,116
42466	GRA Tusket Sustaining Q4 2014	ACE 2014		-	83,075
42467	GRA Wreck Cove Sustaining Q2 2014	ACE 2014		-	2,724,371
42468	GRA Fall River Sustaining Q4 2014	ACE 2014		-	113,285
42470	GRA Hydro Administration Q2 2014	ACE 2014		-	5,201,542
42471	GRA Harmony Sustaining Q4 2014	ACE 2014		-	98,183
42472	GRA Nict.&Parad Sustaining Q4 2014	ACE 2014		-	92,139
42473	GRA Wreck Cove Sustaining Q4 2014	ACE 2014		-	1,185,711
42475	GRA Lequille Sustaining Q4 2014	ACE 2014		-	75,524
42476	GRA Hydro Administration Q4 2014	ACE 2014		-	2,263,837
42477	GRA Roseway Sustaining Q4 2014	ACE 2014		-	120,837
42478	GRA St. Marg's Sustaining Q4 2014	ACE 2014		-	261,660
42480	GRA Bear River Sustaining Q4 2014	ACE 2014		-	45,313
42486	GRA Fast Acting Generation	ACE 2013		5,322,506	16,400,122
42487	GRA - Hardware 2013	ACE 2013		661,031	-
42488	GRA Hardware 2014	ACE 2014		-	394,026
42489	GRA Software 2013	ACE 2013		3,745,840	-
42490	GRA Software 2014	ACE 2014		-	3,546,234

*2012 Spending amounts are as included in the Application and do not necessarily correspond to the 2012 ACE filing or the amounts that will be submitted for later approval

NON-CONFIDENTIAL

Request IR-11:

Please list all capital items included in the rate base which have not received Final Cost approval from the UARB.

a) Include the approved work order total, the final cost (if concluded), and the amount included in rate base along with the date it was included.

b) For each of the above, list the individual depreciation amounts and ROE amounts included in the Application.

Response IR-11:

(a) Please refer to Attachment 1 which includes capital item approved work order totals included in rate base as of the end of 2014 for projects requiring final cost approval. The final costs amounts will only be available once the project is completed and all costs of the projects have been collected and submitted to the Board. The amounts and timing of additions to rate base would be each project's annual spend.

(b) NS Power's asset management accounting system does not calculate depreciation by project, only to the depreciation group detail. NS Power does not track return on equity (ROE) by asset.

Projects In Service & Ready for Final Costing

CI	Project	Functional Class	In Service Date	Work Order Status	UARB Approved $	Project Spend to Date (May 31, 2012)	Notes
20280	LIN, INSTALLATION OF A WASTEWATER TREATMENT FACILITY	Steam Generation Plant	2003	in service	5,569,520	5,420,997	
25918	LM6000 TUC #5 TRANSMISSION	Transmission Plant	2005	in service	1,044,099	670,476	
19753	ANN - UNIT OVERHAUL	Hydro Generation Plant	2007	in service	2,731,897	2,695,919	
14366	SHH- DIB PIPELINE REPLACEMENT	Hydro Generation Plant	2008	completed	4,466,066	3,820,694	
14719	POT - CONDENSER TUBE REPLACEMENT	Steam Generation Plant	2008	in service	2,433,350	2,088,744	
28293	Cowie Hill Modified Underground Replacement	Distribution Plant	2008	in service	1,073,850	1,377,050	
28345	LIN-REPLACE ROTARY DUMPER	Steam Generation Plant	2008	in service	4,760,040	4,959,508	
25588	SCADA Replacement	General Plant	2008	completed	2,241,494	2,170,484	
28609	91H-GT3 TRANSFORMER REFURBISHMENT - TUC	Transmission Plant	2008	in service	2,710,031	2,521,980	
29982	TUC Unit #3 Turbine IP Blade Tenon	Steam Generation Plant	2008	completed	1,225,303	993,546	
10900	HYD DEB # 10 - Generator Rewind	Hydro Generation Plant	2009	in service	1,022,620	1,119,504	
25210	TRE5 Bag House Addition	Steam Generation Plant	2009	in service	29,949,968	28,928,605	
25566	REPLACE DNR MICROWAVE CIRCUITS	General Plant	2009	in service	1,906,120	2,205,252	
28295	CONSTRUCT 137H-HAMONDS PLAINS RD. 138/25 KV SUBSTATION	Transmission Plant	2009	in service	2,963,820	4,003,879	
28474	ST CROIX INSTALL NEW TRANSFORMER & BUS	Transmission Plant	2009	in service	4,602,698	4,070,458	
28488	2007 & 2008 Work Vehicle Replacement	General Plant	2009	completed	6,940,539	6,865,798	
28490	2007 & 2008 TRANSPORTATION VEHICLE	General Plant	2009	in service	3,096,483	2,957,001	
28552	TRE5 Replace Trenton 5 Generator	Steam Generation Plant	2009	in service	16,618,590	15,834,753	
28702	REPLACE BRIDGEWATER TRANSFORMER 89W	Transmission Plant	2009	in service	1,391,477	1,773,084	
28727	GREAT BARREN DAM SAFETY	Hydro Generation Plant	2009	completed	1,806,825	2,301,559	
28865	POT-UNIT#2 LOW NOX COMBUSTION FIRING	Steam Generation Plant	2009	in service	4,504,430	3,563,196	
29822	Pt. Tupper Relocate Port Malcolm Rd	Steam Generation Plant	2009	in service	2,149,043	1,632,187	
31203	HYD Toms Lake Dam Safety Remedial W	Hydro Generation Plant	2009	in service	3,136,532	2,008,811	
33542	Upgrade L-8002	Transmission Plant	2009	in service	1,601,290	1,188,673	
28413	Work Management System Replacement	General Plant	2010	completed	16,555,468	16,531,877	
28570	HYD Hollow Bridge Generator Rewind	Hydro Generation Plant	2010	posted to CPR	1,510,310	1,492,476	
28752	LM6000 - Overhaul TUC #5 Engine	Gas Turbine Generation Plant	2010	in service	2,532,039	943,711	
28788	3RD PARTY HIGH VOLUME CALL ANSWER SYSTEM	General Plant	2010	in service	2,052,571	1,336,627	
29012	UPGRADE L6537	Transmission Plant	2010	completed	2,386,936	2,234,559	
29013	82V Elmsdale Transformer Addition	Transmission Plant	2010	in service	2,592,775	2,920,567	
37609	LIN - Unit #1 Rotor Rewind	Steam Generation Plant	2010	in service	3,493,032	3,461,093	
38362	TUC U&U #1 GEN ROTOR RESTORE	Steam Generation Plant	2010	in service	4,063,982	3,629,160	
38402	CT U&U LM#4 Engine Refurbish	Gas Turbine Generation Plant	2010	in service	4,222,686	4,317,434	
38442	LIN-U&U Unit#2 ESP Flow Modification	Steam Generation Plant	2010	in service	1,719,930	1,691,228	
38834	TRE5 - Turbine Upgrades - LP/IP/HP	Steam Generation Plant	2010	in service	5,929,964	5,924,256	
38888	50N-412 Targeted Replacements	Distribution Plant	2010	in service	996,683	1,251,833	
38942	TUC #3 GENERATOR ROTOR REWIND	Steam Generation Plant	2010	in service	1,798,080	1,445,911	
38943	LIN1 - Boiler Refurbishment	Steam Generation Plant	2010	in service	1,658,592	1,651,741	
32442	HYD Ridge Spillway Refurbishment	Hydro Generation Plant	2010	in service	2,626,819	1,569,003	
31244	HYD Paradise Wood Stave Pipeline R	Hydro Generation Plant	2010	in service	11,162,662	9,386,934	
33642	2009 Transportation Vehicle Replace	General Plant	2010	completed	1,259,968	1,153,747	
33766	11S-411 Targeted Replacements	Distribution Plant	2010	in service	817,950	1,012,042	
33942	U&U Coon Pond Pipeline Replacement	Hydro Generation Plant	2010	in service	2,075,549	1,600,480	
35642	2009 Recloser Additions	Distribution Plant	2010	completed	1,512,766	1,562,370	
11004	Canaan Rd Circuit Breaker Additions	Transmission Plant	2011	in service	1,990,631	2,129,612	
29131	FAC Space 2011	General Plant	2011	in service	53,395,000	53,395,000	Amounts do not include AFUDC
28726	HYD Carlton Lake Dam Refurbishment	Hydro Generation Plant	2011	in service	6,325,300	6,321,271	
34582	Class 3 Light Work Vehicles	General Plant	2011	in service	1,063,981	936,668	
34583	Transportation Vehicle Replacements	General Plant	2011	in service	1,723,031	1,448,480	
34602	25 kV Feeder Extension Bissett Road	Distribution Plant	2011	in service	1,036,178	1,285,635	
36942	1H-B62 Bus Replacement Water St U&U	Transmission Plant	2011	in service	1,048,857	1,052,046	
38022	2010 Recloser Additions	Distribution Plant	2011	in service	1,400,271	1,644,623	
38024	2010 Dist. Cutout Replacements	Distribution Plant	2011	in service	2,000,606	1,962,996	
38027	2010 Trans Switch & Breaker Upgrade	Transmission Plant	2011	in service	2,070,094	2,059,890	

Projects In Service & Ready for Final Costing (Cont'd)

CI	Project	Functional Class	In Service Date	Work Order Status	UARB Approved $	Project Spend to Date (May 31, 2012)	Notes
38062	2010 Off Road to Roadside	Distribution Plant	2011	in service	1,000,119	1,120,828	
38110	2010 Tx Line Insulator Replacement	Transmission Plant	2011	in service	2,236,148	1,500,525	
38122	2010 PCB Equip. Removal/Destruction	Transmission Plant	2011	in service	1,487,135	1,638,107	
38732	1H Water St Replace 138 kV GIS	Transmission Plant	2011	in service	8,371,040	8,607,010	
38819	51V Tremont Circuit Breaker & Bus	Transmission Plant	2011	in service	7,452,511	7,454,027	
38826	POT - DCS upgrade	Steam Generation Plant	2011	in service	1,349,773	1,349,493	
38852	Work Vehicle Replacement	General Plant	2011	in service	6,064,000	6,061,709	
38856	L7011 Deteriorated Replacements	Transmission Plant	2011	in service	2,055,736	1,756,236	
38857	L7004 Deteriorated Replacements	Transmission Plant	2011	in service	2,467,028	2,449,207	
38878	2010 Subs Cutout and Insul. Replace	Transmission Plant	2011	in service	1,506,414	488,664	
33525	Canaan Rd 43V to Tremont 51V Line	Transmission Plant	2011	in service	8,016,435	7,282,367	
34843	Oracle NLA License	General Plant	2011	in service	1,016,000	543,311	
40425	Kempt Road Transformer	Transmission Plant	2011	in service	1,093,699	1,052,265	
40763	LIN4 U&U ESP Flow Mod	Steam Generation Plant	2011	in service	1,573,776	1,466,173	
39529	POT - Turbine Major 2011	Steam Generation Plant	2011	in service	4,741,727	5,181,600	
40280	2011 Trans Switch & Breaker Upgrade	Transmission Plant	2011	in service	2,866,718	3,796,899	
40281	2011 Tx Line Insulator Replacement	Transmission Plant	2011	in service	3,018,100	3,986,587	
40288	2011 PCB Equipment Removals	Transmission Plant	2011	in service	2,510,193	1,833,334	
40327	Glen Dhu 138 kV Substation	Transmission Plant	2011	in service	3,447,000	3,406,924	
28098	TUC 6 Waste Heat Recovery	Steam Generation Plant	2012	in service	92,996,628	92,900,000	
38182	2010 Backup Control Centre	General Plant	2012	in service	3,222,066	2,851,840	
28487	LIN Supplemental Water Supply	Steam Generation Plant	2008	in service	1,218,910	3,364,602	Pending UARB ATO Approval - Revised CI Total = $3,367,744

Projects In Service & Not Ready for Final Costing

CI	Project	Functional Class	In Service Date	Work Order Status	UARB Approved $	Project Spend to Date (May 31, 2012)	Notes
34182	LIN Unit #1 Mercury Abatement	Steam Generation Plant	2010	in service	2,450,269	2,046,286	
34202	LIN Unit #2 Mercury Abatement	Steam Generation Plant	2010	in service	2,450,269	1,974,443	
34203	LIN Unit #3 Mercury Abatement	Steam Generation Plant	2010	in service	4,962,536	4,831,204	
34222	LIN Unit #4 Mercury Abatement	Steam Generation Plant	2010	in service	2,450,269	1,978,872	
34223	POT Mercury Abatement Project	Steam Generation Plant	2010	in service	3,325,846	2,838,031	
34224	TRE Unit#5 Mercury Abatement	Steam Generation Plant	2010	in service	2,157,162	1,874,711	
34242	TRE Unit #6 Mercury Abatement	Steam Generation Plant	2010	in service	2,819,152	2,134,966	
36882	Nuttby Mountain Wind Project Dev	Wind Generation Plant	2010	in service	116,508,507	110,985,836	
37942	Nuttby Mountain Wind Project Substation	Transmission Plant	2010	in service	2,895,574	2,939,879	
39084	Point Tupper Wind Project	Wind Generation Plant	2010	in service	27,784,864	25,727,080	
39323	Digby Wind Project	Wind Generation Plant	2011	in service	67,758,698	64,393,468	
39626	Digby Wind Project Substation	Transmission Plant	2011	in service	4,586,277	4,319,506	
39627	Digby Wind Project Trans Line	Transmission Plant	2011	in service	4,156,325	4,175,882	
39628	Digby Wind Project Interconnect	Transmission Plant	2011	in service	3,270,060	3,895,162	
40103	U&U Load Control Demo	General Plant	2010	in service	4,293,793	1,578,891	
41005	Parrsboro Tidal Interconnection	Transmission Plant	2012	in service	1,734,780	1,508,784	
29010	Install 138-25KV Transformer At 22C	Transmission Plant	2010	in service	1,738,545	1,637,807	
28678	HYD Renewable In-Stream Tidal Gen	Hydro Generation Plant	2009	in service	3,300,000	3,540,503	SDTC Credit received in June reducing the amount by $240,503
14371	HYD - AVO #2 PIPELINE REPLACE	Hydro Generation Plant	2011	in service	3,815,396	3,823,554	
17830	HYD - STM Big Indian Lake Dam Safety	Hydro Generation Plant	2011	in service	4,288,237	3,115,697	
38859	HYD Big Falls Headgate Replacement	Hydro Generation Plant	2011	in service	5,941,366	5,941,685	
34622	Upgrade L-8002	Transmission Plant	2011	in service	2,222,639	2,417,152	
29008	Construct 139H Dartmouth Crossing Substn	Transmission Plant	2010	in service	3,969,281	4,681,153	

Projects Not In Service

CI	Project	Functional Class	In Service Date	Work Order Status	UARB Approved $	Project Spend to Date (May 31, 2012)	Notes
16374	HYD Gaspereau Dam Safety	Hydro Generation Plant		open	4,354,889	3,742,801	
25575	Reliability Keltic Drive New Feeder	Distribution Plant		open	1,717,903	2,193,965	
29009	Right of Way Purchase Northern NS	General Plant		open	4,462,493	2,384,940	
41552	131H Lucasville Transformer Addition	Transmission Plant		open	1,844,385	1,063,587	
30954	LIN3-ESP Gas Flow Modification	Steam Generation Plant		open	1,497,064	92,151	
31204	HYD - Donahoe Lake Dam Refurbishment	Hydro Generation Plant		open	1,597,494	247,005	
31245	HYD - Sandy Lake Dam Refurbishment	Hydro Generation Plant		open	5,579,410	313,195	
33624	Spare Generator Transformer	Transmission Plant		open	4,351,660	24,361	
35083	LIN 2011 Ash Site Sealing and Cappi	Steam Generation Plant		open	1,112,451	80,977	
35742	Connectivity Upgrade	General Plant		open	3,202,179	3,159,009	
36902	LIN1- ESP Gas Flow Modification	Steam Generation Plant		open	1,494,278	492,672	
41844	L8004 & L7005 Reinsulate	Transmission Plant		open	1,139,264	3,666	
41988	HYD - U&U Big Falls #5 Overhaul	Hydro Generation Plant		open	1,351,605	845,489	
39029	PH Biomass Project	Steam Generation Plant		open	207,479,791	176,761,995	
40430	PH Biomass Tx Interconnection	Transmission Plant		in service	1,070,615	1,200,781	Board Approved a project total of $208.5M; The transmission portion of the project was separated from the generation project.
39545	HYD - U&U Ladder Upgrades	Hydro Generation Plant		open	1,148,156	995,333	
41143	HYD -Tidewater Surge Tank Refurbish	Hydro Generation Plant		open	1,211,641	86,664	
41348	2012 Protection Upgrades Onslow	Transmission Plant		open	2,274,015	232,765	
41387	2012 Transmission Line Insulator Re	Transmission Plant		open	3,619,166	767,658	
41392	2012 Distribution Cutout Replacement	Distribution Plant		open	2,596,796	1,339,432	
41426	2012 Transmission Switch & Breaker	Transmission Plant		open	2,000,849	172,570	
41429	2012 Substation PCB Equipment Removal	Transmission Plant		open	1,854,665	277,008	
41430	2012 Subst. Recloser Replacement	Transmission Plant		open	2,120,686	1,109,793	
41432	L7009 Lidar Upgrades & Maintenance	Transmission Plant		open	2,942,809	595,477	
39932	TRE - Ash Site Phase 2 Development	Steam Generation Plant		open	5,783,337	2,144,755	
40317	1H Transformer & Breaker Addition	Transmission Plant		open	4,267,698	397,020	
40403	Work & Asset Management	General Plant		open	5,804,918	2,858,361	
40282	HYD- Coon Pond Dam Refurbishment	Hydro Generation Plant		open	2,595,361	134,119	

Projects Not Approved by the UARB

CI	Project	Functional Class	In Service Date	Work Order Status	UARB Approved $	Project Spend to Date (May 31, 2012)	Notes
41537	Amherst 138kV Substation	Transmission Plant		in service		498,050	
41534	2012 Reliability Technologies Distribution	Distribution Plant		open		62,502	
41797	Brier Island Crossing	Distribution Plant		open		16,293	
41766	Commercial AMI Pilot	General Plant		open		14,602	
41845	Residential AMI Pilot	General Plant				14,602	
18448	TUC - Cooling Water System Biofouling Control	Steam Generation Plant				11,492	
38868	HYD Marshall Falls Hydro Station	Hydro Generation Plant				377,396	
41126	HYD Annapolis - Sluiceway and Powerhouse Stop Log Refurbishment	Hydro Generation Plant				120,836	
41519	Harbour East 138 kV Transmission Line	Transmission Plant				23,509	
41520	Harbour East Substation - Eastern Passage	Transmission Plant				-	
40320	LED Street Light Conversion	Distribution Plant				-	
41534	2012 Reliability Technologies Distribution	Distribution Plant				62,502	
40314	Main Computer Centre Upgrade	General Plant				254,893	
40278	OMS Upgrade 2011	General Plant				47,274	
40648	Field Mobility System	General Plant				-	

NON-CONFIDENTIAL

Request IR-12:

With respect to the rate of return earned:

a) Please identify the actual rate of return that has been earned in each of the past 10 years.
b) Please state the allowed range of ROE for each of the past 10 years.
c) Please identify all years where the rate of return earned has been less than the minimum allowed.
d) How many of those years in which the rate of return was achieved, were funded, at least partially, with the assistance of amended tax filings?

