REDACTED

Request IR-140:

Reference: Report by Milliken HR, Confidential Attachment 1 to NSPI's Response to Liberty IR-107.

(a) **On page 1 there is reference to [redacted]. Please indicate what is considered to be the [redacted].**

(b) **Please provide each of the documents relied on by Milliken HR which are referred to in footnotes (i) to (vi) of the Report.**

(c) **For each of the 3-year averages set out in the chart on page 2 of the Report, please list each of the [redacted] used to determine the average for each of the seven identified categories.**

(d) **Please provide a chart listing all NSPI employees (this can be done numerically to avoid providing employee names) showing the employee's position at NSPI, the employee's age and the employee's years of service with NSPI. Please indicate for each employee whether they are unionized or non-unionized, and for unionized employees what union they are a member of.**

(e) **Please indicate the current total of unionized employees at NSPI and indicate how many unionized employees have voluntarily left the employment of NSPI in each of the years 2006 through 2010 other than by way of retirement or acceptance of a severance package offered by NSPI (i.e. essentially those unionized employees who have decided to leave the employment of NSPI for another job, career change, etc.).**

(f) **Please indicate over the time period 2006-2010 how many new unionized employees were hired by NSPI in each of those years.**

REDACTED

(g) On page 2 of the Report there is reference to [redacted]. What is meant by a [redacted]?

(h) Please indicate when NSPI anticipates commencing collective bargaining with the International Brotherhood of Electrical Workers regarding the Collective Agreement to replace the existing Collective Agreement which is set to terminate March 31, 2012.

(i) Please indicate how many employees NSPI has hired from NPB collectively during the time period July 1, 2008 to July 1, 2011.

Response IR-140:

(a) [redacted].

(b) Please reference attached documents:

Reference (i): Please refer to Confidential Attachment 1

Reference (ii): Please refer to Confidential Attachment 2

REDACTED

Additional Reference Information (ii)

Source: Towers Watson Power Services Salary Survey, 2010			**Towers Perrin Investor Owned Utilities**	
Position	**Pay Grade**	**NSPI 2011 Job Rate ($)**	**Base Salary Market Median ($)**	**Base Salary Range Midpoint Median ($)**
ENGINEER, SPECIALIST	[redacted]	[redacted]	[redacted]	[redacted]

Reference (iii) – Please refer to Confidential Attachment 3

Reference (iv) – Please refer to Confidential Attachment 1

Reference (v) – Please refer to Confidential Attachment 4

Reference (vi) – This was a quote from an on-line publication source stating it expects the Canadian economy to stabilize in 2011 versus previous years.

(c) Please refer to Confidential Attachment 4.

(d) The data requested would disclose personal confidential information about specific employees (for example, where there is only one employee in a particular position), the release of which would violate the privacy of the affected individuals. Please refer to Confidential Attachment 5 for a List as of April 30, 2011 with employee’s age, years of service with NSPI, and if they are unionized or non-unionized. The employee data in the attached table includes all active, regular and active, term employees effective as of the date provided. All unionized employees are members of IBEW Local 1928.

(e) As of April 30, 2011, NSPI had 1,009 unionized employees.

REDACTED

The chart below outlines voluntary terminations for the period January 1, 2006 – December 31, 2010, excluding retirements or acceptance of a severance package.

Year	Number of Employees
2006	27
2007	23
2008	26
2009	17
2010	18
Grand Total	**111**

(f) The chart below indicates the number of new unionized employees hired by NSPI for the period 2006-2010. The employee data in the table below includes all regular unionized employees, hired during the periods outlined and excludes term employees.

Number of Employees	
Year	**Regular**
2006	58
2007	75
2008	73
2009	67
2010	42
Grand Total	**315**

(g) [redacted].

(h) Collective Bargaining may commence no sooner than 60 days prior to expiry of the Collective Agreement on March 31, 2012.

(i) NSPI does not track the number of employees hired from other companies.

NON-CONFIDENTIAL

Request IR-141:

Reference: NSPI Response to Liberty IRs 49 and 126.

(a) Please indicate why the administrative overhead rates for any given category fluctuate so widely from year to year, eg. 2009 compliance through 2010 Actuals and 2011 forecast (in Liberty IR-126), and 2012 forecast (in Liberty, IR -49).

(b) Please describe in detail how the percentage administrative overhead rate is developed, using one category for the 2012 forecast as an example.

Response IR-141:

(a) Administrative overhead rates are based on the budgets for the upcoming year. Changes in the budgeted amounts for eligible expenses, operating labour and capital labour will cause the rates to vary year over year. For example, the Customer Operations overhead rates have decreased because eligible expenses have remained relatively constant between the 2009 budget and the 2011 budget, while capital labour has increased over the same period.

(b) The rates used for the 2012 forecast are the same as those used for the 2011 ACE Plan. Please refer to Attachment 1 for the calculation of the rates.

2011 O/H Rates Attachment 1 Page 1 of 3

Power Production

PP Regular			
Total Eligible Expenses	A)	9,875,794	
Total Capital Labour re: Thermal Plants	B)	4,325,206	
Total Thermal Plant Labour	C)	41,124,411	
Capital Labour Percentage	D)	10.5%	B/C
Eligible expenses to be capitalized	E)	1,038,674	A*D
PP Regular O/H Rate for Self Constructed Assets		**24.0%**	E/B
Hydro			
Total Eligible Expenses	F)	1,047,760	
Total Capital Labour re: Hydro	G)	397,839	
Total Hydro Labour	H)	5,672,323	
Capital Labour Percentage	I)	7.0%	G/H
Eligible expenses to be capitalized	J)	73,487	F*I
Hydro O/H Rate for Self Constructed Assets		**18.5%**	J/G
Contractor			
Total Contracts	K)	92,403,782	
Total Eligible Expenses		10,923,554	
Less Eligible Capital already recovered		(1,112,160)	
Remaining Eligible Expenses	L)	9,811,393	
Estimated Labour Contained in Contracts	M)	36,961,513	
Total Capital Labour re: PP Contracts	N)	79,035,202	
Capital Labour Percentage	O)	46.8%	M/N
Total A/O applied to Contracts	P)	4,588,385	L*O
PP Contractor O/H Rate		**5.0%**	P/K

2011 O/H Rates Attachment 1 Page 2 of 3

Customer Operations

Regular			
Total Eligible Expenses	A)	43,974,336	
Total Capital Labour	B)	15,324,984	
Total Customer Operations Labour	C)	56,971,272	
Capital Labour Percentage	D)	26.9%	B/C
Eligible Expenses to be Capitalized	E)	11,828,874	A*D
Regular O/H Rate for Self Constructed Assets		**77.2%**	E/B
Contract			
Total Contracts	F)	32,933,007	
Total Eligible Expenses		43,974,336	
Less Eligible Capital already recovered		(11,828,874)	
Remaining Eligible Expenses	G)	32,145,462	
Estimated Labour Contained in Contracts	H)	13,173,203	
Total Capital Labour	I)	54,819,491	
Contract labour %	J)	24.0%	H/I
Total Capital Expenses related to Contracts	K)	7,724,601	G*J
Contract O/H Rate		**23.5%**	K/F
Vehicle			
Estimated Regular Labour		14,306,457	
Estimated Overtime Labour @ 50%		1,018,527	
Total Estimate Labour to calculate Vehicle AO	L)	15,324,984	
Vehicle Expenses related to Operating Activities		6,115,864	
Vehicle Expenses related to Capital Activities	M)	7,764,515	
Total Vehicle Expenses (Excludes Depreciation)		13,880,379	
Vehicle O/H Rate		**50.7%**	M/L

2011 O/H Rates

Attachment 1 Page 3 of 3

Shared Services

Regular			
Total Eligible Expenses	A)	1,449,979	
Total Capital Labour	B)	166,750	
Total Labour	C)	2,719,333	
Capital Labour Percentage	D)	6.1%	B/C
Eligible Expenses to be Capitalized	E)	88,913	A*D
Regular O/H Rate for Self Constructed Assets		**53.3%**	E/B

NON-CONFIDENTIAL

Request IR-142:

Reference: NSPI Response to Liberty IR 130(d).

As only 50% of incentive costs are included in regulated OM&G costs, please confirm that only 50% of the amounts paid out as incentive payments impact NSPI's regulated ROE. If this cannot be confirmed, please explain the inter-relationship between the 50% of incentive costs which are not included in regulated OM&G costs, and the development of NSPI's ROE.

Response IR-142:

Confirmed.

REDACTED

Request IR-143:

Reference: NSPI Response to NPB IR-13. NSPI states that:

> **Given the wide range of measures that may be required, individual actions are not individually budgeted.**

(a) Please indicate the individual actions that NSPI is currently aware of which it anticipates will be dealt with in 2012 in relation to its Power Production Division.

(b) Please indicate the current hourly rate being charged to NSPI by the lead external counsel in the arbitration referred to in NSPI's response to NPB IR-13 and the current hourly rate being charged to NSPI by the lead external counsel assisting NSPI on the GRA Application.

Response IR-143:

(a) [redacted].

(b) Nova Scotia Power will provide this information to the UARB upon request.

NON-CONFIDENTIAL

Request IR-144:

Reference: NSPI Response to NPB IR-69. NSPI indicated that it did not track information regarding the number of employees who have left NSPI citing wages/salaries as the main reason for leaving NSPI.

(a) Does NSPI generally attempt to track the reasons why its employees leave its employ? If not, why not?

(b) Is it NSPI's practice to conduct exit interviews for employees where possible? If not, why not?

(c) Please provide all information in NSPI's possession with respect to departing employees for the years 2009, 2010 and 2011 year-to-date, including any studies and analyses in this regard. (Please feel free to redact any and all reference to individual employee names.)

Response IR-144:

(a-c) Nova Scotia Power does not typically track the reasons why employees leave the company. It is not Nova Scotia Power's regular practice to do exit interviews. As Nova Scotia Power does not typically track this information, no studies or analyses are available.

NON-CONFIDENTIAL

Request IR-145:

Reference: In response to NPB IR-36, the Company states that it did not have the requested information.

Please provide whatever information is available (e.g., original book cost, capital improvements, retirements, accumulated depreciation) that is available for each of NSPI's thermal plants.

Response IR-145:

Please see the table below for the Average Rate Base for the Steam Function broken down by location.

Plant	**2012 Average Rate Base ($000)**
Lingan	322,123
Point Aconi	326,405
Point Tupper	97,561
Tufts Cove	204,087
Trenton	266,798
Point Tupper Marine Terminal	33,774
Power Production General	220,732
Total	**1,471,480**

Request IR-146:

Reference: In response to NPB IR-39, the Company states that it did not undertake an analysis of how its proposed changes in the ELI 2P-RTP rate might have affected historical results.

Is it fair to say that NSPI made no adjustments to its projected revenue from the ELI 2P-RTP class that would reflect the proposed changes? If that is not a correct assumption, please provide NSPI's estimate of how the proposed revisions to the rate will impact projected revenue in 2012.

Response IR-146:

The proposed revisions have no implications on the 2012 test year. (Please refer to the Application, DE-03 – DE-04, revenue evidence, page 136, lines 7 and 8). The 2012 test year revenue of ELI 2P-RTP is determined only by the Customer Baseline Base Cost Rate. The revenues associated with the Debit/Credit mechanism are set at zero for the rate setting purposes as it is difficult to predict customers load shifting behavior in advance and the mechanism itself is designed to produce cost-neutral results on the utility and other customers.

The proposed changes to the billing provisions of the ELI 2P-RTP are concerned only with the failure of the rate to provide the utility with an adequate opportunity to recover its costs of serving ELI 2P-RTP customers.

CONFIDENTIAL (Attachment Only)

Request IR-147:

Reference: In response to NPB IR-45, it states that

> **these proportions are estimates based on the typical type of product bundles that are available when entering into purchased power contracts.**

Please provide copies of representative purchased power contracts that would support this assertion.

Response IR-147:

The proportions of 45 percent fixed and 55 percent variable, as used for the allocation purposes of the purchased power regular costs in this application, have been used consistently since the 2007 rate case (please refer to Attachment 1, which is SEB IR-135 from the GRA 2007). This allocation ratio was examined in the IR processes of the GRA proceedings of 2007 and 2009 and two FAM proceedings of 2010 and 2011.

In response to this request NSPI has reviewed purchased power contract records from 2010. The breakdown of the values of 2010 contracts between the firm versus non-firm categories is 81/19. The details of the 2010 contracts are included in Confidential Attachment 2, filed electronically.

2007 **NSUARB-P-886**

NOVA SCOTIA UTILITY AND REVIEW BOARD

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

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

RESPONSE TO INFORMATION REQUEST

TO: NSPI

FROM: SEB

Question IR-135: **Please justify and support the classification of the $31.8 million of purchased power expense into fixed and variable as shown on lines 2 and 3, column 1 of Exhibit 5 of Attachment G.**

Response IR-135: Typical product bundles available when entering into purchased power contracts are:

- Non-firm energy, which can be viewed primarily as variable cost;
- Firm energy, which can be viewed as a mixture of fixed and variable costs;
- Capacity only, which can be viewed primarily as fixed costs.

The expected mix of these three products produces the classification split shown on Exhibit 5 of Attachment G in the Direct Evidence.

NON-CONFIDENTIAL

Request IR-148:

Reference:

Please provide for each of Nuttby Wind Project, Digby Wind Project and Point Tupper Wind Project:

(a) The mid-year rate base amount attributable to each of those projects for 2012 per the 2012 GRA, and

(b) The annual depreciation expense for each of these projects that are included in the 2012 GRA revenue requirement.

Response IR-148:

(a-b) Please refer to the table below.

Project	**Mid-year Rate Base Amount ($)**	**Depreciation Expense ($)**
Nuttby Wind	101,379,692	4,470,479
Digby Wind	60,353,415	2,601,935
Point Tupper Wind	23,505,549	1,037,270

CONFIDENTIAL (Attachment Only)

Request IR-149:

Reference: OE-01A, Attachement 1 and OP-06

(a) Please provide any studies NSPI has conducted or reviewed to quantify or estimate the amount of no-load heat loss, i.e., the amount of fuel consumed when plants are held in spinning reserve but not producing energy.

(b) Please provide the minimum run levels for each of NSPI's thermal units.

Response IR-149:

(a) Spinning reserve is defined as the difference between a unit's actual generation and its maximum generating capacity (subject to any de-ratings). Units counted towards spinning reserve are synchronized to the system and are producing energy.

(b) Please refer to Confidential Attachment 1.

REDACTED

Request IR-150:

Reference:

The general and fuel module unit report of Strategist shown in Confidential Attachment 3 to GRA OE-01A, page 7 of 9, shows a heat rate of Tusket 1 combustion turbine of [redacted] MMBtu/MWh but an Average variable cost of only [redacted] per MWh. Please explain how this is possible.

Response IR-150:

This occurred when information was copied from .txt format to .doc format. The correct figure is [redacted] per MWh. This does not change Total Fuel and Purchased Power.

REDACTED

Request IR-151:

Reference: Response to NPB IR-60 and IR-111

(a) Please explain the separate functions that Bunker C and furnace oil perform at each of

(i) [redacted];

(ii) [redacted]; and

(iii) [redacted],

and indicate whether natural gas can perform these same functions.

(b) Please calculate the 2012 fuel cost savings assuming natural gas replacement of Bunker C and furnace oil at each of

(i) [redacted];

(ii) [redacted]; and

(iii) [redacted].

(c) Please calculate the 2012 fuel cost savings assuming natural gas replacement of diesel fuel at [redacted].

(d) NSPI's responses to NPB IR-60 and IR-111 indicate various work that will not be completed prior to the hearing in this matter. In order to be of assistance to the

REDACTED

Board and parties, please provide NSPI's current best estimate of any capital costs and expenses that could be incurred to permit natural gas to be used to achieve the savings identified in parts (b) and (c).

(e) Is a natural gas pipeline required for providing natural gas to NSPI's generating units, or could a free-standing storage tank or other process/methodology provide adequate natural gas to replace Bunker C and/or furnace oil and/or diesel fuel?

(f) Please indicate whether NSPI has looked into acquiring natural gas for any of its generating stations other than by pipeline. If NSPI has looked into this, please provide details.

Response IR-151:

(a) Bunker C and furnace oil perform the same services at each of the above stations.

Furnace oil is used for the initial "lighting off" of the boiler igniters. These igniters then are used to provide the flame source to light the Bunker C oil guns. The Bunker C fuel provides two services.

The first is to provide initial heating of the boiler to produce warm up steam and flame stability until the boiler load is sufficient to support the operation of coal burners. This period generally spans boiler warm up to the introduction of the second level of coal burners being placed in service.

The second is to provide support energy and/or flame stability to the furnace during operation period where available coal energy is in-sufficient to support the needed load or for stability during low-load operating conditions.

REDACTED

Natural gas could be used to provide both of these services provided the necessary infrastructure was added to the boilers to utilize this fuel for these purposes and provided it was available in sufficient quantity.

(b) A high level estimate of fuel savings is being prepared for Point Tupper. No other estimates of fuel savings are available because conversion studies for these units have not been carried out.

(c) Please refer to NPB IR-111. A reasonable estimate of fuel savings will not be available until this work is complete.

(d) Natural gas cost conversion studies for these units have not been carried out within the last 5 years, therefore no reasonable capital budget estimates are currently available.

(e) LNG (liquefied compressed natural gas) or CNG (compressed natural gas) could be used for the same services provided by furnace oil and HFO. However, this would require the installation of new infrastructure for the delivery, storage and handling of LNG/CNG. LNG/CNG is more expensive than pipeline natural gas and its use has not been explored by NSPI for these applications to determine if adequate LNG/CNG could be supplied.

(f) No, NSPI has not looked into acquiring natural gas for any of its generating stations other than by pipeline.

REDACTED

Request IR-152:

Reference: Response to NPB IR-58 and Liberty IR-14

(a) Please quantify the 2012 assumed discount per MMBTU and in total for "lower price" term gas as compared to "higher-priced" spot market gas, as described in Liberty IR 14(a).

(b) Please indicate the 2012 percentage of NSPI total natural gas requirements that are expected to be sourced from

(i) spot purchases, and

(ii) long term contracts.

(c) NPB IR-58 requested the quantity, sourcing and pricing assumptions for Fuel for Resale costs and recoveries, as well as the justifications provided in Liberty IR-14. Please complete the response.

Response IR-152:

The response to this request is confidential.

REDACTED

Request IR-153:

Reference: RB-02 - RB-16. The proposed rate base includes an amount for FAM deferral.

(a) Please provide all the workpapers showing the development of the FAM deferral amount that is included in rate base.

(b) Please confirm that, under the FAM Plan of Administration, NSPI earns interest and/or carrying charges on the FAM deferral amount that it proposes to include in rate base. If confirmed, please explain why NSPI believes the FAM deferral amount should be included in rate base.

Response IR-153:

(a) Please refer to following table for details on the FAM deferral balances for 2010-2012.

	2010 ($M)	[redacted]	**2012 ($M)**
Opening Balance	(9.9)	[redacted]	71.4
Current Over/Under Recovery	76.7	[redacted]	-
Prior Year "AA" Recovery	22.3	[redacted]	-
"BA" Recovery	-	[redacted]	(50.2)
Interest	3.8	[redacted]	3.5
Ending FAM Deferral Balance	92.9	[redacted]	24.7

(b) Confirmed. Please refer to CA IR-102.

REDACTED

Request IR-154:

Reference: DE 03-04, Figure 7.2, on page 114, shows the deferred charges and credits are included in rate base.

(a) Please confirm that the Financing Charges shown on RB-02-RB-16, Attachment 1, page 1 of 1, are the Defeasance and Finance Charges shown on Figure 7.2 page 114 of 161. If they are different, please explain the difference.

(b) Please confirm that the Tax Charges shown on RB-02-RB-16, Attachment 1, page 1 of 1, are the Section 21 and 2005 Q1 taxes. If they are different, please explain the differences.

(c) Please identify the amounts of the items that are included in the Other General Charges shown on Figure 7.2, page 114 of 161, and RB 02 RB 16, Attachment 1, page 1 of 1.

(d) Please reconcile the difference between the 2012 average numbers on Figure 7.2 with the numbers for the deferred charges shown on RB-02-RB-16, Attachment 1, page 1 of 1, in the Proposed Rates 2012 column. In this answer, please break out the "defeasance and financing" charges separately.

(e) Please provide a cite or reference to a board Order(s) that authorizes including in rate base the "Prepaid Pension Asset", the "FAM regulatory asset", and "Future Income Taxes".

Response IR-154:

(a) Confirmed.

REDACTED

(b) Confirmed.

(c) Please refer to the following table for items included in 'Other General Charges' (line 13), on RB-02 – RB-16 that make up part of the 2012 Average for 'Other' shown in Figure 7.2. 'Other Deferred Credits', (line 16) on RB-02 – RB-16, make up the remainder. Note that figures reflect whole numbers which may cause $0.1 million in rounding differences on some line items.

$Millions	**Amount**	
Other General Charges	**2011F**	**2012**
DSM (pre 2010)	[redacted]	3.2
Vegetation Management	[redacted]	1.0
Other (Renewable Energy Deposits)	[redacted]	0.9
Total Other General Charges	[redacted]	**5.1**
Other Deferred Credits		
Railway Land - 10 year amortization	[redacted]	-
Pier Land - 10 year amortization	[redacted]	-
Rail Maint. Center - 10 year amortization	[redacted]	-
Repurchase Liability for the rail center	[redacted]	(0.5)
Renewable Energy	[redacted]	(1.5)
Other / Wind	[redacted]	(2.0)
DSM Cost Recovery	[redacted]	(0.3)
Posted Margin	[redacted]	2.5
Total Other Deferred Credits	[redacted]	**(1.9)**
Total Other	[redacted]	**3.2**

REDACTED

(d) Please refer to the following table comprised of figures extracted from RB-02-RB-16 that reconcile with the 2012 Average figures in Figure 7.2. Note that figures reflect whole numbers which may cause $0.1 million in rounding differences on some line items.

$ Millions	**Amount**			
Deferred Charges & Credits	**2011**	**2012**	**2012 Average**	**RB-02-RB-16 Reference**
Defeasance	[redacted]	70.9	76.9	Line 8
Financing Charges	[redacted]	10.3	11.1	Line 8
Section 21 and 2005 Q1 taxes	[redacted]	46.3	55.5	Line 9
Prepaid Pension Asset	[redacted]	59.7	58.2	Line 10
FAM Regulatory Asset	[redacted]	24.7	48.1	Line 12
Asset Retirement Obligation	[redacted]	(154.0)	(149.2)	Line 14
Future Income Taxes	[redacted]	(7.7)	(14.9)	Line 15
Other	[redacted]	3.2	4.5	Lines 13 & 16
Total	[redacted]	**53.4**	**90.0**	

(e) Please refer to NPB IR-80.

NON-CONFIDENTIAL

Request IR-155:

Reference: DE-03, DE-04, Section 5.2, Labour-Related Increases.

Please provide the level of overtime hours and dollars expensed by NSPI for each year from 2006 through 2010.

Response IR-155:

Please refer to the table below for overtime labour hours and expense:

	2006	**2007**	**2008**	**2009**	**2010**
OT Labour Expense	$10.6M	$15.1M	$14.3M	$18.8M	$22.9M
OT Labour Hours	267,528	362,804	337,642	420,727	455,594

These amounts include capital and OM&G. Overtime requirements vary from year to year, due for example to the level of storms experienced, and the amount of power plant shut down maintenance required. Please refer also to NPB-IR-57 Attachment 1 which contains the OM&G portion of storm related overtime.

NON-CONFIDENTIAL

Request IR-156:

Reference: Liberty IR-57, 58 and NPB IR-75.

(a) In reference to Liberty IR-57, please define "term labour".

(b) In reference to Liberty IR-57, please provide examples of charges for "personal equipment".

(c) Do NSPI's calculations of "Storm Operating Costs" in response to Liberty IR-57 and IR-58 include all costs associated with NSPI's storm expense, or is there a further amount of storm-related OM&G expenses included in base OM&G costs? If the latter, please indicate the amount of storm-related OM&G expenses in addition to the $8.7 million in Storm Operating Costs included in the 2012 test year.

(d) With respect to the costs shown in NPB IR-75, please identify all costs that were internal to NSPI operations, and the costs of any capitalized expenses for replacing infrastructure.

(e) Please provide further details regarding how NSPI determines which costs are considered "Storm Operating Costs", NSPI's description of Level 2, 3, and 4 storms, and provide a copy of the IEEE standard 1366-2003 used to categorize storms referenced in the response.

(f) Attachment 1 to NPB IR-75 shows "Other Storm Events" for 2006, 2007, and 2008. Please explain why these amounts do not appear to have been tracked separately, as shown in 2009 and 2010, and indicate whether there were additional storms that were not tracked.

NON-CONFIDENTIAL

Response IR-156:

(a) "Term labour" refers to those employees who are not hired on a permanent basis but rather are hired for a specific period of time or task.

(b) Some examples of "personal equipment" include, but are not limited to: gloves, rubber glove liners & bags, safety glasses, flash jackets, flame retardant clothing, rain gear, steel toed boots, chainsaw boots, overalls, tool belts, hardhats, hat harnesses & liners, chainsaw muffs & pants, safety vests (hunting season), fall arrest belts and lanyards.