Response IR-12:

(a-b) Please refer to Booth IR-3 Attachment 1.

(c) In the last ten years, actual return on equity (ROE) was lower than the allowed range in 2004, 2005, and 2007.

(d) In the last ten years, there were four years where tax amendments for prior years were recorded. Of those four years only two years rate of return was achieved partially due to including the results of amended tax filings.

CONFIDENTIAL (Attachment Only)

Request IR-13:

Please provide policy documentation related to what is permitted in rate base and what approvals are required prior to inclusion in rate base for purposes of earning a return.

Response IR-13:

Please refer to Attachment 1 and to NSUARB IR-9. Through rate application decisions, the Board has approved the inclusion of rate base items. Please refer to Attachment 2 for 2012 GRA NSPI (NPB) IR-80 and Partially Confidential Attachment 3 for 2012 GRA NSPI (NPB) IR-158 that detail specific rate base items.

GENERAL INFORMATION

RATE BASE - 1520

DEFINITION

01 Rate base is comprised of the net value of certain assets upon which Nova Scotia Power Inc. ("NSPI") can earn a specified rate of return. The rate base and rate of return are approved by the Nova Scotia Utility and Review Board ("UARB") in compliance with the Public Utilities Act.

02 The rate base and the allowed rate of return are periodically reviewed by the UARB.

POLICIES

03 The components of rate base should include:

a. Cost (gross historical cost less capital contributions) less accumulated depreciation of used and useful plant in service;

b. Construction Work-in-Progress;

c. Allowance for materials and supplies;

d. Allowance for working capital;

e. Deferred charges and credits;

f. Contract receivable resulting from the settlement between NSPI and its natural gas supplier.

04 The excess of the purchase price paid for an acquired company over the amount to be included in rates as approved by the UARB should be excluded from rate base.

05 Assets held for future use should be excluded from rate base unless UARB approval has been obtained.

NON-CONFIDENTIAL

Request IR-80:

In reference to Figure 7.2 please provide copies of the excerpts from the UARB which allowed recovery of these deferred charges or credits. Also, please provide a detailed description of each deferred account and the circumstances why it was established.

Response IR-80:

Defeasance & Finance Charges:

Please refer to Attachment 1 for a copy of the relevant excerpt from the UARB's decision from the 1993 Rate Decision[1].

Defeasance: Upon privatization in 1992, NSPI became responsible for managing a portfolio 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 as permitted by the UARB.

Financing issue costs: Included in financing issue costs are unamortized debt financing costs, discounts and premiums which are amortized over the term of the related debt.

Section 21 and Q1 2005 taxes:

NSPI's 2007 GRA applied for approval of the recovery of the deferral of the Section 21 taxes and Q1 2005 taxes in customer rates. NSPI and stakeholders entered into a settlement agreement with respect to the 2007 GRA. Please refer to Attachment 2 for a copy of the Minutes of Settlement. Paragraph 8 confirms that the parties agreed to no changes from NSPI's Application

[1] NSPI 1993 Rate Case, UARB Decision, NSUARB-NSPI-P-863, March 24, 1993, pages 24-25.

for rate base, return on rate base, return on equity, OM&G, regulatory amortization and income taxes. The UARB's decision of February 5, 2007[2] approved this settlement.

NSPI has a 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 deductions in its corporate income tax returns that were ultimately disallowed by a decision of the Supreme Court of Canada. In its February 2007 decision, the UARB approved recovery of this regulatory asset over eight years, commencing April 1, 2007.

Prepaid Pension Asset:

Please refer to Attachment 3 for a copy of UARB-approved, NSPI Accounting Policy 2400.

Fuel Adjustment Mechanism:

Please refer to Attachment 4 for a copy of the relevant excerpt from the UARB's decision approving the FAM[3]. Please also refer to Attachment 5 for a copy of the UARB-approved NSPI Accounting Policy 5110.

Asset Retirement Obligations:

Please refer to Attachment 6 for a copy of UARB-approved NSPI Accounting Policy 6320.

Asset retirement obligations ("ARO") are recognized when incurred and represent the fair value, using the Company's credit-adjusted risk-free rate, of the Company's estimated future cash flows necessary to discharge legal obligations related to reclamation of land at the Company's thermal, hydro and combustion turbine sites, and disposal of polychlorinated biphenyls ("PCBs") in its

[2] 2007 Rate Case, UARB Decision, NSUARB-NSPI-P-886, February 5, 2007.
[3] 2009 Rate Case Decision, NSUARB-NSPI-P-888, November 5, 2008, paragraphs 126-136.

transmission and distribution equipment. Estimated future cash flows are based on the Company's completed depreciation studies, prior experience, estimated useful lives, governmental regulatory requirements and the costs of activities such as demolition, restoration and remedial work based on present-day methods and technologies. Actual results may differ from these estimates.

Future Income Taxes:

Paragraph 5 of NSPI Accounting Policy 5110 (Attachment 5) states:

> Future income tax is recorded on the FAM Regulatory Asset (Liability) balance resulting in a future income asset or liability. The income tax expense (recovery) is recorded based on NSPI's applicable statutory income tax rates for the period expected to apply when the 'FAM Regulatory Asset (Liability)' reverses.

Please also refer to Attachment 7, UARB-approved NSPI Accounting Policy 5900. Paragraph 5 states:

> The Company will recognize a deferred regulatory asset (liability) related to FAM. Deferred income tax expense (benefit) and a corresponding deferred income tax (liability) asset related to the FAM will be recognized based on the enacted income tax rate(s) for the period(s) when the FAM regulatory asset (liability) is expected to reverse.

Please also refer to Attachment 8 which discusses Future Income Taxes treatment under FAM.

Other:

The three main accounts in this category are Vegetation Management, DSM and Renewable Energy Deposits.

NON-CONFIDENTIAL

Please refer to Attachment 9 for a copy of the excerpt from the UARB decision approving the DSM deferral[4]. Please refer to Attachment 10 for a copy of the UARB decision approving the vegetation management deferral[5].

The UARB agreed to allow NSPI to defer up to $12.8 million of demand side management expenditures for the period January 1, 2008, through December 31, 2009, to be recovered in rates over six years commencing January 1, 2009.

The UARB agreed to allow NSPI to defer up to $2.0 million of vegetation management spending in 2008 to be recovered in rates in a future period. The investment in vegetation management spending was part of a specific initiative to improve the reliability of service provided to customers.

Renewable Energy deposits accounts relate to study deposits received from interconnection customers as part of the Generator Interconnection Procedures and deposits related to contractual obligations.

[4] 2009 Rate Case Decision, NSUARB-NSPI-P-888, November 5, 2008, paragraph 107.
[5] UARB correspondence to NSPI, March 12, 2008; P-401.32.

Productivity Improvement

In a January, 1992 news release issued by Nova Scotia Power Corporation announcing its privatization, Mr. Comeau is stated to have said that "He believes privatization will encourage the company to achieve further efficiencies and better cost control, ultimately leading to lower rates than otherwise would have been the case".

The Board expects the Company to proceed aggressively with its cost control efforts. The Company will be expected to present tangible evidence at its next rate hearing that real success is being achieved in controlling expenses and improving productivity. The Board will expect the Company to achieve these improvements without detrimentally affecting customer service.

Capital Structure

The Board views a range of 8%-10% for preferred share capital and a range of 33%-35% for common share capital to be appropriate.

Debt Defeasance

The Board accepts the argument that the debt defeasance expense is one which was imposed on the Company by the government. It is a legitimate expense in lieu of the Provincial Government guarantee. The net expense, if any, to be recovered from rates, will not impose an undue burden on its customers.

The Board retained R. A. Radchuck, F.C.A., of Peat Marwick Thorne to review the proposals and calculations of NSPI with respect to debt defeasance. He concluded that the net cost of defeasance will be more than offset, over the life of the program, by reductions in interest expense, and that, therefore, "it is possible, at this time, to assume that the net cost of defeasance over the full term of the debt (with the exception of future issues) would be minimal".

The Board will allow NSPI to recover the imposed cost of defeasance through customers' rates. The increase in book value of the debt, the issue cost of the new debt and the acquisition cost of the defeasance assets are to be written off on a specific issue basis over the term of the new debt issues.

Deferral of Point Aconi Costs

In view of the Company's forecast of changes in the yearly revenue requirement, the Board accepts the proposed plan for deferring the recognition of certain costs of the Point Aconi generating station.

Return on Common Equity

In reviewing the evidence presented by Ms. McLeod, the Board has several concerns. The criteria used in selecting companies for the **comparable earnings** test appear to favour consistently good performers. In order for the necessary calculations to be made, the companies selected could not have negative earnings. Although the market-to-book ratio of the sample is very high and shows earnings well in excess of the cost of capital, no downward adjustment was made.

These factors bring into question her conclusion that "the returns earned by the sample of 16 unregulated corporations can be viewed generally as the returns that an investor in NSPI would otherwise have available from an investment of comparable risk", because the investor would need to know in advance how to exclude companies that might show a loss.

A further concern with her **comparable earnings** methodology is that actual performance was used for the years 1982-1991 and projected returns for 1992 and 1993. The Board considers it inappropriate to include projections when performing comparable earnings analysis. The probable error

2006 NOVA SCOTIA UTILITY AND REVIEW BOARD P-886

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

- and -

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

MINUTES OF SETTLEMENT

WHEREAS the Applicant, Nova Scotia Power Inc. ("NSPI"), the undersigned Intervenors (Avon Valley et al, the Consumer Advocate, the Halifax Regional Municipality, and the Municipal Electric Utilities Co-operative of Nova Scotia), and the staff of the Nova Scotia Utility and Review Board, have reached agreement on the matters in issue in this Application;

AND WHEREAS this Agreement is subject to review and approval by the Nova Scotia Utility and Review Board;

THE UNDERSIGNED PARTIES ("the parties") HEREBY AGREE and respectfully request the Utility and Review Board ("UARB") to approve:

1. NSPI's 2007 test year revenue requirement is set at $1,159.5 million, with new rates effective April 1, 2007.

2. NSPI's 2007 forecasted fuel expense is set at $470 million, with the natural gas margin set at $47 million. In the event NSPI's actual natural gas margin does not achieve a level of $47 million, NSPI may defer for later recovery in rates any difference, down to $39 million, for a maximum deferral of $8 million.

3. The third year of the phase in of depreciation rates is deferred for recovery in the next general rate application.

4. All parties agree in principle that the UARB should adopt a Fuel Adjustment Mechanism ("FAM"). The parties request the UARB to establish a process that commences as soon as possible to establish a FAM. The parties will work constructively on the content or elements of a FAM. A FAM hearing will begin no later than July 15, 2007.

5. NSPI shall file with the UARB and the parties (subject to the usual undertakings regarding confidentiality), on or before October 31, 2007, an updated forecast for fuel and purchased power and other significant projected cost changes for 2008.

Any of the parties may ask the UARB to consider whether there should be a proceeding to adjust rates for 2008.

6. Excess earnings by NSPI, if any, in 2007 and 2008 will be applied to the S21 unamortized balance.

7. NSPI's request for a deferral of first quarter 2007 fuel costs is withdrawn.

8. There are no further changes to NSPI's Application including: rate base and return on rate base, return on equity, OM&G, regulatory amortizations and income taxes.

9. NSPI's request for a true-up for the 2P-RTP is deferred to the December 1 annual review of the ELI 2P-RTP rate.

10. The UARB directive from the 2006 Rate Case regarding the study of NSPI's OM&G is not deemed to be completed by this Agreement.

11. The Revenue to Cost ratio methodology as described by Dr. Stutz at pages 15 and 16 of his December 20, 2006 Evidence will be adopted, except for modifications to incorporate a change to the unmetered rate class, for which the combined C3 weighting factor will be .82 for billing services and call centres.

12. Subject to paragraph 4, above, this agreement does not preclude NSPI or any of the parties from taking any positions in future regulatory proceedings.

AGREED, and signed by legal Counsel or other authorized representative, THIS 21st DAY OF JANUARY, 2007.

Nova Scotia Power Inc.

Per: Rene Gallant

Avon Valley et al

Per: Robert G. Grant, Q.C.

Consumer Advocate

Per: John Merrick, Q.C.

Halifax Regional Municipality

Per: Martin C. Ward, Q.C.

Municipal Electric Utilities Co-operative Of Nova Scotia

Per: Don Regan

UARB Staff

Per: Bruce Outhouse, Q.C.

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Nova Scotia Power Inc.	**Avon Valley et al**
Per: Rene Gallant	Per: Robert G. Grant, Q.C.
Consumer Advocate	**Halifax Regional Municipality**
Per: John Merrick, Q.C.	Per: Martin C. Ward, Q.C.
Municipal Electric Utilities Co-operative Of Nova Scotia	**UARB Staff**
Per: Don Regan	Per: Bruce Outhouse, Q.C.

GENERAL

01 The Company maintains contributory defined-benefit and defined-contribution pension plans that cover substantially all employees, and plans providing non-pension benefits for its retirees.

02 The 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.

03 Other retirement benefit plans include: unfunded pension arrangements, unfunded long service award and contributory health care plan.

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

POLICIES

05 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 service and management's best assumptions. The projected benefit obligation is valued based on market interest rates at the valuation date.

06 Adjustments to the projected benefit obligation arising from plan amendments are amortized on a straight-line basis over the expected average remaining service period (“ARSP”) of active employees.

07 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 asset gains and losses over a five-year period.

08 For any given year, when Nova Scotia Power Inc’s (“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 projected benefit obligation and the market-related value of the plan assets, an amount equal to the excess divided by the ARSP is amortized on a straight-line basis.

09 On January 1, 2011, NSPI adopted the US accounting standard on employee future benefits retrospectively with restatement.

10 Plan surpluses are recognized as assets and plan deficits are recognized as liabilities on the balance sheet. The difference between plan surplus (deficits) and accrued benefit assets (liabilities) is recognized in accumulated other comprehensive income.

PROCEDURES

11 Actuarial valuations are performed annually for all plans.

12 Pension expense, as determined in the annual actuarial valuation, is charged to both operating departments and corporate adjustments.

13 Pension funding for pre-funded plans are paid as determined in an annual actuarial valuation.

14 Pension plan assets are invested by fund managers. Monthly statements are provided by the trustee showing asset market values, investment income, pension benefits, refunds of contributions and plan expenses.

15 A Statement of Net Assets and a Statement of Changes in Net Assets for all pension plans are prepared quarterly. These statements show pension asset market values, contributions receivable, accounts payable, investment income, changes in market values, contributions received, pension benefits paid, refunds of contributions and plan expenses.

16 For the defined benefit pension plan, employee contributions for current service are matched by NSPI through the payroll system and remitted to the trustee for investment by fund managers. Additional employer contributions for current service and/or past service, where required, are also remitted to the trustee for investment by the fund managers.

17 For the defined contribution pension plan, employee and employer contributions are remitted to a pension plan administrator and invested according to instructions provided by the employee.

18 For the defined benefit pension plan, administrative expenses are paid by NSPI and reimbursed from the pension fund through requests to the trustee.

10.4 Submissions - Board Consultants

[123] Both Dr. Stutz and Mr. Antonuk indicated in their testimony at the hearing that they are satisfied the FAM is ready to be implemented.

[124] Dr. Stutz concluded in his Statement:

> Sections 1 to 8 of the Agreement deal with the Fuel Adjustment Mechanism (FAM). I agree that the FAM is substantially complete. The arrangements to finalize it provided in the Agreement are reasonable and appropriate. I know of no "unsettled issue" likely to prevent the FAM from coming into operation on January 1, 2009.
>
> [Stutz Statement, Exhibit N-75]

[125] In his testimony, Mr. Antonuk of Liberty indicated that it is appropriate to implement the FAM at this point and that three remaining issues can be resolved prior to its implementation:

> Yes. We believe that that is appropriate and it's difficult to see the settlement operating without the adoption of a FAM based on the way it's structured, and I think its structure clearly contemplates that. For our part, we're optimistic that while there remain issues to be resolved with respect to the FAM that those can and should, and I hope will, be resolved by the parties amicably. In the event they're not, I think they're the kinds of issues that are clearly amenable to prompt and effective resolution by the Board in any event. And those issues are three. One is the use of the API-4 index for performing the forecast of solid fuels. We're in agreement with the NSPI proposal to use that forecast but want that forecast use to be revisited in approximately a year. I believe we actually have agreement on that at the present time but it's not yet committed to writing. The second issue is that we are still working on language that addresses the degree to which there will or won't be consultation by the fuel auditor prior to the commencement of the fuel audits called for by the FAM, and the third is the method to be used for estimating import power sales, and on those latter two discussions -- or issues, discussions have been active among the FAM collaborative participants and I expect those discussions to continue and hopefully to be resolved in the immediate future.
>
> [Transcript, September 18, 2008, pp. 130-131]

10.5 Findings

[126] The implementation of the FAM received full support from the signatories to the Agreement, effective January 1, 2009. In clause 3 of the Agreement, the parties undertake to finalize the FAM documentation and NSPI agrees to file, for Board approval,

a final Tariff and Plan of Administration no later than October 15, 2008. Those documents have been filed and are under review by the Board. The Base Cost of Fuel is proposed to be set at $545 million in 2009 rates.