(c) Generally, using the descriptions in the Emergency Services Response Restoration Plan (ESRP), costs associated with events managed as Level 2 storms or higher would be allocated to the "storm" accounts. Level 1 storm costs in some cases would be allocated to storm accounts, with the distinguishing factor generally being if the storm response took in excess of eight hours and required resources in addition to those that had been planned for that day. All other outage restoration costs, involving weather and non-weather related causes are considered to be part of regular operations, and the costs are not broken out separately.

(d) Please refer to the table below. The summary of capital expenditures includes internal and external costs.

	Internal to NSPI	Capital Expenditures
2006	$2,403,165	$953,744
2007	$5,438,387	$4,862,642
2008	$4,431,155	$2,680,352
2009	$3,530,318	$1,552,553
2010	$7,088,823	$3,868,027

(e) Please refer to part (c) for a description of the allocation costs to storm accounts.

Please see below for NSPI's description of outage response levels 2, 3 and 4 for storm events, as described in Section 3.1 of the ESRP.

Level 2 – Multi-Region Service Restoration Response

A Level 2 service restoration response shall be initiated by the Director of Regional Operations (or designate) when it is anticipated that restoration can be completed within 36 hours when less than 50,000 customers are out or within 24 hours when more than 50,000 customers are out.

If assistance from resources external to NSPI are deemed to be required to restore service then the response shall be declared as a Level 3, unless Level 4 applies.

Level 3 – Provincial Service Restoration Response (With Outside Resources)

A Level 3 service restoration response shall be initiated by the Storm Lead 3 when it is anticipated that restoration will be completed within 72 hours with more than 50,000 customers out or will take longer than 36 hours with less than 50,000 customers out.

Level 4 – Corporate Service Restoration Response

A Level 4 service restoration response shall be initiated by the Storm Lead 4 when the extent of the emergency / outage affects more than 50,000 customers and exceeds the capacity of NSPI and external resources to restore electrical services in less than 72 hours.

In the event where a State or Local Provincial Emergency is declared, NSPI will coordinate service restoration priorities under the direction of the Operations Director of the Provincial Emergency Operations Centre of the Emergency Measures Organization.

A Level 3 and Level 4 service restoration response results in the opening of the Emergency Operations Centre (EOC) and the establishment of the EOC team.

IEEE standard 1366-2003 was purchased by NSPI; the terms and conditions of that purchase do not allow sharing of the information with another party. This information can be purchased at http://standards.ieee.org/findstds/standard/1366-2003.html. It should be noted that this standard is used to define outage reporting statistics, and as such is unrelated to NSPI's ESRP storm response level definitions.

(f) The processes involved with tracking storm events and related costs have evolved significantly at NSPI over the past several years. The level of detail available prior to 2009 is less because the information was not tracked, except for major storm events which were tracked separately from other storms and normal activity.

NON-CONFIDENTIAL

Request IR-157:

Reference: OR-05. Uncollectibles.

Please provide any written policies or procedures NSPI follows in writing off an account receivable, including a description of the amount of time (days) from the bill being delinquent until the time the account is written off. Please also provide any written policy or rule which delineates how long a customer has to pay their bill before that bill is considered delinquent.

Response IR-157:

The current timeline of each collection step for a residential bi-monthly billed customer is as follows:

Day 1	Customer billed (Bill 1).
Day 30	Bill 1 due in full.
Day 36	The NSPI Customer Information System (CIS) automatically reviews the account to determine if it is paid in full. If not paid in full, and the balance is greater than $5.00, a 1.5 percent late charge is applied to the account. If the balance is greater than $100.00 a friendly reminder bill message is flagged to print on the next bill (Bill 2).
Day 60	Bill 2 is produced and sent with a friendly reminder message and an additional interest charge of 1.5 percent if applicable and if Bill 1 remains unpaid and are applicable.

NON-CONFIDENTIAL

Day 90 — Bill 2 is due in full plus past arrears.

Day 96 — The account is reviewed to determine if it is paid in full. If not paid in full, and the balance is greater than $5.00, an additional 1.5 percent late charge is applied to the account. If the balance is greater than $100.00 a friendly reminder bill message is flagged to print on the next bill. If the balance is greater than $100.00 and includes more than the current bill and one late charge, CIS generates a 14 day disconnection notice which is then mailed.

Day 111 — The account is reviewed to determine if the account balance is still greater than $100.00. If it is greater than $100.00, the account is automatically transferred to the disconnection work file. The disconnection work file is uploaded into the predictive dialer overnight.

Day 112 — Using a predictive dialer, NSPI attempts to contact the customer. Upon successful contact, a Customer Service Representative (CSR) determines if the customer is eligible for payment arrangements. If the customer is eligible for payment arrangements, the time lines going forward will be dependent on the length of the arrangement. These dates can range from 30 days to 12 months based on customers' input on ability to pay. If the customer is not eligible for payment arrangements and the arrears amount is greater than $200.00 or it has been more than 6-months since the last payment, the CSR gives a verbal 24-hour notice of disconnection.

Day 113 — If a 24-hour notice of disconnection was issued, a CSR reviews the account to see if payment was received. If not, a courtesy call is placed and a disconnection for non-payment order is created. The disconnection date will be based on field staff availability and shared with the customer on the courtesy call.

Once a customer has been disconnected for non-payment a final bill is issued. The customer has 41 days from the date of the final bill to pay the closing bill amount before it is written off and released to a third party agency.

If a customer voluntarily disconnects their service with an outstanding balance the write off process is longer. If the customer does not pay the balance in full 41 days after the closing bill, the account appears on a manual report and collections activities begin. This will include attempts to contact the customer to secure payment arrangements. If Nova Scotia Power is unsuccessful securing arrangements by day 141, the account is written off and released to a third party agency.

Please refer to Section 5.4 and Section 6 of the Regulations and Procedures for additional information.

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]	**2012**
Opening Balance		(22.2)
FAM Future Income Tax Expense		14.5
Ending Balance		(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 presentation in its 1993 and 1996 rate applications. This Board, in prior NSPI rate decisions, has based the revenue requirement for the test year 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 common equity is determined, it is possible to calculate the return on average rate base." (Paragraph 174, Decision, 23 October 2002, 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-159:

Reference: SR-04, Attachment 1.

Please provide the workpapers detailing the collection lag for the CWC Study.

Response IR-159:

Please refer to NPB IR-161 (a).

NON-CONFIDENTIAL

Request IR-160:

Reference: SR-04, Attachment 1.

Please provide a list of all cases in which Mr. Browne has testified regarding cash working capital. Please also provide the CWC schedules which support each time he testified on cash working capital.

Response IR-160:

Please refer to SR-04 Attachment 1, pages 34-38 for Mr. Browne's experience and Attachment 1 of this IR for copies of CWC schedules supporting his evidence in other cases.

JTBrowne
Consulting

Nova Scotia Power Inc.

Discussion Paper
On
Cash Working Capital

October, 2005

DRAFT

For Discussion Purposes Only

October 17, 2005

Costing &
Regulatory Consulting

Privileged and Confidential

Prepared at Request of Counsel

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APPENDICES

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INTRODUCTION

Nova Scotia Power Inc. ("NSPI") has a rate application before the Nova Scotia Utility and Review Board ("NSURB"). As part of this proceeding, it is expecting a challenge to its calculation of the necessary cash working capital ("NCWC") component of its necessary working capital ("NWC").

To assist NSPI's company witnesses in preparing to address questions related to its NCWC, NSPI has asked me to provide a background discussion paper. The key focus of the paper is on what should be covered by a lead lag study and NCWC:

- just cash operating expenses; or
- cash operating expenses plus one or more of interest, depreciation and/or equity return.

The next section discusses Canadian practice. This is followed by a section that addresses the application of regulatory principles to the determination of NCWC. The section on Canadian practice is supported by Appendix 1 which provides greater detail on specific cases where the issue of NCWC has been addressed. The focus of this paper is Canadian practice, however, some limited examples of US practice were also identified and they are presented in Appendix 2.

This paper has been prepared solely to provide background material for discussion purposes. Although some of the material in this paper may be used in preparing a submission, it is not expected that this paper will be submitted as evidence in a regulatory proceeding. More importantly, it has not been prepared to meet such a purpose.

PRACTICE

This section discusses current Canadian practice related to the determination of NCWC included in the rate bases of Canadian regulated utilities.

It is often difficult to establish the basis for the calculation of the NCWC approved by Canadian regulators, and even more difficult to identify the reasoning behind the regulatory decisions. There do not appear to be any formal written requirements for determining NCWC in Canada. To the extent that they exist, the requirements are set out in decisions. In many cases, current regulatory decisions state little more than that an amount of working capital has been approved. In some cases, reference is made only to the total amount of rate base that has been approved.

As a general rule, regulators discuss the reasoning for their decisions only where there is a controversy. Once a practice has been dealt with and accepted, future decisions tend to make little or no mention of the details of the approved practice or why it is appropriate.

The following review of Canadian practice is based primarily on a review of regulatory decisions and filed documents, and in some cases, discussions with representatives from utilities and regulatory boards. Further details supporting the discussion in this section are presented in Appendix 1.

APPROACHES TO ESTABLISHING NCWC

Utilities regulated under a return on invested capital methodology have no need to establish a rate base and therefore no need to identify their NCWC. However, most of the major investor owned utilities in Canada are regulated under a return on rate base methodology. With this methodology, utilities normally identify their NCWC and include it in the determination of their rate base.

As set out in by Phillips in “The Regulation of Public Utilities” there are three approaches to determining NCWC:

> *… the cash component may be determined in three basic ways: (1) A detailed lead/lag study, which measures the amount of time before expenses must be paid (expense lead) and compares it with the amount of time before revenues are received (revenue lag). (2) a formula approach (developed to avoid a costly lead/lag study in every case), which commonly uses one-eighth of a utility’s annual operating and maintenance expenses, excluding fuel and purchased power. … (3) The balance sheet method, representing the difference between a utility’s current assets and liabilities. …*[1]

[1] Phillips, Charles F. Jr.; The Regulation of Public Utilities; (Arlington Virginia; Public Utilities Reports Inc., 1993); pg. 348-349.

For major Canadian utilities the most common approach to establishing NCWC is a lead lag study. A formula is used for Ontario electric distribution utilities; however, this likely reflects the large number of these utilities, and in many cases, their small size. I am not aware of any significant Canadian utility that bases its NCWC on the balance sheet method.

Although a balance sheet approach is rarely used to establish NCWC, if ever, it is implicitly used with a return on invest capital methodology. Invested capital equals net assets including the balance amount of receivables and payables.

TRADITIONAL APPROACH TO A LEAD/LAG STUDY

Traditionally, utilities have included only their cash operating expenses in their lead lag studies (including taxes[2]). The companies:

- calculate their revenue lag (i.e., the weighted average time from the provision of service to the time that the cash from the services is received)
- calculate their expense lag (i.e., the weighted average time from the provision of service till the time that their operating expenses are paid)
- subtract their expense lag from their revenue lag to determine the net lag in days and convert this net lag into a ratio (i.e., net lag divided by 365)
- apply the net lag ratio to the company's cash operating expenses to determine its NCWC.

The traditional approach excludes depreciation, interest and equity return from the lead lag study and the calculation of NCWC. I have not seen a discussion in a Canadian regulatory decision as to why these items are excluded. Presumably, it has been a long standing practice and therefore is not addressed in recent decisions.

With this traditional approach, receivables are considered in a utility's NCWC only to the extent that they relate to cash operating expenses. For example, the portion related to depreciation, interest and return is ignored.

ALBERTA APPROACH

For a number of years, the Alberta Energy and Utilities Board ("AEUB") has taken a more comprehensive approach to NCWC. It has approved NCWC that covers all of the expenses included in the revenue requirement. For example, in a 1997 decision, the AEUB stated:

[2] In some cases, taxes are dealt with separately from NCWC in the determination of NWC.

> *The determination of the cash working capital component of NWC recognizes the financing necessary to enable a utility to pay the costs associated with each of the elements of revenue requirement, considering the timing of the expenditures in relation to the receipt of revenues. The cost elements of the revenue requirement are operating expenses, income taxes, depreciation, long-term debt, preferred equity and common equity, including dividends and retained earnings*[3]

The major revenue requirement items covered by the AEUB approach that are not covered by the traditional approach are as follows:

- depreciation
- interest
- preferred dividends
- equity return

Under the Alberta approach, the revenue lag for the above items is the same as for the cash operating expenses.

In the case of interest and preferred dividends there is a known payment date. For example, long term interest payments are usually made semi-annually. This results in an average expense lag of about 91 days.

In the case of depreciation and equity return, the practice of the AEUB up to 1997 was to include these items in the lead lag studies with a zero expense lag. The reason was set out in a 1997 decision:

> *Revenue cash flows to cover depreciation and return on common equity are internal sources of funds used to finance plant additions, to refinance debt and preferred securities and for other corporate purposes. Generally, there is no certainty respecting the timing of these types of expenditures throughout the year. Accordingly, the Board in the past has accepted that these expenditures occur on a uniform basis throughout the year, with a payment date equivalent to the provision of service date. Therefore,… depreciation and common equity have been assigned a zero expense lag, resulting in a net lag equivalent to the entire revenue lag.*[4]

In the same decision, the AEUB decided that a zero lag should apply to only half of the common equity return while the other half should have an expense lag that reflects quarterly dividend payments:

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[3] AEUB; Decision U97065 - 1996 Electric Tariff Applications; October 31, 1997; pg. 499.

[4] AEUB; Decision U97065 - 1996 Electric Tariff Applications; October 31, 1997; pg. 500-501.

The Board continues to hold the view that inclusion of depreciation and common equity return in NWC is appropriate. The portion of the common equity return held as retained earnings is comparable to and can be handled in the same way as depreciation. However, the portion of the common equity return paid out in dividends is more comparable to and should be handled in the same way as preferred equity. … The Board considers it reasonable to make such an assumption and considers that a 50% pay-out with quarterly dividends would reflect a conservative assumption appropriate for the purpose of NWC computations.[5]

INTEREST EXPENSE

A current area of controversy is the treatment of interest expense in the calculation of NCWC. Under the traditional approach it has been ignored; however there is a question as to whether it should be treated the same as cash operating expenses.

At least three utilities outside of Alberta have voluntarily accepted the inclusion of interest expense in the determination of their lead lag study and NCWC: Hydro One Networks Inc. ("Hydro One"), Centra Gas Manitoba Inc. (Centra Gas) and FortisBC. However, the utilities did not include depreciation and equity return.

- Hydro One currently has a rate application before the OEB. As part of its filings, it submitted a lead lag study that included a net lag related to interest expense but not depreciation or common equity return. It appears that interest on long term expense was included because it was recommended by Hydro One's consultant[6]. The OEB has not yet rendered a decision on the utility's application.

- According to a representative of Centra Gas, its lead lag study includes interest expense. The only revenue requirement items excluded are bad debt expense, depreciation and amortization and equity return. According to the Centra representative, interest was included because of a recommendation from one of the utility's consultants in the early 1990's

- As part of its last rate filing, FortisBC included interest expense in its lead lag study and the determination of its NCWC. It did not include depreciation and equity return. In the resulting decision issued on May 31, 2005, the British Columbia Utilities Commission ("BCUC") approved the utility's requested rate base without commenting on the determination of its NWC.[7]

In at least one case, A Canadian regulator has specifically rejected the inclusion of interest expense in the determination of NWC. The Newfoundland & Labrador Board Of

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5 AEUB; Decision U97065 - 1996 Electric Tariff Applications; October 31, 1997; pg. 500.

6 Hydro One: Application re: RP–2005-0020/EB-2005-0378; August 17, 2005; Exhibit D1, Tab 1. Schedule 4.

7 BCUC; FORTISBC; May 31, 2005; pg. 27.

Commissioners Of Public Utilities ("NLPUB") had requested that Newfoundland and Labrador Hydro address this issue. In its response, the utility stated that it adjusted its interest expense to account for the difference between the time that bond interest is paid and the time the related funds are received from ratepayers. As indicated in the 2004 decision, the NLPUB accepted NLH's position:

> *NLH was also directed in Order No. P. U. 7(2002-2003) to provide a study of the implications upon cash working capital allowance of the timing difference between the payment of semi-annual long-term bond interest and the receipt of the funds for their payment. This report was filed in this proceeding. (Exhibit JCR-1) The report concludes that NLH's current method of forecasting interest expense and the cost of debt already reflects the timing of semiannual interest payments and recommended continuation of the current methodology for the determination of NLH's cash working capital allowance. …*[8]

> *The Board is satisfied that the approach and methodology used by NLH in calculating its average rate base and return on rate base for the 2004 test year is appropriate.*[9]

SUMMARY

Most of the major Canadian regulated utilities are regulated under a return on rate base methodology and calculate an amount for NCWC to include in their rate base. Generally, these utilities support their estimate of NCWC with a lead lag study

Traditionally utilities have included only cash operating expenses (including taxes) in their lead lad studies and the determination of their NCWC. Receivables are recognized only to the extent that they relate to the expenses considered in the determination of NCWC.

For a number of years, the Albertan utilities have been unique in that they have included all of the expenses included in their revenue requirement in their lead lag studies and the determination of their NCWC. The difference with the expenses recognized under the traditional approach are: depreciation, interest, preferred dividends and equity return.

A current area of controversy is whether the traditional approach should be expanded to include interest expense in the lead lag studies and determination of NCWC. At least three utilities outside of Alberta have voluntarily made this change.

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[8] NLPUB; ORDER No. P.U. 14 (2004); May 4, 2004; pg. 82.

[9] NLPUB; ORDER No. P.U. 14 (2004); May 4, 2004; pg. 83.

APPLICATION OF REGULATORY PRINCIPLES

This section addresses the basic principles related to the determination of rate base and then applies them to the main items that may be included in NCWC:

- cash operating expenses
- depreciation
- interest and preferred dividends
- common equity return
- payables related to materials and supplies
- payables related to capital expenditures.

BASIC PRINCIPLES

A key principle in Canadian rate regulation is the cost of service standard. This standard states that a regulated entity should be permitted to set rates that allow it the opportunity to recover its costs for regulated operations, including a fair rate of return on its investment devoted to regulated operations – no more, no less. In accordance with this standard, a utility should be permitted the opportunity to recover its cost of financing its investment in regulated operations, both its cost of interest and its cost of equity.

Most utilities employ a return on rate base methodology whereby the financing costs are determined by multiplying the utility's rate base by its weighted average cost of capital. The latter being the average cost to finance a dollar of investment in the utility.

With a return on rate base methodology, a utility's rate base should represent the net investment that the utility has had to make in order to provide regulated operations, i.e., its net financing requirements. This is essentially equal to:

- the amount that the utility has had to pay out but has not yet had an opportunity to recover as cash from ratepayers[10]; less
- the amount of cash the utility has had an opportunity to recover from ratepayers to cover expenses that the utility has not yet paid[11].

[10] It would also include equity return that the utility has not yet had an opportunity to recover - for example, the equity component of AFUDC that has been capitalized and included in the cost of property plant and equipment.

CASH OPERATING EXPENSES

Cash operating expenses should be included in a lead lag study and the determination of NCWC.

A utility has to finance its payments for cash operating expenses until such time as it has an opportunity to recover the cash from ratepayers to cover those expenses (i.e., revenue lag less expense lag). As a result, the net amount should be included in rate base. If it has an opportunity to recover the cash from ratepayers prior to the time payment is made (net expense lag), the resulting cash flow is available to reduce its financing requirements and should be deducted from rate base.

DEPRECIATION

Depreciation should be included in a lead lag study and the determination of NCWC. It should have an expense lag of zero.

Standard practice is to include in rate base the average of the opening and closing net amount of property, plant and equipment. This average amount would therefore include half the depreciation expense for the year. It is as if depreciation were removed from rate base in the middle of the year.

There would be no financing implications if a utility received the cash for depreciation expense in the middle of the year. It would receive cash for the depreciation and reduce its financing requirements at the same time the depreciation was removed from rate base. However, a utility recovers its depreciation expense throughout the year.

If there were no revenue lag, there would still be no net financing implications. Half of the deprecation would be recovered before the middle of the year, providing a source of funding; while half would be recovered after the middle of the year, creating a funding requirement. The additional funding and the funding requirement would tend to average out over the year. Including the depreciation in the property plant and equipment for half the year would adequately recognize the average financing requirements of the utility.

However, if there is a revenue lag, there would be a net financing requirement in addition to what is covered by including property plant and equipment in rate base. The recovery of the depreciation expense would be delayed. The additional financing requirement would equal to the amount of depreciation times the average revenue lag.

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[11] In some cases, these amounts are treated as no-cost capital rather than being deducted in the calculation of rate base. For example, where a utility includes deferred taxes in its revenue requirement, it may include the deferred tax liability in the determination of its weighted average cost of capital as a zero cost source of capital rather than deducting the deferred taxes liability from its rate base.

INTEREST AND PREFERRED DIVIDENDS

Interest expense should be included in a lead lag study and the determination of NCWC.

Interest expense is included in rates as the expense is accrued, whereas the payments for interest on long tern debt are usually made semi-annually. The payments cover the interest for the six months up to the date of that the interest is payable. Therefore, there is a source of funding from the time that the interest included in rates is collected from ratepayers until the time the interest payments are made. The average amount of this funding that can be used to reduce the utility's financing requirements is equal to the interest expenses times the average difference between the expense lag on the interest payments and the revenue lag.

The same argument applies to the issue of preferred dividends.

COMMON EQUITY RETURN

The first issue is whether common equity returns should affect the calculation of the NCWC. A possible reason for excluding equity returns is that they relate to investor supplied funds. This view has been taken by the California Public Utilities Commission ("CPUC") in its Standard Practice U-16-W, "Determination of Working Cash Allowance"[12]. In this document the CPUC stated:

> *The detailed basis of determining working cash allowance is normally referred to as the "weighted average or lead-lag days" method. Fundamentally, the same principles apply for the detailed basis as for the simplified basis, that is, first the operational cash requirement is determined and then amounts of monies available through tax accruals and other funds not supplied by the investor are deducted from the operational requirement.*[13]

Presumably, with this perspective, any consideration of the impact of when the equity return is received should be reflected in the allowed returns.

If common equity returns should be considered in a lead lag study and the determination of NCWC, the appropriate treatment of the common equity return depends on assumptions as to when the equity investors are entitled to the return. For example:

- If it is assumed that the equity returns are intended to accrue to the investors as service is provided, there would be a funding requirement equal to the equity return times the average revenue lag. To provide the equity investors with their

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[12] It appears that the argument was made for all investor supplied funds, including debt.

[13] CPUC; Standard Practice U-16-W - Determination of Working Cash Allowance; May 16, 2002.

return as service is provided, the utility would have to fund the return until it was collected from ratepayers.

- If it is assumed that the equity returns are intended to accrue to investors at the end of the year, there would be a source of funding to reduce the utility's financing requirements. It would, on average, equal the equity return times the net expense lag, where this lag would equal the difference between half a year (i.e., 182.5 days) and the average revenue lag.

PAYABLES RELATED TO MATERIALS AND SUPPLIES

There is an argument for recognizing the accounts payable related to materials and supplies in a lead lag study and the determination of NCWC.

Normally an estimate of the average amount of materials and supplies is included in the calculation of NWC. However, amounts are generally added to materials and supplies before payment is made and amounts are removed from materials and supplies before the utility has an opportunity to recover the amounts from ratepayers. Therefore there is a revenue lag and an expense lag related to materials and supplies.

This may not be an issue. The revenue and expense lags would be recognized where a utility includes the expensing of materials and supplies with the cash operating expenses for purposes of a lead lag study and the determination of NCWC. Alternatively, when the impact of both revenue and expense lags is considered, the net impact on revenue requirements may not be material.

PAYABLES RELATED TO CAPITAL EXPENDITURES

There is an argument for recognizing the accounts payable related to capital expenditures in a lead lag study and the determination of NCWC.

There will usually be payables related to capital expenditures. To the extent that the capital expenditures are added to construction work in progress ("CWIP") or rate base when they are purchased, rather than when they are paid, the utility's financing requirements will be overstated.

There is "rough justice" in recognizing capital expenditures. The practice of using the average of opening and closing balances implicitly assumes that all capital expenditures occur in the middle of the year. Therefore, it may be argued that attempting to fine tune the recognition process by adjusting for accounts payable is not warranted. Alternatively, the impact on revenue requirements may not be material.

To the extent that an adjustment is made for payables related to capital expenditures and the amount is material, the adjustment should be made to the property, plant and equipment accounts.

SUMMARY

The rate base should essentially include the net amount of cash that the utility has had to pay out but has not yet had an opportunity to recover as cash from charging allowed rates[14].

Interest and depreciation should be included in a lead lag study and the determination of NCWC. At least in theory, the rate base should be reduced for the payables related to capital expenditures.

There is a question as to whether equity returns should affect the calculation of NCWC. If they should, the appropriate treatment depends on assumptions about the returns that equity investors have been allowed.

[14] It should also include equity returns that the utility has not yet been allowed to recover as cash from charging allowed rates.

LEAD LAG STUDIES CANADIAN PRACTICE

This appendix provides a summary of Canadian regulatory practice related to the determination of NCWC with a focus on whether depreciation, interest and equity return are included in the supporting lead lag studies.