[127] Further, the Board observes that implementation of the FAM was not opposed by the formal intervenors who did not sign the Agreement.

[128] In their testimony at the hearing, Dr. Stutz and Mr. Antonuk, the Board's consultants, agreed that it was appropriate to implement the FAM at this point. While a few points remain outstanding, they are confident that any such items can be resolved prior to the proposed implementation date.

[129] In this regard, the Board observes that the development of the FAM has followed an extensive collaborative process between NSPI and its stakeholders. The Board's consultants were also involved throughout the entire process. All parties involved in this consultative exercise expressed their general satisfaction with the preliminary Plan of Administration filed with the Board in June 2008.

[130] In its Rate Decision dated February 5, 2007, and in its Decision dated December 10, 2007 giving conditional approval to the FAM, the Board identified at least four prerequisites prior to the implementation of a FAM:

> ...
>
> 1. an adequate and appropriate fuel procurement policy at NSPI in which the Board has confidence;
>
> 2. timely disclosure of complete and adequate information by NSPI so as to ensure confidence that the procurement policy is being appropriately administered;
>
> 3. disclosure and transparency with respect to the administration of the FAM;
>
> 4. a meaningful audit process under the administration of the Board.
>
> [Board Decision, P-887, December 10, 2007, para. 45]

[131] Based upon its review of the evidence and the submissions of the parties, the Board is satisfied that these prerequisites have been fulfilled. The consultative process has also addressed other issues.

[132] The Board is mindful of the concerns of NSPI's customers with respect to the implementation of a FAM. While some may contend that a FAM could result in reduced transparency and less oversight, the reality is quite the opposite. Any future adjustments to the Base Cost of Fuel will occur in an even more transparent manner than is presently the case. Under the FAM, the fuel forecasting process will be subjected to more periodic review by the Board and intervenors.

[133] The Board refers to its previous comments on these points:

> [76] The Board views a FAM as a tool which can actually provide a closer and more timely oversight of NSPI's fuel costs than is presently the case. As noted elsewhere in this decision, under a FAM, assessments as to the reasonableness of fuel expenses and NSPI's performance in obtaining fuel at the lowest price reasonably possible, will be carried out by the Board, as well as Intervenors, on an ongoing and more frequent basis than in the past. In the last ten years, this form of fuel costs examination has occurred four times—always in conjunction with general rate applications. Under a FAM, fuel costs will be determined on an annual basis, following the reporting, analysis and stakeholder involvement in the FAM process throughout the preceding year, which forms the basis for any adjustment.
>
> [77] Customers should also understand that, under a FAM, the rate they pay to NSPI will not go up and down every time the cost of fuel fluctuates. In other words, a FAM will not operate in the same manner as they experience at the gas pumps, where prices can change every week.
>
> [78] Even under the proposed January 1, 2009 implementation date of the FAM, the earliest time a fuel adjustment change to rates could possibly occur would be January 1, 2010. Also, it could only occur then if the previous year's fuel costs passed all the reporting, auditing, and review tests designed to ensure that the cost to be passed on to ratepayers is as low as reasonably possible—a result which, in the Board's opinion, improves its ability to protect the public interest.
>
> [Board Decision, P-887, December 10, 2007, paras. 76-78]

[134] The Board also observes that the implementation of the FAM is accompanied by a 0.2% reduction in the return on equity that can be earned by NSPI (i.e., the target

ROE will decrease from 9.55% to 9.35%). The lower return on equity results in a reduced revenue requirement to be recovered in customers' rates.

[135] Finally, there is a further benefit of a FAM for customers. The implementation of the FAM will allow NSPI to recover its prudently incurred fuel costs. This, in turn, will lower NSPI's business risk profile and foster the improved financial health of the utility over the long term, which could possibly lead to an improved outlook from bond-rating agencies and cause them to upgrade their rating for NSPI. Ultimately, this could benefit ratepayers by reducing NSPI's debt and interest charges, possibly lessening the pressure for rate increases in the future. An improved rating could also positively impact NSPI's ability to procure fuel commodities and to access capital markets for upcoming infrastructure projects.

[136] Taking into account all of the foregoing, the Board approves the FAM, on the basis of the provisions contained in the Agreement. The FAM shall take effect on January 1, 2009, conditional on the final approval of the Tariff and Plan of Administration.

11.0 WRITTEN AND ORAL SUBMISSIONS FROM THE PUBLIC

[137] In the advertised Notice of Public Hearing concerning NSPI's rate application, the public was advised that they could file submissions with the Board outlining their views regarding NSPI's application. In response to this notification, the Board received thirty-one written submissions from the public, plus six individuals made presentations at the evening session on September 17, 2008.

BACKGROUND

01 The Nova Scotia Utility and Review Board ("UARB") approved the implementation of a Fuel Adjustment Mechanism ("FAM") in the 2009 General Rate Decision effective January 1, 2009.

DEFINITION

02 The FAM includes the difference between actual fuel costs and amounts recovered from customers in the current period and in the two preceding years. The following are the components of the FAM:

a) Base Fuel Costs - Customer rates are set to recover the base amount of fuel costs. The differences between NSPI's actual fuel costs and the fuel costs recovered through the base fuel cost (i.e. what is charged and recovered from consumers) accumulate each month in the FAM as a Regulatory Asset (if NSPI under recovers actual fuel costs) or as a Regulatory Liability (if NSPI over-recovers actual fuel costs). The fuel base rate is reset every two years through a formal regulatory process or during a general rate application.

b) Actual Adjustment ("AA") – The AA results from dividing the previous year's FAM Regulatory Asset (Liability) balance by the current year's sales forecast. The AA is used in determining the current year's electricity rates. As amounts are recovered (rebated) from (to) customers in the current year, the remaining balance of the AA amount decreases.

c) Balance Adjustment("BA") - The BA is the residual amount of the AA related to subsequent years that was not fully recovered through the AA, which is based on sales forecasts. The BA rate is established similar to the AA rate using the cumulative remaining FAM Regulatory Asset (Liability) balance divided by forecasted sales for the period. Any residual BA balance at the end of a period is applied to the subsequent year and used in the determination of future BA rates.

d) Incentive (discentive) - On the accumulated FAM amount under or over-recovered in any given year, before interest, an amount of 10% of the amount less the difference between the incentive threshold and the base fuel costs, to a maximum of five million dollars will be calculated and will reduce (increase) the FAM Regulatory Asset (Liability) balance and fuel adjustment on the Statement of Earnings.

POLICIES

03 Differences between actual fuel costs and amounts recovered from customers accumulate in the FAM Regulatory Asset (Liability) included in "Other Assets" or "Other Liabilities" on the Balance Sheet and subsequently become an adjustment (either an addition or deduction) to the subsequent year's electricity rates.

04 Interest is earned at the current year's weighted average cost of capital ("WACC") compounded semi annually on the accumulated FAM Regulatory Asset (Liability) balance. NSPI earns the interest on a

Regulatory Asset and the customer earns the interest on a Regulatory Liability. The interest accumulates in the FAM Regulatory Asset (Liability) account.

05 Future income tax is recorded on the FAM Regulatory Asset (Liability) balance resulting in a future income asset or liability. The income tax expense (recovery) is recorded based on NSPI's applicable statutory income tax rates for the period expected to apply when the 'FAM Regulatory Asset (Liability)' reverses.

06 The incentive (discentive) is determined at the end of each year. Each quarter an accrual is recorded based on forecasted sales and fuel expenses for the remainder of the year.

07 The balance accumulated in the FAM Regulatory Asset (Liability) includes the incentive (disincentive) component of the FAM and any interest.

08 The revenue related to the fuel under or over recovery in the current year is not billed and collected until subsequent years. Revenue is therefore recognized when the FAM is billed or refunded to customers.

09 Customer rates to recover (refund) the FAM Regulatory Asset (Liability) balance are approved by the UARB. A regulatory filing which includes 10 months of actual results and two months of forecast data is filed in November of each year for rates effective January 1st of the subsequent year. Differences in forecast amounts for the two months are recovered through the BA.

PROCEDURES

10 The FAM Regulatory Asset (Liability) is recorded on the balance sheet with Other Assets (Liabilities). The interest and incentive is accumulated to the FAM Regulatory Asset (Liability). The effect of income tax is recorded on the balance sheet as a Future Income Tax Asset or Liability.

11 The FAM is recorded on the income statement as an addition or deduction to expenses referred to as Fuel Adjustment. The Fuel Adjustment reflects the net amount of over or under-recoveries from the current year's base fuel costs, including the incentive, the recognition of AA amounts from the prior year and the recognition of BA amounts from two years ago.

12 Revenues associated with the recovery (rebate) of FAM fuel costs are reported as electric revenues. The interest associated with the FAM Regulatory Asset (Liability) is recorded as interest income or interest expense.

DEFINITION

01 An asset retirement obligation is an obligation associated with the retirement of a tangible long-lived asset that an entity is required to settle as a result of an existing or enacted law, statute, ordinance, or written or oral contract or by legal construction of a contract under the doctrine of promissory estoppel.[1]

GENERAL

02 The present value of this estimated future expenditure is recognized as a liability with an equivalent amount added to the carrying amount of the associated fixed asset consistent with *FASB ASC 410-20.*

03 The Nova Scotia Utility and Review Board ("UARB") provided a depreciation order effective January 1, 2004 approving the amount of future expenditures associated with the removal of long-lived assets. Any difference between the amount approved by the UARB as depreciation expense and the amount that is calculated under GAAP is recognized as a regulated asset.

POLICY

04 A liability for an asset retirement obligation should be recognized when a reasonable estimate of fair value can be made.[2]

05 Upon initial recognition, the carrying amount of the related long-lived asset will be increased by the same amount as the asset retirement liability. Subsequently, asset retirement costs will be allocated to expense using a systematic and rational method over the useful life of the asset.[3]

06 After initial recognition, period-to-period changes in the liability should be recognized in the liability for the asset retirement obligation resulting from passage of time and revisions to either the timing or the amount of the original estimate.[4]

[1] FASB ASC 410-20-15-2
[2] FASB ASC 410-20-25-4
[3] FASB ASC 410-20-35-2
[4] FASB ASC 410-20-35-3

NOVA SCOTIA POWER
An Emera Company

COST OF OPERATIONS

INCOME TAXES - 5900

POLICY

01 Income tax expense should be categorized as current or deferred income tax expense as appropriate.

02 The Company uses the applicable enacted tax rate when measuring current and deferred income tax expense.

03 The Company follows the flow-through method of accounting for investment tax credits (“ITC’s”). ITC’s are recorded in the year earned as a reduction to income tax expense to the extent that realization of such benefit is more likely than not.

04 The Company recognizes deferred income tax assets (liabilities) as appropriate. To the extent deferred income taxes are expected to be recovered from or returned to customers in future rates, the Company will recognize a deferred regulatory asset (liability)[1]

05 The Company will recognize a deferred regulatory asset (liability) related to FAM. Deferred income tax expense (benefit) and a corresponding deferred income tax (liability) asset related to the FAM will be recognized based on the enacted income tax rate(s) for the period(s) when the FAM regulatory asset (liability) is expected to reverse.

FEDERAL INCOME TAXES

06 The Company is subject to federal income tax at prescribed rates applied to taxable income.

PROVINCIAL INCOME TAXES

07 The Company is subject to provincial income tax at prescribed rates applied to taxable income.

TAX ON LARGE CORPORATIONS

08 The Company is subject to a provincial capital tax (“PCT”) at prescribed rates applied to taxable capital.

PART VI.1 TAX

09 The Company is subject to Part VI.1 tax at a prescribed rate applied to preferred share dividends paid. The Company receives a tax deduction equal to a prescribed multiple of the Part VI.1 tax.

1 FASB ASC 980-740-25-2

INCOME TAXES - 5900

NOVA SCOTIA POWER
An Emera Company

PROCEDURES

10 A monthly income tax provision is recorded by multiplying the Company's effective combined federal and provincial income tax rate forecasted for the year (calculated without inclusion of the forecasted FAM adjustment) by the net earnings before tax for the period. The monthly income tax provision with respect to FAM is based on the actual FAM adjustment for the period multiplied by the enacted tax rate.

11 The Company prepares an estimate of its taxable capital using a forecasted year-end balance sheet. The taxable capital forecast is then multiplied by the enacted tax rate to determine the PCT expense for the year. The PCT estimate is prorated based upon days to determine the amount to accrue each month.

12 The net Part VI.1 tax is calculated using enacted rates and recorded as an additional cost (recovery) of the preferred share dividend. It is reclassified to current income tax expense for external reporting purposes. The monthly Part VI.1 tax expense is based on the amount of preferred dividends declared in the month. The monthly Part VI.1 tax deduction is based on the annual forecasted Part VI.1 deduction prorated based upon the total preferred dividends declared in a month.

13 The Company currently follows the policy of claiming sufficient capital cost allowance and cumulative eligible capital (the tax system's equivalent of depreciation and amortization), to minimize taxable income.

14 Federal and provincial income taxes are included in general ledger account 086 - Income Tax Expense and Provincial Capital Tax is included in account 067. The net Part V1.1 tax is included in general ledger account 786 – Tax on Preferred Dividends.

NOVA SCOTIA POWER
An Emera Company

March 23, 2009

Nancy McNeil
Clerk of the Board
Nova Scotia Utility and Review Board
1601 Lower Water Street, 3rd Floor
P.O. Box1692, Unit "M"
Halifax, NS B3J 3S3

Dear Ms. McNeil,

Effective January1, 2009, NSPI implemented the fuel adjustment mechanism (FAM) that was approved by the UARB in the 2009 Rate decision. Attached is a description of how NSPI will be accounting for the mechanism. NSPI requested Grant Thornton to review the proposed accounting treatment related to the FAM and they concluded the following:

> we wish to confirm we are in agreement with the conclusions and positions taken by management and that the proposed accounting treatment is appropriate under Canadian generally accepted accounting principles.

Attached is a description of the accounting treatment for the FAM and a letter from Grant Thornton confirming NSPI's position.

We respectfully submit the FAM accounting description for information.

I would be pleased to have our accounting personnel and advisors meet with the Board, or its designates, at the Board's convenience if the Board would consider this helpful.

For more information, please do not hesitate to contact the undersigned.

Regards,

GBlunden

Greg Blunden, CA
Vice President Finance & Treasurer
Nova Scotia Power Inc.

Attach.

cc: Rene Gallant
Claudette Porter
Eric Ferguson

Fuel Adjustment Mechanism Overview

The purpose of this document is to provide an overview of the approved Fuel Adjustment Mechanism as well as, management's position on the associated accounting and financial reporting implications.

Background

The Nova Scotia Utility and Review Board approved the implementation of a Fuel Adjustment Mechanism (FAM) in the 2009 General Rate Decision effective January 1, 2009. The FAM is being established to mitigate the effects of volatile fuel costs on the electricity rates paid by the customers of Nova Scotia Power Incorporated (NSPI). The FAM design protects the financial integrity of the Company and delivers timely price signals to customers to promote efficient use of electricity. Differences between actual fuel costs and amounts recovered from customers will accumulate in the FAM deferral account and subsequently become an adjustment (either an addition or deduction) to the following year's electricity rates.

Components of the FAM

- Base Fuel Cost

  In the implementation year, 2009, the difference between NSPI's actual fuel costs and the fuel costs recovered through the base fuel cost (i.e. what is charged and recovered from consumers) will accumulate each month in the FAM as a regulatory asset (if NSPI under-recovers actual fuel costs) or as a regulatory liability (if NSPI over-recovers actual fuel costs). In each month of under-recovery, the 'FAM Regulatory Asset' will be debited and an account called 'Amortization of Fuel Expense' is credited. This will effectively increase assets and decrease expenses (therefore increase equity). The opposite occurs in the case of over-recovery. For 2009, the base fuel cost is set at $545 million ($42.41 per MWh). Customer rates are set to recover this base amount of fuel cost.

  Revenue associated with the deferred balance is not considered earned at this point due to it not meeting the three general criteria as outlined in CICA Handbook Section 3400 Revenue. The earnings process must be complete, measurability is reasonably assured, and collectability is reasonably assured. "Performance should be regarded as having been achieved when reasonable assurance exists regarding the measurement of the consideration that will be derived from rendering the service or performing the long-term contract" (CICA HB 3400.08). In particular, it is the lack of measurability that prevents revenue related to the fuel under or over recovery from being recognized in 2009 as it will not be billed and collected until 2010.

- Interest

  As the FAM regulatory asset or liability accumulates, interest is earned at the current year's weighted average cost of capital (WACC) based on the principles applied in calculating the Allowance for Funds Used During Construction (AFUDC), by either NSPI (in the case of a regulatory asset) or the customer (in the case of a regulatory liability). The interest will accumulate in the FAM regulatory asset or liability account. In the case of under-recovery, the 'FAM Regulatory Asset' is debited and AFUDC is credited. The opposite entry occurs in the case of over-recovery.

- Incentive

  There is an incentive portion of the FAM to encourage NSPI to effectively manage fuel costs. On the accumulated FAM amount under or over-recovered in any given year, before interest, an amount of 10% of the amount less the difference between the incentive threshold and the base fuel costs, to a maximum of five million dollars will be calculated and will reduce the regulatory asset or liability and amortization of fuel expense. The incentive is determined at the end of each year. For reporting purposes, an accrual will be reviewed on a quarterly basis and reassessed based on forecasted sales and fuel expenses for the remainder of the year. For 2009, the incentive threshold is calculated using a base fuel cost amount of $590 million ($45.95 per MWh)

  For example: For 2009, in the case of an under-recovery (regulatory asset) of $60 million, 10% of the under-recovered amount ($60 million) less the difference between the incentive threshold of $590 million and base fuel cost of $545 million (i.e.($60-$45)x10% or $1.5 million) would be credited to the 'FAM Regulatory Asset' and debited to 'Amortization of Fuel Expense'.