NEWFOUNDLAND & LABRADOR BOARD OF COMMISSIONERS OF PUBLIC UTILITIES ("NLPUB")

In a 2002 decision, the NLPUB addressed the issue of working capital for Newfoundland and Labrador Hydro ("NLH"). The utility based its NCWC on its cash operating expenses. However the witness for an intervenor (Mr. Mark Drazen) recommended that that the calculation recognize interest expense:

> *With the exception of the witness for LC/W, Mr. Drazen, there were no substantial comments or changes suggested to disagree with the approach taken by NLH. Mr. Drazen expressed the view that the calculation should recognize the timing difference between the payment of semi-annual long-term bond interest and the receipt of the funds for their payment.*[1]

The NLPUB concluded that Mr. Drazen's argument had merit but required further study:

> *The Board agrees in principle with Mr. Drazen's proposal and acknowledges that there appears to be a benefit to NLH from the timing of funds received and the payment of interest on long-term bonds. The Board also recognizes the comments of Mr. Brushett of GT, who stated that a detailed review of Mr. Drazen's calculations or an analysis of the full impact of any benefits or costs has not been prepared.*[2]

As a result, the Board ordered NLH to present an analysis of the issue at its next rate hearing.

As part of its next rate proceeding in 2004, NLH presented a short report on the calculation of its cash working capital allowance (Exhibit JCR-1). In this report, NLH maintained that any benefit from the delay in paying interest was reflected in its cost of debt rate:

> *NLH was also directed in Order No. P. U. 7(2002-2003) to provide a study of the implications upon cash working capital allowance of the timing difference between the payment of semi-annual long-term bond interest and the receipt of the funds for*

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1 NLPUB; Order No. P.U. 7 (2002-2003); June 7, 2002; pg. 100.

2 NLPUB; Order No. P.U. 7 (2002-2003); June 7, 2002; pg. 100.

their payment. This report was filed in this proceeding. (Exhibit JCR-1) The report concludes that NLH's current method of forecasting interest expense and the cost of debt already reflects the timing of semiannual interest payments and recommended continuation of the current methodology for the determination of NLH's cash working capital allowance. Both Grant Thornton and Ms. McShane supported NLH's recommendation that the current methodology for calculating the cash working capital allowance be continued.[3]

In the report submitted by NLH (i.e., Exhibit JCR-1), the summary stated that if interest payments are to be considered in the working capital calculation so should other relevant items:

If interest payments are to be included in the lead/lag study, all items related to financing need to be included. If the cash working capital allowance is interpreted in the broad sense of measuring the full extent to which investors have financed the full cost of service, leads and lags on all elements of the return of and on capital need to be taken into account.

Hydro recommends to the Board that it continue to approve the methodology utilized by Hydro for the determination of its cash working capital allowance. That approach focuses on Hydro's operating expenses and measures the additional capital provided by investors to sustain day-to-day operations between the time service is provided and payment received.

This analysis concludes that, while there may be a theoretical validity to an approach which considers all financial terms, including depreciation, that approach adds a degree of complexity which is unwarranted for the purpose of estimating a reasonable cash working capital allowance, particularly given that Hydro's method of forecasting interest expense and the cost of debt already reflects the timing of semi-annual interest payments.

NLPUB stated that it was satisfied with approach and methodology that NLH used in calculating its cash working capital.

The Board is satisfied that the approach and methodology used by NLH in calculating its average rate base and return on rate base for the 2004 test year is appropriate. [4]

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[3] NLPUB; ORDER No. P.U. 14 (2004); May 4, 2004; pg. 82-83.

[4] NLPUB; ORDER No. P.U. 14 (2004); May 4, 2004; pg. 83.

NEW BRUNSWICK BOARD OF COMMISSIONERS OF PUBLIC UTILITIES ("NBPUB")

In 2003, the NBPUB issued a decision dealing with New Brunswick Power Corporation in connection with an Open Access Transmission Tariff. In this decision, the utility based its working capital on a formula that was applied to operating expenses and the NBPUB concluded that the formula was acceptable:

> *The working capital allowance of $4.7 million was calculated through a formula that uses a fixed percentage of operating expenses. This formula is acceptable to the Board.*[5]

New Brunswick Power Distribution and Customer Service Corporation ("Disco") has recently filed a rate application. In this application, its revenue requirement reflects a return on invested capital / cost of service methodology rather than a return on rate base methodology. As a result, NCWC is not determined.

RÉGIE DE L'ÉNERGIE ("RÉGIE")

According to Hydro-Québec, they have considered only cash operating expenses in their lead lag studies. However, Hydro-Québec Distribution ("Distribution") is currently in a rate proceeding and one of its intervenors has suggested that interest expense should also be considered. The expert for this intervenor is Mark Drazen.

The Régie de l'énergie, requested Distribution to file the implications of including interest expense in its lead lag study. In its filing, Distribution included the implications of including interest, depreciation, dividends and retained earnings. However, the utility has requested that the Régie base its allowed necessary cash working capital on its lead lag study as originally filed.

Hearings for the above noted proceeding have not yet started and a decision is not expected until March 2006.

ONTARIO ENERGY BOARD ("OEB")

On the electric side, a formula is used for establishing the NCWC for most of the electric utilities. This probably reflects the large number of electric utilities and the relatively small size for many of them. However, there has been some discussion as to whether a lead lag study might be used to support the formula.

One of the major Ontario electric utilities is Hydro One Networks Inc. ("Hydro One"). The utility has filed a rate application before the OEB, and as required by a previous

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[5] NBPUB; re: New Brunswick Power Corporation in connection with an Open Access Transmission Tariff; March 13, 2003; pg. 9.

OEB order, this filing it has included a lead lag study. The study includes interest expense but not depreciation or equity return. It appears that originally Hydro One was not going to include interest expense but did so on the recommendation of its consultant[6]. The OEB has not yet rendered a decision on this application.

A representative of the OEB who works with the gas utilities stated that there are no formal requirements for a lead lag study. According to a representative of Enbridge Gas Distribution ("EGD") which is regulated by the OEB, EGD's lead lag study considers only cash operating expenses and not interest, depreciation or return.

MANITOBA PUBLIC UTILITIES BOARD ("MPUB")

Manitoba Hydro is regulated using a return on invested capital / cost of service methodology. As a result, necessary cash working capital is not determined.

According to a representative of Centra Gas Manitoba Inc. (Centra Gas), the utility's lead lag study and NCWC includes everything in its revenue requirement except for bad debt expense, depreciation and amortization and equity return. He said that interest expense was included voluntarily on the recommendation of a consultant in the early 1990's.

ALBERTA ENERGY & UTILITIES BOARD ("AEUB")

The AEUB provided an extensive review of NCWC in a 1997 decision dealing with four Albertan electric utilities, including Transalta Utilities Corporation ("TAU").

In this decision, the AEUB took a comprehensive view of the elements to be considered in conducting a lead lag study:

> *The determination of the cash working capital component of NWC recognizes the financing necessary to enable a utility to pay the costs associated with each of the elements of revenue requirement, considering the timing of the expenditures in relation to the receipt of revenues. The cost elements of the revenue requirement are: operating expenses, income taxes, depreciation, long-term debt, preferred equity and common equity, including dividends and retained earnings.*[7]

The AEUB stated its reasons for recognizing net cash working capital:

> *… A net lag requires that the utility borrow the funds necessary to bridge the lag between payment of expense and receipt of revenue. Conversely, a net lead allows the utility to invest the funds received in advance of the expense payment. The Board*

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[6] Hydro One: Application re: RP–2005-0020/EB-2005-0378; August 17, 2005; Exhibit D1, Tab 1. Schedule 4.

[7] AEUB; Decision U97065 - 1996 Electric Tariff Applications; October 31, 1997; pg. 499.

notes that, in actual practice, the investments would be netted against the borrowings.

In the rate-setting process, this requirement for borrowing or investment is recognized by an increase or reduction in NWC. Consistent with actual practice, the requirement for borrowing is offset by the opportunity for investment, resulting in a net NWC requirement. The respective amounts are determined using a lead/lag study, which calculates the positive or negative values attributable to the number of net lag or lead days for each element of the revenue requirement. …[8]

The AEUB set out the following reasoning for assigning a zero expense lag to depreciation and return on equity:

... As stated above, such a determination can be made where the payment schedule is certain, which is the case for all revenue requirement elements other than depreciation and return on common equity. Revenue cash flows to cover depreciation and return on common equity are internal sources of funds used to finance plant additions, to refinance debt and preferred securities and for other corporate purposes. Generally, there is no certainty respecting the timing of these types of expenditures throughout the year. Accordingly, the Board in the past has accepted that these expenditures occur on a uniform basis throughout the year, with a payment date equivalent to the provision of service date. Therefore, in accordance with scenario A above, depreciation and common equity have been assigned a zero expense lag, resulting in a net lag equivalent to the entire revenue lag.[9]

In this decision the AEUB changed its position on the treatment of common equity returns. It concluded that the portion paid out as dividends should be handled the same as preferred equity (i.e., the same as interest expense):

The Board continues to hold the view that inclusion of depreciation and common equity return in NWC is appropriate. The portion of the common equity return held as retained earnings is comparable to and can be handled in the same way as depreciation. However, the portion of the common equity return paid out in dividends is more comparable to and should be handled in the same way as preferred equity. The Board acknowledges that the existing methodology, which has been approved by the Board and adopted by the Utilities, treats the total common equity return as being held as retained earnings. It does not take into account the payment schedule that generally exists for the portion of common equity return that may be paid out in dividends on a periodic basis throughout the year. The Board considers that if an assumption were made respecting a payout ratio and frequency of dividend pay-out, the dividend portion of common equity return could be treated,

8 AEUB; Decision U97065 - 1996 Electric Tariff Applications; October 31, 1997; pg. 500.

9 AEUB; Decision U97065 - 1996 Electric Tariff Applications; October 31, 1997; pg. 500-501.

for working capital purposes, in the same manner as preferred equity. The Board considers it reasonable to make such an assumption and considers that a 50% pay-out with quarterly dividends would reflect a conservative assumption appropriate for the purpose of NWC computations.[10]

The AEUB concluded:

… the Board directs TransAlta, in its refiling, to revise the lead/lag study to reflect a common equity pay-out ratio of 50% with a quarterly dividend payment cycle. This will require the separation of the common equity component into two equal components (e.g., the dividend and retained earnings components). The dividend component of common equity return should be treated in the same manner as preferred equity return, whereas the retained earnings component should be treated in the same manner as depreciation for the purposes of calculating NWC.[11]

In the proceedings, an intervenor (IPCAA) argued that including the equity return in necessary working capital had a compounding effect on the allowed rate of return. The AEUB rejected this argument:

The Board notes IPCAA's submission that the Board should fix the allowed equity rate of return recognizing that inclusion of equity return in necessary working capital has a compounding effect on the allowed rate of return. The Board notes that IPCAA's position is based on an assumption of continuous compounding of the total return on equity. The Board considers that IPCAA's position fails to recognize that the portion of equity return held for retained earnings is an internally generated source of funds required to meet capital and refinancing expenditures, with no opportunity for reinvestment on a continuous compounding basis. With respect to the portion of common equity used for dividend payments, the Board notes that continuous compounding requires the somewhat unrealistic assumption that the temporary excess in dividend equity funds prior to pay-out would be reinvested on a daily basis in activities sufficient to generate the allowed equity rate of return. In theory, this excess could only be reinvested for a period of time equal to the lead days and at a rate lower than the allowed equity rate of return. In practice, the excess would be netted against borrowings, reducing the need to borrow.[12]

It appears that the AEUB has maintained its positions on NCWC. In a 2005 decision, the AEUB approved the cash working capital allowance requested by FortisAlberta[13]. From the schedules that support the $59.9 million in NWC approved by the AEUB, it is apparent that FortisAlberta included depreciation, interest and equity return in its lead lag

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[10] AEUB; Decision U97065 - 1996 Electric Tariff Applications; October 31, 1997; pg. 501.

[11] AEUB; Decision U97065 - 1996 Electric Tariff Applications; October 31, 1997; pg. 502.

[12] AEUB; Decision U97065 - 1996 Electric Tariff Applications; October 31, 1997; pg. 501.

[13] AEUB; Decision 2005-053; May 24, 2005; pg. 16.

study and the determination of its NCWC. Consistent with Decision U97065, half of the equity return was treated as dividends and half as retained earnings.

BRITISH COLUMBIA UTILITIES COMMISSION ("BCUC")

It is not clear what the requirements are in BC. BC Hydro is regulated on a return on invested capital / cost of service methodology. As a result, necessary cash working capital is not determined. However, it appears that the major investor owned utilities do establish a rate base and the cash working capital included in the rate base is based on a lead lag study.

According to a representative of FortisBC, the BCUC does not have a prescribed methodology for lead lag studies. As part of a recent rate proceeding, FortisBC filed the calculation of its working capital allowance which included the results of a lead lag study. The study covered cash operating expenses plus interest, but did not include depreciation and return.

According to the representative of FortisBC, the utility was not directed by the BCUC to include interest expense, but did so because it was a cash expense. Depreciation and return were excluded because they were not cash expenses. The BCUC accepted FortisBC's proposed rate base and therefore its proposed working capital.[14]

Although FortisBC believed that it should include interest expense, it appears that Terasen Gas (Vancouver Island) Inc. does not. In its 2006-2007 Revenue Requirements Application, the utility set out its cash working capital requirements, including the results of its lead lag study. As indicated on Schedule 11 of its application, the utility's proposed cash working capital is based on a lead lag study that includes only cash operating expenses: cost of sales, transportation costs, lease payments for equipment and system asset, operating and maintenance expenses, BC capital tax, municipal tax, PST (7% of total rev-res rev), large corporations tax, GST (7% of total revenue) and income taxes. The BCUC has not yet rendered a decision on this application.

NATIONAL ENERGY BOARD

It appears that lead lag studies for the NEB consider only cash operating expenses.

The NEB has a filing manual and Guide P of this manual deals with tolls and tariffs. In providing guidance for filings to support a pipelines rate base, Section P.2 Rate Base states:

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[14] BCUC; FORTISBC; May 31, 2005; pg. 27.

> *… for cash working capital, a time lag analysis for the base year if a change is proposed from the most recent NEB approved average number of days between operating expense payment dates and revenue receipt dates; …*

In a recent filing, TransCanada PipeLines Limited filed a "Time Lag Review" that only included cash operating expenses. It did not include interest expense, depreciation or return. The resulting net lag was then applied to net operating, maintenance and administrative expense. In approving the utility's applied for rate base, which include NCWC, the NEB stated:

> *… No party raised concerns with respect to the applied-for Rate Base or its components….*[15]

[15] NEB; RH-2-2004 Phase I; September 2004; pg. 7

LEAD LAG STUDIES
LIMITED SELECTION OF US PRACTICE

This appendix provides a very limited and selected review of US regulatory practice related to the determination of NCWC with a focus on whether depreciation, interest and equity return are included in the supporting lead lag studies. The focus of this discussion paper is Canadian practice and therefore a concerted effort was not made to review US practice.

FEDERAL ENERGY REGULATORY COMMISSION ("FERC")

The FERC Office of Markets, Tariffs and Rates has issued "Instruction Manual for Electronic Filing of the Rate Filings. In addressing "Schedule E-1. Computation of Cash Working Capital Adjusting Rate Base" the document states:

> *Show the computation of cash working capital claimed as an adjustment to the gas company's rate base. Any adjustment to rate base requested must be based on a fully-developed and reliable lead-lag study. The components of the lead-lag study must include actual total company revenues, purchased gas costs, storage expense, transportation and compression of gas by others, salaries and wages, administrative and general expenses, income taxes payable, taxes other than income taxes, and any other operating and maintenance expenses for the base period. Cash working capital allowances in the form of additions to rate base may not exceed one-eighth of the annual operating expenses, as adjusted, net of non-cash items.*[1]

The document does not specifically exclude depreciation or financing costs. However, the document lists a number of cash operating costs that must be included in the components for a lead lag study and this list does not include depreciation or financing costs.

CALIFORNIA PUBLIC UTILITIES COMMISSION ("CPUC")

The Water Division of the CPUC issued Standard Practice U-16-W, "Determination of Working Cash Allowance", dated May 2002. The document was intended to describe staff practices and serve as a guide to staff engineers or analysts in determining the working cash allowance. It appears that the document would have interest and equity return excluded from a lead lag study and the determination of NCWC because they relate to investor supplied funds:

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[1] FERC; Office of Markets, Tariffs and Rates; Instruction Manual for Electronic Filing of the Rate Filings Form Approved OMB No. 1902-0153; January 1997; pg. 23.

The detailed basis of determining working cash allowance is normally referred to as the "weighted average or lead-lag days" method. Fundamentally, the same principles apply for the detailed basis as for the simplified basis, that is, first the operational cash requirement is determined and then amounts of monies available through tax accruals and other funds not supplied by the investor are deducted from the operational requirement. The term investor as used herein is defined as one who invests (to lay out money or capital) in business with the view of obtaining an income or profit; to convert into some form of wealth other than money, as securities or real estate, with the expectation of deriving income.[2]

Although Standard Practice U-16-W would exclude interest and equity return, it would include depreciation expense.

…The expenses used to develop lag days are separated into their basic components, such as purchased commodities, company labor expensed, types of employee benefits, types of taxes, depreciation, materials, goods and services.

…Since book depreciation expense is occurring uniformly day by day and accumulated depreciation is deducted from the rate base, the practice is to include depreciation provisions at zero lag days.[3]

PUBLIC UTILITY COMMISSION OF TEXAS ("TPUC")

The TPUC provides specific directions for the lead lag studies of investor owned electric utilities in its "Substantive Rules Applicable to Electric Service Providers". These directions require that the studies consider only cash items:

For all investor-owned electric utilities a reasonable allowance for cash working capital, including a request of zero, will be determined by the use of a lead-lag study. A lead-lag study will be performed in accordance with the following criteria:

(-a-) The lead-lag study will use the cash method; all non-cash items, including but not limited to depreciation, amortization, deferred taxes, prepaid items, and return (including interest on long-term debt and dividends on preferred stock), will not be considered. …[4]

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[2] CPUC; Standard Practice U-16-W - Determination of Working Cash Allowance; May 16, 2002.

[3] CPUC; Standard Practice U-16-W - Determination of Working Cash Allowance; May 16, 2002.

[4] TPUC; Substantive Rules - Chapter 25 Applicable to Electric Service Providers; 25.231(c)(2)(B)(iii)(IV)(-a-).

JTBrowne
Consulting

Newfoundland Power

Regulatory Accounting Issues Related to 2007 Rate Application

May 4, 2007

Costing &
Regulatory Consulting

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INTRODUCTION

Newfoundland Power ("NP") is making an application to the Newfoundland & Labrador Board of Commissioners of Public Utilities ("Board") for new rates to be effective on January 1, 2008.

As part of its application, NP is proposing a number of changes to its regulatory accounting policies and presenting an estimate of its cash working capital. NP has asked me as a Chartered Accountant and economist with experience in addressing regulatory issues[1] to address, from a regulatory perspective, a number of questions concerning the appropriateness of these changes and the calculation of its cash working capital. These questions deal with the following six issues which can be grouped into three categories:

Future Employee Benefits:

- Recovery of Other Post Employment Benefits (OPEBs)
- Tax Effecting Future Employee Benefits

Amortization of Deferrals and Reserves:

- Amortization of Regulatory Deferrals
- Amortization of Reserve Balances

Transition to Asset Rate Base Method:

- Adjustments to Rate Base
- Cash Working Capital

In addressing NP's questions, I will be referring to established regulatory principles. A discussion of the relevant regulatory principles is presented in Exhibit JTBC-2.

In preparing this report, I have relied on financial data and other information about NP that was provided to me by the utility. My mandate dealt solely with accounting and regulatory principles and policies and the application of those principles and policies. As a result, I was not asked, and did not perform, any audit or other verification procedures on data and information provided to me by NP.

The following sections address the questions related to each of the six issues noted above. In each section, the underlying issues and the relevant background are set out, the utility's proposal is summarized and analysed, and a response is provided.

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[1] A copy of my resume has been attached as Exhibit JTBC-1.

RECOVERY OF OTHER POST EMPLOYMENT BENEFITS

INTRODUCTION

NP's future employee benefits include both pensions and other post employment benefits ("OPEBs"). The latter are composed of health, medical and life insurance for retirees and their dependents, as well as employee retirement allowances. For regulatory purposes, NP recognizes its pension expense on an accrual basis but its OPEB expense on a cash basis.

Beginning on January 1, 2008, NP is proposing to recognize its OPEB expense on an accrual basis for regulatory purposes. It is also proposing that treatment of its OPEB Regulatory Asset (i.e., the cumulative difference between the OPEB costs accrued under GAAP and what it has been allowed to recover under the cash basis) be deferred until a future date.

NP has asked me if its proposal to adopt accrual accounting for its OPEB expense and defer treatment of its OPEB Regulatory Asset at December 31, 2007 is consistent with established regulatory principles and appropriate in the context of NP.

BACKGROUND

Section 3461 of the CICA Handbook "Employee Future Benefits" sets out how companies must report their future employee benefit costs for financial reporting purposes[2]. Prior to the issuance of Section 3461, there was no specific guidance in Canada on how to account for future employee benefits other than pensions. Many companies applied the pay-as-you-go, or cash approach, whereby the cost of the benefits is expensed as the payments are made.

Section 3461 replaced Section 3460. Whereas Section 3460 dealt only with pensions, Section 3461 deals with all future employee benefits. Section 3461 is applicable to fiscal years beginning on or after January 1, 2000.

With Section 3461, companies must account for the cost of OPEBs in the same way as they account for pensions. The expense must be accrued and can no longer be recognized on a cash basis, at least for financial reporting purposes. The accrual method results in a better matching of costs to the periods for which the costs were incurred. With the cash basis, costs may be recognized years, if not decades, after the period for which they were incurred.

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[2] For general purpose financial reporting, companies must follow generally accepted accounting principles ("GAAP"). In setting regulatory accounting policies, regulators often follow GAAP but are usually not required to do so.

As a result of Section 3461, a number of utilities and their regulators have reviewed the method for recovering OPEB costs and switched from the cash to the accrual method.[3]

Where the OPEBs are provided through a defined benefit plan, as is the case with NP, Section 3461 requires that the calculation of the OPEB expense include:

- the current service cost;
- plus interest on the accrued benefit obligation;
- less the return on any plan assets that have been invested to fund the future liability;
- plus / less the amortization of any actuarial gain or loss; and
- plus / less the amortization of any transitional asset or obligation.[4]

The current service cost is the present value of the future OPEB payments as a result of employee services provided in the current period – i.e., the amount that if invested today would grow with interest to equal the future OPEB payments as a result of services provided in the current period.

The accrued benefit obligation is the present value of the future OPEB payments as a result of past employee services. The current service cost plus the future interest on the related accrued benefit obligation are intended to accumulate to an amount equal to the future OPEB payments due to current service.

Unlike pension plans, companies generally do not fund their OPEB plans. As a result, they have no interest income on plan assets and tend to have an accrued benefit liability. This liability represents the difference between what has been expensed and what has been paid out.

Actuarial gains and losses arise because the expense for a defined benefit plan is based on assumptions. Where actual results differ from what was assumed or there is a change in assumptions related to past periods, the result is recognized as an actuarial gain or loss.

Adoption of Section 3461 usually resulted in a transitional obligation. Before amortization, it would have equalled the cumulative difference between what should have been expensed in the past under Section 3461 and what was actually expensed[5]. For NP

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[3] This is supported by a survey completed by NP and discussed in the Company's "Application And Company Evidence" under Section 3.6 "Employee Future Benefits"

[4] Section 3461 sets out other potential components of the expense for a defined benefit plan. However, they are not applicable to NP's OPEBs.

[5] The definition of a "transitional obligation" is set out in the CICA Handbook in paragraph 034 of Section 3461 "Future Employee Benefits".

and most other utilities, it equalled the cumulative difference between the accrual and cash basis at the time they adopted Section 3461 for financial reporting purposes.

For financial reporting purposes, NP adopted Section 3461 as of January 1, 2000. It applied the new section prospectively, amortizing the resulting transitional obligation on a straight-line basis over almost 18 years, the expected average remaining service period of the plan members at that time.

It should be noted that Section 3461 establishes what is required under GAAP which sets out financial statement accounting and reporting requirements. However GAAP is designed for financial reporting purposes, not rate setting. Although it often provides useful guidance for regulators in setting rates, regulators can and do deviate from GAAP where they believe it is appropriate in setting just and reasonable rates.

Although NP adopted accrual accounting for financial reporting purposes in accordance with GAAP, it continued to recognize its OPEB expense on a cash basis for regulatory purposes. The main reason for maintaining the cash basis was the impact on rates from a change to the accrual method.

In a report prepared for NP's last general rate application ("GRA"), I wrote:

> *From the perspective of the principle of intergenerational equity, the accrual method for recovering OPEB costs is preferable to the pay-as-you-go method proposed by NP. However, the NP proposal is a practical approach that recognizes the impact of dealing with the transition from one method to the other.*[6]

In its decision following that application, the Board accepted the continued use of the cash basis:

> *To avoid rate impact on consumers the Board is prepared to accept NP's proposal to continue with using the cash basis for recognizing expenses for other employee future benefits.*[7]

At least one other regulator has recognized the need to consider the impact on rates of a change from the cash to the accrual basis. In a 2003 decision, the British Columbia Utilities Commission ("BCUC") approved the continued use of the accrual method for BC Gas while noting that it had approved the "pay-as-you-go" method for two other utilities to avoid rate shock.