- Income taxes

  As a regulated entity, historically NSPI followed the taxes payable method of accounting for its income tax. Beginning in 2009 the Company is required to record future income taxes in accordance with CICA 3465 Income Taxes.

  Currently, the reported income tax expense is based on the current income tax paid. For purposes of reporting the FAM, NSPI will record the future income tax impact by recognizing either a future income asset or liability. The income tax expense (recovery) will be recorded based on NSPI's applicable statutory income tax rates for the period expected to apply when the 'FAM Regulatory Asset (Liability)' reverses.

  Recovering the FAM on a net of tax basis is aligned with the regulatory revenue principles in determining customer rates for the FAM adjustment. The FAM mechanism for setting customer rates and ultimately determining NSPI's revenues reflects a recovery (refund) of fuel costs and associated interest carrying costs excluding any tax effects. This is unique as the rate setting mechanism for recovering other deferred regulatory assets typically includes a full general rate application which inherently reflects the associated tax effects. It is anticipated that if NSPI did not record an income tax provision associated with the FAM, NSPI's effective tax rate would be volatile and would be in contradiction to the fundamental design of the FAM.

NSPI's income tax accounting policy will be amended to incorporate the addition of the FAM. This will include a specific paragraph reference to the income tax treatment. A draft of the amended income tax policy is included as an attachment.

At year end, the under or over-recovered amount, with interest and incentive adjustment net of income taxes will be the total FAM deferral amount for 2009 recorded on NSPI financial statements. For purposes of establishing customer rates to recover (refund) the balance before taxes, a regulatory filing including 10 months of actual results and two months of forecast data will be processed in November of each year for rates effective January 1st of the subsequent year. Differences in forecast amounts for the two months will be recovered through the 'Balance Adjustment'.

2010 Rate ($/Kwh) = Base Rate ($/Kwh) +/- [2009 FAM Amount ($) / 2010 Sales Forecast (Kwh)]

- Actual Adjustment

The result of dividing the 2009 FAM balance by the 2010 sales forecast is called 'Actual Adjustment', or AA. This is the adjustment used to determine the 2010 electrical rate. As amounts are recovered from customers in 2010, the balance of the AA amount decreases. Revenue is now considered earned and is recorded. The associated expense deferred from 2009 can now be amortized in 2010. The 'FAM Regulatory Asset' is credited and the 'Amortization of Fuel Expense' is debited. Revenues are credited as earned and accounts receivable/cash are debited.

Throughout 2010 while recovering the AA amount related to 2009, the regulatory asset or liability accounts will continue to accumulate due to the variance between 2010's actual fuel costs and the amounts recovered through the fuel base rate. The fuel base rate itself is reset every two years through a formal regulatory process.

- Balance Adjustment

It is inevitable that estimates will not equal actual sales and fuel costs. Therefore the AA from one year (i.e. 2009) will not be fully recovered in the following year (i.e. 2010) as it is based on forecasted 2010 sales. The 'Balance Adjustment', or BA, for 2010 is the residual amount of the AA related to 2009 (and any subsequent years) that was not fully recovered in 2010. The BA becomes another adjustment that will only first affect electricity rates in 2011. The BA rate is established similar to the AA rate using the cumulative asset (liability) divided by forecasted sales for the period. Any residual BA balance at the end of a period is simply applied to the subsequent year and used in the determination of future BA rates. In this way, all actual fuel costs are recovered from customers.

2011 Rate ($/Kwh) = [Base Rate] +/- [2010 "AA"] +/- [2009 "BA"]

Effect of FAM on Financial Statements

The 'FAM Regulatory Asset (Liability)' will be recorded on the balance sheet with deferred charges (credits). The interest, incentive, and effects of income tax will be accumulated to the asset or liability. Disclosure in the financial statement notes with deferred charges (credits) will include separate recognition of the 'FAM Regulatory Asset (Liability)'.

The income statement in the first year (2009) will show an addition or deduction to expenses on a line called 'Amortization of Fuel Expense' based on the over or under-recovered amounts net of the incentive portion. Beginning in 2010, the 'Amortization of Fuel Expense' will reflect the net amount of over or under-recoveries from 2010 base fuel costs and the credit or debit recognition of 'Actual Adjustment' amounts from 2009.

Revenues associated with the recovery of FAM fuel costs will be reported as electric revenues. The interest associated with the 'FAM Regulatory Asset (Liability)' will be recorded as AFUDC. The income tax provision recorded will be reported as part of income taxes on the statement of earnings.

The Statement of Cash Flow will include an additional line to remove the deferral, as this transaction does not affect cash flow until the following year with the receipt of associated revenues.

Journal Entry Summary

To illustrate the financial effects of the FAM accounting, a summary of journal entries follows:

2009:

1) Assuming actual fuel costs of $600 million (Under-recovery of $600-545=$55 million):

   Dt: FAM Regulatory Asset $55 million

   Ct: Amortization of Fuel Expense $55 million

2) Record incentive portion of FAM ($55-(590-545)) x 10% = $1 million):

Dt: Amortization of Fuel Expense $1 million

Ct: FAM Regulatory Asset $1 million

3) Recognize interest amounts of $2 million:

Dt: FAM Regulatory Asset $2 million

Ct: AFUDC $2 million

4) Record income tax provision for FAM deferral amounts assuming an applicable statutory tax rate of 35% ($55-1+2) x 35%:

Dt: Income tax expense $19.6 million

Ct: Future income tax liability $19.6 million

2010:

1) Record revenue recognition of 'Actual Adjustment' FAM amounts:

Dt: Cash (Accounts Receivable) $56 million

Ct: Electric Revenues $56 million

Dt: Amortization of Fuel Expense $56 million

Ct: FAM Regulatory Asset $56 million

Dt: Future income tax liability $19.6 million

Ct: Income tax expense $19.6 million

Financial Reporting Disclosure

The specific disclosure within the financial statements related to the FAM includes:

Deferred Charges and Credits

Fuel Adjustment Mechanism

The Nova Scotia Utility and Review Board approved the implementation of a Fuel Adjustment Mechanism (FAM) in the 2009 General Rate Decision effective January 1, 2009. The FAM is being established to mitigate the effects of volatile fuel costs on the electricity rates paid by the customers of NSPI. The FAM design protects the financial integrity of the Company and delivers timely price signals to customers to promote efficient use of electricity. Differences between actual fuel costs and amounts recovered from customers will accumulate in the FAM regulatory asset (liability) and subsequently become an adjustment (either an addition or deduction) to the following year's electricity rates. The FAM asset (liability) bears AFUDC. The FAM is also subject to an incentive portion with NSPI retaining or absorbing 10% of the under or over-recovered amount less the difference between the incentive threshold and the base fuel cost to a maximum of $5 million. The FAM regulatory asset (liability) is recorded before taxes. The Company has also recognized a future income tax liability (asset) based on NSPI's applicable statutory income tax. The FAM is recognized by NSPI as a regulatory asset or liability based on the expectation that successive rates will be adjusted to provide recovery from, or refund to, customers in the following period. In the absence of FAM regulatory approval, fuel costs would be expensed as incurred and net earnings for 2009 would be $XX million lower (2008 - nil).

Conclusions

The proposed accounting and financial reporting of the FAM is aligned with the regulatory framework and basic principles of the FAM. The reporting and disclosure provides transparency and the appropriate level of detail.

The financial reporting implications with the FAM have been incorporated into the analysis and research work related to the implementation of International Financial Reporting Standards. These findings will be integrated with future accounting and financial reporting policies.

Grant Thornton

January 30, 2009

Ms. Claudette Porter, CA
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Dear Ms. Porter:

Re: Proposed accounting for fuel adjustment mechanism in fiscal 2009

We recently received your request to review the proposed accounting treatment related to the Fuel Adjustment Mechanism of Nova Scotia Power Inc. ("the Company") which is effective beginning in fiscal 2009. You have asked us to confirm the appropriateness of the proposed accounting treatment under Canadian generally accepted accounting principles ("GAAP").

Based on our review of the proposed accounting treatment of the Fuel Adjustment Mechanism, attached as Appendix A, we wish to confirm we are in agreement with the conclusions and positions taken by management and that the proposed accounting treatment is appropriate under Canadian generally accepted accounting principles.

If you have any questions, please contact us.

Yours sincerely,
Grant Thornton LLP

Grant Thornton LLP

G. Hutchings, CA
Partner

[Exhibit N-1(a), p. 85]

[105] NSPI's application proposed to recover the 2008 and 2009 Demand Side Management (DSM) costs as follows:

> With the DSM investment as outlined in the DSM Settlement Agreement of $3.1 million for 2008 and $9.8 million for 2009, the total forecast expenditure over the 2008-2009 period is $12.9 million. NSPI is requesting recovery of this $12.9 million in equal increments over 2009, 2010 and 2011. NSPI proposes that $4.3 million be incorporated into the 2009 test year revenue requirement to reflect DSM costs. The recovery is further discussed in Section 5 of this Application.
>
> [Exhibit N-1(a), p. 86]

[106] The Agreement proposes that the amortization period for the 2008 and 2009 DSM costs be increased from three years to six years[10]. The net effect of this change is the reduction of the revenue requirement by $2.1 million in 2009[11].

8.2 Findings

[107] The Board has considered the amortization of the 2008 and 2009 DSM program costs over six years as proposed in the Agreement. Based on the size of rate increases proposed in the application, the Board agrees that it is reasonable to amortize these expenditures over a longer period than the three years proposed in the Application. The Board approves the amortization of DSM expenditures for 2008 and 2009 in the amount of $12.9 million over six years starting in 2009.

[10] Exhibit –69, para. 11

[11] Exhibit N-72

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March 12, 2008

By email: rene.gallant@emera.com

Mr. Rene Gallant
General Manager & Regulatory Counsel
Nova Scotia Power Inc.
PO Box 910, Scotia Square
Halifax, Nova Scotia B3J 2W5

Dear Mr. Gallant:

Power Outage Review Decision - Distribution System Vegetation Management - P-401.32

This letter is further to NSPI's correspondence of February 15, 2008, in response to a request from the Board dated December 18, 2007, for an update from NSPI with respect to its plans to address the above-noted outstanding matter.

As you are aware, the adequacy of NSPI's Distribution System Vegetation Management activities is a concern dating back to the power outage review decision issued by the Board on August 5, 2005, following a public hearing process conducted in a number of communities across the Province in April and May of 2005. This review was at the request of then Premier John Hamm and resulted from extensive and lengthy outages, affecting in excess of 160,000 customers, during and after a major storm in November of 2004.

The Board's decision determined that a review of this issue should be conducted. In a report dated November 29, 2005. Liberty Consulting Group found that:

- All circuits, including those recently maintained, require attention to vegetation management. The overall condition of the power system with regard to vegetation control is poor.

- NSPI does not have an effective and formal full circuit vegetation management program.

- NSPI's procedures and practices are weak in tracking work order completion, maintaining transmission line right-of-way buffer strips, evaluating reliability projects, and classifying outage data for reliability reporting.

- NSPI did not consistently performed [sic] corrective maintenance over the 2002-2004 period.

- The reliability statistics of circuits 70W-321, 77V-401, 78W-301, 15N-421, 113H-432, and 62N-414 rank poorly when compared to regional statistics, even when storms and transmission-caused outages are excluded. NSPI should investigate the causes of this performance and identify corrective actions.

The Board further commented on this issue in correspondence related to a final cost work order request by NSPI dated December 18, 2007:

> You may recall that in correspondence dated December 15, 2006 to Dan Muldoon, General Manager of Customer Operations, NSPI; the Board noted that while it would approve a requested expenditure of $3.6 million for a Distribution System Vegetation Management program, in view of its long-standing concerns that absent such action the reliability of service to NSPI customers would continue to decline, it also noted that:
>
> > . . .
> >
> > NSPI states that its request for Board approval of this project is on the basis that the expenditure of $3.6 million can be recovered in customer rates. However, in view of the fact that NSPI's October 10, 2006 general rate application does not include this cost in its test year revenue requirement, approval of this project, on the basis set out by NSPI, would result in a corresponding increase to the 2007 test year revenue requirement. This was clearly a foreseeable expenditure which NSPI could have provided for in its filing. As NSPI is aware, the issue concerning revisions to the revenue requirement filed by NSPI in its rate application has been raised by a number of intervenors in the upcoming rate hearing and was one of the matters heard by the Board at the preliminary hearing on December 7, 2006. In the Board's direction to the parties, issued on December 8, 2006, the reference to the revenue requirement states:
> >
> > > <u>Confirmation of Revenue Request</u>
> > >
> > > NSPI confirmed that the revenue request being applied for was the revenue request filed with its evidence of October 10, 2006. It has not been amended and will not be amended by NSPI.
> >
> > The Board is certainly prepared to approve this important and necessary program should NSPI wish to proceed on the basis that ongoing annual costs associated with this project would be included in future rate applications. The matter will be explored further in the upcoming rate hearing.
>
> As you are aware, the Board's February 2, 2007 decision on NSPI's rate application confirmed its approval of the Settlement Agreement ("SA") which, in part, provided for a revenue requirement of $1,159.5 million. In view of the SA, "further exploration of this issue" did not occur at the 2007 rate hearing.

In its update on this issue, NSPI is now requesting approval for a $2 million increase in vegetation management spending, with recovery of same deferred, stating that:

> . . .

> ... NSPI plans to increase expenditure on vegetation management during 2008. The Company will spend an additional $2 million on vegetation management on the distribution system. NSPI also hereby respectfully requests UARB approval for deferred recovery of these additional costs.
>
> NSPI knows reliable electric service is important to our customers. Increased investment in vegetation management, based on a sound plan, is a key part of meeting customer expectations. The Company will work with the Board and stakeholders to develop support for the program and the remaining additional required funding over the long term. In light of the interest in reliability and the vegetation management program generally in prior proceedings, the Company is providing a copy of this correspondence and attachments to stakeholders for information.
>
> [NSPI, Correspondence to Board, dated February 15, 2008]

In view of the long-standing concerns of the Board and the public in this matter, and the fact that, as NSPI acknowledged in its September 29, 2006 response to Liberty's report, vegetation encroachment on the system is the single largest cause of electric service interruption, the Board finds that this spending increase is required in order to improve the reliability of service provided to customers. Accordingly, the Board approves the additional $2 million spending in 2008 on the basis that it is both appropriate and justifiable. The Board also approves the proposed deferral of this expenditure, including the recovery period, subject to review at the next rate hearing.

Yours truly,

Nancy McNeil

Nancy McNeil
Regulatory Affairs Officer/Clerk

c.c. Eric Ferguson
Bruce Outhouse, Q.C.
John Merrick, Q.C. - Consumer Advocate
George Cooper, Q.C. - New Page/Bowater
Robert Grant, Q.C. - Avon Valley et al
Don Regan - MEUNSC
Mary Ellen Donovan - HRM
Robert Patzelt, Q.C. - CME
Brendan Haley - Ecology Action Centre
Claire McNeil - Affordable Energy Coalition
Mark Reiksts - Province of Nova Scotia

REDACTED

Request IR-158:

Reference: FOR-13, Attachment 1.

(a) Attachment 1, lines 8 through 12, show Financing Issue Costs. Are the financing issue costs included in the development of the rate of return? If the answer is yes, please discuss why it is appropriate to include the financing issue costs in rate base and rate of return?

(b) Lines 30 to 33 show Deferred Charges - Future Income Taxes on FAM. Please provide the workpapers supporting the development of the numbers shown for Forecast 2011 and Test Year Forecast 2012, and describe the nature and cause of these deferred charges.

Response IR-158:

(a) The financing issue costs are included in the development of the rate of return and rate base. This item was raised by this Intervenor previously in the 2009 General Rate Application (P-888) and in the 2005 General Rate Application (P- 881). Please refer to Attachment 1. The UARB's decision in both rate applications reflects the inclusion of financing issue costs in rate base and rate of return.

(b) Please refer to the following table for details on Deferred Charges related to the Future Income Taxes on FAM. Figures presented reflect whole numbers which may cause $0.1 million in rounding differences on some line items.

REDACTED

$ Millions	Amount	
Future Income Tax Liabilities	[redacted]	
Opening Balance	[redacted]	(22.2)
FAM Future Income Tax Expense	[redacted]	14.5
Ending Balance	[redacted]	(7.7)

Please refer to Partially Confidential Attachment 2 for detailed calculations for FAM Future Income Tax Expense. Please refer to NPB IR-80 for nature and cause of these deferred charges.

NON-CONFIDENTIAL

Request IR-47:

With respect to page 162, Direct Evidence, Figure 8.2, please identify the appropriate sections of the Board orders which authorize such charges to be deferred and included in rate base.

Response IR-47:

The UARB approves NSPI's rate base, including deferred charges, by approving the revenue requirement and rates in each general rate application. This issue was raised by this Intervenor in the 2005 General Rate Application (P-881). Please refer to Attachments 1 and 2.

Section 5.6 of the 2006 Rate Decision (P-882) referred to NSPI's rate base and specifically to a deferral of Q1 2005 taxes, which were subsequently approved by the Board.

The Board specifically approved deferred recovery of Section 21 and Q1 taxes in the 2007 General Rate Application (P-886), pursuant to a Settlement Agreement supported by this Intervenor.

2004 **NSUARB-P-881**

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: **STORA / BOWATER**

Question IR-226: **Table 10 shows amortization of Deferred Financing Charges. Please provide a detailed explanation of the Deferred Financing Charges.**

Response IR-226: Amortization of deferred financing charges includes the amortization of discounts, issue costs and defeasance.

The issue of long-term debt is usually an involved process in which the Company may retain the services of brokers, lawyers and auditors.

Discounts on long-term debt arise when the current market rate is higher than the stated rate on the debt when debt is issued. Deferral of these costs is consistent with the Generally Accepted Accounting Principles (GAAP).

2004 **NSUARB-P-881**

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: STORA / BOWATER

Question IR-227: **Please explain why the Deferred Financing Charges should be collected from ratepayers.**

Response IR-227: Deferred financing charges total $14.7 million of which $13.2 million relates to defeasance. The $1.5 million balance of the deferred financing charges relate to the amortization of issue and discount costs which are normal costs of financing recoverable from ratepayers. (Please see SEB IR-226).