> *While the Commission has approved the "pay-as-you-go" method for Pacific Northern Gas Ltd. and Aquila Networks Canada (British Columbia) Ltd., it did so to*

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[6] John T Browne; Newfoundland Power - Accounting and Regulatory Issues Related to Future Employee Benefits and the Hydro Production Equalization Reserve; October 11, 2002; pg. 13.

[7] Newfoundland & Labrador Board Of Commissioners Of Public Utilities; Order No. P.U. 19 (2003); June 20, 2003; pg. 83.

avoid rate shock at the time of the Orders. This situation does not exist for BC Gas. ***The Commission accepts the continuation of the accrual basis of accounting for OPEB for the 2003 Revenue Requirements.***[8]

Although the Board accepted NP's continued use of the cash basis, in its 2003 decision it went on to require NP to develop a plan for moving towards the accrual method:

The Board is concerned about the potential liability for employee future benefits and is of the view that NP should explore using the accrual method of accounting for these benefits. The Board recognizes that there are significant transitional obligations associated with this change in accounting policy but once the transitional obligation has been met these costs should decrease. … The Board will direct NP to propose a plan at its next general rate application for moving towards the accrual method of accounting for employee future benefits as recommended by CICA. The Board emphasizes such a plan should be presented to the Board as an alternative to the existing method and should address the transitional impact with a view to fulfilling NP's obligation to its employees while at the same time moderating its impact on rates…[9]

Since it has been expected that the Board will allow NP to recover in future rates the difference between its GAAP expense for OPEBs (i.e., determined in accordance with Section 3461) and what it was allowed to recover in rates, NP has recognized a regulatory asset for financial reporting purposes equal to the cumulative difference (i.e., OPEB Regulatory Asset).

NP'S PROPOSAL

For rate setting purposes, NP is proposing to adopt the accrual basis for recognizing its OPEB costs, beginning on January 1, 2008. With this proposal, NP's OPEB expense for regulatory purposes would be exactly the same as the expense determined under GAAP.

The change to the accrual basis raises the issue of how to deal with the transitional costs – i.e., the cumulative difference between the costs that would have been expensed in the past under the accrual basis and the costs that were actually expensed under the cash basis. If NP were to continue with the cash basis, these costs would be recoverable in the period in which payment is made. It should be noted that the lower expense in past periods due to the use of the cash basis did not benefit NP but its customers who paid lower rates.

The transitional costs fall into two categories with some overlap: the transitional obligation and the OPEB Regulatory Asset. The first amount arose from adoption of

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[8] BCUC; BC Gas Utility Ltd. 2003 Revenue Requirements Application; February 4, 2003; pg. 37.

[9] Newfoundland & Labrador Board Of Commissioners Of Public Utilities; Order No. P.U. 19 (2003); June 20, 2003; pg. 83.

Section 3461 while the second arose from the continued use of the cash basis for regulatory purposes.

- The transitional obligation was determined at the time NP adopted Section 3461 for financial reporting purposes (i.e., January 1, 2000). It equals the cumulative difference between what NP would have expensed under the accrual method in accordance with Section 3461 and the actual amount it had expensed under the cash basis. Consistent with Section 3461, this amount is being amortized for financial reporting purposes on a straight-line basis over 17.6 years - the estimated remaining service life of the covered employees at the time Section 3461 was adopted. At January 1, 2000, the transitional obligation was $25.1 million. At January 1, 2008, the amount of the transitional obligation that will have been amortized and included in the OPEB Regulatory Asset will be $11.4 million, leaving an unamortized balance of $13.7 million

- The OPEB Regulatory Asset represents the cumulative difference between what NP has accrued for financial reporting purposes in accordance with GAAP and what it has recognized for regulatory purposes using the cash basis. Since NP was using the cash basis for financial reporting purposes prior to 2000, this difference has arisen over the period since January 1, 2000. At December 31, 2007, the OPEB Regulatory Asset is expected to be $34.1 million, which will include the $11.4 million of the transitional obligation that will have been amortized for financial reporting purposes.

In the case of the transitional obligation that has not been amortized for financial reporting purposes at January 1, 2008 (i.e., $13.7 million), NP is proposing to recover this amount in rates through the use of the GAAP expense. The GAAP expense includes amortization of the transitional obligation – about 1/18 of the original balance each year.

In the case of the OPEB Regulatory Asset, which includes the portion of the transitional obligation that will have been accrued for financial reporting purposes on January 1, 2008, NP is proposing that the decision on its amortization be deferred until a future date. This is being done to enhance rate stability.

As discussed in a later section, NP is also proposing to tax effect it future employee benefit expenses, including its OPEB expense. This will reduce the impact on rates of changing from the cash to the accrual method.

Table 1 sets out the impact of NP's proposal on its revenue requirement in 2008. With the accrual method, NP's OPEB expense is expected to be $7.5 million.

Adopting the accrual method will affect NP's rate base. The OPEB expense, and the amount NP is allowed to recover from customers, will exceed its current OPEB payments. The cumulative difference will equal the difference between its OPEB Liability and its OPEB Regulatory Asset. As discussed in a later section, where NP is allowed to recover costs prior to payment, the amounts should be deducted from rate base

Table 1

Impact on Revenue Requirement of Recognizing OPEB Expense on Accrual Basis 2008 ($ million)

OPEB Expense - Accrual Basis	7.5
Reduction in Allowed Return	(0.3)
	7.2
Recovery of Additional Taxes	3.3
Rev. Req. W/O Tax Effecting	10.5
Impact of Tax Effecting	
Decrease in Tax Expense	(3.1)
Increase in Financing Costs	0.1
	(3.0)
Total Revenue Requirement	7.5
OPEB Expense - Cash Basis	1.1
Increase in Revenue Requirement	6.4

until payment is made. Accordingly, NP is proposing to reduce its rate base by what NP is referring to as its Accrued OPEB Liability[10] – this amount will equal the cumulative difference between the amount of OPEBs NP has expensed and what it has paid out on account of its OPEBs (i.e., the amount by which the OPEB Liability in its financial statements exceeds the OPEB Regulatory Asset in its financial statements).

The reduction in rate base will reduce NP's financing costs. In 2008, this decrease is estimated to be $0.3 million. NP's Accrued Benefit Liability is expected to rise in future years resulting in further reductions in its rate base and financing costs.

[10] This issue is addressed in the section "Adjustments to Rate Base".

NP currently uses the flow-through method in recognizing the tax deductions related to future employee benefits. With this method, the change to the accrual basis for recognizing OPEB expense would increase the amount included in NP's revenue requirement to cover its income taxes. There are three components to this net increase

- NP receives a tax deduction for only the cash payments it makes on account of OPEBs. Since the revenue required to cover the accrual expense is greater than its cash payments, NP's taxable income will increase by the difference.

- A portion of NP's allowed return consists of return on equity which is taxable. Reducing NP's allowed return will reduce its equity return and the associated income taxes.

- Increasing rates to cover an increase in income tax costs will further increase NP's taxable income resulting in a further increase in its income tax costs.

It is expected that the net effect would be an increase in its income tax costs of $3.3 million in 2008.

NP's proposal to tax effect its post employment benefit expenses will result in a decrease in the amount of tax it recovers through current rates on account of its OPEB expense. Since this will reduce taxable income, there will be a further reduction in NP's revenue requirement. The overall impact is expected to be a reduction in revenue requirements of about $3.1 million in 2008.

Tax effecting NP's OPEB expense will tend to increase its financing costs. With tax effecting, NP will pay more in taxes than it recovers in current rates with the expectation that it will recover the difference through future rates. The difference must be financed until NP has an opportunity to recover the costs from customers, and therefore, should be included it its rate base. This will result in an increase in the allowed return included in its revenue requirement. Since a portion of the allowed return consists of equity return that is taxable, this will result in a further increase in the income tax cost included in its revenue requirement. In 2008, the overall impact will be small and is expected to be $0.1 million.

Considering all of the above, under the accrual basis, the total revenue requirement due to OPEBs will be $7.5 million in 2008

Under the cash basis, the impact of OPEBs on NP's revenue requirement would equal its OPEB payments less the amount capitalized, which are expected to be $1.1 million in 2008. Therefore the net effect on NP's revenue requirement from changing to the accrual basis is forecast to be $6.4 million in 2008.

As noted above, changing to the accrual basis will have impacts on NP's rate base. The impacts are set out in Table 2.

Table 2

Impact on Rate Base of Recognizing OPEB Expense on Accrual Basis 2008 ($ million)

Accrued OPEB Liability	(6.3)
Future Tax Asset	2.0
Capital Assets	(0.1)
Change in Rate Base	(4.4)
Change in Average Rate Base	(2.2)

At January 1, 2008, both the OPEB Regulatory Asset and the OPEB Liability will be $34.1 million. However, with OPEB expense exceeding OPEB payments, the OPEB liability will increase over time while the OPEB Regulatory Asset will remain the same[11]. The difference will represent the amount that NP has had an opportunity to recover in rates on account of future payments. The net effect (i.e., the Accrued OPEB Liability) will be a decrease in rate base of $6.3 million in 2008.

Tax effecting the OPEB expense will result in a future tax asset that is expected to be $2.0 million in 2008.

The overall impact for 2008 is expected to be a decrease of $4.4 million in NP's year-end rate base and $2.2 million in its average rate base.

ANALYSIS

In determining whether to shift to the accrual method for recognizing OPEBs, the key regulatory principles are the cost of service standard, the principle of intergenerational equity and the principle of rate stability and predictability. Other factors to consider are general regulated utility practice and consistency in the treatment of future employee benefits.

[11] Until such time as the Board decides that it should be amortized and recovered through rates.

Cost of Service

Consistent with the cost of service standard, NP's proposal will allow it to recover only its cost of service.

NP's proposal changes the period in which it recognizes its OPEB costs, but not the amount. By advancing the recovery of OPEB costs, it will reduce its financing costs, but NP is proposing that the net reduction in its financing costs be used to reduce its revenue requirement.

Intergenerational Equity

The principle of intergenerational equity supports the use of the accrual method. Consistent with this principle, the accrual method results in a better matching of costs to the periods for which the costs are incurred. It results in current customers paying for the future OPEB costs resulting from providing service in the current period. With the cash method, customers pay for the OPEB costs as they are incurred, even though those costs may result for providing service to customer years, or even decades, earlier.

This principle has been recognized by other regulatory tribunals in approving the accrual basis for recognizing OPEB's. For example, in a 2004 decision dealing with BC Hydro, the British Columbia Utilities Commission ("BCUC") stated:

> *The Commission Panel finds that the accrual method does provide a better matching of costs to the period in which the service was provided. The Commission Panel further notes that the requested change from the cash basis to the accrual basis of accounting for post retirement benefits will not, in this instance, have a significant affect on rates. … **The Commission Panel approves the accounting change from the cash method to the accrual method for post-retirement benefits.*** [12]

In a 2001 decision dealing with Union Gas, the Ontario Energy Board stated:

> *The Board recognizes that Union's proposal to change from a cash basis to an accrual basis for accounting for pensions and post-retirement benefits reflects a change in GAAP that has been adopted by the CICA and accomplishes the objective of matching the costs to the period in which the obligations arose. There was limited opposition to this change and further, in the Board's view, this may remove some potential variation in this expense. The Board accepts this changed practice for rate-making purposes.* [13]

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[12] BCUC; British Columbia Hydro And Power Authority 2004/05 to 2005/06 Revenue Requirements Application and British Columbia Transmission Corporation Application for Deferral Accounts; October 29, 2004; pg. 168.

[13] Ontario Energy Board; Decision With Reasons - RP-1999-0017; July 21, 2001; pg. 69.

Changing to the accrual method will result in transitional costs which raises issues of intergenerational equity. The transitional costs must be recovered prospectively although they relate to services provided in past periods.

Intergenerational equity would normally require that costs related to past periods be recovered as quickly as is reasonable so that the customers that eventually pay for the costs are the same as those that benefited from their incurrence.

In the case of the transitional costs associated with the transitional obligation, the costs accumulated over a long period ending on December 31, 1999. In this case, many of the customers of the periods that gave rise to the costs are no longer around and intergenerational equity is better met by spreading the cost over an extended period so as to minimize the burden placed on the customers of any one period.

NP's treatment of the transitional obligation that will be unamortized for financial reporting purposes on January 1, 2008, is consistent with the above. The balance will be amortized on a straight-line basis over a ten-year period – i.e., approximately 1/18 of the transitional obligation will be amortized in each year. Before considering the impact on financing costs, it will increase NP's revenue requirement by $2.2 million per year ($1.4 million of amortization plus the effect on income taxes).

In the cases of the costs associated with the OPEB Regulatory Asset less the amortization of the transitional obligation, the costs arose over a relatively recent period. Accordingly, the principle of intergenerational equity would require that they be recovered as soon as is practical. However, as discussed below, consideration should be given to the impact on rates and the principle of rate stability and predictability.

Rate Stability & Predictability

NP's reluctance to implement the accrual method at an earlier date has been due to concerns over rate stability. Although NP is proposing to change to the accrual method and to begin to deal with the transitional costs, it is still concerned about rate stability and the impact on customers. As a result it is proposing that amortization of the OPEB Regulatory Asset be deferred until a future date.

NP's proposal will require a rate increase of 5.3%. With inflation in the range of 2% to 2.5%, the proposed increase is higher than inflation, but not unduly. However, further deferring the shift to the accrual method will increase the OPEB Regulatory Asset and the amount of deferred costs that will have to be recovered from future customers.

If NP were to amortize the OPEB Regulatory Asset over the remaining period that the transitional obligation is being amortized (i.e., 10 years), it would require an additional $3.2 million in revenue before considering the impact on taxes, and $5.0 million after[14]. This translates into an additional rate increase of almost one percentage point.

[14] Both amounts reflect a small decrease in financing costs.

Also, with the accrual method, the OPEB expense will exceed the OPEB payments resulting in a reduction in rate base and the cost of financing the rate base. Primarily due to the decrease in financing costs, the impact of OPEBs on NP's revenue requirement is expected to fall by about a half million dollars per year. These decreases will help to create room to deal with the OPEB Regulatory Asset in the future.

Industry Practice

A noted above, with the issuance of section 3461 and the requirement to recognize OPEB costs on an accrual basis for financial reporting purposes, several Canadian utilities have adopted the accrual basis for rate setting purposes.

Consistency

NP's proposal will result in all of its future employee benefits being treated on a consistent basis – i.e., OPEBs and pension costs.

CONCLUSION

NP's proposal to change from cash to the accrual basis in recognizing OPEB costs for regulatory purposes is consistent with the cost of service standard since it will allow NP to recover its costs of providing service, but only its costs of providing service.

The change from the cash to the accrual basis results in a better matching of costs to the periods in which the related services are provided. The change is therefore supported by the principle of intergenerational equity.

A change to the accrual method gives rise to transitional costs: the unamortized transitional obligation and the OPEB Regulatory Asset. Amortizing the remaining unamortized transitional obligation over approximately 10 years is consistent with the principle of intergenerational equity. On its own, the principle of intergenerational equity would support the amortization of most of the OPEB Regulatory Asset over a short period. However, this would have a significant impact on rates. In addition, the impact of changing to the accrual method will decrease over time, making it easier to accommodate the amortization of the OPEB Regulatory Asset at a future date. NP's proposal to defer the amortization of its OPEB Regulatory Asset is a practical solution that recognizes the principle of rate stability and predictability.

Although there are utilities that still use the cash basis, a significant number of the major Canadian utilities now employ the accrual basis. Also, adopting the accrual basis will result in a consistent treatment of all NP's future employee benefits.

Therefore, NP's proposal to adopt accrual accounting for its OPEB expense but defer treatment of its OPEB Regulatory Asset at December 31, 2007 is consistent with established regulatory principles and appropriate in the context of NP.

TAX EFFECTING POST EMPLOYMENT BENEFITS

With both NP's pension and OPEB expense, the associated tax deduction (and related impact on income taxes) is currently recognized for regulatory purposes when it is received and used to reduce NP's tax payments (i.e., flow-through method). This occurs when the cash is paid to fund or pay the future employee liabilities.

NP is proposing to tax effect its post employment expenses effective January 1, 2008. This means that it would recognize the tax savings associated with the future employee benefits on an accrual basis, i.e., when the related expense is recognized.

NP has asked me if its proposal to tax effect its future employee benefits is consistent with established regulatory principles and appropriate in the context of NP.

BACKGROUND

The tax authorities do not always recognize revenues and expenses in the same period as accountants. For example, capital cost allowance (i.e., depreciation for tax purposes) is usually recognized on a different basis than depreciation. Capital cost allowance ("CCA") is usually higher than depreciation in the early years of an asset's life, but this is offset by lower CCA in the later years. The total amount deducted for both CCA and depreciation is the same, what is different is the amount deducted in a given period.

With these timing differences, a portion of taxable income is recognized in a different period than the associated accounting income, resulting in some taxes being payable in a period other than the period in which the related income is considered earned for accounting purposes.

Even though the total amount expensed for tax and accounting purposes is the same, timing difference produce a financial benefit or cost. Where the payment of taxes is deferred, a utility has the use of the funds it would otherwise pay in taxes until the taxes are actually paid. This decreases its financing costs. Where the payment of taxes is accelerated, a utility's funding requirements are increased over the period that payment is accelerated. This increases its financing costs.

Under GAAP, most companies must report their income tax expense on an accrual basis. This means that companies report their income tax expense related to the income earned in the current period, regardless of when the taxes become payable. For example, where CCA on a new asset exceeds the current depreciation expense, current taxable income and the related taxes are reduced but this is offset by an increase in future taxable income and related taxes. Under the accrual method, the increase in future income taxes is recognized as a liability and expensed in the current period.

It is a common practice for Canadian energy utilities to employ the flow-through method for recognizing their income tax expense for regulatory purposes. With this method, income tax expense is recognized in the period that it becomes payable, regardless of the period to which it relates.

Although energy utilities tend to use the flow-through method, there are cases where Canadian energy utilities use, or partially use, the accrual method. Also the Canadian Radio-television and Telecommunications Commission ("CRTC") held the view that the telecommunications companies regulated by it should use the accrual method. The CRTC had considered the flow-through method, but rejected it[15].

NP currently uses a combination of the accrual and the flow-through methods. It uses the flow-through method except that it recognizes timing differences related to:

- its reserves; and
- capital assets, excluding GEC, so long as the timing differences do not result in a tax asset.

At the current time, the CICA Handbook allows regulated utilities to uses the flow-through method for financial reporting purposes where they use that method in setting rates and certain conditions are met. It is expected that this exception will soon be removed and all companies will have to use the accrual method for financial reporting purposes. However, this change will not affect reported income. Utilities currently using the flow through method for financial reporting purposes will recognize a regulatory asset equal to their future income tax liability arising from the accrual method, or a regulatory liability equal to their future income tax asset[16].

NP'S PROPOSAL

NP is proposing to tax effect its future employee benefit expenses – i.e., apply the accrual method to the recognition of income tax savings related to its pension and OPEB expenses. On a going forward basis, tax deductions would be recognized in the same period the related future employee benefit expenses are recognized.

There is the issue of past timing differences that have not been recognized and that have not yet reversed. NP is proposing that the impact of these past timing differences on future income taxes recoverable be recognized as they normally would under the flow through method – i.e., they would be recovered on the same basis as they would under the current accounting policy.

On a going forward basis, where an expense is less than the related income tax deduction due to a timing difference, current income taxes payable would be less that the current income tax expense – i.e., NP would pay less for income tax than it had an opportunity to

[15] CRTC; Telecom Decision CRTC 89-9 - Deferred Tax Liability; July 17, 1989.

[16] At the current time, utilities essentially net their future income tax liabilities and future income tax assets against their related regulatory assets and liabilities.

recover from customers in that period. This difference would be credited to its future tax liability (an increase) or future tax asset (a decrease) as appropriate.

Where the expense exceeds the deduction due to a timing difference, current income taxes payable would exceed the current income tax expense – i.e., NP would pay more income tax than it had an opportunity to recover from customers in that period. This difference would be debited to its future tax liability (a decrease) or future tax asset (an increase) as appropriate.

Any future tax liability would equal the amount NP had an opportunity to collect from customers to pay for future income taxes. It would represent funds supplied by customers that were available to finance NP's rate base. Accordingly, the future tax liability would be deducted in determining NP's rate base. Any future tax asset would represent a cost paid by NP that it had not yet had an opportunity to recover from customers. Accordingly, it would be added in determining NP's rate base.

Table 3 sets out the expected impact in 2008 from tax effecting NP's future employee benefits.

In the case of pensions, the expense will be less than the current deduction. Therefore, NP's proposal will increase its revenue requirement related to pensions. The increase is expected to be $0.5 million. Since the recovery of future income taxes will increase its current taxable income, there will be a further increase in its tax expense of $0.3 million. It will also contribute to the build up of its future income tax liability that will reduce its rate base and financing costs. This will result in a reduction of $30,000.

In the case of the OPEBs, the expense will exceed the current tax deduction. Therefore, NP's proposal will reduce its revenue requirement related to OPEBs. The reduction is expected to be $2.0 million before considering income taxes and $3.1 million after. It will also result in a build-up of a future income tax asset which will increase its rate base and financing costs. This will result in an increase of $0.1 million.

The overall impact on NP's revenue requirement in 2008 is expected to be a decrease of $2.2 million.

Table 3

Impact on Revenue Requirement Tax Effecting Future Employee Benefits 2008 ($ million)	
Pension Costs	
Future Income Taxes	0.5
Tax effects	0.3
	0.8
Impact on Financing Costs	(0.0)
	0.8
OPEB Costs	
Future Income Taxes	(2.0)
Tax effects	(1.1)
	(3.1)
Impact on Financing Costs	0.1
	(3.0)
Total Revenue Requirement	(2.2)

ANALYSIS

In considering NP's proposal to employ the accrual method for recognizing income taxes related to its future employee benefits, the key regulatory principles are the cost of service standard, the principle of intergenerational equity and the principle of rate stability and predictability.

Cost of Service

The accrual method for recognizing income taxes is consistent with the cost of service standard – at least where the future tax assets and liabilities are included in the determination of rate base.

With the accrual method, a utility is allowed the opportunity to recover only its estimated income taxes.

With the accrual method, there may be additional financing costs, or reductions in financing costs, that should be passed on to customers in accordance with the cost of service standard.

- Where the tax expense that a utility is allowed to recover through rates is less than the expected tax payments, the utility will have to fund the difference until it is able to collect the difference from customers. This will increase the utility's investment and financing costs.

- Where the tax expense that a utility is allowed to recover through rates exceeds the expected tax payments, the utility will have the use of the difference until it has to pay the difference. This will decrease the utility's investment and financing costs.

By adding any future tax asset to its rate base and deducting any future tax liability, NP's proposal will result in any change in estimated financing costs being passed on to ratepayers in accordance with the cost of service standard.

Intergenerational Equity

The principle of intergenerational equity supports the use of the accrual method for recognizing income taxes. With the accrual method, tax savings are matched with their associated expense and reduce the net cost in the period that the related service is provided, regardless of the period in which the expense is deducted for tax purposes. With the flow-through method, the tax savings may be passed on to customers years before, or after, the period in which the related service is provided and the expense is recovered from customers.

Rate Stability & Predictability

NP's proposal to employ the accrual method for recognizing income taxes related to its post employment benefits will help to enhance rate stability and predictability. The resulting reduction in current income tax expense will help to offset the increase in revenue requirement required by adopting the accrual method for recognizing OPEB costs.

Counter Argument

It appears that the main reason for using the flow-through method is the belief that deferred taxes can be deferred indefinitely. For example, in "Principles of Public Utility Rates (Second Edition)", Bonbright et al. state:

> *The main argument for a commission's refusal to make any deferred-tax allowance in a rate case – for the flow-through principle – is that, as long as the tax law remains unchanged and as long as additions to depreciable corporate assets exceed*

> *retirements, the tax deferment will be continuous and hence amount, in effect to a permanent tax savings.* [17]

It should be noted that a tax deferral associated with a particular cost is not indefinite. For example, in the case of the accelerated write off of capital assets for tax purposes, the CCA exceeds depreciation expense in the early years, but this will be reversed over the life of the asset[18]. The tax deferral can only be extended by acquiring new assets – i.e., offsetting the increase in taxes with deductions related to a new cost.

Even if it is accepted that future taxes can be permanently deferred, there is the issue of how the resulting benefits should be allocated to periods. Consider the case of the accelerated write-off of capital costs for tax purposes. With the flow-through method, the benefits flow to the customers only in the earlier years of an asset's life and only if there is a net increase in deferred taxes. In the later years of the asset's life, or over the life of the assets that are required to maintain the deferral, there is no benefit. This point was recognized by Bonbright et al.:

> *But under flow-through, the major benefit of the tax reduction would go to the earlier ratepayers, in the years in which the tax payments have been reduced, instead of being apportioned among ratepayers more nearly in proportion to their relative responsibility for payments for services resulting in eventual tax liabilities.*

A claimed advantage for the flow-through method is that it tends to result in lower rates, at least as long as the timing differences result in the tax deductions exceeding the associated expense. However, in the case of the OPEB expense, the expense will exceed the tax deduction for the foreseeable future. As a result, the flow-through method will result in higher rates, at least as it relates to OPEBs.

CONCLUSION

Tax effecting future employee benefit expenses (i.e., the accrual basis) is consistent with the cost of service standard, the principle of intergenerational equity and the principle of rate stability and predictability.