With respect to the defeasance amount, the Board dealt with defeasance during the 1993 Rate Proceeding at which time the Board stated "The Board accepts the argument that the debt defeasance expense is one which was imposed on the Company by the government." (Page 24, Decision, 24 March 1993, NSPI Rate Proceeding, NSP-863).

In its Order of 6 April, 1993, arising out of that Rate Case the Board directed:

"The Company shall recover the costs related to the defeasance of debt guaranteed by the Province of Nova Scotia from utility customers. The increase in book value of the debt, the issue cost of the new debt and the acquisition cost of the defeasance assets are to be written off on a specific issue basis over the term of the new debt issues. With respect to the write off of the increase in book value of the debt, the term of the new debt may be considered to include refinancing, but shall not exceed the remaining life of the defeased debt."

During the 2002 Rate Proceeding SEB raised a series of issues concerning defeasance which it characterized as "a 'mismatch' between NSPI's rate base and its capitalization". (See Stora Bowater Non-Confidential Closing

2004 **NSUARB-P-881**

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: STORA / BOWATER

Response IR-227: (cont'd)

Argument, 2002 Rate Proceeding, page 44-57 and pages 60-61). None of those issues were resolved in Stora's favour.

Instead the Board stated in its Decision in the 2002 Rate Proceeding:

"In its post-hearing brief, NSPI points out that it has presented its financial tables consistent with its pr esentation in it s 1993 and 1996 rate applications. This Board, in prior NSPI rate decis ions, h as based th e revenue requirement for the test yea r on an allowed return on equity. The Board's focus has been a return on equity, and not a return on rate base. Once the rate of return on comm on equity is determ ined, it is possible to calculate the return on av erage rate base." (Paragraph 174, Decision, 23 October 20 02, NSPI Rate Proceeding, NSUARB-NSPI-875, 2002 NSUARB 59).

FAM FIT Expense		
	Forecast 2011 ($M)	Proposed Rates 2012 ($M)
FAM Fuel Deferral (incl Interest) [A]	[redacted]	$ (46.7)
Tax Rate [A]		31.0%
FAM FIT (Tax Rate [A])		$ (14.5)
FAM Fuel Deferral (incl Interest) [B]		$ -
Tax Rate [B]		
FAM FIT (Tax Rate [B])		$ -
Total FAM FIT		$ (14.5)

Notes:

1) Figures presented reflect whole numbers which may cause rounding differences on some line items.

NON-CONFIDENTIAL

Request IR-14:

With respect to rate base and regulated capitalization, please reconcile the two balances as of the December 31, 2011 year end.

Response IR-14:

The 2011 Regulated Statements filed with the Board reflected a total of $3,469.8 million for Regulated Capitalization on December 31, 2011.[1] In RB-02–RB-16 line 23 of the Application, the total for ending 2011 is $3,470.0 million; the difference of $0.2 million is a result of rounding.

Items comprising the $3,469.8 million reflected in the Regulated Statements per OP-01 Attachment 5 of the Application are:

	2011
Debt	
Long-term debt	$1,961.0
Short-term debt	63.9
Adjustment for unregulated assets & earnings	(91.8)
Preferred equity	132.2
Equity	
Common shares	1,034.7
Retained Earnings	369.7
Total Regulated Capitalization	**$3,469.8**

[1] OP-01 Attachment 5 of the Application.

NON-CONFIDENTIAL

Request IR-15:

Please identify and provide details regarding any costs included in the Application which are related to any aspect of the Muskrat Falls-Maritime Link project.

Response IR-15:

There are no costs included in the Application related to the Maritime Link project.

NON-CONFIDENTIAL

Request IR-16:

Reference DE-03 - DE-04, p. 7 of 159, lines 19 to 21:

> **NS Power predicts that meeting Nova Scotia's Renewable Electricity Standard by incorporating new renewable energy into our generation mix will add an incremental 1 or 2 percent per year to the factors that affect rates.**

Please reconcile this statement with a recent media interview with the President and CEO of Emera where he is reported in *allNovaScotia.com* as saying the cost of the $1.2 billion Maritime Link will add 2% to 3% to customer bills.

Response IR-16:

NS Power's Evidence does not consider the effect of the Maritime Link on rates.

NON-CONFIDENTIAL

Request IR-17:

Please itemize each deferral and the associated amount that NSPI anticipates will exist as of January 1, 2015.

a) Include a description of each item, an explanation of the deferral amount, and details regarding recovery of each deferral.
b) Separately describe all financial benefits that NSPI could receive for shareholders or for ratepayers regarding each deferral.
c) Describe all ratepayer costs in the Application that are associated with each deferral.

Response IR-17:

(a) In the 2013 General Rate Application, through the Rate Stabilization Plan, NS Power forecasts the Fixed Cost Recovery (FCR) Deferral to remain. For details regarding the balance and the anticipated recovery of the FCR Deferral, please refer to Liberty IR-39 Attachment 1.

(b) Please refer to DE-03–DE-04, Section 2, page 27 of 159, lines 26-28 and page 28 of 159, lines 12-18 of the Application where NS Power discusses the benefits to the FCR Deferral in the Rate Stabilization Plan.

(c) Customer costs associated with the FCR Deferral are the respective carrying costs associated with the outstanding balance. These costs are profiled monthly, by year, in Liberty IR-39 Attachment 1.

NON-CONFIDENTIAL

Request IR-18:

What benefit to rate payers does deferring the Fuel Adjustment Mechanism until 2015 have? What are the associated costs?

Response IR-18:

By deferring the Fuel Adjustment Mechanism (FAM) until 2015, customer rates are held constant at a 3 percent increase in each of 2013 and 2014, irrespective of actual fuel costs. As a component of the Rate Stabilization Plan, this will provide customers with predictable rates and increases lower than would be possible without a deferral. This will keep rate increases closer to the rate of inflation while Nova Scotia Power and its customers adjust to a system with a lower load contributing to full fixed costs.

If the actual fuel results for 2013 or 2014 cause a reduction in FAM rates, customers will receive the benefit of that reduction through a deferred fuel credit with associated interest earned based on NS Power weighted average cost of capital. If results cause FAM rates to increase, customers will have a deferred balance plus associated interest costs based on NS Power weighted average cost of capital. Either way, the deferred amounts will be incorporated into customer rates in 2015. The interest costs or revenue will not be known until actual fuel costs are known.

NON-CONFIDENTIAL

Request IR-19:

Reference DE-03 - DE-04, p. 35, lines 1 - 2:

Please explain how NSPI determined that the province's "unsettled economic climate" would result in a 400 GWh reduction during 2013 and 2014.

Response IR-19:

The load forecast was prepared using the sector economic models as described in the 2012 Load Forecast Report included in SR-02 of the Application. The resulting 2013 forecast was 1,926 GWh lower than the 2012 GRA forecast filed in May of 2011,[1] of which 1,500 GWh was due to the closed paper mill as noted in the text. The remaining reduction of over 400 GWh in the other customer classes was largely due to the change in economic conditions since the previous forecast.

[1] NSPI 2012 General Rate Application, NSUARB-NSPI-P-892, May 13, 2011, Section 8 Load Forecast, page 118.

NON-CONFIDENTIAL

Request IR-20:

Reference DE-03 - DE-04, p. 35, lines 10 - 12 and p. 36, lines 4 - 6:

> **At the time that our forecasts were prepared, the future of the mill remained uncertain. As a result, our forecast reflects the view that the mill will not contribute to system fixed costs in 2013 and 2014.**
>
> **For 2013, the net impact of the reduced load, considering both mills and other customer groups, is a revenue shortfall of $53 million.**

a) Please explain what is meant by "both mills and other customer groups".

b) What is the revenue shortfall amount attributed to the Port Hawkesbury mill for 2013 and for 2014? Please provide all calculations.

c) What is the revenue shortfall amount attributed to customers other than the Port Hawkesbury mill for 2013 and for 2014? Please elaborate and provide all calculations.

d) Now that NSPI has worked through the details regarding supply arrangement for the Port Hawkesbury mill, and has applied to the UARB for approval of a load retention rate for PWCC, does NSPI still believe that the mill will not contribute to system fixed costs in 2013 and 2014?

   i. If no, please provide a revised forecast and calculations of the fixed cost shortfall for each year.

   ii. If yes, please explain its rationale for filing the load retention rate application and justify its reasons for supporting same.

Response IR-20:

(a) "Both mills" refers to the two largest paper mills (NewPage in Port Hawkesbury and Bowater in Liverpool), and "other customer groups" refers to all other customer groups: residential, commercial, industrial, municipal and unmetered.

(b) The $53 million is calculated for 2013, and is the difference between the fixed costs in the 2012 GRA Compliance Filing and the fixed costs in the 2013 test year.[1] The revenue shortfall attributed to the Port Hawkesbury mill for 2013 is $36.9 million, and is determined as follows:

Fixed cost contribution rate ($/kWh) * total energy (kWh) + customer charge

In the 2012 GRA Compliance Filing, the Port Hawkesbury mill contribution was calculated based on the Extra Large Industrial Two Part Real Time Pricing (ELI 2P-RTP) rate:

ELI 2P-RTP = 0.02539 $/kWh * 1,443 GWh * 1,000,000 kWh/GWh + (20,700 $/month * 12 months)

(c) The revenue shortfall amount attributed to all other customers is $16.7 million. For details of the calculation, please refer to Multeese IR-6 Attachment 1, column W, rows 5 - 23. Note that the Port Hawkesbury mill amount is included in line 16, class ELI 2P-RTP.

(d) NS Power does not yet know if the tariff will be approved by the Board and if the tax strategy will be approved by Canada Revenue Agency (CRA). Should both be approved and the mill takes 1 TWh of energy, fixed cost recovery is expected to be approximately $2 million for 2013 plus a potential for profit sharing. As described in the Port

[1] NSPI 2012 General Rate Application, Compliance Filing, NSUARB-NSPI-P-892, December 09, 2011.

Hawkesbury mill Load Retention Tariff (LRT) Application, NS Power proposes that the Board require NS Power to direct all fixed cost contributions from the mill to reduce the Fixed Cost Recovery Deferral. Therefore, if the LRT arrangement for the mill is approved as filed, there is no need to adjust the Rate Stabilization Plan or make any recalculations under the General Rate Application; the LRT arrangements will require NS Power to use the fixed cost contribution for the benefit of customers by reducing the deferral by the exact amount of the contribution, whatever actual amount is recovered.

NON-CONFIDENTIAL

Request IR-21:

Reference DE-03 - DE-04, p. 36, line 2, regarding fixed costs associated with the Port Hawkesbury mill:

Please quantify the reference to spreading those fixed costs among "fewer customers".

Response IR-21:

For clarity, the above-noted reference refers to "fixed costs of the system" or "the fixed costs of the plants and equipment used to generate and distribute electricity", not "fixed costs associated with the Port Hawkesbury mill", as suggested above. The reference to "fewer customers" was intended to refer to the loss of the two largest customers from contributing to the fixed costs of the system at the levels which they have historically contributed, which are the levels assumed in current rates.

NON-CONFIDENTIAL

Request IR-22:

Given this application includes $53 million related to the "Loss of Load and Fixed Contribution to System Costs" and in the 2012 General Rate Application NSPI undertook to take all prudent and reasonable steps to minimize costs to other ratepayers if the NPB load, or a portion of it, remains off the system, please indicate:

a) What efforts have been made to reduce costs associated with redundant assets resulting from lost load?
b) Based on the lost load, what portion of the current rate base would not be considered used and useful?
c) Has any balance been removed from the rate base for purposes of calculating the rate of return?
d) Why does NSPI feel these losses should be recovered from other ratepayers?
e) What portion of the losses related to lost load has been absorbed by NSPI?

Response IR-22:

(a) There are no redundant assets resulting from the lost load. Rather, the volume of billing determinants over which fixed asset costs can be collected is diminished. While NS Power is operating Lingan units 1 or 2 on a seasonal shutdown basis to create savings of $4.1 million, the units will continue to be used and useful.

(b) All of NS Power's current rate base is considered used and useful.

(c) No, other than normal retirements.

(d-e) NS Power has filed a two-year test year forecast that includes all prudently incurred costs.

CONFIDENTIAL (Attachment Only)

Request IR-23:

Reference DE-03 - DE-04, p. 77, line 22 to p. 78, line 10:

Please expand Figure 6-2 to show a year-by-year comparison from 2000 to 2014 of

- **i. Operating Cost/Customer**
- **ii. Operating Cost/MWh**
- **iii. Generation**
- **iv. CPI**

assuming the rate stabilization proposal is not approved.

Response IR-23:

Please refer to Partially Confidential Attachment 1.

Operating, Maintenance and General Expenses

Years Ended December 31st (Millions of Dollars)	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012F	2013F	2014F	Average Annual
OM&G/MWh (current dollars, excluding pension)	$13.3	$13.7	$13.6	$13.8	$12.5	$13.5	$14.6	$13.6	$14.2	$16.4	$17.3	$19.1	[redacted]	$21.2	$21.8	$15.8
Annual Change		3.2%	-0.8%	1.8%	-9.7%	8.0%	8.2%	-7.0%	4.4%	15.7%	5.2%	10.8%	[redacted]	11.8%	2.7%	3.8%
OM&G/Customer (current dollars, excluding pension)	$343.4	$358.3	$359.9	$371.9	$338.7	$361.6	$351.7	$362.7	$371.5	$410.4	$430.5	$463.7	[redacted]	$456.8	$464.3	$391.3
Annual Change		4.4%	0.5%	3.3%	-8.9%	6.8%	-2.8%	3.1%	2.4%	10.5%	4.9%	7.7%	[redacted]	7.7%	1.6%	2.3%
CPI - NS (Indexed to 2000)	1.00	1.02	1.05	1.08	1.10	1.13	1.16	1.18	1.21	1.22	1.24	1.29	1.31	1.34	1.37	
Annual Change		1.9%	3.0%	3.4%	1.8%	2.8%	2.1%	1.9%	2.9%	0.1%	2.1%	3.8%	1.5%	2.2%	2.2%	2.3%
Generation (GWh)	11,431.7	11,646.2	12,030.7	12,328.8	12,564.9	12,482.8	11,352.4	12,698.9	12,562.7	12,091.6	12,163.6	11,917.1	[redacted]	10,750.9	10,739.9	11,854.9

Notes: 1) Figures presented reflect whole numbers which may cause $0.1M in rounding differences on some line items

NON-CONFIDENTIAL

Request IR-24:

Reference DE-03 - DE-04, pp. 89 to 90:

a) Please identify the amount budgeted for vegetation management in 2013 and 2014.

b) Please provide a table and graph showing the amount of OM&G funds spent on vegetation management for each year from 2000 to 2011 inclusive. Please separately identify funds related to distribution and transmission.

c) Please provide similar information to b) regarding capital funds associated with routines and individual work orders.

d) Please expand Figure 6.6 to cover each of the years from 2000 to 2011 inclusive.

e) Please expand d) above to show NSPI's predicted improvement resulting from spending the additional $3.4 million annually requested in the Application. Include all supporting calculations.

Response IR-24:

(a) Please refer to the figure below for the budgeted operating expenses:

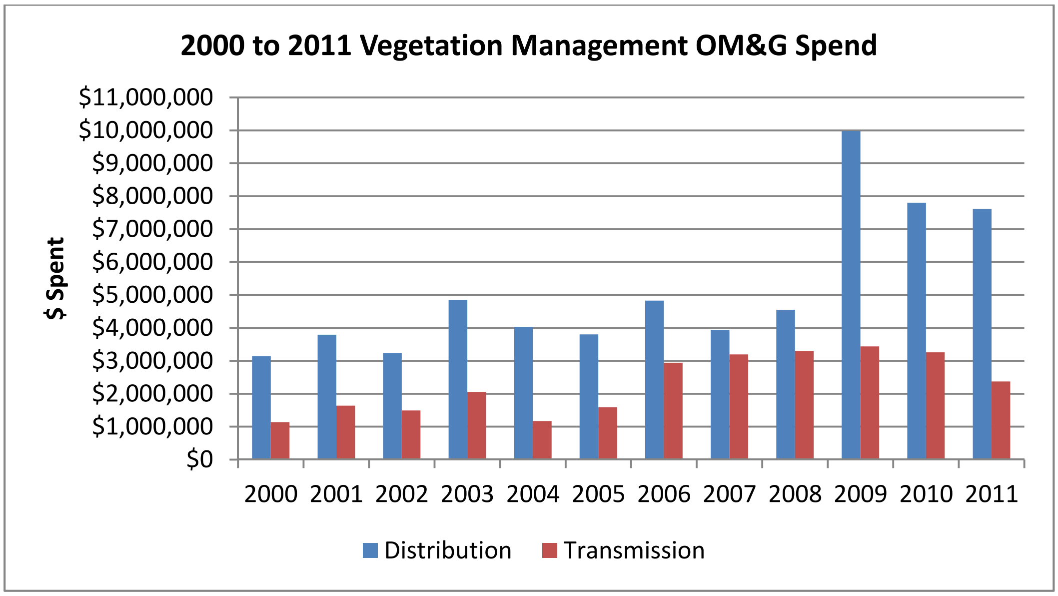
Year	Budget ($M)
2013	14.5
2014	14.7

(b) Please refer to the figures below:

Year	Distribution ($M)	Transmission ($M)
2000	3.1	1.1
2001	3.8	1.6
2002	3.2	1.5
2003	4.8	2.1
2004	4.0	1.2
2005	3.8	1.6