The flow-through method for recognizing income taxes is widely used in setting the rates for Canadian rate regulated entities, especially energy utilities. However, this method is not universally applied and there are a number of examples where the accrual method has been used.

Therefore, NP's proposal to tax effect its future employee benefits is consistent with established regulatory principles and appropriate in the context of NP.

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[17] Bonbright et al.; Principles of Public Utility Rates (Second Edition); (Public Utilities Reports, Inc.; Arlington Virginia; 1988); Pg. 288-289.

[18] CCA is usually calculated on a declining balance basis. As a result, a portion of the timing difference will extend beyond the life of the asset.

AMORTIZATION OF REGULATORY DEFERRALS

NP is proposing to amortize certain deferred revenues and deferred costs ("Specified Deferrals") over a period of five years.

NP has asked me if its proposed amortization of the Specified Deferrals set out in Table 4 is consistent with established regulatory principles and is appropriate in the context of NP.

BACKGROUND

At the end of 2007, NP is expected to have the deferred revenues and deferred costs (i.e., the Specified Deferrals), which are set out in Table 4.

Table 4

Deferred Revenues & Costs December 31, 2007 ($ million)	
Deferred Revenues	
Unrecognized 2005 Unbilled Revenue	16.4
Municipal Tax Liability	4.1
	20.5
Deferred Costs	
Depreciation True-up Deferral	11.6
Replacement Energy Cost Deferral	1.1
	12.7
Net	7.8

The two deferred revenue balances are being treated as amounts collected from customers to meet future revenue requirements, and in effect, timing differences[19]. Instead of flowing to the benefit of shareholders, these amounts have been recognized as regulatory liabilities. The two deferred cost amounts represent costs of providing service that NP has not yet had an opportunity to recover from customers.

Unrecognized 2005 Unbilled Revenue

In 2005, the Board approved a change in NP's revenue recognition policy, from the billed to the accrual method[20], effective January 1, 2006. As a result of this change in policy, NP recognized its unbilled revenue at the end of 2005 ("UUR") as revenue collected to meet future revenue requirements. By the end of 2007, the unamortized UUR (i.e., the amount of the UUR that will not have been used to offset NP's revenue requirements) is expected to be $16.4 million.

NP had also used the billed method for tax purposes. As a result of an agreement with the Canadian Revenue Agency ("CRA"), NP was required to adopt the accrual basis for tax purposes effective January 1, 2006. As part of the agreement with CRA, NP was required to recognize its unbilled revenue at December 2005 as taxable income in equal instalments over a three year period beginning in 2006. The last instalment in 2008 is expected to require additional tax payments of $2.6 million.

Most of the UUR that will have been amortized by the end of 2007 will have been recognized to cover the income taxes related to the UUR.

Municipal Tax Liability

The municipal tax liability ("MTL") represents revenues collected on account of municipal taxes that are being treated as amounts collected from customers to meet future revenue requirements. These amounts are currently being used to reduce NP funding requirements and the related financing costs that are passed on to ratepayers.

Depreciation True-up Deferral

At NP's last GRA proceeding, it was determined that there was a depreciation reserve variance of $17.2 million. In Order No. P.U. 19 (2003), the Board approved the amortization of this variance over a three year period beginning in 2003, resulting in an annual reduction in NP's depreciation expense of $5.8 million per year. With the end of the amortization period, the Board allowed NP to defer recovery in each of 2006 and 2007 of the amount of depreciation previously covered by the amortization of the

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[19] The amounts are timing differences in that the costs to be covered by the revenues will be incurred in a different period than the one in which the revenues where recovered.

[20] Newfoundland & Labrador Board Of Commissioners Of Public Utilities; Order No. P.U. 40(2005); December 23, 2005; pg. 8.

depreciation reserve variance. By the end of 2007, these two deferrals will amount to $11.6 million.

Replacement Energy Cost Deferral

As a result of the refurbishment of the Rattling Brook hydroelectric plant in 2007, NP has estimated that it will have to spend an additional $1.8 million in purchasing power from Newfoundland & Labrador Hydro ("Hydro"), with an after-tax impact of $1.1 million. This additional costs had not been contemplated when NP's existing rates were set. As a result, in Order No. P.U. 39 (2006), the Board approved the deferred recovery of $1.1 million in after-tax replacement energy costs associated with the Rattling Brook hydroelectric plant.

NP'S PROPOSAL

NP is proposing that $2.6 million of the UUR be used to offset the income taxes payable in 2008 as a result of the UUR. It is proposing that the remaining deferred revenue and deferred cost balances discussed above be amortized in equal amounts over a five-year period beginning in 2008.

Excluding the amount of the UUR that will be used to offset income taxes in 2008, the net amortization will amount to $1 million per year. After considering the income taxes effects, this will decrease NP's revenue requirement in each of the five years by $1.2 million.[21]

ANALSYSIS

The key regulatory principles related to the treatment of the Specified Deferrals are the cost of service standard, the principle of intergenerational equity, and the principle of rate stability and predictability. Consideration should also be given to the impact of any amortization on NP's financial integrity.

Cost of Service

The cost of service standard requires that a utility be given the opportunity to recover its costs for providing regulated service, including a fair return on its investment devoted to regulated operations – no more, no less.

In the case of the deferred revenue balances, the amounts are being treated as revenue collected to meet future revenue requirements. Therefore, using these balances to reduce the cost of service recoverable from rates is consistent with the cost of service standard.

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[21] These savings will be partially offset by an increase in financing costs. The net effect of the amortizations will be to increase NP's rate base, and therefore, its financing costs.

In the case of the deferred cost balances, by January 1, 2008, the balances will represent costs that NP has incurred but not yet had an opportunity to recover, Therefore, in accordance with the cost of service standard, NP should be given an opportunity to recover these costs.

Intergenerational Equity

The principle of intergenerational equity helps to determine when costs should be recovered. It requires that customers in a given period should pay only the costs necessary to provide them with service in that period. If costs cannot be recovered in the period for which they were incurred, they should generally be recovered as close to the period for which they were incurred as is reasonable.

Where costs are not recovered in the period for which they were incurred, recovery within a period of three to five years is often viewed as reasonable. With three to five years, the customers who pay for the costs tend to be the same as those you benefited from the incurrence of the costs. It tends to mitigate the impact on rate stability and predictability (discussed below). It also spreads the burden over a number of periods. Since the costs apply to a past period, it may be deemed more equitable to spread the burden over several periods. Similar reasoning applies to an amortization period of three to five years for deferred revenues.

In 2008, NP must pay $2.6 million in taxes related to the UUR. Therefore it is consistent with the principle of intergenerational equity for NP to match part of the UUR with that payment and amortize an amount sufficient to cover it.

In the case of the remaining UUR, the amounts were built up over an extended period going back decades[22]. In the case the MTL, the effective timing difference arose almost 20 years ago. Since many of the customers who paid for the build-up of these deferred revenues are no longer customers, the issue of intergenerational equity is not as important as it would be if the build up were more recent. As a result, there could be an argument for a longer deferral and greater weight should be given the principle of rate stability and predictability; however, amortization over a three to five year period would not be inconsistent with the principle of intergenerational equity.

The deferred costs will be recent costs in 2008, having arisen in 2006 and 2007. Therefore, amortization over a three to five year period would be consistent the principle of intergenerational equity.

[22] The revenue available to cover future revenue requirements due to the use of the billed method arose over the entire period that the billed method was used. Within each year, the net increase in the revenue available to meet future revenue requirements was equal to the difference between the unbilled revenue at the beginning and the unbilled revenue at the end of the year.

Rate Stability

The principle of rate stability and predictability requires that rates should be stable and predictable, at least to the extent practical.

The amortization of a portion of the UUR to cover taxes on the UUR would tend to enhance rate stability and predictability. It would offset a cost related to the UUR.

NP proposed amortization of the remaining net balance of the deferrals over a five year period beginning in 2008 would amount to about $1 million a year before taxes. After considering taxes, the impact would be $1.2 million, or 0.2% of NP's total revenue requirement. Therefore it would not have a material effect on rates during the amortization period nor require a significant increase in rates at the end of the amortization period.

Financial Integrity

Financial integrity is important not only for a utility but also its customers. Where it is reduced, a utility's cost of capital may rise, a cost that in accordance with cost of service standard should be passed on to customers. A reduction may even jeopardize a utility's ability to raise capital required to provide regulated services. A factor affecting a utility's financial integrity is its cash flow.

The net impact of NP's proposal will be a reduction in cash from rates. When a deferred revenue is amortized, part of a utility's revenue requirement is met through the amortization, which does not produce any cash, rather than rates charged to customers. The amortization of NP's deferred revenue balances will be partially offset by the amortization of the deferred cost balances. However, the net effect will be a reduction in its cash flow.

As set out in the evidence of the Company, NP believes that its proposals will allow it to maintain a reasonable level of financial integrity.

CONCLUSION

NP's proposed amortization of the Specified Deferrals (UUR, MTL, Depreciation True-up, and Replacement Energy Costs) is consistent with the cost of service standard, the principle of intergenerational equity, and the principle of rate stability and predictability. It is also expected that it will not have a material impact on its financial integrity.

Therefore, NP's proposed amortization of the Specified Deferrals is consistent with established regulatory principles and is appropriate in the context of NP.

AMORTIZATION OF RESERVE BALANCES

INTRODUCTION

At December 31, 2006, NP's Degree Day Normalization Reserve ("Degree Day Component") had a debit balance of $6.8 million and its Purchased Power Unit Cost Variance Reserve ("Unit Cost Reserve") had a credit balance of $1.3 million. NP is proposing to amortize these amounts over five years.

NP has asked me whether its proposed amortization of the balances in the Degree Day Component and the Unit Cost Reserve over a five-year period is consistent with generally accepted regulatory principles and appropriate in the context of NP.

BACKGROUND

Both the Degree Day Component and the Unit Cost Reserve reduce the variability in NP's income, and therefore the risk that the utility faces. This tends to reduce NP's cost of capital, which is passed on to customers through allowed rates.

Degree Day Normalization Reserve

The Weather Normalization Reserve reduces the volatility in NP's earnings due to variations in hydrology and weather, factors that are outside of NP's control. It has two components:

- the Hydro Production Equalization Reserve adjusts NP's purchase power costs for variations in hydro production due to precipitation levels that are either above or below normal in any given year; and

- the Degree Day Component adjusts NP's revenue and purchase power costs for the effects of abnormal weather conditions.

The intention is that the transfers to and from each of the reserves will net to zero over time; however, this may not be the case.

In 2005 there was a change in the pricing structure for the power that NP purchases from Hydro and more recently there was an increase in the marginal cost of that power. As a result of these changes, the Company believes that it is likely that the balance in the Degree Day Component will not reverse. Should the conditions that would normally result in a reversal arise, NP believes that it is likely that the balance would actually increase

In its last GRA, NP presented evidence that $5.6 million in its Hydro Production Equalization Reserve would not reverse. The Board accepted NP proposal to amortize the $5.6 million over five years, resulting in an annual amortization charge of $1.1 million. This five-year amortization period ends in 2007.

In accepting NP's proposed amortization period of five years, the Board stated:

> *… the Board accepts that five years is a reasonable recovery period which will allow NP to recover its costs while minimizing the impact on consumers. The Board is reluctant to extend recovery of any outstanding balance longer than necessary….*[23].

Purchased Power Unit Cost Variance Reserve

As noted above, in 2005 there was a change in the pricing structure for the power NP purchases from Hydro. Instead of a single energy charge rate, NP now pays a demand charge and a two-tier energy rate. The second tier rate is paid on energy purchases above a set level and reflects Hydro's marginal cost of production.

With this pricing structure, NP's cost of power per kwh can vary due to variations in both energy purchased and peak demand from the estimates used in setting NP's rates. This tends to increase the variability in NP's earnings and the risk that it faces. As a result of the change in pricing structure, the Board approved a reserve (i.e., the Unit Cost Reserve)[24].

The Unit Cost Reserve is charged with, or credited with, the energy cost variance in excess of a deadband. The energy cost variance is equal to the normalized actual amount of energy purchased in kwhs times the difference between the forecast cost of purchased power per kwh and the actual normalized cost.

At the end of 2006, there was a credit in the reserve account of $1.3 million. The entire balance arose in 2006.

NP'S PROPOSAL

NP believes that the Degree Day Component is still relevant and will tend to reverse itself on a going forward basis. However, due to changes in the rates charged by Hydro, the balance of $6.8 million in the reserve at the end of 2006 is not likely to reverse. It is therefore proposing to amortize this $6.8 million over a five-year period beginning in 2008. Five years was chosen because it is consistent with the amortization period that the Board approved for the amortization of the non-reversing portion of the Hydro Production Equalization Reserve.

NP is also proposing to amortize the credit balance in the Unit Cost Reserve of $1.3 million over five years.

Under NP's proposal, the net amount to be amortized for these two reserves would be $5.5 million (i.e., $6.8 million - $1.3 million = $5.5 million) and the net amount

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[23] Newfoundland & Labrador Board of Commissioners of Public Utilities; Order No. P.U. 19 (2003); June 20, 2003; pg. 79.

[24] Newfoundland Board of Commissioners of Public Utilities; P.U. 44(2004; pg. 13.

amortized each year would be $1.1 million a year. After accounting for income taxes, the impact on NP's revenue requirements would be $1.7 million per year.

The net addition to revenue requirements from the above amortizations would be offset by the end to the amortization related to the Hydro Production Equalization Reserve, which ends in 2007. This amortization is essentially equal to the net amount of the proposed amortizations (i.e., $1.7 million)

ANALYSIS

The key principles related to NP's proposed amortization of the balances in the Degree Day Component and the Unit Cost Reserve are the cost of service standard, the principle of intergenerational equity, and the principle of rate stability and predictability.

Cost of Service Standard

Rates are normally set prospectively. Consistent with the cost of service, rates are set so that a utility will have an opportunity to recover its expected costs.

Since rates are set prospectively, a utility normally bears the risk that actual costs may vary from what was expected in setting rates. However, as long as the possibility of recovering more than its costs is offset by the possibility of recovering less, and the utility is adequately compensated for the resulting risk, the cost of service standard is met.

Higher risk results in a higher cost of capital that should be passed on to customers in accordance with the cost of service standard. Therefore regulators often create variance accounts such as the Degree Day Component and the Unit Cost Reserve. The variances captured by these accounts, whether positive or negative, are included in the determination of future rates. This does not change the expected earnings of the utility, (other than reductions due to lower risk) but reduces the variability of its earnings and the risk that it bears.

Where costs are subject to a variance account, rates are set on the basis that any variance (or the portion of the variance covered by the account) will be recovered from or returned to customers. In return for avoiding the impact of a negative variance, a utility forgoes the opportunity to benefit from a positive variance. The inclusion of variances in the determination of future rates is part of the overall opportunity to recover the cost of service. Therefore, if a utility is not allowed an opportunity to recover charges to a variance account, it will not have an opportunity to recover its cost of service. Similarly, if a utility is allowed to retain a credit balance in a variance account for the benefit of its shareholders, it will have an opportunity to recover more than its cost of service.

The balance in the Degree Day Component represents a cost of providing regulated service that NP has not yet had an opportunity to recover. It was expected that the balance would be offset by credits in other periods; however, due to changes outside NP's control, it is now expected that $6.8 million in charges will not reverse. Presumably, if there were a non-reversing credit balance in the account, NP would not be allowed to flow the benefit through to its shareholders. In accordance with the cost of service standard, NP should have a reasonable opportunity to recover the balance through allowed rates.

The balance in the Unit Cost Reserve represents a positive variance and rates were set on the basis that any positive variance would be returned to customers. Therefore, consistent with the cost of service standard, the balances should be refunded to customers[25].

The issue is in what period should it recover the non-reversing amount in the Degree Day Component and refund the balance in the Unit Cost Reserve?

Intergenerational Equity

The non-reversing amount in the Degree Day Component represents costs of providing service in previous periods, with most of the build up of the reserve balance occurring in the last few years. Since it is not possible to adjust past rates, it would normally be appropriate to recover the balance through rates over as short a period as is reasonable, such as within a period of three to five years, so that the customers who eventually pay the additional costs are largely the same as those who benefited from the incurrence of the costs.

However, consideration of equity between periods would also support amortization of the balance in the Degree Day Component over a period greater than one or two years. The charges and credits to the reserve were expected to balance out. However, NP has found that there is a need for an adjustment. Although there may be a need for other adjustments in the future, these types of adjustments would tend to occur periodically and not annually. Since these types of adjustments are expected to occur only periodically, it would be more consistent with maintaining equity between the customers of different periods to spread the adjustments (whether a charge or a credit) over a period of time rather than having the full amount of the adjustment reflected in the rates for the customers of a single period.

The balance in the Unit Cost Reserve arose in 2006. Consistent with the principle of intergenerational equity, the amount should be returned to customers as quickly as is reasonable, which would normally be within a period of three to five years.

Therefore, NP's proposed amortization of the two amounts over five years is consistent with the principle of intergenerational equity.

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[25] This assumes that the possibility of refunding a positive balance and the possibility of recovering a negative balance where offsetting, at least under prudent management.

In allowing the Unit Cost Reserve, the Board stated that it would "retain the discretion to determine the disposition of the reserve, taking into account NP's response to the demand and energy rate to reduce system peak". However, it is assumed that it was expected that any variance would be charged to or returned to customers as long as NP acted prudently.

Rate stability & Predictability

NP is proposing to amortize the debit balance of $6.8 in the Degree Day Component and the credit balance in the Unit Cost Reserve of $1.3 million over a five-year period starting in 2008. After considering the impact on income taxes, this will result in an increase in revenue requirements of $1.7 million in each of the five years – about 0.3% of total revenue requirements, and this increase will be offset by the end of the amortization related to the Hydro Production Equalization Reserve. Moreover, the end of the amortization is unlikely to have a material impact on rates. Therefore, even considering the overall rate increase NP is seeking, NP proposals is consistent with the principle of rate stability and predictability.

CONCLUSION

NP's proposed amortization of the non-reversing balance in the Degree Day Component and the balance in the Unit Cost Reserve over a five-year period is consistent with the cost of service standard, the principle of intergenerational equity and the principle of rate stability and predictability.

Therefore, NP's proposed amortization of the balance in the Degree Day Component and the Unit Cost Reserve over a five-year period is consistent with generally accepted regulatory principles and appropriate in the context of NP.

ADJUSTMENTS TO RATE BASE

INTRODUCTION

In 2008, NP will complete its transition to a return on rate base methodology. Consistent with this change, NP is proposing to make a number of adjustments to the determination of its rate base.

NP has asked me if its proposed adjustments to the determination of its rate base are consistent with established regulatory principles and appropriate in the context of NP.

BACKGROUND

NP is moving to an asset rate base methodology from what was essentially a return on investment capital methodology.

With a return on rate base methodology, a utility's allowed return is calculated as its rate base times its weighted average cost of capital (i.e., allowed rate of return). If it is to have an opportunity to earn a fair return in accordance with the cost of service standard, the utility's rate base should reflect its investment in regulated operations[26]. This investment is essentially equal to the net amount of cash that the utility has had to pay out to provide regulated service but has not yet had an opportunity to recover through rates[27].

Under the old methodology for determining NP's allowed return, changes to rate base that were not reflected in invested capital had no impact on NP's return. For example, any increase in rate base was offset by a corresponding decrease in its allowed rate of return on rate base. At least this was the case where the allowed rate of return was being established for a test year within a general rate application ("GRA")[28].

In a 2003 decision related to NP's last GRA, the Board decided that NP should move to an asset rate base method:

> *The Board finds that the Asset Rate Base method should replace the Invested Capital approach currently used to calculate NP's rate base. The move to the Asset Rate Base method will begin in 2003 by incorporating deferred charges in rate base.*[29/30]

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[26] Where this is not the case, adjustment must be made to the allowed rate of return if a utility is to have an opportunity to earn a fair return.

[27] The rate base may also include allowed equity returns that the utility has not yet had an opportunity to recover through rates. For example, the cost of equity in the allowance for funds used during construction ("AFUDC") is included in the cost of the associated assets.

[28] For other years, this may not have been the case.

[29] Newfoundland and Labrador Board of Commissioners of Public Utilities; Order No. P.U. 19 (2003) - Newfoundland Power Inc. 2003 General Rate Application; June 20, 2003; pg. 71.

NP PROPOSAL

NP is proposing to add the assets in Table 5 to its rate base and to subtract the liabilities in Table 5. These adjustments are necessary if NP's rate base is to equal the net investment that it must finance.

Table 5

2008 Adjustments to Average Rate Base ($ million)	
Assets	
Customer Finance Program Receivables	1.7
Liabilities	
Accrued OPEB Liability	3.2
Accrued Pension Liability	3.0
Customer Security Deposits	0.7
Municipal Tax Liability	3.7
	10.6
Net	(8.9)

The description of the amounts in Table 5 is as follows:

Customer Finance Program Receivables:

> These receivables result from loans to customers related to energy management/conservation programs.

[30] Although not specifically defined in the decision, the "Asset Rate Base method" is assumed to be the return on rate base methodology described above.

Accrued OPEB Liability:

> This is the cumulative amount of OPEBs that NP will have expensed in excess of OPEB payments and is equal to the difference between the OPEB Regulatory Asset[31] and the OPEB Liability[32] appearing on NP's financial statements.

Accrued Pension Liability:

> This is the cumulative amount of pension costs that have been expensed for NP's pension uniformity plan ("PUP") and supplementary employee retirement plan (SERP") in excess of the related payments.

Customer Security Deposits:

> This is the amount of customer security deposits received from customers in accordance with the NP's Schedule of Rates, Rules and Regulations.

Municipal Tax Liability:

> This is the MTL discussed in the previous section. It represents amounts recognized as revenue collected to meet future revenue requirements.

In addition, NP is proposing that its unamortized Deferred Debt Issue Costs be removed from the determination of its rate base, and instead, be subtracted from the amount of debt used in calculating its average cost of debt. These costs arose in connection with the issuance of NP's debt and the amortization of these costs is currently included in the determination of the NP's cost of debt and WACC. NP is making this change so that the debt related amounts are consolidated.

ANALYSIS OF PROPOSAL

NP's proposed adjustments are consistent with the cost of service standard. With the return on rate base methodology, the allowed return is determined by multiplying the utility's rate base by its allowed rate of return. To meet the cost of service standard, the rate base must reflect what the utility must finance, unless there is an offsetting adjustment to the allowed rate of return.

As of January 1, 2008, the OPEB Regulatory Asset and the OPEB Liability will be the same. However, going forward, the amount by which the OPEB Liability exceeds the OPEB Regulatory Asset (i.e., the Accrued OPEB Liability) will represent that amount

[31] The OPEB Regulatory Asset is cumulative amount of OPEB costs that has been accrued for financial reporting purposes (in accordance with GAAP) in excess of what has been expensed for regulatory purposes.

[32] The OPEB Liability is the cumulative amount that has been accrued for financial reporting purposes (in accordance with GAAP) in excess of OPEB payments.

that NP has had an opportunity to recover from its customers for OPEBs in excess of what it has paid out. It will therefore represent amounts available to finance its operations and should be deducted in determining its rate base.

The Customer Finance Program Receivables represents amounts that NP has paid out but not yet recovered from customers. Accordingly, it represents an amount that must be financed by NP and should be added to rate base.

The Accrued Pension Liability, Customer Security Deposits and the Municipal Tax Liability represent amounts that NP has had the opportunity to recover from its customers to cover costs that it has not yet paid out. They represent amounts that are available to finance its operations and therefore should be subtracted in determining NP's rate base.

The Deferred Debt Issue Costs are a cost of financing NP's operations. Until the costs are amortized and NP has an opportunity to recover them from customers, they must be funded by NP. Therefore it is appropriate to include the unamortized balance in its rate base. However, removing the unamortized balance from both rate base and the debt used in calculating the weighted average cost of capital has essentially the same effect on NP's allowed return[33]. It reduces the rate base on which the allowed return is calculated but this is offset by an increase in WACC.

CONCLUSION

NP's proposed adjustments are consistent with the cost of service standard. Except for the deferred issuance costs, the adjustments either add to rate base amounts NP has paid but not had an opportunity to collect from customers or subtract amounts NP has had an opportunity to collect from customers but has not yet had to pay out. These adjustments are necessary if NP's rate base is to reflect the amounts that must be financed to provide regulated service.

In the case of Deferred Debt Issue Costs, removing the unamortized amounts from both rate base and the amount of debt included in the calculation of WACC should have no material impact on its revenue requirement.

Therefore, NP's proposed adjustments to the determination of its rate base are consistent with established regulatory principles and appropriate in the context of NP.

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[33] Where rate base is the same as invested capital, the effect would be exactly the same. This is demonstrated using an example in Exhibit JTBC-3.

CASH WORKING CAPITAL

INTRODUCTION

NP has included an allowance for cash working capital in its rate base. To support the determination of this allowance, it completed a lead-lag study based on 2005 data.

NP has asked me whether the methodology it employed for establishing its cash working capital allowance is consistent with established regulatory practice and appropriate in the context of NP.

BACKGROUND

Cash working capital is part of a utility's investment in regulated operations. In most cases, a utility must pay for its cash operating expenses before it collects from customers the revenues intended to cover those costs. From the time the cash is paid out till the time a utility recovers the related revenues, the amount of the costs must be financed by the utility. Therefore it is appropriate to include an allowance for cash working capital in a utility's rate base[34].