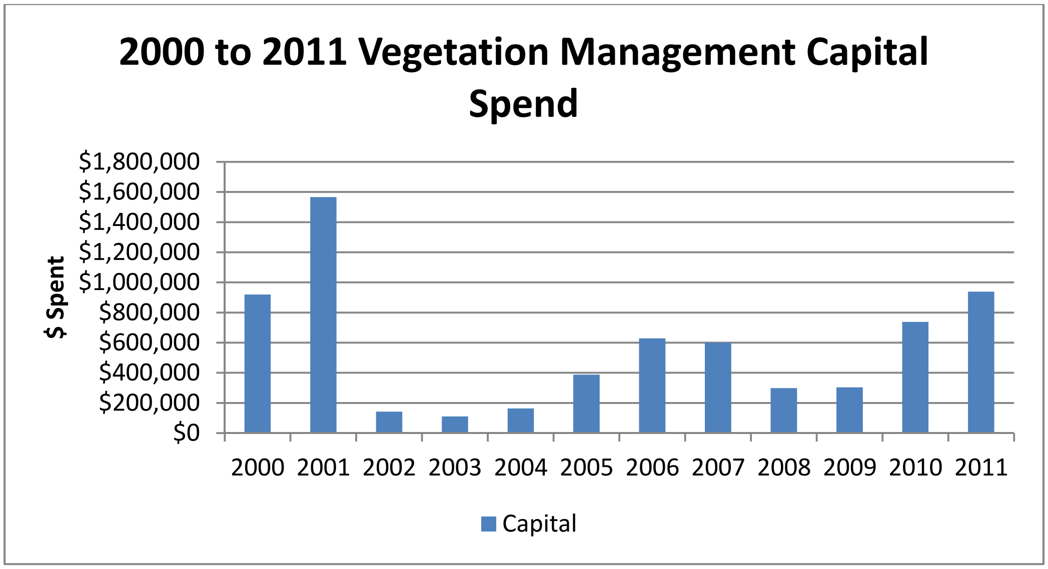
NON-CONFIDENTIAL

Year	Distribution ($M)	Transmission ($M)
2006	4.8	2.9
2007	3.9	3.2
2008	4.6	3.3
2009	10.0	3.4
2010	7.8	3.3
2011	7.6	2.4

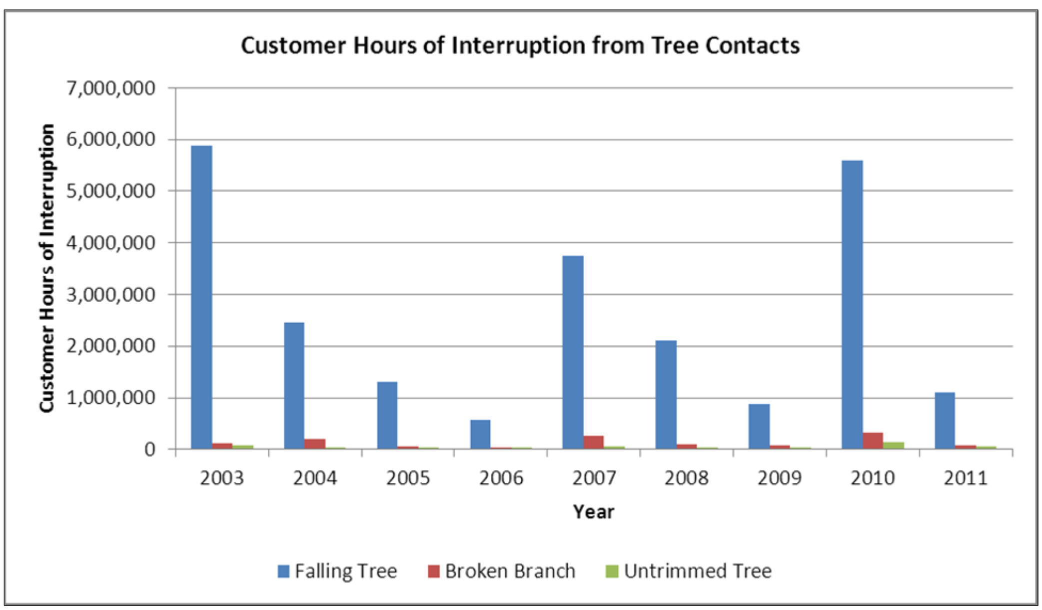


(c) Please refer to the figures below:

Year	Capital ($M)
2000	0.9
2001	1.6
2002	0.1
2003	0.1
2004	0.2
2005	0.4
2006	0.6
2007	0.6
2008	0.3
2009	0.3
2010	0.7
2011	0.9



(d) Specific Tree Contact type is not available prior to 2003. Please refer to the figure below:



(e) Please refer to Liberty IR-60 response (d) and (e).

NON-CONFIDENTIAL

Request IR-25:

Reference DE-03 - DE-04, p. 16 and pp. 90 to 93:

a) Please confirm if the reference to Figure 1-7 on p.92, line 28 should be Figure 6-8.

b) Please expand Figure 6-8 to cover each of the years from 2000 to 2011 inclusive.

c) Please provide a table and graph showing the amount of OM&G funds spent on storm response for each year from 2000 to 2011 inclusive.

d) Please provide similar information to c) regarding capital funds associated with routines and individual work orders.

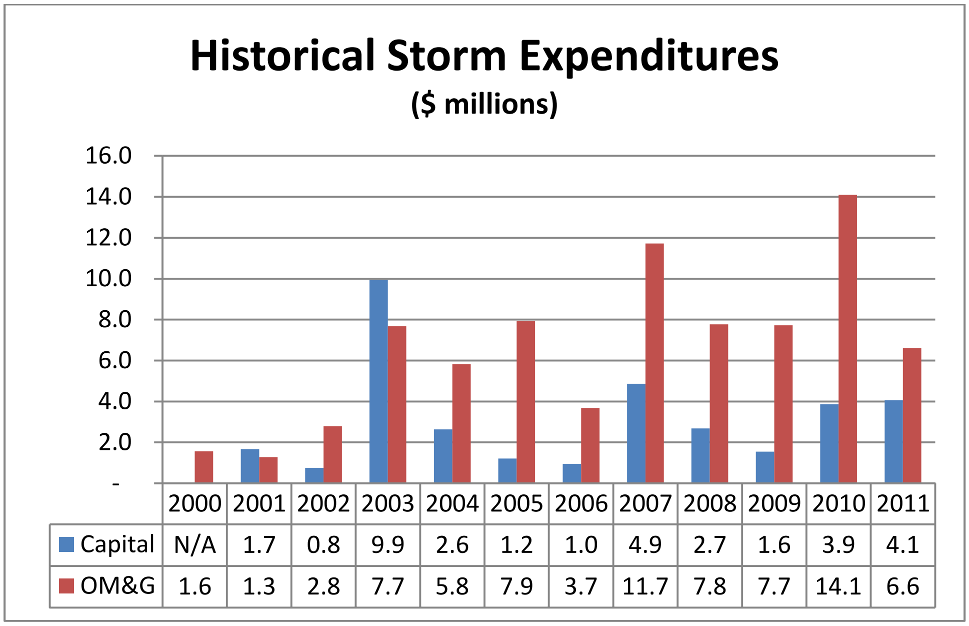
e) On page 16, lines 8 to 10, NSPI states that it proposes to increase the amount of money it spends each year "to improve response time to outages". On page 93, lines 6 to 9, NSPI is requesting an increase of $5.5 million for the storm response program beginning in 2013, for an annual total of $10.5 million. Please identify the improved response time to outages that will be achieved by spending an additional $5.5 million annually, and include all supporting calculations.

Response IR-25:

(a) Confirmed.

(b) NS Power did not track storm events individually prior to 2006. In 2006, the total storm cost was $3.7 million, and there was no one storm event that cost more than $1 million.

(c-d) Please refer to the historical storm expenditures below. Capital expenditures for storms for the year 2000 are not available.



(c) The referenced narrative identified that an additional $8.9 million was requested in this application for increased reliability and faster restoration following outages. Included in this number were $5.5 million for storm response, and $3.4 million for vegetation management. The storm response amount of $5.5 million was not intended to enhance response times; it was solely intended to cover the actual average storm response costs over the past five years. Doing additional vegetation management will, however, improve the response time over the long run for storm response. Additional clearing conducted on right of way, and off right of way, allows easier access for crews to address outages.

NON-CONFIDENTIAL

Request IR-26:

Please provide NSPI's reliability indices for 2000 to 2011 inclusive, including:

a) System Average Interruption Duration Index (SAIDI);

b) System Average Interruption Frequency Index (SAIFI); and

c) Customer Average Interruption Duration Index (CAIDI)

d) Please include a comparison with each of the other Atlantic Provinces and CEA.

Response IR-26:

(a-c) Please refer to the figure below:

Year	SAIFI	SAIDI	CAIDI
2000	3.12	5.44	1.75
2001	2.48	4.05	1.63
2002	2.62	6.09	2.32
2003	3.91	37.94	9.71
2004	3.78	18.42	4.87
2005	3.54	10.34	2.92
2006	2.91	5.00	1.72
2007	3.97	14.18	3.57
2008	4.15	11.29	2.72
2009	2.86	5.80	2.03
2010	4.36	17.61	4.04
2011	3.73	7.90	2.12

(d) Please refer to the figures below:

Atlantic Utilities without NS Power			
Year	**SAIFI**	**SAIDI**	**CAIDI**
2000	4.23	7.85	1.85
2001	3.66	5.91	1.61
2002	4.52	6.30	1.39
2003	4.66	15.33	3.29
2004	3.36	5.19	1.55

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Atlantic Utilities without NS Power			
Year	**SAIFI**	**SAIDI**	**CAIDI**
2005	3.34	5.92	1.77
2006	3.21	4.97	1.55
2007	3.35	7.45	2.22
2008	3.29	7.70	2.34
2009	2.74	4.69	1.71
2010	3.22	9.96	3.10
2011	3.00	7.74	2.58

All CEA Utilities			
Year	**SAIFI**	**SAIDI**	**CAIDI**
2000	2.26	3.23	1.43
2001	2.41	3.67	1.52
2002	2.33	4.06	1.74
2003	2.67	10.65	3.99
2004	1.98	3.95	2.00
2005	2.13	4.80	2.26
2006	2.53	7.85	3.11
2007	2.32	5.47	2.36
2008	2.34	6.29	2.69
2009	2.01	4.20	2.09
2010	2.20	5.17	2.35
2011	2.63	6.16	2.34

NON-CONFIDENTIAL

Request IR-27:

With respect to the proposed revisions to NSPI's accounting policy 5900 - Income Taxes:

a) Please provide the communications between NSPI and the Board related to the proposed revisions to the policy.

b) Please confirm NSPI's current income tax policy creates a benefit for the utility related to the deferred fixed costs because costs deferred for accounting purposes are available as a deduction for tax purposes.

c) Please confirm this also results in additional cost to ratepayers in subsequent years as the costs are recovered due to additional revenue requirement and no deductions available for tax purposes.

d) Please explain what consideration was given to this during the 2012 Settlement Agreement and/or settlement discussions.

e) Given the proposed tax policy is the method followed with the FAM deferrals, please explain why NSPI has not requested this policy apply to all cost deferrals.

Response IR-27:

(a) Please refer to Attachment 1.

(b) Please refer to Attachment 1 for an illustration of the impact to NS Power under the current income tax policy. NS Power does receive a current tax benefit under the current income tax policy for costs incurred which are deferred for recovery from customers in a future period. This is the reason we have requested the change to the tax policy to avoid a benefit to NS Power in 2012 which would then increase rates to customers in 2013.

NON-CONFIDENTIAL

(c) The current income tax policy does result in additional costs to ratepayers in subsequent years as the deferred costs are recovered due to an additional revenue requirement related to income tax expense and no deductions available for tax purposes.

(d) NS Power assumed that the Fixed Cost Recovery (FCR) deferral would be treated similar to the FAM deferral for tax purposes. The matter was not discussed among stakeholders. Subsequent to approval of the Settlement Agreement, NS Power realized that a formal accounting policy change would be necessary. NS Power did not anticipate any concern with accounting for the deferral in a manner that is in the best interests of customers.

(e) NS Power has not requested to apply the proposed tax policy to all cost deferrals as the nature of the FCR deferral and the FAM deferral differ from the other cost deferrals. Certain deferrals related to the deferral of prior year income taxes have no tax impact. The fixed cost deferral and FAM deferral fluctuate and are more volatile than the other deferrals. Other cost deferrals, such as Demand Side Management (DSM) and Vegetation Management do not fluctuate and the amounts were included in rates as part of a previous general rate application. If NS Power followed the same tax policy for the FAM deferral and the FCR deferral the Company would require a new general rate application every year in order to reset rates to recover the deferred costs, due to the fluctuations.

Nova Scotia
POWER
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energy everywhere.

January 5, 2012

Nancy McNeil
Regulatory Affairs Officer/Clerk
Nova Scotia Utility and Review Board
1601 Lower Water Street
3rd Floor
Halifax, NS B3J 3S3

Dear Ms. McNeil,

On November 29, 2011, the Nova Scotia Utility and Review Board (NSUARB, Board) approved Nova Scotia Power's 2012 General Rate Application Settlement Agreement (SA). The SA and Board Decision defers unrecovered NPB contributions to fixed costs, for recovery from customers beginning in 2013.

The creation of this new deferral mechanism requires a change to NSPI's Accounting Policy 5900 – Income Taxes. In order to properly account for the income tax effect of such a deferral, NSPI's Accounting Policy 5900 needs to be revised to expressly allow the Company to align the income tax effect with the timing of recovery of the deferral. The accounting policy already uses this approach with respect to FAM deferrals, and the additional amendment mirrors the existing approach with the FAM.

Effective January 1, 2012, Nova Scotia Power Inc. (NSPI) will record the unrecovered NPB contributions to fixed costs as a deferred asset for accounting purposes similar to the FAM receivable/payable. NSPI will set up the deferred asset on its balance sheet, and the related deferred income tax liability and deferred income tax expense.

NSPI makes this request to amend Accounting Policy 5900 pursuant to section 27 of the Public Utilities Act. As noted by the Board in its December 20, 2010 Decision that approved revisions to NSPI's Accounting Policies and Procedures;

> "Board approval is required for any changes to NSPI's accounting standards and policies before the amendments become effective. According to the *Public Utilities Act,* Chapter 380, s. 27, the Board may prescribe the form of all books, accounts etc.:

Nova Scotia Power
PO Box 910
Halifax, Nova Scotia
Canada B3J 2W5

Customer Service
1.800.428.6230
(428.6230 in HRM)

nspower.ca

> **Form of Books and records of utility**
>
> The Board may prescribe the forms of all books, accounts, papers and records required to be kept by any public utility and every public utility is required to keep and render its books, accounts, papers and records accurately and faithfully in the manner and form prescribed by the Board and to comply with all directions of the Board relating to such books, accounts, papers and records."[1]

NSPI respectfully requests the Board approve the amended Accounting Policy 5900 – Income Taxes. Approval of NSPI's request in this matter by March 15, 2012 will allow NSPI to incorporate this change to its accounting practices prior to the release of Q1 2012 financial statements, which will be considerably helpful in minimizing any reporting confusion with respect to the deferral account.

We would be pleased to have our accounting personnel and advisors meet with the Board, or its consultants, at the Board's convenience upon request.

The proposed amended Accounting Policy 5900 – Income Taxes is attached in both "track change" and clean versions.

For more information, please do not hesitate to contact the undersigned.

Regards,

Eric Ferguson, CMA
Director, Regulatory Affairs
Nova Scotia Power Inc.

Attachments

C: Claudette Porter, CA

[1] NSPI Changes to Accounting Policies and Procedures, NSUARB-NSPI-P-111.6, December 20, 2010, page 5, paragraph 13

COST OF OPERATIONS

INCOME TAXES - 5900

Nova Scotia POWER
An Emera Company

POLICY

01 Income tax expense should be categorized as current or deferred income tax expense as appropriate.

02 The Company uses the applicable enacted tax rate when measuring current and deferred income tax expense.

03 The Company follows the flow-through method of accounting for investment tax credits ("ITC's"). ITC's are recorded in the year earned as a reduction to income tax expense to the extent that realization of such benefit is more likely than not.

04 The Company recognizes deferred income tax assets (liabilities) as appropriate. To the extent deferred income taxes are expected to be recovered from or returned to customers in future rates, the Company will recognize a deferred regulatory asset (liability)[1]

05 The Company will recognize a deferred regulatory asset (liability) related to FAM and the deferral of any unrecovered contributions to fixed costs as detailed in the 2012 General Rate Application Settlement Agreement as approved by the Nova Scotia Utility and Review Board on the 29th November 2011 ("the deferral"). ~~-~~Deferred income tax expense (benefit) and a corresponding deferred income tax (liability) asset related to the FAM and the deferral will be recognized based on the enacted income tax rate(s) for the period(s) when the FAM and the deferral regulatory asset (liability) ~~is~~ are expected to reverse.

FEDERAL INCOME TAXES

06 The Company is subject to federal income tax at prescribed rates applied to taxable income.

PROVINCIAL INCOME TAXES

07 The Company is subject to provincial income tax at prescribed rates applied to taxable income.

TAX ON LARGE CORPORATIONS

08 The Company is subject to a provincial capital tax ("PCT") at prescribed rates applied to taxable capital.

PART VI.1 TAX

09 The Company is subject to Part VI.1 tax at a prescribed rate applied to preferred share dividends paid. The Company receives a tax deduction equal to a prescribed multiple of the Part VI.1 tax.

1 FASB ASC 980-740-25-2

PROCEDURES

10 A monthly income tax provision is recorded by multiplying the Company's effective combined federal and provincial income tax rate forecasted for the year (calculated without inclusion of the forecasted FAM adjustment) by the net earnings before tax for the period. The monthly income tax provision with respect to FAM is based on the actual FAM adjustment for the period multiplied by the enacted tax rate.

11 The Company prepares an estimate of its taxable capital using a forecasted year-end balance sheet. The taxable capital forecast is then multiplied by the enacted tax rate to determine the PCT expense for the year. The PCT estimate is prorated based upon days to determine the amount to accrue each month.

12 The net Part VI.1 tax is calculated using enacted rates and recorded as an additional cost (recovery) of the preferred share dividend. It is reclassified to current income tax expense for external reporting purposes. The monthly Part VI.1 tax expense is based on the amount of preferred dividends declared in the month. The monthly Part VI.1 tax deduction is based on the annual forecasted Part VI.1 deduction prorated based upon the total preferred dividends declared in a month.

13 The Company currently follows the policy of claiming sufficient capital cost allowance and cumulative eligible capital (the tax system's equivalent of depreciation and amortization), to minimize taxable income.

14 Federal and provincial income taxes, including net Part VI.1 tax, are included in general ledger account 086 - Income Tax Expense and Provincial Capital Tax is included in account 067.~~The net Part V1.1 tax is included in general ledger account 786 – Tax on Preferred Dividends.~~

COST OF OPERATIONS

INCOME TAXES - 5900

POLICY

01 Income tax expense should be categorized as current or deferred income tax expense as appropriate.

02 The Company uses the applicable enacted tax rate when measuring current and deferred income tax expense.

03 The Company follows the flow-through method of accounting for investment tax credits ("ITC's"). ITC's are recorded in the year earned as a reduction to income tax expense to the extent that realization of such benefit is more likely than not.

04 The Company recognizes deferred income tax assets (liabilities) as appropriate. To the extent deferred income taxes are expected to be recovered from or returned to customers in future rates, the Company will recognize a deferred regulatory asset (liability)[1]

05 The Company will recognize a deferred regulatory asset (liability) related to FAM and the deferral of any unrecovered contributions to fixed costs as detailed in the 2012 General Rate Application Settlement Agreement as approved by the Nova Scotia Utility and Review Board on the 29th November 2011 ("the deferral"). Deferred income tax expense (benefit) and a corresponding deferred income tax (liability) asset related to the FAM and the deferral will be recognized based on the enacted income tax rate(s) for the period(s) when the FAM and the deferral regulatory asset (liability) are expected to reverse.

FEDERAL INCOME TAXES

06 The Company is subject to federal income tax at prescribed rates applied to taxable income.

PROVINCIAL INCOME TAXES

07 The Company is subject to provincial income tax at prescribed rates applied to taxable income.

TAX ON LARGE CORPORATIONS

08 The Company is subject to a provincial capital tax ("PCT") at prescribed rates applied to taxable capital.

PART VI.1 TAX

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1 FASB ASC 980-740-25-2

Nova Scotia POWER
An Emera Company

PROCEDURES

10 A monthly income tax provision is recorded by multiplying the Company's effective combined federal and provincial income tax rate forecasted for the year (calculated without inclusion of the forecasted FAM adjustment) by the net earnings before tax for the period. The monthly income tax provision with respect to FAM is based on the actual FAM adjustment for the period multiplied by the enacted tax rate.

11 The Company prepares an estimate of its taxable capital using a forecasted year-end balance sheet. The taxable capital forecast is then multiplied by the enacted tax rate to determine the PCT expense for the year. The PCT estimate is prorated based upon days to determine the amount to accrue each month.

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13 The Company currently follows the policy of claiming sufficient capital cost allowance and cumulative eligible capital (the tax system's equivalent of depreciation and amortization), to minimize taxable income.

14 Federal and provincial income taxes, including net Part VI.1 tax, are included in general ledger account 086 - Income Tax Expense and Provincial Capital Tax is included in account 067.

Nova Scotia Utility and Review Board

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January 5, 2012

E-mail: eric.ferguson@nspower.ca

Mr. Eric Ferguson
Director, Regulatory Affairs
Nova Scotia Power Inc.
1223 Lower Water Street
PO Box 910
Halifax, NS B3J 2W5

Dear Mr. Ferguson:

Nova Scotia Power Inc. – Accounting Policy and Procedures Manual – Accounting Policy 5900 – Income Taxes – P-111.6 / Matter No. M04760

Receipt is acknowledged of your letter dated January 5, 2012, requesting Board approval to amend Accounting Policy 5900 – Income Taxes.

Your letter advises that approval of this request by March 15, 2012 will allow NSPI to incorporate the change to its accounting practices prior to the release of Q1 2012 financial statements.

This is to advise that your request has been directed to the Board.

Yours very truly,

Nancy McNeil

Nancy McNeil
Regulatory Affairs Officer/Clerk

c.c. S. Bruce Outhouse, Q.C., Board Counsel — By email
Claudette Porter, CA, NSPI — By email

Document: 199363

2012 **NSUARB-NSPI-P-111.6**
M04760

NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF: **THE PUBLIC UTILITIES ACT**

- and -

IN THE MATTER OF: **A REQUEST** by **Nova Scotia Power Incorporated** ("NSPI") for Approval of amendments to Accounting Policy 5900 – Income Tax (Matter No. M04760)

INFORMATION REQUESTS

To: Mr. Eric Ferguson, CMA
Director, Regulatory Affairs
Nova Scotia Power Inc.
Email: eric.ferguson@nspower.ca

From: Board Staff
Nova Scotia Utility and Review Board

Responses Due: **Friday, March 9, 2012**

Copies: 3 hard copies and an electronic copy (PDF searchable)

Contact Person: Mr. Eric Kirby, CMA, Analyst
Nova Scotia Utility and Review Board
3rd Floor, 1601 Lower Water Street
Halifax, NS B3J 3S3
Tel: (902) 424-4448
Fax: (902) 424-3919
Email: kirbyem@gov.ns.ca

Issued at Halifax, Nova Scotia, this 23rd day of February, 2012.

Nancy McNeil

Nancy McNeil, Regulatory Affairs Officer/Clerk

IR-1:

Please provide an example of the quarterly journal entries that would be made if an unrecovered contribution to fixed costs of $30,000,000, from New Page not being able to return to operations in 2012, is differed and assuming the proposed amendment to Policy 05 is approved. Please include all entries including those for income taxes.

IR-2:

What would the consequences be if the amendments to Policy 05 are not approved?

IR-3:

Please refer to the amendment to Procedure 14.

a) Does this amendment in any way relate to the income tax effect of the deferral of unrecovered NPB contributions to fixed costs?
b) If, no, what is the purpose/outcome of this proposed amendment?
c) Will this proposed amendment have an effect on any line item in either the Balance Sheet or Income Statement?
d) Was the net Part VI.1 tax the only entry to GL account 786?

NSUARB-NSPI-P-111.6
Matter No. 04760
NSPI Responses to UARB Information Requests

NON-CONFIDENTIAL

Request IR-1:

Please provide an example of the quarterly journal entries that would be made if an unrecovered contribution to fixed costs of $30,000,000, from NewPage not being able to return to operations in 2012, is deferred and assuming the proposed amendment to Policy 05 is approved. Please include all entries including those for income taxes.

Response IR-1:

Please refer to Attachment 1.

As demonstrated by the entries in Attachment 1 the income tax effect of the deferral is aligned with the timing of the recovery of the deferral.

Quaterly entries in 2012 (Assumed each quarter's deferral amount is the same for ease of illustation)
No entries for interest on the unrecovered balance have been included.

1) Record fixed costs incurred during the quarter			
Dr. Various fixed cost expenses	7,500,000		
Cr. Cash/Accounts payable		7,500,000	
2) Record current income tax provision related to actual fixed costs incurred using the enacted statutory income tax rate of 31%.			
Dr. Income Taxes receivable	2,325,000		
Cr. Current income tax recovery		2,325,000	
3) Record quaterly deferral of unrecovered NewPage contributions to fixed costs			
Dr. Fixed Cost Deferral Regulatory Asset	7,500,000		
Cr. Fixed cost recovery adjustment		7,500,000	
4) Record deferred income tax provision related to deferral amount using the enacted statutory income tax rate of 31%			
Dr. Deferred income tax expense	2,325,000		
Cr. Deferred income tax liability		2,325,000	
Impact on Net Income before taxes			-
Impact on income taxes			-
Impact on Net Income			-

Quaterly entries in 2013 (Assumed recovery of the $30,000,000 in 2013 and each quarter's recovery amount is the same for ease of illustation)
No entries for interest on the unrecovered balance have been included.

1) Record revenue earned during the quarter			
Dr. Cash/Accounts receivable	7,500,000		
Cr. Revenue		7,500,000	
2) Record current income tax provision related to revenue earned using the enacted statutory income tax rate of 31%.			
Dr. Current income tax expense	2,325,000		
Cr. Income taxes payable		2,325,000	
3) Record quaterly recovery of unrecovered NewPage contributions to fixed costs from 2012.			
Dr. Fixed cost recovery adjustment	7,500,000		
Cr. Fixed Cost Deferral Regulatory asset		7,500,000	
4) Record deferred income tax provision related to deferral amount using the enacted statutory income tax rate of 31%			
Dr. Deferred income tax liability	2,325,000		
Cr. Deferred income tax recovery		2,325,000	
Impact of Net Income before taxes			-
Impact on income taxes			-
Impact on Net Income			-

NSUARB-NSPI-P-111.6
Matter No. 04760
NSPI Responses to UARB Information Requests

NON-CONFIDENTIAL

Request IR-2:

What would the consequences be if the amendments to Policy 05 are not approved?

Response IR-2:

If the amendments to Policy 05 are not approved, deferred income taxes with respect to the deferral of unrecovered contributions to fixed costs will be recorded in accordance with Policy 04. The income tax effect will not be aligned with the recovery of the deferral.

For example, assuming a $30,000,000 deferral in 2012, net income before tax related to the unrecovered fixed costs would be $Nil as the $30,000,000 of actual fixed costs incurred would be offset by a $30,000,000 fixed cost recovery adjustment. However, a current income tax recovery of $9,300,000 ($30,000,000 x 31%) would be recorded which reflects the tax associated with the actual fixed costs incurred.

Assuming the deferral was recovered from customers in 2013 (for ease of illustration), net income before tax would again be $Nil since $30,000,000 of revenue would be offset by a $30,000,000 fixed cost recovery adjustment. However, a current income tax expense of $9,300,000 ($30,000,000 x 31%) would be recorded which reflects the tax associated with the actual revenue earned.

If the amendments to Policy 05 are approved, using the same assumptions above, there would be $Nil impact on income before tax in 2012 and 2013, and also $Nil impact on tax since the current tax described above would be fully offset by the same amount of deferred tax each year, as illustrated by the impact of the quarterly journal entries described in IR-001. The total tax impact is therefore aligned with the net income impact of the actual fixed costs, deferral and subsequent recovery of the actual fixed costs.

NSUARB-NSPI-P-111.6
Matter No. 04760
NSPI Responses to UARB Information Requests

NON-CONFIDENTIAL

Request IR-3:

Please refer to the amendment to Procedure 14.

a) **Does this amendment in any way relate to the income tax effect of the deferral of unrecovered NPB contributions to fixed costs?**
b) **If, no, what is the purpose/outcome of this proposed amendment?**
c) **Will this proposed amendment have an effect on any line item in either the Balance Sheet or Income Statement?**
d) **Was the net Part VI.1 tax the only entry to GL account 786?**

Response IR-3:

a) No
b) Net Part VI.1 tax is included with current income tax expense for external reporting purposes. Recording the net Part VI.1 tax directly in account 086 – Income Tax Expense instead of in account 786 – Tax on Preferred Dividends simplifies the accounting process by removing the necessity of a reclassification entry for external reporting purposes.
c) No
d) Yes

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March 6, 2012

E-mail: eric.ferguson@nspower.ca

Mr. Eric Ferguson
Director, Regulatory Affairs
Nova Scotia Power Inc.
1223 Lower Water Street
PO Box 910
Halifax, NS B3J 2W5

Dear Mr. Ferguson:

Nova Scotia Power Inc. – Accounting Policy and Procedures Manual – Accounting Policy 5900 – Income Taxes – P-111.6 / Matter No. M04760

Receipt is acknowledged on March 6, 2012, of Nova Scotia Power Inc.'s responses to Information Requests (IR-1 to IR-3) issued by the Board on February 23, 2012 in the above-noted matter.

This information has been directed to the Board.

Yours very truly,

Nancy McNeil

Nancy McNeil
Regulatory Affairs Officer/Clerk

c.c. Tim Wood, Manager, Commercial Projects By email

Document: 201399

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March 20, 2012

By email: eric.ferguson@nspower.com

Mr. Eric Ferguson, CMA
Director, Regulatory Affairs
Nova Scotia Power Inc.
P.O. Box 910, 1223 Lower Water Street
Halifax, NS B3J 3S8

Dear Mr. Ferguson:

NSPI Request for Approval for Amendments to Accounting Policy 5900 – Income Taxes (P-111.6 / Matter No. M04760)

The Board received Nova Scotia Power Inc.'s ("NSPI") application, dated January 5, 2012, for approval of amendments to Accounting Policy 5900 – Income Taxes. This application was augmented by answers to Information Requests dated March 6, 2012.

The application consists of two amendments; one to a Policy at paragraph 05 and the other to a Procedure at paragraph 14.

The Board understands that the amendment to the Policy at paragraph 05 would align the treatment of income taxes of the fixed cost deferral and recovery to that of the Fuel Adjustment Mechanism. The requested change has the effect of recording the deferred tax related to the fixed cost recovery as an additional recovery from rate payers. This, in effect, increases by 31%, the total recovery of the actual fixed costs.

The Settlement Agreement (SA) section that supported the creation of the fixed cost deferral states, in part:

> b) ... The forecast amount of 2012 fixed cost recovery will be quantified as part of the NSPI 2012 GRA Compliance Filing, on which all parties will have the right to comment.
>
> [2012 Settlement Agreement, pg. 1]

In the Compliance Filing, received by the Board on December 9, 2011, the treatment of Income taxes, as they relate to the deferral, was not explicitly stated and no comments were made by the parties involved with the SA.

Board Order NSPI-P-892 and NSPI-P-202 dated December 21, 2011, stated:

> 7. The Settlement Agreement and the Board Decision defer the impact of any loss of load from NewPage or Bowater to 2013. A review of the deferral amount will occur in 2012 as part of a 2013 general rate application or during the FAM proceeding in late 2012.

It is not the practice of the Board to approve an individual amount that may affect revenue requirements that has not been considered in the context of a General Rate Application ("GRA"). To be in accordance with the general terms in the SA, to which NSPI was a principal party, and to be in accordance with past Board practice, this matter should be dealt with either through a GRA or the FAM proceeding in late 2012, and not part of an application to change an accounting policy.

The request to amend the Policy at paragraph 05 of 5900 – Income Taxes, is denied at this time. NSPI can reapply for a change if it is approved as part of a future decision.

The Board accepts that the proposed amendment to the Procedure at paragraph 14 will simplify reporting by eliminating the necessity to reclassify certain entries for external reporting purposes as well as reduce the number of GL accounts.

The Board approves the amendment to the Procedure at paragraph 14 of Accounting Policy 5900 – Income Taxes.

Yours very truly,

Murray Doehler, CA, P.Eng.
Member

Nova Scotia
POWER
An Emera Company

energy everywhere.

April 5, 2012

Nancy McNeil
Regulatory Affairs Officer/Clerk
Nova Scotia Utility and Review Board
1601 Lower Water Street, 3rd Floor
P.O. Box 1692, Unit "M"
Halifax, NS B3J 3S3

Re: NSPI Request for Approval for Amendments to Accounting Policy 5900 - Income Taxes *(P-111.61* Matter No. M04760)

Dear Ms. McNeil:

The Board's March 20, 2012 letter declines Nova Scotia Power's request to revise Accounting Policy 5900. We are writing to ask the Board to reconsider this decision in light of the further, and hopefully better, explanation contained herein. We recognize that requests for reconsideration are unusual and should not be made lightly; however, we believe that reconsideration is warranted in this instance because it would be in the best interest of our customers.

It appears, unfortunately, that Nova Scotia Power's original request and IR responses somehow misled the Board, leading to the conclusion that "The requested change has the effect of recording the deferred tax related to the fixed cost recovery as an additional recovery from rate payers. This, in effect, increases by 31%, the total recovery of the actual fixed costs."

Rather than cause an additional recovery from ratepayers, the requested change to the accounting policy would help to prevent the need to seek future additional recovery from our customers. This is because, without the requested change, Nova Scotia Power will need to seek higher rates in the future in order to fully recover both the deferral and the tax implications of that recovery. Under the existing accounting policy, the tax treatment of the deferral will require Nova Scotia Power to record increased earnings in 2012 and drive the need for higher rates in future due to higher income tax expense when the deferral is being recovered.

The following tables will help to illustrate how the change in accounting policy will affect customers:

Summary of Revenue Requirement Effect of Income Tax Accounting Policy Change- Illustration

No Change to Accounting Policy

The income statement impact of not approving the requested change is shown in the table below. For illustration purposes, this assumes the deferral in 2012 equates to $30 million and the deferral is fully recovered in 2013. We expect the deferral to be higher than $30M. The 2013 revenue requirement amounts are not tax-effected in this illustration, which exacerbates the situation.

(in millions)	2012	Comment	2013	comment
Revenue	($30)	Revenue not collected in 2012 but deferred	$30	Deferred Revenue collected in 2013
Fixed Cost adjustment	30		(30)	
Income tax expense (recovery)	(9.3)	Tax deduction available $30M * 31%	9.3	
Earnings	$9.3	Additional earnings not presently incorporated in 2012 forecast	($9.3)	Additional expense that will need to be recovered as a 2013 cost of service

With 2012 rates already set, Nova Scotia Power will end up recording an additional $9.3M in earnings (more when the deferral is higher than $30M). In the 2013 test year Nova Scotia Power would experience an additional $9.3 million income tax expense which will increase the requested revenue requirement in 2013 by $13.5 million (more when the deferral amount is higher than the $30 million used for illustrative purposes).

Approval of NSPI Application

By approving the accounting policy change requested and allowing the recording of deferred taxes then the earnings volatility is removed and customers are fairly treated with no impact to rates in either year. The impact would be as follows:

(in millions)	2012		2013	
Revenue	($30)	Revenue not collected in 2012 but deferred	$30	Deferred Revenue collected in 2013
Fixed Cost adjustment	30		(30)	
Income tax expense (recovery)	(9.3)	Deduction available $30M * 31%	9.3	
Deferred income tax expense	9.3	Deferred income tax calculation of $30M * 31%	(9.3)	Deferred income tax calculation $30M * 31%
Earnings	NIL	No change to earnings	NIL	No change to earnings

The proposed accounting policy change has no bearing on how the deferral works, the amount of the deferral, or any matter relating to the deferral other than ensuring that the tax effect will match the accounting for the deferral (whatever amount it ends up to be and whatever the time period for recovery may be). In hindsight, as the Board notes, Nova Scotia Power wishes that it had raised this tax treatment during the GRA settlement discussions. However, Nova Scotia Power's proposal is an effort to help customers and remove any complication that may arise in the treatment of this regulatory accounting item. And it is exactly the accounting approach the Board has previously approved for the FAM.