In discussing the calculation of working capital, Bonbright et al. state:

> *None of the methods for calculating the working capital allowance will produce a result that is precisely correct. The purpose of the calculation should be to arrive at an amount that is reasonable and contains no obvious defects, and which is not so time consuming to compute that the costs exceeds the benefit. To determine working capital in a retail rate case, a utility may combine cash working capital determined by a lead-lag study, plus average balances of the investment in materials and supplies ….*[35]

As traditionally defined, a utility's working capital allowance considers only cash working capital plus inventories[36], where cash working capital is defined as the investment required to finance cash operating expenses from the time they are paid until the time they are recovered from customers. As a result, it considers only payables associated with cash operating expenses and receivables associated with the revenues intended to recover these costs. Although not a cash operating expenses, it is common practice to consider the financing related to sales taxes such as the HST.

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[34] Where the revenues related to a cost are recovered before payment is made for the costs, there is a reduction in the net investment in regulated operations. This net reduction should be subtracted in determining a utility's rate base.

[35] Bonbright et al.; Principles of Public Utility Rates (Second Edition); (Public Utilities Reports, Inc.; Arlington Virginia; 1988); pg. 243-244.

[36] There may be some other miscellaneous items. For example, where appropriate, there may be an allowance for minimum cash balances.

Most major utilities use a lead-lag study to establish their cash working capital. Other approaches include the balance sheet method and the formula approach, but they are generally viewed as less accurate measurements of the net investment in cash working capital.

With the lead-lag method, a utility determines the average time from payment of cash operating expenses to the time those costs are recovered from customers. This time period is usually broken down into two periods: the revenue lag – which represents the time from the provision of service to the time the related revenues are collected from customers; and the expense lag – which represents the time from the provision of service to the time the related cash operating expenses are paid for. The difference between these two periods is divided by 365 to establish the average amount of cash working capital required per dollar of cash operating expense. The result is applied to the estimated amount of cash operating expenses to determine the cash working capital that should be included in the utility's rate base.

NP'S PROPOSAL

NP is proposing to include $9.3 million in its rate base on account of cash working capital. This amount reflects the traditional definition of cash working capital and is based on a lead-lag study.

NP completed a lead-lag study using data from 2005, the last year for which complete financial data was available. Before calculating the leads and lags, it removed non-recurring and non cash items. It then applied the resulting leads and lags to the estimated revenues, cash operating expenses and HST for 2008 to establish its cash working capital for 2008.

ANALYSIS

My mandate was to review the methodology employed in establishing NP's cash working capital allowance and did not include a review of the related calculations and studies supporting the calculations (e.g., the review of invoice payments). As a result, the review on which my conclusion is based consisted of, and was limited to, the methodology that NP stated that it employed.

CONCLUSION

Based my review as noted above, the methodology described by NP in establishing its cash working capital allowance is consistent with established regulatory practice and appropriate in the context of NP.

RESUME - JOHN T. BROWNE

Summary:

John Browne has been providing costing and regulatory consulting services to utilities and telecommunications companies for 23 years.

He has directed and worked on a wide range of studies for regulated companies dealing with accounting and cost allocation principles, cost of service determination, product costing/pricing, rate of return, capital structure, and methods of regulation.

He has appeared as an expert witness on accounting, costing and financial issues before the following regulatory tribunals: Canadian Radio-television and Telecommunications Commission, Canadian Transport Commission, the Alberta Public Utilities Board / the Alberta Energy and Utilities Board, the Manitoba Public Utilities Board, Newfoundland and Labrador Board of Commissioners of Public Utilities and the Nova Scotia Board of Commissioners of Public Utilities.

Education / Professional Qualifications:

- Bachelor of Commerce - Queen's University
- Master of Arts (Economics) - Queen's University
- completed the course work and comprehensive exam requirements of the doctorate program in economics
- Chartered Accountant

Committees/ Publications

Mr. Browne was Chairman of the Canadian Institute of Chartered Accountants (“CICA”) Study Group that produced the CICA research report “Financial Reporting By Rate Regulated Enterprises”. He also co-authored the CA Magazine articles “A Matter Of Principles - Part I” and “A Matter Of Principles - Part II” that dealt with accounting by rate-regulated enterprises.

He co-authored the Deloitte & Touche publication “Basics of Canadian Rate Regulation” and authored the Deloitte & Touche monograph “The Contractual Pitfalls of Relying on GAAP”.

He wrote and distributed the monograph “Fundamentals of Rate Regulation”, an update of “Basics of Canadian Rate Regulation” and has written and distributed a number of comment papers dealing with various regulatory issues.

Key Clients:

Mr. Browne's major clients have included: Newfoundland Power Inc., Nova Scotia Power Inc., New Brunswick Power Corporation, Hydro Quebec, Ontario Hydro, Manitoba Hydro, SaskPower, Edmonton Power/EPCOR, Enmax, Ottawa Hydro, Canadian Electricity Association, Ontario Energy Board, Atco Gas, Enbridge, Newfoundland Telephone Company Ltd., Bell Canada, Manitoba Telephone System, Saskatchewan Telecommunications, AGT/TELUS, Teleglobe, Telesat Canada, Southwestern Bell Telephone Company, New York Telephone and The Telecommunication Authority of Singapore.

Selected Assignments:

- Completed a survey of Canadian regulators to determine what they viewed as their objectives and how they interpreted those objectives.
- Provided a one-day workshop on regulatory issues to an electric utility with both distribution and transmission operations. The key focus was on performance-based regulation and affiliate transactions.
- Advised an electric utility on issues related to the calculation of cash working capital.
- Prepared and delivered a half day seminar on accounting for the effects of rate regulation for a Canadian electric utility.
- Assisted Hydro-Québec by researching issues related to the determination of rate base for a first time rate application and preparing a report that recommended how the utility's rate base should be established at its initial rate hearing.
- Researched and analysed the issue of a deferral plan for the introduction of a new plant into rate base. Prepared evidence on the issue for Nova Scotia Power and appeared as an expert witness. Subsequently prepared evidence and appeared as an expert witness on changes to the deferral of the costs on the plant due to changes in circumstances.
- Assisted Newfoundland Power by providing an opinion on regulatory accounting policies including: relationship of regulatory accounting policies to GAAP, the use of the accrual vs. billed method for recognizing revenue, the treatment of unrecognized unbilled revenue and policies related to the utility's transition to an asset rate base methodology. The opinion was submitted to the utility's regulator and expert testimony was provided.
- Prepared a report for Hydro-Québec TransÉnergie that addressed regulatory issues related to the transfer of assets into the utility's regulated rate base.

- Researched and analysed the methodology for calculating working capital for Edmonton Power. Prepared evidence on the issue and appeared as an expert witness.

- Researched, analysed and presented a recommendation that an electric utility should be allowed to defer tax costs so that the utility could avoid a rate increase followed by a rate decrease.

- Reviewed various regulatory issues as part of the due diligence for the Altalink's purchase of TransAlta's transmission assets in Alberta.

- Provided a written opinion for Nova Scotia Power on its regulatory treatment of amounts related to an income tax dispute. The report dealt with past taxes that had not been recovered in allowed rates and future taxes that may not be payable.

- Prepared a report for SaskPower, an integrated electric utility, that addressed the issues related to including or excluding non-core operations from the scope of rate regulation and the regulatory implications for any dealings between these types of operations and its core regulated operations.

- Provided a written opinion for Newfoundland Power on accounting and regulatory issues related to future employee benefits and the company's hydro production equalization reserve. The opinion was included in the company's rate submission.

- Reviewed a utility's lead-lag study to determine whether the methodology was reasonable and adequately supported the net cash working capital that should be included in its rate base.

- Researched and analysed the issues of phase-in and risk sharing for Edmonton Power's Genesee plant and prepared a recommendation that was submitted to the utility's regulator. Expert testimony was also provided.

- Completed a study for New Brunswick Power that identified and evaluated the options for restructuring the electric power industry in New Brunswick and privatizing all or part of the Company. As part of the assignment, reviewed the developments occurring throughout the world with a focus on North America.

- Provided a written opinion for Nova Scotia Power that addressed whether its proposal to change from market value to market related value in determining its pension expense was consistent with generally accepted accounting principles and established regulatory principles.

- Assisted a diversified energy company by reviewing its transfer prices to and from regulated operations and recommending changes.

- Assisted a telecommunications company in developing and supporting a position on working capital for a regulatory hearing.

- Prepared evidence for a hearing before the Newfoundland Board of Commissioners of Public Utilities that dealt with regulatory control, regulatory reporting, return for a public sector utility and the accounting issues of inter-corporate charges and employee future benefits.

- Prepared a report that dealt with the corporate charges from a parent company to a regulated gas utility. The report evaluated the consistency of the charges with the past decisions of the OEB and its Affiliate Relationships Code for Gas Distributors. The report was submitted to the OEB.

- Assisted Ontario Hydro Services Company (now Hydro One), in understanding its regulatory options by researching and providing advice on a number of regulatory issues related to transfer pricing, structural organization, accounting for income taxes, relationships with affiliated companies, performance-based regulation, etc.

- Researched and evaluated options for the regulation of Nova Scotia Power. A recommendation was submitted to the utility's regulator and expert testimony provided.

- Analysed the issue of the appropriate accounting and regulatory treatment of Nova Scotia Power's defeasance program. Prepared evidence and appeared as an expert witness on the issue.

- Researched and evaluated the appropriateness of Newfoundland Power Inc.'s inter-corporate charges. A recommendation with support was submitted to the Newfoundland and Labrador Board of Commissioners of Public Utilities.

- Prepared an opinion for SaskPower on the proper accounting for its capital reconstruction charge that recognized its position as an electric utility with rates set on a cost recovery basis.

- Assisted the Ontario Energy Board Staff in identifying the parameters for a costing study to be completed by a gas distribution utility regulated by the Board.

- Assisted New Brunswick Electric Power in addressing various accounting issues related to its first rate hearing.

- Researched, analysed and prepared a recommendation on the issue of whether Nova Scotia Power should recover a purchase premium paid by the utility on the purchase of a distribution utility.

- Completed a study and prepared a report for Edmonton Power recommending an appropriate capital structure for regulatory purposes that formed part of the utility's 1996 submission to the Alberta Energy and Utility Board.

- Advised Manitoba Hydro on the development of appropriate financial targets and prepared evidence on the issue for submission to the utility's regulator. The assignment required researching and analysing the issue of appropriate financial targets for a government owned utility.

- Researched and analysed various issues dealing with the introduction of price-cap regulation for a telecommunications company and prepared position papers for the company.

- Analysed and recommended an appropriate capital structure for Ottawa Hydro (a municipally owned utility) in the context of the restructuring of the Ontario electric power industry.

- Advised the business unit of a major telecommunications company on the appropriate basis for establishing the transfer prices to be charged to other business units within the company.

- Assessed the feasibility of a co-generation power project proposed by one of Ontario Hydro's customers. The study was required before the utility could offer discounted rates to the customer to dissuade it from proceeding with the project.

- Evaluated the ability of a telecommunications company's existing costing systems to meet CRTC Phase III costing requirements and provided an opinion on whether the methodology would be defensible.

REGULATORY PRINCIPLES

Regulators must review and set rates in accordance with their empowering legislation. However, this legislation seldom contains detailed guidance on how to set rates and often states little more than that rates must be just and reasonable.

The lack of detailed guidance means that regulatory boards not only have the opportunity to exercise a significant amount of judgment in setting or approving rates, they are required to do so. To assist them in exercising their judgment, they frequently refer to established regulatory principles to guide them in determining what is appropriate in a particular case.

No single authority sets regulatory principles. Instead, principles become established through their general acceptance by regulators, and in some cases, reflect court decisions. Unfortunately, the principles may sometimes be in conflict and tradeoffs are required.

In the context of the issues on which NP has requested an opinion, the following principles are relevant:

- just and reasonable;
- cost of service standard;
- prudence standard;
- fair return;
- intergenerational equity; and
- rate stability and predictability.

JUST & REASONABLE

The primary regulatory principle, and the one most likely to be incorporated into regulatory legislation, is that rates should be just and reasonable. "Just and reasonable" applies to both ratepayers and regulated entities. It requires a weighting of the legitimate interests of both parties.

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

Unfortunately, "just and reasonable" is a vague and subjective concept. It provides an overall direction to regulators but little specific guidance.

COST OF SERVICE STANDARD

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

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

This standard does not require that a regulated entity be guaranteed a fair return, only that it have an opportunity to earn it. In most cases, rates are set prospectively, based on estimated future costs. If the entity over-recovers, it normally keeps the excess. If it under-recovers, it bears the deficiency.

The opportunity to earn a fair return implies that the possibilities of under and over-earning are offsetting. Using more technical language, allowed rates should provide an expected rate of return equal to the fair rate of return, where the expected rate of return is equal to the average of the possible rates of return weighted by the probability of their occurrence[1].

The cost of service standard is consistent with what is expected to occur in a competitive market, where the prices for goods and services tend to equal the cost of providing them, including a fair return. This is important since it is often argued that rate regulation is a proxy for competition[2] and it tends to be withdrawn where there is adequate competition to protect ratepayers.

The standard also reflects fairness and the necessity to offer adequate incentives for providing regulated services:

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

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

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1 For example, if there is a 40% probability of an 8% return, and a 60% probability of a 12% return, the expected return is 10.4%: (8% x 40%) + (12% x 60%) = 10.4%.

2 For example, in a 2001 decision the Ontario Energy Board ("OEB") stated: *The Board notes that the general role of the regulator is to act as a proxy for competition….* (OEB; ; RP-2001-0032; December 13, 2002 para. 5.11.49)

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

PRUDENCE STANDARD

The prudence standard modifies the cost of service standard. Under this standard, ratepayers should be charged only for prudently incurred costs. This recognizes the fact that regulated entities have a responsibility to manage themselves in a prudent manner.

Prudency is determined by considering whether management decisions were consistent with what a reasonable person with appropriate competence might have decided in a similar situation. This should not be done in hindsight. A regulated entity's management can be expected to rely only on information reasonably available to it when it makes its decisions. In addition, it is generally assumed that management has acted prudently unless evidence exists to the contrary.

In a recent decision, the Ontario Energy Board ("OEB") set out four principles that are reflective of the common interpretation of the prudence standard:

- *Decisions made by the utility's management should generally be presumed to be prudent unless challenged on reasonable grounds.*

- *To be prudent, a decision must have been reasonable under the circumstances that were known or ought to have been known to the utility at the time the decision was made.*

- *Hindsight should not be used in determining prudence, although consideration of the outcome of the decision may legitimately be used to overcome the presumption of prudence.*

- *Prudence must be determined in a retrospective factual inquiry, in that the evidence must be concerned with the time the decision was made and must be based on facts about the elements that could or did enter into the decision at the time.*[3]

[3] OEB; Enbridge Consumers Gas Distribution Inc., RP-2001-0032; December 13, 2001; para. 3.12.2.

FAIR RATE OF RETURN

Under the cost of service standard, a regulated entity should have an opportunity to recover its costs for regulated operations, including a fair rate of return. To be considered fair, the return must be:

- Commensurate with returns on investments of similar risk;
- Sufficient to assure financial integrity; and
- Sufficient to attract necessary capital.

The first standard is consistent with the economic definition of the cost of equity and the goal of treating equity investors fairly. From an economic perspective, the cost of making an investment is the return foregone by not investing in an alternative investment of similar risk. In fairness, investors should have the opportunity to earn a return commensurate with what they could expect to earn from non-regulated investments of similar risk.

The second and third standards reflect both investor and customer interests. A regulated entity must be financially viable and have adequate returns to attract necessary capital if it is to be able to service ratepayers. Generally, if the first standard is met, so will the others.

The basis for these criteria is found in two US Supreme Court decisions frequently quoted in regulatory proceedings:

- Bluefield Water Works & Improvement Company v. Public Service Commission of the State of West Virginia et al. (262 US 679, 1923); and
- Federal Power Commission et al. v. Hope Natural Gas Co. (320 US 591, 1944).

The first standard was also set out by the Supreme Court of Canada (in Northwestern Utilities Limited v. The City of Edmonton and Alberta Public Utilities Board; 1929, SCR 186, 193), which defined a fair return as meaning:

> *The company will be allowed as large a return on the capital invested in its enterprise (which will be net to the company) as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise.*

INTERGENERATIONAL EQUITY

The principle of intergenerational equity deals with how the cost of service should be recovered from ratepayers. Under this principle, ratepayers in a given period should pay only the costs necessary to provide them with service in that period. They should not have to pay for any costs incurred to provide service to ratepayers in another period. This principle is consistent with setting just and reasonable rates within each period.

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

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

This principle's importance depends on the periods involved. Customers in one year tend to be the same as those in the next and their relative usage generally doesn't vary that much from year to year. Having customers in one year pay more as a result of costs incurred to provide service in the previous year would not be as serious a breach of this principle as it would be if they had to pay more because of service provided to customers 10 years earlier. In the first case, it is more likely that the costs will be borne by those that benefited from their incurrence, and in proportion to the benefits they received.

If costs can't be recovered in the period for which they were incurred, it's generally best to recover them in a period as close as possible to the one for which they were incurred.

RATE STABILITY AND PREDICTABILITY

Another principle that deals with how the cost of service should be recovered is the principle of rate stability and predictability. It requires rates to remain stable and predictable – at least to the extent practical.

This principle recognizes that it is usually easier for ratepayers to deal with gradual and predictable rate increases. It may justify smoothing out changes in rates to avoid sharp rate climbs or temporary fluctuations.

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

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

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

CHANGES TO RATE BASE & INVESTED CAPITAL

The following demonstrates that, where invested capital equals rate base, reducing both invested capital and rate base by the same amount will have not impact on a utility's allowed return.

In the example presented below, invested capital and rate base are both initially equal to $1,000 and the return on rate base is equal to the total financing costs of $100. After reducing both invested capital and rate base by $150, the return on rate base is still $100. Although there is a reduction in rate base, this is offset by an increase in the weighted average cost of capital ("WACC").

Impact of Reducing Both Rate Base and Invested Capital	
Basic Assumptions:	
Financing costs:	$100
Initial:	
Invested Capital	$1,000
Initial Rate Base	$1,000
With $150 Reduction:	
Invested Capital	$1,000 - $150 = $850
Initial Rate Base	$1,000 - $150 = $850
Initial Return on Rate Base:	
WACC	$100 / $1,000 = 10%
Return on Rate Base	10% * $1,000 = $100
Return on Rate Base With Reductions:	
WACC	$100 / $850 = 11.765%
Return on Rate Base	11.765% * $850 = $100

Cash Working Capital Lead/Lag Study

May 2007

NEWFOUNDLAND POWER
A FORTIS COMPANY

Table of Contents

1.0 INTRODUCTION

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

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

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

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

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

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

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

2.0 METHOD AND APPROACH

2.1 Method

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

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

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

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

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

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

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

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

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

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

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

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

2.2 Approach

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

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

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

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

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

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

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

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

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

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

3.0 LEAD/LAG STUDY

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

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

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

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

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

3.1 Revenue Lag

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

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

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

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

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

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

3.2 Expense Lag

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

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

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

3.3 HST Adjustment

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

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

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

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

3.4 2008 Test Year CWC Allowance

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

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

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

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

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

[7] (Balance Sheet Working Capital, beginning of the year plus Balance Sheet Working Capital, end of the year) divided by 2. Balance sheet working capital is the difference between current assets and current liabilities at the balance sheet date.
[8] See Table 1 in *A Report on the Implementation of the Asset Rate Base Method*.
[9] $140,000 times weighted average cost of capital equals $140,000 times 8.82 percent equals $12,348.

4.0 CONCLUDING

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

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

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

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

Newfoundland Power Inc.

2008 Revenue Lag

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

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

Newfoundland Power Inc.

2008 Expense Lag

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

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

Newfoundland Power Inc.

2008 HST Adjustment

		HST ($000's)	Net (Lead) Lag Days	CWC Allowance [1] ($000's)
1	Consumer Billings	(71,569)	(22.54)	(4,437)
2	Other Billings	(1,410)	46.75	180
3	Purchased Power	45,596	40.43	5,035
4	Operating Expenses	2,247	0.42	2
5				**780**
6				
7				
8				
9				
10				

11 [1] (Lead) Lag Days / 365 * HST

Newfoundland Power Inc.

2008 Cash Working Capital Allowance

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

NON CONFIDENTIAL

Request IR-161:

Reference: SR-04 and FOR-15, Attachment 1.

(a) This Attachment shows Lag Days in Column (a) for 2009 Compliance and Proposed 2012. Please provide the workpapers and all supporting documents that were used to develop the Lag Days for 2009 and 2012.

(b) Please provide the standard payment time that NSPI customers have to pay their bills.

(c) The Proposed Load Retention Tariff Pricing Mechanism (filed as Appendix G to the Evidence of each of NewPage and Bowater on June 22, 2011) would require these customers to make weekly payments. Please confirm that there would be a redcution to NSPI's proposed 2012 Cash Working Capital requirement if these customers paid weekly, and provide NSPI's best estimate of the reduction.

Response IR-161:

(a) Please refer to Attachment 1. Confidential Attachments 2 and 3 are available for viewing at NSPI offices.

(b) Standard payment terms for bi-monthly customers are 30 days and for monthly customers, payment terms are 20 days.

(c) This analysis has not been completed because NPB's application for a Load Retention Tariff was filed by NPB following the completion and filing of NSPI's application. The proposed Load Retention Tariff Pricing Mechanism as filed by NPB would result in changes to the cash working capital calculations due to a change in payment schedule and

NON CONFIDENTIAL

a change in revenue mix within different customer classes. For example, with a higher proportion of revenue coming from customers that are billed bi-monthly, the cash working capital amount may be higher. NSPI has not done an analysis to assess this component of revenue requirement under the proposed load retention rate.

JTBrowne
Consulting

Nova Scotia Power Inc

Lead-Lag Study
For Determining
Cash Working Capital

November 2006

Costing &
Regulatory Consulting

TABLE OF CONTENTS

INTRODUCTION

Nova Scotia Power Inc. ("NSPI") is an integrated electric utility. Its rates are regulated by the Nova Scotia Utility and Review Board ("NSUARB") using a return on rate base methodology. This methodology allows NSPI an opportunity to recover through its regulated rates a fair return on its rate base. To support the amount of cash working capital included in its 2007 rate base, the utility has conducted a lead-lag study.

Based on its lead-lag study, NSPI has estimated its cash working capital for the 2007 test year to be $78.7 million. The calculation of this amount is set out in Table 1 which replicates Table 12 in the "Summary of Results" section.

Table 1 presents:

- the major categories of cash operating expenses;
- the revenue lag ("Rev. Lag") which is discussed in a latter section and is the same for each expense category;
- the expense lag ("Exp. Lag") for each expense category which are discussed in a latter section;
- the net lag for each expense category which is equal to the revenue lag less the expense lag;
- the cash working capital percentage ("CWC %") for each expense category which is equal to the net lag divided by 365;
- the cash working capital for each expense category which is equal to the cash operating expense times the cash working capital percentage;
- the total of the cash working capital for each of the cash operating expense categories;
- the cash working capital associated with the HST and GST which is discussed in a latter section; and
- the total cash working capital that should be included in NSPI's 2007 rate base.

Table 1

Nova Scotia Power Inc.
Cash Working Capital
2007

	2007 ($,000)	Rev Lag	Exp Lag	Net Lag	CWC %	Working Capital ($,000)
Fuels	630,632	49.92	26.46	23.46	6.4	40,533
Cost of Goods Sold	1,126	49.92	20.60	29.32	8.0	91
OM&G - Labour	112,261	49.92	21.34	28.58	7.8	8,790
OM&G - Other	90,553	49.92	30.22	19.70	5.4	4,887
Grants in lieu of Taxes	33,437	49.92	-135.38	185.30	50.8	16,975
Income Taxes, LCT & PCT	87,622	49.92	14.71	35.21	9.6	8,453
						79,729
HST-Collected	166,055			-14.05	-3.8	-6,392
HST-Paid	65,725			29.55	8.1	5,321
						-1,071
						78,658

NSPI has asked me as a chartered accountant and economist with experience in addressing regulatory issues[1] to:

- Advise on the methodology for its lead-lag study.

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[1] A copy of my resume has been attached as Exhibit JTB-1.

- Review its lead-lag study to determine whether the methodology is reasonable and adequately supports the net cash working capital that should be included in its rate base for the 2007 test year.

My review covered the methodology for NSPI's lead-lag study and the application of that methodology to NSPI's major revenue and expense categories. However, it did not include an audit or other verification procedures on the calculations included in the study. Also the lead-lag study used financial data and other information as inputs. I was not asked and did not audit these inputs or complete any other verifications procedures on them.

The next section of this report sets out the approach and methodology used in NSPI's lead-lag study. This is followed by sections that discuss the revenue lag, the expense lags for each of the cash operating expense categories, and the impact of the HST / GST on NSPI's cash working capital. The final two sections summarize the results of NSPI's lead-lag study and present my opinion on the study.

APPROACH & METHODOLOGY

NSPI has completed a lead-lag study to support the cash working capital included in its rate base for the 2007 test year.

CASH WORKING CAPITAL

In carrying out its operations, a utility incurs costs that are recovered through its revenues. However, there is usually a lag from the time that a utility pays for the costs to provide service and the time it collects the revenues to recover those costs. Cash working capital represents the investment to fund operating expenses until they are recovered through the collection of revenues.

NSPI is regulated under a return on rate base methodology whereby a return is included in the revenue requirement it is allowed to recover through rates. The return is expected to compensate the utility for the cost of its investment in regulated operations and is calculated by multiplying the utility's average rate base by its weighted average cost of capital. This rate base should equal its investment required for regulated operations, including cash working capital.

SCOPE

NSPI has employed the definition of cash working capital traditionally used by utilities. This traditional definition defines cash working capital as the investment required to finance cash operating expenses from the time they are paid until the time they are recovered from customers.

In determining cash working capital, the traditional definition considers only payables associated with cash operating expenses and receivables associated with the revenues intended to recover these costs.

The Alberta Energy and Utilities Board has used a more comprehensive definition that recognizes the impact of all expenses and revenues on net cash working capital requirements. Although there may be merits to the comprehensive approach, the movement from the traditional to the comprehensive approach should not be done on a piecemeal basis where parties attempt to include changes they like while excluding the ones that they do not.

NSPI's choice of the traditional approach is consistent with the NSUARB's last decision dealing with NSPI. In that decision, the Board approved the traditional approach to determining cash working capital and rejected piecemeal changes proposed by intervenors.

METHOD

NSPI has chosen to use a lead-lag study to determine its cash working capital. This method is the one most commonly used by major Canadian utilities and the one used to support the utility's cash working capital last approved by the NSUARB.

With the lead-lag method, a utility determines the average time from payment of cash operating expenses to the time those costs are recovered from customers. This establishes the average amount of cash working capital required per dollar of cash operating expenses. The result is applied to the estimated amount of cash operating expenses to determine the cash working capital that should be included in the utility's rate base. This approach tends to reflect the most accurate measure of the cash working capital required by a utility.

The measurement of the time between payment and recovery of cash operating expenses is usually broken into two steps: the time between the provision of service and the time of recovery, and the time between the provision of service and payment. The net lag (or lead) is determined by subtracting the second period of time from the first.

A lead lag study involves the following steps:

- Determine the average net lag from the time of sale to the time that the revenues are collected from customers (i.e., revenue lag).
- Determine the average net lead or lag from the time of sale to the time of payment for each major category of cash operating expense (i.e., expense lag).
- Calculate the average net lag for each category of cash operating expense by subtracting the average expense lag for that category from the average revenue lag.
- Calculate the net cash working capital associated with each category of cash operating expense (i.e., expense * net lag / 365)
- Calculate the total of the working capital associated with each cash operating expense.[2]
- Add the net impact of the collection and payment of HST / GST on working capital.

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[2] Alternatively:

- Calculate the total weighted average net lead or lag by taking a weighted average of the net lead or lag for each category of cash operating expense.
- Calculate the working capital associated with the cash operating expenses by dividing the total weighted average net lag by 365 and multiplying the result by the amount of cash operating expenses.

DATA

In completing its lead-lag study, NSPI used data from 2005. This is the most recent year for which a complete year of data was available. NSPI started with the total revenues and expenses from its 2005 regulated statements and then made the following adjustments.

- NSPI removed the $3.7 million deduction from revenues related to the securitization of its receivables. For regulatory purposes, the $3.7 million is considered part of NSPI's interest costs. This is consistent with the 2006 decision of the NSUARB, where the Board stated:

  > *… the securitization transaction is substantively similar in nature to a utility that pledges its accounts receivable as collateral to obtain a short-term credit facility. In effect, the transaction simply substitutes the debt owed by NSPI to one group (i.e., short-term bond holders) by debt owed to another group (i.e., the trust). … The Board concludes that the securitization program does not reduce NSPI's revenue lag and, accordingly, the transactions should have no impact on the CWC allowance requirement.*

- NSPI removed the amounts listed in Table 2 from its expenses because they were either not cash operating expenses, or in the case of some credits, did not reduce its cash operating expenses. It also deducted other significant non-recurring income.

HEDGES

NSPI hedges both foreign exchange and commodity prices. The impact of these hedges was not considered in the lead lag study. The hedges usually settle close to the payment date, or in the case of natural gas sales the receipt date, minimizing the impact on cash working capital. More importantly, on an ongoing basis, there could be gains or losses on the hedges.

ADJUSTMENTS FOR 2007

Once the study was completed using data from 2005, the results were adjusted for expected changes between 2005 and 2007 that were expected to have a material impact on NSPI's cash working capital. These changes are set out in the "Summary of Results" section.

Table 2

Lead / Lag Study Exclusions From 2005 Expenses	
	$ (,000,000)
Bad Debt Expense	4.5
Amortization of Severance Costs	3.2
Deferred Provincial Grants & Taxes	-4.6
Depreciation Expense	117.5
Accretion Expense	0.9
Glace Bay	6.2
Other Non-recurring Income	-8.0
Interest Expense	110.2
AFUDC	-2.1
Income Tax Deferred	-12.2
Preferred Dividends	14.1
	229.7

NET LAG - REVENUES

The net revenue lag represents the average number of days between the provision of service and the date that the revenue from the service is collected from customers. It is comprised of three lags:

- service lag - the number of days between the provision of service and the end of the service period;
- billing lag - the number of days between the end of the service period and the date that an invoice is issued; and
- collection lag – the number of days between the date that an invoice is issued and the date the money is collected from customers.

NSPI calculated a weighted average revenue lag of 49.92 days. As set out in Table 3, this is a weighted average of the lags for each of the following revenue categories:

- Bi-monthly
- Monthly
- Large Customers
- Power Grid Sales
- Natural Gas

BI-MONTHLY AND MONTHLY

Domestic (i.e. residential), commercial and industrial customers are billed either bi-monthly or monthly with billing dates spread throughout the month. Standard payment terms are 30 days for bi-monthly customers and 20 days for monthly customers.

The average service lag was 29.42 days for bi-monthly customers and 14.71 days for monthly customers. The billing lag for both types of customers was 2 days.

The average collection lag was determined by dividing the average accounts receivable by the average daily billings (i.e., total billings divided by 365). Prior to this calculation, the allowance for bad debts was removed from accounts receivable and the bad debt expense was removed from the total billings. It was assumed that bad debts applied only to the bi-monthly and monthly accounts. Both the allowance for bad debts and the bad debt expense were allocated on the basis of the average accounts receivable balances.

Table 3

Revenue
Net Lag
2005

	2005 Revenues		Lag			
	$, 000	%	Service	Billing & Collection	Net	Weighted Average
Bi-monthly	479,292	41.53	29.42	36.21	65.63	27.26
Monthly	265,542	23.01	14.71	24.14	38.85	8.93
Large Customers	216,216	18.74	14.71	22.92	37.63	7.05
Power Grid Sales	10,880	0.94	14.71	20.00	34.71	0.33
Natural Gas	182,097	15.78	14.71	25.52	40.23	6.35
	1,154,027					49.92

The average accounts receivable was calculated as the average of the weekly balances. Only forty weeks of data were available. For the missing weeks, the average for the remaining weeks of that month were used[3].

The above calculations produced a weighted average collection lag of 34.21 days for bi-monthly customers and 22.14 days for monthly customers.

LARGE CUSTOMERS

51 customers fall in the category of Large Customers. They are billed on the last day of the month for service in that month. The standard payment terms are 20 days.

Since Large Customers are billed monthly, the average service lag was 14.71 days. The billing lag was 1 day.

[3] For each month there was at least one week of data.

To determine the average collection period, NSPI conducted a detailed review of all billings to Large Customers in 2005. It identified the invoice date and the payment date for each bill and calculated a weighted average collection lag of 21.92 days.

GRID SALES

Grid sales are sales to customers outside of Nova Scotia. Sales for each month are invoiced in the following month and settled on the 20th of that month by electronic funds transfer directly into NSPI's bank account. This results in an average service lag of 14.71 days and a billing and collection lag of 20 days.

NATURAL GAS SALES

Where it is economic to do so, NSPI resells natural gas. Gas can be sold throughout a month with settlement towards the end of the following month. This produces a service lag ranging from 13.5 to 15 days. NSPI reviewed each of the invoices covering its natural gas sales in 2005 to identify the billing and collection lags. It then calculated the total net lag for each invoice and the weighted average net lag for all invoices.

NET LAG - CASH OPERATING EXPENSES

The expense lag represents the time from the provision of service by NSPI to the time the related cash operating expenses are paid. It can comprise three lags:

- service lag - the number of days between the provision of service by NSPI's suppliers and the end of the service period;
- billing lag - the number of days between the end of the service period, or the date goods are acquired, and the date that an invoice is issued; and
- payment lag – the number of days between the date that an invoice is issued and the date the amount is paid to suppliers.

NSPI divided its cash operating expenses into the following categories and calculated a net expense lag for each category:

- Fuels
- Cost of Goods Sold
- OM&G – Labour
- OM&G – Other
- Taxes Other Than HST/GST

FUELS

Normally, the expense lead or lag is determined in relation to the point in time the related services are provided to customers. However, other than natural gas, fuel is placed in inventory and the average amount of inventory is included in NSPI's rate base. In these cases, the net expense lead equals:

- the average time in inventory; less
- the average time between the fuel being inventoried and paid.

Since the time in inventory is recognized by including the average inventory in rate base, the time between the fuel being inventoried and paid should be recognized as a reduction in cash working capital. Therefore, except for natural gas, the expense lag is determined by the average time between the fuel being added to inventory and the time payment is made to the suppliers.

Table 4 sets out the calculation of the weighted average expense lag for fuels.

Table 4

Fuels
Net Lag
2005

	2005 ($,000)	%	Net Lag	Weighted Net Lag
Natural Gas	141,934	25.6	38.60	9.88
Heavy Fuel Oil	101,393	18.3	17.15	3.13
Light Fuel Oil	2,251	0.4	32.57	0.13
Diesel	1,127	0.2	34.16	0.07
Solid Fuel (Coal)	255,845	46.1	20.24	9.34
Additives	4,254	0.8	27.17	0.21
Purchased Power	48,052	8.6	30.96	2.68
Other	842			
TOTAL	555,698			25.44

Natural Gas

Natural gas is acquired and either burned or re-sold throughout the month resulting in a service lag of between 13.5 and 15 days. To determine the billing lag and payment lag for natural gas, NSPI reviewed all of the purchases for 2005. The weighted average of the sum of the service, billing and payment lags for each payment was then calculated.

Heavy Fuel Oil

To determine the average time between the date heavy fuel oil was recorded in inventory and the date the suppliers were paid, NSPI reviewed all of the purchases for 2005. The weighted average of the net lag for each payment was then calculated.

Light Fuel Oil

To determine the average time between the date light fuel oil was recorded in inventory and the date the suppliers were paid, NSPI reviewed all of the purchases for three month in 2005 (March, July and November). The net lag for each payment was then determined and the weighted average net lag calculated.

Diesel

To determine the average time between the date diesel was recorded in inventory and the date the suppliers were paid, NSPI reviewed all of the purchases for 2005. The weighted average of the net lag for each payment was then calculated.

Solid Fuel (Coal and Petcoke)

To determine the average time between the date coal was recorded in inventory and the date the suppliers were paid, NSPI reviewed all of the purchases for 2005. The weighted average of the net lag for each payment was then calculated.

Additives

There are three types of additives: limestone, utilimag 40 and fireshield. To determine the average time between the date the additives were recorded in inventory and the date the suppliers were paid, NSPI reviewed purchases in 2005. For utilimag 40 and fireshield it reviewed all of the purchase in 2005 while for limestone it reviewed purchases from three months in 2005 (March, July and November). NSPI then calculated a weighted average net lag for utilimag 40 and firestone, and for the limestone sample. A weighted average was then taken of these two amounts with the weight applied to limestone reflecting the total purchases in 2005.

Purchased Power

NSPI is billed monthly for purchased power and it was assumed that purchased power is acquired throughout the month. As a result the service lag varied from 13.5 to 15 days. To determine the billing lag and payment lag, NSPI reviewed the purchased power acquired in 2005. The weighted average of the sum of the service, billing and payment lags for each payment was then calculated.

COST OF GOODS SOLD

Cost of goods sold refers to the cost of electro thermal storage (“ETS”) units and their installation.

The net lag was calculated as the weighted average of the net lag on the cost of the ETS units and the net lag on the cost of installation.

- To estimate the net lag on the cost of the ETS units, invoices from 2005 equal to 83% of the total cost of units expensed in 2005 were reviewed. Information from these invoices was used to establish the lag from the time the units were placed in inventory till the time the suppliers were paid.

- To estimate the net lag on the cost of installation, invoices representing 10% of the installation costs in 2005 were reviewed to establish the net lag from the date of installation to the date the suppliers were paid.

OM&G – LABOUR

As a result of labour costs, payments are made to employees, the government for taxes and other parties for employee benefits. Table 5 sets out the weighted average expense lag for labour. The total labour costs in Table 5 are $13.4 million higher than the labour costs expensed in 2005 since they are before deductions for capitalized labour and regulatory adjustments.

Table 5

OMG- Labour
Net Lag
2005

	2005	%	Net Lag	Weighted Net Lag
Net Pay – Bi-Weekly	61,191	50.7	14.50	7.36
Net Pay –Weekly	1,349	1.1	8.00	0.09
Net Pay - Incentive	783	0.7	237.00	1.54
Government Payments – Bi-Weekly	36,231	30.0	22.12	6.64
Government Payments –Weekly	816	0.7	15.19	0.10
Government Payments – Incentive	648	0.5	244.00	1.31
Employee Benefits – Paid With Payroll	14,715	12.2	14.50	1.77
Employee Benefits – Other	4,887	4.1	62.49	2.53
TOTAL	120,620			21.34

Net Payments to Employees

The payments to employees are net of deductions for income taxes, the employees' share of other government payments (e.g., EI and CPP) and employee benefits.

Most NSPI employees are paid bi-weekly. They are paid for the two weeks ending each second Thursday, with payments deposited in their bank accounts on the following Friday. The payments are funded by NSPI on the day of deposit. This results in a service lag of 6.5 days and a payment lag of 8 days for a total net lag of 14.5 days.

Employees are paid weekly only if hired for a short period of time. They are paid for the period Sunday through Saturday and the amounts are deposited in their accounts on the following Thursday. The payments are funded by NSPI on the day of deposit. This results in a service lag of 3 days and a payment lag of 5 days for a total net lag of 8 days.

Employees on the weekly payroll are not eligible for employee benefits or the incentive payments.

An incentive payment or bonus is paid to employees in February of the following year. Since only half the payment is recognized as an expense for regulatory purposes, only half the payment was considered in the lead-lag study. The service period covers the entire year resulting in an average service period of 182 days. The payments for 2005 were deposited in employee accounts on February 24, 2006, resulting in a payment lag of 55 days. Combining the service and payment lag resulted in a total average lag of 237 days.

Government Payments

Government payments include the employees' income tax deductions, the employee and employer share of Employment Insurance ("EI") and Canada Pension Plan ("CPP") payments, and the employer's Workman's Compensation Benefits ("WCB") payments.

NSPI reviewed the actual payments made to the government associated with each of the three types of employee payments (i.e., bi-monthly payroll, monthly payroll and incentive payment) to establish the average payment period. The service period was the same as with the payments to employees.

The review found an average payment lag of 15.62 days for the government payments associated with the bi-weekly payroll, 12.19 for the government payments associated with the weekly payroll and 62 days for the government payments associated with the incentive payment in 2006.

Employee Benefits

Employee benefits include amounts deducted from employees' pay for health and dental, long-term disability, pension etc. It also includes the employer portion of these payments other than the pension payments included in "OM&G Excluding Labour" as "Employee Benefits". These latter payments are the employer pension payments in excess of those that match the employee pension payments.

The payments for employee benefits were divided into two categories: those paid on the same day employees are paid and those paid on other dates. In the case of the latter payments, NSPI reviewed almost all of the payments to establish the payment lag.

Relatively minor amounts such as the payments for the Apprenticeship Fund ($92,000) were not covered by the review and were included with the employee benefits paid on the same day employees are paid.

The employee benefits relate only to the bi-weekly pay and therefore have the same service period of 6.5 days. The employee benefits paid on the same day employees are paid would have the same payment lag as the bi-monthly payment to employees of 8 days. NSPI's review of employee benefits paid on other dates found an average payment lag of 55.99 days.

OM&G – EXCLUDING LABOUR

The net "OM&G Excluding Labour" expense (hereafter referred to as OM&G) for 2005 was $75.0 million. This net amount consisted of gross expenses of $98.1 million less capitalized overheads of $12.1 million and cost recoveries of $11.0 million. Table 6 sets out the weighted average expense lag for OM&G.

NSPI calculated a net expense lag for 11 categories of OM&G expense representing $84.4 million or 86.0% of the gross OM&G expense. The weighted average of these 11 net lags was 30.22 days and this amount was used as the net expense lag for all OM&G. In effect, NSPI assumed that:

- The remaining $13.8 million in OM&G expenses (14.0% of the total gross OM&G expense) had an average net expense lag equal to the weighted average for the expense categories reviewed.

- The expenses related to amounts capitalized and recovered had an average expense lag equal to the weighted average for the expense categories reviewed.

NSPI found support for the lags associated with each of the 11categories. In total, it found support for the lags associated with $42.9 million of the OM&G expenses. This represented 50.8% of the total expenses in the 11 categories and 43.7% of the total OM&G expenses of $98.1 million.

- For 8 of the 11 categories, NSPI determined the net lag by reviewing a sample of invoices. In total, it reviewed 157 invoices totalling $35.7 million. This represented 42.3% of the total amount of these 8 categories and 36.4% of the total gross OM&G expense.

- For two of the remaining three categories (Freight Postage & Delivery and Telephones) representing 4.5% of the total gross OM&G expense, NSPI estimated the net lag assuming normal service and payment periods.

- For the remaining category (Fleet Fuel), $2.8 million was included with other expenses on 12 invoices. NSPI determined net lags using the billing and payment lag from these 12 invoices and a service lag ranging from 13.5 to 15 days. It then calculated a weighted average net lag where the weights reflected the total amount of each invoice. The $2.8 million represented 91.5% of Fleet Fuel and 2.9% of the total gross OM&G expense.

Table 6

OM&G- Excluding Labour
Net Lag
2005

	2005	%	Net Lag	Weighted Net Lag
Materials	11,212	13.3	50.34	6.69
Contracts	31,118	36.9	60.72	22.40
Freight, Post. & Del.	2,630	3.1	34.09	1.06
Telephones	1,758	2.1	39.14	0.82
Consulting	4,975	5.9	43.99	2.59
Fleet Fuel	3,054	3.6	49.91	1.81
Rental & Maint.	2,573	3.1	-64.45	-1.97
Legal & Audit	2,209	2.6	63.70	1.67
Employee Benefits	17,039	20.2	13.46	2.72
Insurance	3,738	4.4	-154.83	-6.86
Rent	4,056	4.8	-14.71	-0.71
	84,362			30.22
Other OM&G Expenses	13,776			
	98,138			
Capitalized & Recovered	-23,111			
TOTAL	75,027			

GRANTS IN LIEU OF TAXES

NSPI does not pay municipal taxes other than deed transfer tax. Instead it pays grants in lieu of taxes to the Provincial government. The amounts are paid in two instalments each year:

- January 31 – covering the period January 1 through December 31 of the current year
- June 1 – covering the period from April 1 of the current year through March 31 of the following year.

Table 7 sets out the weighted average expense lag for "Grants in Lieu of Taxes".

Table 7

Grants In Lieu of Taxes
Net Lag
2005

Payment	2005 Expense	%	Service Lag	Payment Lead	Net Lead	Weighted Net Lead
June 2004	3,984	12.4	44.50	302.00	257.50	31.96
January 2005	15,934	49.7	182.00	333.00	151.00	74.96
June 2005	12,178	37.9	137.00	212.00	75.00	28.46
	32,096					135.38

Income LCT & PCT

NSPI makes instalments on its income taxes, large corporations tax ("LCT") and provincial capital tax ("PCT") at the end of each month with a final true-up at the end of February of the following year.

The income and capital tax payments for 2005 had characteristics that are not expected to be repeated in 2007. Therefore the net lag was calculated using the expected instalments for 2007.

In 2007, NSPI will make 12 equal instalments that will total the expected amount of its taxes for the year. Since the payments are made at the end of each month, the average service lag will be 14.71 days, the payment lag will be zero and the total net lag will be 14.71 days.

HST

NSPI collects the harmonized sales tax ("HST") from its customers which it then refunds to the government. It pays HST as part of the cost of its goods and services and pays the goods and services tax ("GST") to the government on imports. It then receives a refund from the government for the HST and GST paid. Although HST and GST are not cash operating expenses, they do affect cash working capital and this impact is normally included in the determination of a utility's cash working capital.

NSPI has the use of the HST it collects from the time it is collected from customers till the time it passes the funds on to the government. This reduces NSPI's net cash working capital requirements.

NSPI must fund the HST and GST payments from the time it pays them as part of the payments to its suppliers (or in the case of GST, as a direct payment to the government) and the time it receives a refund of the payments from the government. In virtually all cases, NSPI does not receive a direct refund. Instead it nets the refund it is entitled to from its payments of HST collected.

Table 8

HST
Impact on Working Capital
2005

	$,000	Net Lag/Lead	CWC %	Working Capital ($,000)
HST Collected	143,955	-14.05	-3.8	-5,541
HST / GST Paid	65,886	30.21	8.3	5.453
				-88

HST COLLECTED

NSPI collects HST on most of its in-province sales although there are some exceptions, such as sales to first nations customers. NSPI does not collect HST on sales to customers outside of Canada. Many of its grid sales and almost all of its natural gas sales are to such customers. The amounts collected are paid to the government at the end of the month following the month in which the customer's invoice is dated.

NSPI estimated the HST collected by category of sale. It estimated the average lead for each category from time the HST is collected till the time it is paid as the difference between:

- the number of days between the date an invoice was issued and the date the HST included in the invoice was paid to the government; and

- the number of days between the date an invoice was issued and the date HST included in the invoice was collected from customers.

HST is payable on the last day of the month following the month in which the invoice is dated. Therefore, the number of days between the issuing of an invoice and paying HST to the government depends on when the invoice was issued. For this purpose, the following was assumed:

- Bi-monthly and Monthly: throughout the month;

- Large Customers: on the last day of each month;

- Grid Sales: first day of each month.

The time between the invoice and collection dates is the collection lag. These lags were determined in establishing NSPI's weighted average net revenue lag.

Table 9

Impact of HST Collected on Working Capital 2005

	HST $, 000	HST %	Net Lead	Weighted Net Lead
Bi-monthly & Monthly	111,113	77.2	15.72	12.13
Large Customers	32,426	22.5	8.00	1.80
Power Grid Sales	377	0.3	41.76	0.11
Natural Gas	39	0.0	35.33	0.01
	143,955			14.05

HST PAID

NSPI receives a refund for HST paid on the goods and services it acquires. The refund of HST paid is netted against the payment to the government at the end of the month following the month that the invoice is dated. GST rather than HST is paid on imports at the end of the month in which goods are received and refundable at the end of the following month.

Invoices not processed before the end of the month are included with the invoices in the following month, thereby delaying the refund of HST. NSPI has ignored this possibility in the calculation of its net cash working capital and has not attempted to quantify it. This would tend to underestimate the amount of net cash working capital NSPI requires.

NSPI estimated the HST paid by category of expense and estimated the average lag for each category from the time HST is paid till the time it is refunded as the difference between:

- the number of days between the date an invoice was issued and the date the HST included in the invoice was refunded; and
- the number of days between the date an invoice was issued and the date HST included in the invoice was paid to suppliers.

NSPI assumed invoices are issued throughout the month resulting in an average time from the issuing of an invoice to receiving a refund of 45.63 days. The time from the issuing of an invoice to the payment date is the payment lag which was determined in establishing the expense lags for each category.

In the case of the GST, the amounts are paid to the government at the end of the month and refunded at the end of the next month resulting in a net lag of 30.42 days.

Table 10

Impact of HST Paid
on
Working Capital
2005

	HST / GST		Invoice to			
	$, 000	%	Refund	Paid	Net	Weighted Net Lag
OM&G	11,353	17.2	45.63	27.87	17.76	3.06
Cost of Goods Sold						
Natural Gas	25,074	38.0	45.63	10.05	35.58	13.54
Heavy Fuel Oil	3	0.00	45.63	4.96	40.67	0.00
Light Fuel Oil	314	0.5	45.63	32.55	13.08	0.06
Diesel	209	0.3	45.63	34.16	11.47	0.04
Solid Fuel (Coal)	3,294	5.0	45.63	22.28	23.35	1.17
Additives	429	0.7	45.63	26.93	18.70	0.12
Purchased Power	5,784	8.8	45.63	8.65	36.98	3.25
Total HST	46,460					
GST	19,425	29.5			30.42	8.97
	65,886					30.21

SUMMARY OF RESULTS

Table 11 summarizes NSPI's cash working capital based on 2005 data. It reflects what has been discussed in previous sections.