While the Board suggests this can be addressed in a later application, such an approach would cause NS Power to record cash taxes on the deferral for external reporting in the interim thereby showing increased earnings. More importantly, we will have to forecast a higher 2013 revenue requirement in order to reflect the increased tax liability in 2013 that we are trying to avoid. In the interim while the main element of the deferral is being determined before the Board, Nova Scotia Power will be recording higher earnings in 2012 that will not be available to customers to offset against the future tax liability.

This is a similar issue to that raised by the Board Staff financial consultant in the GRA in relation to FAM accounting. During that proceeding, Nova Scotia Power met by conference call with the Board's consultant, Donna Ramas, and explained that Accounting Policy 5900 aligns the tax treatment with the timing of FAM deferrals. The current accounting policy explains that Nova Scotia Power uses cash taxes for accounting purposes with the exception of the FAM which uses deferred taxes. After that call, Ms.

Ramas changed her original opinion and agreed that Nova Scotia Power accounts for the FAM deferral and tax correctly. We simply want to do the same for the fixed cost deferral. A change to Accounting Policy 5900 is required because the fixed cost recovery deferral most recently approved is not specifically stated as exempted from cash taxes.

Nova Scotia Power apologizes for any misunderstanding our application may have caused. We would be pleased to have our Vice President of Finance, Claudette Porter, meet with Board staff or its advisors to respond to any questions.

Nova Scotia Power believes strongly that this accounting policy change will help reduce future customer rates if approved. We appreciate the Board's further consideration of this request.

Yours truly,

J. René Gallant
Vice President Regulatory Affairs

C: Claudette Porter
Bruce Outhouse, Q.C.

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May 4, 2012

By email: rene.gallant@nspower.ca

Mr. J. Rene Gallant
Vice President Regulatory Affairs
Nova Scotia Power Inc.
P.O. Box 910, 1223 Lower Water Street
Halifax, NS B3J 2W5

Dear Mr. Gallant:

NSPI Request for Reconsideration of Decision Dated March 20, 2012 Regarding Amendments to Accounting Policy 5900 – Income Taxes (Formerly Matter No. M04760) (P-111.6 / Matter No. M04895)

On April 5, 2012 the Board received Nova Scotia Power Inc.'s ("NSPI") second request for approval for amendments to Accounting Policy 5900 – Income Taxes, originally filed January 5, 2012. In the Board's letter dated March 20, 2012 the Board denied NSPI's request to revise the income tax policy to permit an adjustment to the fixed cost deferral outlined in the 2012 General Rate Application's Settlement Agreement ("SA"). In NSPI's most recent letter of April 5, 2012, NSPI is requesting the Board to reconsider its decision.

NSPI has the potential for significant overearnings due to the difference between the tax and the accounting deductions ("timing differences") and the value of the fixed cost regulatory deferral in 2012. Under NSPI's current accounting policy the utility would be entitled to deduct the fixed costs for tax purposes, reducing the income tax provision and increasing the net income in 2012. In future years, as the deferral is recovered, there will be no corresponding tax deduction available. In order to ensure sufficient cash flow to cover the tax cost in those future years NSPI would require additional funding.

The Board agrees tax savings associated with the deferral are not funds that should assist NSPI in maximizing its earnings only to the detriment of rate payers and it is likely this was not the intent of the parties to the settlement.

Under US GAAP, NSPI is required to record a deferred tax provision for all timing differences. Furthermore, if allowed by a regulator, a regulated utility can record an offsetting deferred regulatory asset to be recovered from future rate payers (the "regulatory recovery"). This has the effect of recording, as income tax expense, the amount which is actually owing to the Canada Revenue Agency by NSPI for that period. The Board has previously approved NSPI's use of this regulatory recovery.

The use of the regulatory recovery was suspended, upon the request of NSPI, for the Fuel Adjustment Mechanism ("FAM"). Because of the material distortion in income that will be created by the deferral of fixed costs, the same suspension is being requested by NSPI.

The Board approves the suspension of the regulatory recovery applicable to the deferral of fixed costs for 2012. The continuation of the suspension for this (if needed), or any other regulatory deferral, should be an issue canvassed at a future proceeding. This approval of the suspension does not include the proposed wording of the amendment to accounting policy 5900. NSPI should meet with Board staff to agree on the wording changes.

The Board reiterates its position that it is not the Board's usual practice to approve an individual amount that may affect revenue requirements that has not been considered in the context of a General Rate Application ("GRA"). To be in accordance with the general terms in the SA, to which NSPI was a principal party, and to be in accordance with past Board practice, matters such as this, generally, should be dealt with either through a GRA or FAM proceeding and not as an application to change an accounting policy.

Yours truly,

Murray Doehler, CA, P.Eng.
Member

c.c.	S. Bruce Outhouse, Q.C., Board Counsel	By email
	Claudette Porter, CA, NSPI	By email

NON-CONFIDENTIAL

Request IR-28:

With respect to the current rate stabilization plan, NSPI is proposing further deferrals:

a) What tax policy has NSPI applied to the proposed deferrals?
b) Please identify what, if any, benefits related to tax deductions will be available to NSPI in 2013 and 2014 based on the proposal put forth.
c) If NSPI has not proposed applying the same tax policy to these deferrals as those proposed for the fixed cost recovery deferral, please explain why?
d) If the proposed deferral results in any additional undisclosed costs to the ratepayers is NSPI prepared to absorb these?

Response IR-28:

(a) NS Power has applied the same tax policy to the proposed deferrals as we use with the FAM and the Fixed Cost Recovery (FCR) deferral as applied for in this Application. The Company will recognize a deferred regulatory asset (liability) related to the deferrals. Deferred income tax expense (benefit) and a corresponding deferred income tax (liability) asset related to the deferrals will be recognized based on the enacted income tax rate(s) for the period(s) when the deferral regulatory asset is expected to reverse.

(b) Please refer to NSUARB IR-27 Attachment 1 for an illustration of the tax impact to NS Power based on the proposed tax policy applied for in the Application. Under the proposed policy, NS Power would receive a current tax benefit in 2013 and 2014 for costs incurred which are deferred for recovery from customers in a future period which would be offset by a future tax expense.

(c) NS Power is proposing to apply the same tax policy to the FCR deferral in 2013 and 2014 as that proposed for the 2012 FCR deferral and as applied for in this Application.

(d) Under the proposed rate stabilization plan any portion of the Board-approved forecasted revenue requirement not recovered by the 3 percent annual increases will be deferred. NS Power is not aware of any undisclosed costs, and would not expect to recover a cost of which it is aware but has not disclosed.

NON-CONFIDENTIAL

Request IR-29:

NSPI has had numerous income tax reassessments resulting from amended tax filings in recent years;

a) What has the actual tax rate, based on taxes assessed by CRA, been for NSPI in each of the past 10 years? What is the resulting average tax rate over the past 10 years?

b) How does the impact of tax reassessments impact the costs to ratepayers?

c) How would claiming additional deductions within amended tax filings differ from the scenario outlined in the requested Income Tax Policy revisions related to increased earnings to NSPI and increased cost to ratepayers related to the fixed cost deferral?

Response IR-29:

(a) Please refer to Attachment 1.

(b) Tax reassessments that result in refunds reduce rates for customers in early years. Without such income tax reassessments, NS Power may have to request rate increases. Positive income tax reassessments may allow NS Power to earn within its allowable return on equity range without requiring rate increases.

(c) NS Power records the impact of tax return amendments in accordance with its Income Taxes Accounting Policy 5900. Please refer to Attachment 2.

The requested income tax policy revision with respect to the Fixed Cost Recovery deferral was specific to a regulatory asset approved by the Board between general rate applications.

NON-CONFIDENTIAL

Even though the scenarios are accounted for differently from a tax accounting policy perspective, both scenarios are being recorded in a manner that is in the best interest of customers.

Recording the impact of tax reassessments on a cash tax basis and therefore impacting current tax only is in the best interest of customers as discussed in response (b) above. With respect to the fixed cost deferral, NS Power's current income tax policy results in additional costs to customers in subsequent years as the deferred costs are recovered due to an additional revenue requirement related to income tax expense. The proposed income tax policy revisions would require deferred income taxes be recorded which would offset the additional current income tax expense and eliminate the additional revenue requirement as the deferred costs are recovered.

Tax year	Actual tax rate
2011	not yet assessed
2010	4.9%
2009	30.0%
2008	33.8%
2007	13.3%
2006	41.5%
2005	37.6%
2004	35.9%
2003	31.6%
2002	39.4%
2001	23.0%
Average	29.8%

COST OF OPERATIONS

INCOME TAXES - 5900

NOVA SCOTIA POWER
An Emera Company

POLICY

01 Income tax expense should be categorized as current or deferred income tax expense as appropriate.

02 The Company uses the applicable enacted tax rate when measuring current and deferred income tax expense.

03 The Company follows the flow-through method of accounting for investment tax credits ("ITC's"). ITC's are recorded in the year earned as a reduction to income tax expense to the extent that realization of such benefit is more likely than not.

04 The Company recognizes deferred income tax assets (liabilities) as appropriate. To the extent deferred income taxes are expected to be recovered from or returned to customers in future rates, the Company will recognize a deferred regulatory asset (liability)[1]

05 The Company will recognize a deferred regulatory asset (liability) related to FAM. Deferred income tax expense (benefit) and a corresponding deferred income tax (liability) asset related to the FAM will be recognized based on the enacted income tax rate(s) for the period(s) when the FAM regulatory asset (liability) is expected to reverse.

FEDERAL INCOME TAXES

06 The Company is subject to federal income tax at prescribed rates applied to taxable income.

PROVINCIAL INCOME TAXES

07 The Company is subject to provincial income tax at prescribed rates applied to taxable income.

TAX ON LARGE CORPORATIONS

08 The Company is subject to a provincial capital tax ("PCT") at prescribed rates applied to taxable capital.

PART VI.1 TAX

09 The Company is subject to Part VI.1 tax at a prescribed rate applied to preferred share dividends paid. The Company receives a tax deduction equal to a prescribed multiple of the Part VI.1 tax.

1 FASB ASC 980-740-25-2

PROCEDURES

10 A monthly income tax provision is recorded by multiplying the Company's effective combined federal and provincial income tax rate forecasted for the year (calculated without inclusion of the forecasted FAM adjustment) by the net earnings before tax for the period. The monthly income tax provision with respect to FAM is based on the actual FAM adjustment for the period multiplied by the enacted tax rate.

11 The Company prepares an estimate of its taxable capital using a forecasted year-end balance sheet. The taxable capital forecast is then multiplied by the enacted tax rate to determine the PCT expense for the year. The PCT estimate is prorated based upon days to determine the amount to accrue each month.

12 The net Part VI.1 tax is calculated using enacted rates and recorded as an additional cost (recovery) of the preferred share dividend. It is reclassified to current income tax expense for external reporting purposes. The monthly Part VI.1 tax expense is based on the amount of preferred dividends declared in the month. The monthly Part VI.1 tax deduction is based on the annual forecasted Part VI.1 deduction prorated based upon the total preferred dividends declared in a month.

13 The Company currently follows the policy of claiming sufficient capital cost allowance and cumulative eligible capital (the tax system's equivalent of depreciation and amortization), to minimize taxable income.

14 Federal and provincial income taxes are included in general ledger account 086 - Income Tax Expense and Provincial Capital Tax is included in account 067. The net Part V1.1 tax is included in general ledger account 786 – Tax on Preferred Dividends.

NON-CONFIDENTIAL

Request IR-30:

With respect to the pension liability balance of $420 million in the 2011 Audited Financial Statements:

a) Please identify what portion of this balance is currently unfunded.
b) Please explain what changes NSPI has made to their investment policies in an effort to control losses?
c) Please explain what has been identified as the primary drivers creating the significant and growing unfunded balance?

Response IR-30:

(a) The pension liability figure of $420 million from the 2011 Audited Financial Statements represents the long term (non-current) liability under US GAAP for pension and non-pension plans. The current liability for pension and non-pension plans was $8.3 million. The sum of the current and long term liability under US GAAP represents the funded status (market value of assets less the projected benefit obligation) of the plans based on actuarial assumptions for accounting purposes. As such there is a total shortfall of $428.3 million on an accounting basis at December 31, 2011.

The largest plan among NS Power's pension and non-pension plans is the NS Power Employee's registered pension. The cash funding requirement is partly determined based on the going concern funded status; the reported accounting position does not impact cash funding requirements. The going concern shortfall of the NS Power Employee's registered pension plan measured using the market value of assets as at December 31, 2011 was approximately $185 million.

(b) The current environment of low and declining interest rates combined with lower investment returns is posing a challenge to the funded status of all defined benefit pension plans in North America. In this challenging environment, NS Power continues to focus on understanding and managing risk within the Plan balanced with achieving consistent returns over time. The Plan's investment returns continue to meet their benchmarks. Please refer to Eckler IR-1.

(c) Primary drivers contributing to the increase in the shortfall on an accounting basis from December 31, 2010, to December 31, 2011, were:

- the reduction in the discount rate (from 5.5 percent to 5.0 percent) which increased the projected benefit obligation; and

- low investment returns during 2011 which resulted in the interest component on the projected benefit obligations exceeding the interest earned on Plan assets.

The increase in the shortfall was partially offset by 2011 NS Power contributions to the plans which exceeded 2011 benefit payments.

NON-CONFIDENTIAL

Request IR-31:

Reference DE-03 - DE-04 Appendix J p. 1 of 3:

NSPI proposes to change clause (2) to read as follows:

> **The customers will reduce their available interruptible system load by the amount required by NSPI within ten (10) minutes of NSPI initiating a telephone call to send notice to the customer's dedicated telephone number requiring such reduction. The customer must maintain a dedicated telephone number and dedicated telephone system in working order at all times and must have a designated staff person to answer the dedicated telephone at all times. The failure of the customer to receive a notice that has been initiated and sent by NSPI to the customer's dedicated telephone number, including failure of the customer to answer the telephone, shall not excuse the customer from its responsibilities under this rider.**

a) Please define "dedicated telephone system".

b) Aside from a customer failing to answer the telephone, please explain the circumstances under which a customer might fail to receive a notice that has been initiated and sent by NSPI.

c) Are there any situations which might "excuse the customer from its responsibilities under this rider"? Please elaborate.

d) Considering NSPI's reliance on customers interrupting their load as a substitute for installing additional generating capacity, please explain what assurance NSPI has that simply "initiating a telephone call" will result in that call actually being received by the customer so that load can in fact be interrupted.

e) Does NSPI consider this approach to load interruption to be as reliable as the alternative of NSPI controlling the startup of dedicated generation? Please explain.

f) To what extent does NSPI have insufficient generation that necessitates continuation of the interruptible rider?

Response IR-31:

(a) A dedicated telephone system is either a landline telephone or cellular telephone that has been installed or obtained exclusively for the purpose of receiving phone calls pertaining to supply interruption Advisories, Alerts and Interruptions and the cancellations thereof from NS Power.

(b) The customer will not receive the message if they have switched off the ringer on the phone instrument, or if the telephone is not maintained in good working order or if the phone is not monitored at all times or cannot be heard ringing over plant ambient noise. NS Power will consider that a call was successfully initiated and sent to the customer's dedicated telephone line when confirmed by the data capturing function of the automated dialling system.

(c) Where customers have advised NS Power in advance, of the requirement to perform maintenance or repair work on the equipment used to perform the rapid shutdown, the customer may be temporarily excused from the Rider requirements.

(d-e) NS Power's automated dialling system produces evidence that NS Power's call is initiated and sent to the customer's dedicated telephone line. Customers can ignore the ringing telephone, fail to maintain their telephone in proper working order or claim that the telephone did not ring, all of which would violate the customer obligations and should result in a penalty. Therefore, NS Power acknowledges that simply initiating the call does not guarantee that the customer will in fact interrupt as required. Since January 2009 NS Power has initiated 91 individual interruption calls (five events) to customers subscribed to the Interruptible Rider of the Large Industrial Tariff. The automated telephone system was used for all but 6 of these calls. In 86 instances customers reduced load as required. One customer admitted that they received the call, but chose not to interrupt. In the four other cases, the non-compliant load was a small fraction of the total load reduction required. The Rider has proven successful in reducing load rapidly. A failure of a combustion turbine to start would be the approximate equivalent of up to fifteen customers failing to respond in a single event. NS Power believes that the value provided to interruptible customers through reduced rates, the rigour with which NS Power implements the program (including the use of an automated telephone system which can confirm that a call has been initiated and sent to a customer's dedicated telephone line), and the deterrent effect on non-compliance gained through the application of tariff penalties for non-compliance will all contribute to a high degree of compliance with supply interruption calls initiated in accordance with the tariff.

(f) NS Power relies on the Interruptible Rider Program as a cost effective substitute for fast response units that can be dispatched within 10 minutes. This is required to respond to a system contingency that causes or will cause an unscheduled flow across the Nova Scotia /New Brunswick intertie that might negatively affect system stability. NS Power is obliged to maintain:

- 171 MW of Ten Minute reserve which includes 33 MW of Spinning reserve. This is equivalent to the Company's largest single on-line contingency – Point Aconi net output (requirement is reduced to the next largest on-line contingency when Point Aconi is not operating).

- An additional 50 MW of Thirty Minute reserve.

Absent the interruptible program, NS Power would experience a deficiency in installed combustion turbine capacity.

NON-CONFIDENTIAL

Request IR-32:

Reference DE-03 - DE-04, p. 155, line 6 to p. 156, line 15:

A number of charges included in NSPI Regulations 7.1, 7.2, and 7.3 are proposed to increase in 2013 and again in 2014 and are supported by the statement that the proposed rate is based on 2012 rate, or on estimated 2013 rate, plus the general rate increase applicable to above the line customers. Please provide justification for increasing those charges above the 3% proposed rate stabilization amount and also justify why they should be increased at all.

Response IR-32:

Under the proposed Rate Stabilization Plan, NS Power treated the miscellaneous services as one revenue category. The application of the approved methodology for setting charges for these services resulted in the overall increase to miscellaneous revenues of 1.6 percent which is below the 3 percent threshold.