Table 11

Nova Scotia Power Inc.
Cash Working Capital
2005

	2005 ($,000)	Rev Lag	Exp Lag	Net Lag	CWC %	Working Capital ($,000)
Fuels	555,698	49.92	25.44	24.48	6.7	37,270
Cost of Goods Sold	1,142	49.92	20.60	29.32	8.0	92
OM&G - Labour	107,245	49.92	21.34	28.58	7.8	8,397
OM&G - Other	75,027	49.92	30.22	19.70	5.4	4,049
Grants in lieu of Taxes	32,096	49.92	-135.38	185.30	50.8	16,294
Income Taxes, LCT & PCT	55,610	49.92	14.71	35.21	9.6	5,365
						71,467
HST-Collected	143,955			-14.05	-3.8	-5,541
HST-Paid	65,886			30.21	8.3	5,453
						-88
						71,379

To estimate its cash working capital for 2007, NSPI started with its lead-lag study for 2005 and then, to reflect material changes expected between 2005 and 2007, NSPI made the following adjustments:

- replaced the cash operating expenses for 2005 with the estimates for 2007;
- changed the expense lag for fuels to reflect changes in the expected mix of fuels in 2007;
- changed the impact of HST on cash working capital to reflect the decrease in HST and GST rates by one percentage point, estimated changes in the amounts to which HST/GST will be applied, and changes in the mix of expenses to which the HST/ GST will be applied.

With the above changes, NSPI's estimated cash working capital for 2007 is $78.7 million as calculated in Table 12.

Table 12

Nova Scotia Power Inc. Cash Working Capital 2007						
	2007 ($,000)	Rev Lag	Exp Lag	Net Lag	CWC %	Working Capital ($,000)
Fuels	630,632	49.92	26.46	23.46	6.4	40,533
Cost of Goods Sold	1,126	49.92	20.60	29.32	8.0	91
OM&G - Labour	112,261	49.92	21.34	28.58	7.8	8,790
OM&G - Other	90,553	49.92	30.22	19.70	5.4	4,887
Grants in lieu of Taxes	33,437	49.92	-135.38	185.30	50.8	16,975
Income Taxes, LCT & PCT	87,622	49.92	14.71	35.21	9.6	8,453
						79,729
HST-Collected	166,055			-14.05	-3.8	-6,392
HST-Paid	65,725			29.55	8.1	5,321
						-1,071
						78,658

OPINION

I have reviewed the NSPI lead-lag study used to support the cash working capital included in NSPI's rate base for the 2007 test year.

The lead-lag study was completed by NSPI, although I advised NSPI on the methodology used in the study and the application of that methodology to the major categories of NSPI's revenues and expenses to establish appropriate leads and lags. The study was conducted using data from 2005. 2005 was chosen because it was the most recent year for which a complete year of data was available. The initial results were then updated for expected material differences between 2005 and 2007.

My review covered the methodology used in the study. This methodology has been summarized in the previous sections of this report. The review included a review of documentation and supporting schedules and discussions with NSPI employees.

The lead-lag study used various financial data and other information as inputs. For example, NSPI collected information on the time between the date of various invoices and the date those invoices were paid and it provided information on its operations that affected the estimation of its cash working capital. I did not audit or perform any other verification procedures on these inputs. Also checking the calculation included in the study was outside the scope of my review.

Based on my review as set out above, the methodology that NSPI used in its lead-lag study is reasonable and adequately supports the inclusion in NSPI's rate base for the 2007 test year of $78.7 million for cash working capital.

RESUME - JOHN T. BROWNE

Summary: John Browne has been providing costing and regulatory consulting services to utilities and telecommunications companies for 22 years. Prior to establishing his own practice seven years ago, he was a consultant with Deloitte and Touche LLP, the last seven years as a partner.

He has directed and worked on a wide range of studies for regulated companies dealing with accounting and cost allocation principles, cost of service determination, product costing/pricing, rate of return, capital structure, and methods of regulation.

He has appeared as an expert witness on accounting, costing and financial issues before following regulatory tribunals: Canadian Radio-television and Telecommunications Commission, Canadian Transport Commission, the Alberta Public Utilities Board / the Alberta Energy and Utilities Board, the Manitoba Public Utilities Board, Newfoundland and Labrador Board of Commissioners of Public Utilities and the Nova Scotia Board of Commissioners of Public Utilities.

Education / Professional Qualifications:

- Bachelor of Commerce - Queen's University
- Master of Arts (Economics) - Queen's University
- completed the course work and comprehensive exam requirements of the doctorate program in economics
- Chartered Accountant

Committees/ Publications: Mr. Browne was Chairman of the Canadian Institute of Chartered Accountants ("CICA") Study Group that produced the CICA research report "Financial Reporting By Rate Regulated Enterprises". He also co-authored the CA Magazine articles "A Matter Of Principles - Part I" and "A Matter Of Principles - Part II" that dealt with accounting by rate-regulated enterprises.

He co-authored the Deloitte & Touche publication "Basics of Canadian Rate Regulation" and authored the Deloitte & Touche monograph "The Contractual Pitfalls of Relying on GAAP".

Key Clients: Mr. Browne's major clients have included: Newfoundland Power Inc., Nova Scotia Power Inc., New Brunswick Power Corporation, Hydro Quebec, Ontario Hydro, Manitoba Hydro, SaskPower, Edmonton Power, Ottawa Hydro, Canadian Electricity Association, Ontario Energy Board, Atco Gas, Enbridge, Newfoundland Telephone Company Ltd., Bell Canada, Manitoba Telephone System, Saskatchewan Telecommunications, AGT/TELUS, Teleglobe, Telesat Canada, Southwestern Bell Telephone

Company, New York Telephone and The Telecommunication Authority of Singapore.

Selected Assignments:

- Completed a survey of Canadian regulators to determine what they viewed as their objectives and how they interpreted those objectives.

- Provided a one-day workshop on regulatory issues to an electric utility with both distribution and transmission operations. The key focus was on performance-based regulation and affiliate transactions.

- Researched and analysed the methodology for calculating working capital for Edmonton Power. Prepared evidence on the issue and appeared as an expert witness.

- Prepared and delivered a half day seminar on accounting for the effects of rate regulation for a Canadian electric utility.

- Assisted Hydro-Québec by researching issues related to the determination of rate base for a first time rate application and preparing a report that recommended how the utility's rate base should be established at its initial rate hearing.

- Researched and analysed the issue of a deferral plan for the introduction of a new plant into rate base. Prepared evidence on the issue for Nova Scotia Power and appeared as an expert witness. Subsequently prepared evidence and appeared as an expert witness on changes to the deferral of the costs on the plant due to changes in circumstances.

- Assisted Newfoundland Power by providing an opinion on regulatory accounting policies including: relationship of regulatory accounting policies to GAAP, the use of the accrual vs. billed method for recognizing revenue, the treatment of unrecognized unbilled revenue and policies related to the utility's transition to an asset rate base methodology. The opinion was submitted to the utility's regulator and expert testimony was provided.

- Prepared a report for Hydro-Québec TransÉnergie that addressed regulatory issues related to the transfer of assets into the utility's regulated rate base.

- Advised an electric utility on issues related to the calculation of cash working capital

- Researched, analysed and presented a recommendation that an electric utility should be allowed to defer tax costs so that the utility could avoid a rate increase followed by a rate decrease.

- Reviewed various regulatory issues as part of the due diligence for the Altalink's purchase of TransAlta's transmission assets in Alberta.

- Provided a written opinion for Nova Scotia Power on its regulatory treatment of amounts related to an income tax dispute. The report dealt with past taxes that had not been recovered in allowed rates and future taxes that may not be payable.

- Prepared a report for SaskPower, an integrated electric utility, that addressed the issues related to including or excluding non-core operations from the scope of rate regulation and the regulatory implications for any dealings between these types of operations and its core regulated operations.

- Provided a written opinion for Newfoundland Light & Power on accounting and regulatory issues related to future employee benefits and the company's hydro production equalization reserve. The opinion was included in the company's rate submission.

- Researched and analysed the issues of phase-in and risk sharing for Edmonton Power's Genesee plant and prepared a recommendation that was submitted to the utility's regulator. Expert testimony was also provided.

- Completed a study for New Brunswick Power that identified and evaluated the options for restructuring the electric power industry in New Brunswick and privatizing all or part of the Company. As part of the assignment, reviewed the developments occurring throughout the world with a focus on North America.

- Provided a written opinion for Nova Scotia Power that addressed whether its proposal to change from market value to market related value in determining its pension expense was consistent with generally accepted accounting principles and established regulatory principles.

- Assisted a diversified energy company by reviewing its transfer prices to and from regulated operations and recommending changes.

- Assisted a telecommunications company in developing and supporting a position on working capital for a regulatory hearing.

- Prepared evidence for a hearing before the Newfoundland Board of Commissioners of Public Utilities that dealt with regulatory control, regulatory reporting, return for a public sector utility and the accounting issues of inter-corporate charges and employee future benefits.

- Prepared a report that dealt with the corporate charges from a parent company to a regulated gas utility. The report evaluated the consistency of the charges with the past decisions of the OEB and its Affiliate Relationships Code for Gas Distributors. The report was submitted to the OEB.

- Assisted Ontario Hydro Services Company (now Hydro One), in understanding its regulatory options by researching and providing advice on a number of regulatory issues related to transfer pricing, structural organization, accounting for income taxes, relationships with affiliated companies, performance-based regulation, etc.

- Researched and evaluated options for the regulation of Nova Scotia Power. A recommendation was submitted to the utility's regulator and expert testimony provided.

- Analysed the issue of the appropriate accounting and regulatory treatment of Nova Scotia Power's defeasance program. Prepared evidence and appeared as an expert witness on the issue.

- Researched and evaluated the appropriateness of Newfoundland Power Inc.'s inter-corporate charges. A recommendation with support was submitted to the Newfoundland and Labrador Board of Commissioners of Public Utilities.

- Prepared an opinion for SaskPower on the proper accounting for its capital reconstruction charge that recognized its position as an electric utility with rates set on a cost recovery basis.

- Completed a study and recommended a cost of equity rate for Edmonton Power for each of the years 1985, 1986, 1987, 1988, 1989, 1993 and 1996. The reports for 1985, 1986 and 1996 were included in the Company's rate submissions to the Public Utilities Board of Alberta / Alberta Electric and Utility Board and expert testimony was provided at a public hearing.

- Assisted the Ontario Energy Board Staff in identifying the parameters for a costing study to be completed by a gas distribution utility regulated by the Board.

- Assisted New Brunswick Electric Power in addressing various accounting issues related to its first rate hearing.

- Researched, analysed and prepared a recommendation on the issue of whether Nova Scotia Power should recover a purchase premium paid by the utility on the purchase of a distribution utility.

- Completed a study to establish an appropriate capital structure for Edmonton Power and prepared a report recommending an appropriate capital structure for regulatory purposes that formed part of the utility's 1996 submission to the Alberta Energy and Utility Board.

- Advised Manitoba Hydro on the development of appropriate financial targets and prepared evidence on the issue for submission to the utility's regulator. The assignment required researching and analysing the issue of appropriate financial targets for a government owned utility.

- Researched and analysed various issues dealing with the introduction of price-cap regulation for a telecommunications company and prepared position papers for the company.

- Analysed and recommended an appropriate capital structure for Ottawa Hydro (a municipally owned utility) in the context of the restructuring of the Ontario electric power industry.

- Assisted a government owned telecommunications company in a review of the methods by which it could be regulated. The assignment included a review of its changing financial requirements, and the need for the company to improve its equity position.

- Advised the business unit of a major telecommunications company on the appropriate basis for establishing the transfer prices to be charged to other business units within the company.

- Evaluated the ability of a telecommunications company's existing costing systems to meet CRTC Phase III costing requirements and provided an opinion on whether the methodology would be defensible.

NON-CONFIDENTIAL

Request IR-162:

Reference: Liberty IR-56, Attachment 1, page 3.

Please provide the February 2009 report prepared by Scotia Weather Services Inc. referenced in the 2011 report.

Response IR-162:

Please refer to Attachment 1.

Severe Weather in the Canadian Maritimes: A Study Of The Recent Trends of High Winds And Ice Accretion Events

Prepared for

Nova Scotia Power Inc
Halifax, N.S.

By

Scotia Weather Services Inc.
192 Wyse Road, Suite 8
Dartmouth Nova Scotia
B3A 1M9

D. Reichheld[1]
M. MacLeod[1]

Abstract

Over the six year period from 2003 to 2008, Nova Scotia Power Inc. (NSPI) has said that they experienced a significant reduction in the reliability of its electric power transmission and distribution networks in Nova Scotia. To improve the performance of its networks, NSPI has recently made a commitment to its clients to improve its level of service to all its clients. A quick analysis of the large scale outages since 2003, seems to imply that weather or specifically, severe weather, is likely a major causal factor in the large scale power outage episodes within Nova Scotia. It is therefore the main purpose of this study to test this hypothesis, and, if valid, determine the influence the weather has had on the system, based on historical weather data obtained by Environment Canada, and reliability data obtained by NSPI. Depending on the determination of influence, it is also a concern whether recent years are abnormal when compared to the climate normals.

It is general knowledge within the electric power distribution industry in North America that the two of the main weather elements that impact power lines and the supporting towers (or poles) are strong wind gusts, and ice or wet snow accretion in concert with strong wind speeds. In order to validate the assumption that there has been an increase in severe weather, we examined the trends across Nova Scotia during the period of 1994-2002 where NSPI saw relatively favourable reliability, and during the period of 2003-2008, where there was a dip in the general reliability. We also examined long term trends across the province to compare any recent trends found to the climatology of the region, in order to establish the expected return periods of various severe weather events. The long term climatology was also compared to that of surrounding regions (specifically New Brunswick and Prince Edward Island). Finally, the trends for all the severe weather elements (high winds, and ice/snow accretion) over the 1994 to 2008 period, were combined and compared to reliability data provided by NSPI, to determine any correlation between recent weather events.

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Introduction

In September 2003, Hurricane Juan made landfall near Halifax, Nova Scotia as a minimal Category 2 hurricane on the Saffir-Simpson scale of Hurricanes. At the time of landfall, wind gusts near the city peaked near 150 km/h, and for at least three hours were above 90 km/h. The Hurricane continued on a northward path, cutting across central Nova Scotia then through Prince Edward Island later in the night, before merging with a non-tropical low pressure system over northern Quebec on September 30th. The extreme winds persisted for no more than 2-3 hours over any given location; however, this was enough to bring significant damage to the power transmission and distribution systems, as well as other things, in its path. In the five years following the storm, Nova Scotia Power Inc. (NSPI) has been the target of public criticism of its ability to maintain its system and, recently, the utility has committed to improving its system, thus service to its clients, by increasing its reliability. One component of this commitment is the concern of the influence of weather on the system, thus the motivation for this study.

The aim of this study will be to examine weather events that would adversely affect the reliability of an above-ground power grid, and ascertain the degree of influence they have had on the power grid in Nova Scotia. Specifically, the elements of concern in the province of Nova Scotia are wind gusts, and ice/wet snow accretion, especially significant accretion followed by strong winds. Wind gusts, by definition, are short term increases in wind speed that exceed the sustained wind speed by at least 10 km/h, and are reported when they exceed 30 km/h (Environment Canada, 2006). This short term variability has a significant effect on an object by applying a wide variation of stresses over a short time, which can cause a failure in the structure of an object more frequently than experienced by applying a steady force. This varying stress load is applied not only to the support structures of the power lines (which can be designed to withstand a certain degree of this type of stress), but also to objects near the power lines. One group of objects that is near many of the power lines within Nova Scotia's power grid are trees. When a tree is subjected to this variation of stresses, it will either experience branch breakage and loss, or catastrophic breakage of the main trunk structure, causing the tree itself to fall. The branches or fallen trees many times end up impacting the lines and either shorting the system, or damaging the support structures of the (Simpson and Van Bossuyt, 1996).

Ice accretion occurs when freezing rain, or wet snow, impacts objects that are cooled to below the freezing point of water, and freezes upon impact. When this happens on power lines, it adds weight to the lines, which in turn may cause the system to fail at a lower wind threshold. Again, this also applies to objects in the vicinity of the power lines, such as trees, which could fall down and affect the lines and their supporting structure (Nahmias and Hoffman, 2005).

Examples of these types of conditions causing power disruptions can be seen from a couple of extreme examples. The first such example is that of Hurricane Juan in September 2003, where wind gusts in excess of 100 km/h felled many trees, and as a result many power lines were brought down and large scale power outage resulted.

Another example is the ice storm that occurred over Quebec, Ontario, and the US northeast in January 1998, where several days of freezing rain and drizzle built several centimeters of ice on the power lines, causing the spectacular failure of the support system. While these examples are extreme ones, they do illustrate the damage each type of weather element can inflict upon power transmission and distribution systems.

High Winds

As mentioned in the Introduction, high wind speeds, specifically wind gusts have a strong negative effect on a power grid, specifically ones that have a lot of trees or other objects nearby. In order to determine whether the recent decline in reliability is due to an increase of high wind events, we need to examine the trends of the winds over several stations across the province.

The Data:

The data set acquired from Environment Canada is extensive in that it contains hourly observations from all manned stations since they started (in most cases this means data back to the 1950's and 1960's), and automatic stations back to 1994 or when they were installed (if after 1994). This data includes air temperature, dew point temperature, wind speed and direction, weather, and several other parameters. It is important to note at this point that by "hourly data" we mean observations that were made at the given stations at the top of the hour. This data therefore represents conditions at the time of observations only, not over the past hour. Unfortunately, one parameter not included in this particular dataset is the wind gusts, however, this was provided in a separate data set, although with no data prior to 1994. Wind gusts are available prior to 1994, however, only as the daily maximum, not as hourly values as we have with other data. Since knowing the duration of high wind gusts on an hourly basis is important in this study, this group of data was insufficient for our study. Also, Environment Canada has already completed a report that studied extreme wind gusts within the Atlantic region, and has it posted on their website at: http://www.hazards.ca, (Richards and Abuamer, 2007). This report was more an investigation on the climatology of extreme conditions, so data that includes only gust maxima was sufficient.

In addition to the Environment Canada data, we also purchased the historical data from the National Weather Service in the US for the Bangor, Maine station. This dataset includes the wind speed and wind gusts for the Bangor station back to 1994, and was primarily used to verify any trends we may see in the Canadian Maritimes.

In determining what stations to include in our assessment, we needed to take into account that our purpose was to get a representative picture of the winds across the province over time. This means that the placement of the observation stations needed to be considered before including the data in our assessment. The reasoning for this is simply that while the data is certainly valid, in certain circumstances the station has been sited in either a highly exposed location right on the coastline as a representation of the marine winds, or a location of know extreme events (i.e. Grand Etang where southeasterly winds are amplified by the Cape Breton Highlands). The magnitude, and to a much greater degree, the frequency of high winds over such locations are such that they will completely mask and overshadow the signal from the remaining stations which have been sited more for airport/airfields, population centres, or simply located in an otherwise data-sparse area. This is not to deny that there is a significant portion of the population in Nova Scotia near the coastlines, nor that these customers would see stronger winds than what most inland stations would report, but to include these stations would make this a study of the trends of the marine districts around Nova Scotia and those of the Cape Breton Highlands due to the overwhelming strength of the signal in the data. However, given all of this, we did not completely ignore these stations either. While the data could not be included within the provincial averages, we did look at the trends over each station individually, and as such refer to the data set as a whole when drawing any conclusions about overall trends or patterns.

There were two different time periods that we wished to examine in this study, which required further filtering of the stations available. For establishing a base climatology, we needed stations that satisfied the WMO criteria for calculating climate normals. These criteria include: Calculations must be made on data over a 30 year period, updated every 10 years, the current period being 1971-2000. Also, the data for a station must be continuous, where there's no more than 18% of data missing per year. For more recent studies, where we are comparing trends from recent years, we applied a similar consistency criteria (data must be reasonably continuous), however, we confined the timeframe to the years 1994-2008 to allow for a comparison of the wind gusts as well as the sustained winds.

The Analysis:

With the data gathered, the first question to be answered is whether Nova Scotia has seen an increase in high wind gusts in the past six years (2003-2008) where NSPI's reliability has seen a general decrease, as compared to the previous six years (1997-2002) where their reliability was comparable to that of the Electrical Association (CEA) average for Atlantic region utilities (Fig. 1). To do this comparison, we first needed to set a threshold to define "high wind gusts". For the purposes of this study we have defined high wind gusts as any gust greater or equal to 90 km/h. While this threshold is somewhat arbitrary, NSPI has observed that 90 km/h appears to be a critical point at which minor outages become major, especially if the conditions persist over at least three hours (Mike Sampson, Personal Conversation).

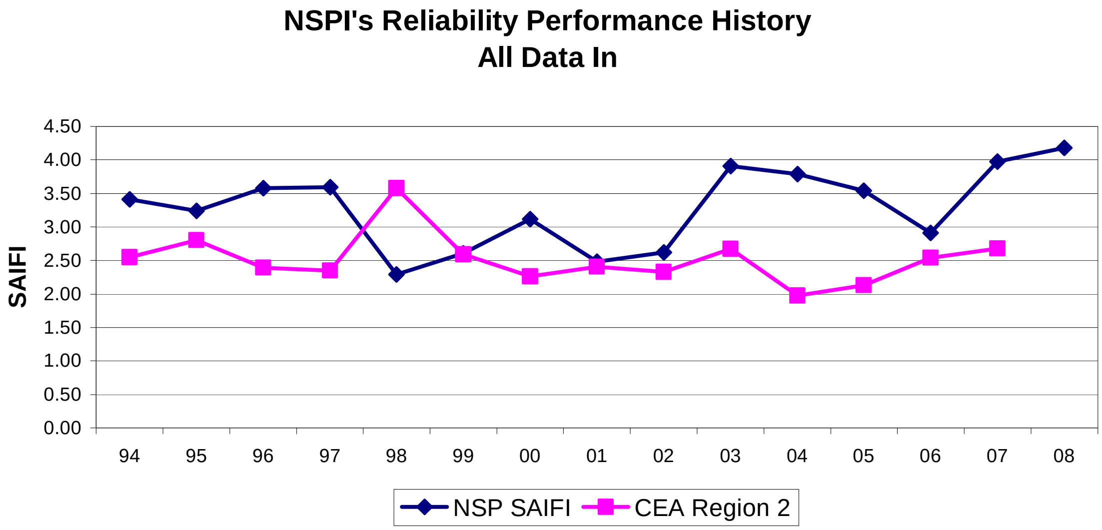

Fig. 1 NSPI Reliability compared to Average of Canadian Utilities (provided by NSPI)

Using the station selection criteria above for the short term study, we compared the number of occurrences of high wind gusts per year at several stations across the province for the years 1994 to 2008 (1994 being the earliest date where wind gust, and automatic station data is available in the Environment Canada dataset). For this comparison, we have defined a report of a high wind gust on one hourly observation as one occurrence. The stations in Nova Scotia that have been included in this comparison are: Yarmouth Airport, CFB Greenwood, Halifax Stanfield International Airport, and Sydney Airport, as well as Automatic Stations at: Amherst, Nappan, Truro, Debert, and Western Head. The stations at Amherst and Nappan are considered as one station, as Amherst was shut down by 2006 and was replaced by the one in Nappan. The same procedure is applied to Truro and Debert, where the Truro station was stopped by 2005, and was replaced by the one in Debert.

For the second part of the comparison we also looked at the peak wind gusts at each of the above stations for each year. It should also be noted here, that these will not necessarily be the peak gusts recorded at the stations, merely the maximum values reported on the hourly observations (in many cases the peak gust reported occurs between the hourly observations). This distinction should not significantly affect the results, as the intention is to compare the relative intensity of the wind gusts as a function of time, not to investigate the nature of particular storms.

Having done the comparisons for high wind gusts, and yearly peak gusts, we needed to determine the context of the results, not only to understand whether recent years show extreme values as compared to the climatology, but also to determine if it is part of a long term trend. In order to do this we needed to establish a long-term climatology of wind gusts, which meant repeating the previous procedure, but for a period from 1971 to 2000 and compare this to the recent data. Unfortunately, as mentioned before, our dataset only includes wind gust data back to 1994, also we have no data prior to 1994 for the automatic stations that we included in our gust analyses. Instead, we used the sustained winds as a measure for the trends of the winds over the long term.

Sustained wind speeds, unlike gusts, are defined as an average of the wind over a given period of time; typically either 2 minutes or 10 minutes. While the two parameters; sustained and gusts, are related, the relationship between them varies according to the meteorological situation, and the geographical layout of the observing station. So while the specific variations of each parameter will not match, the overall trends should reflect each other. Finally, while gusts are more damaging to a power grid as described above, strong sustained winds can also have a negative effect, so including the trends for this weather element would be beneficial. For this comparison, we applied a threshold of 60 km/h for the sustained winds, as we assumed a rough difference of 30 km/h between sustained winds and gusts.

The Results:

When we compared the number of hours wind gusts were 90 km/h or more for each station per year, we found that most stations across Nova Scotia actually showed very little trend over the past twelve years, or if they did, it was a downwards trend. However, the station at Halifax Stanfield International Airport was a notable exception. In the years from the beginning of our dataset, 1994, to 2004 there were relatively few occurrences of high wind gusts at the station (Fig.2). Included in this, is 2003 with Hurricane Juan, which reported a peak gust of 143 km/h (119 km/h on the nearest hourly observation), which does show in the peak gust for the year. However, since the bar graph is a representation of frequency or duration, and the high winds with Juan lasted only 3-4 hours, it has a somewhat smaller impact on that particular chart. After 2004, the airport saw a dramatic increase in occurrences of high wind gusts, with three of the last four years (2005, 2007, and 2008), seeing an increase that approximately doubles the maxima from previous years.

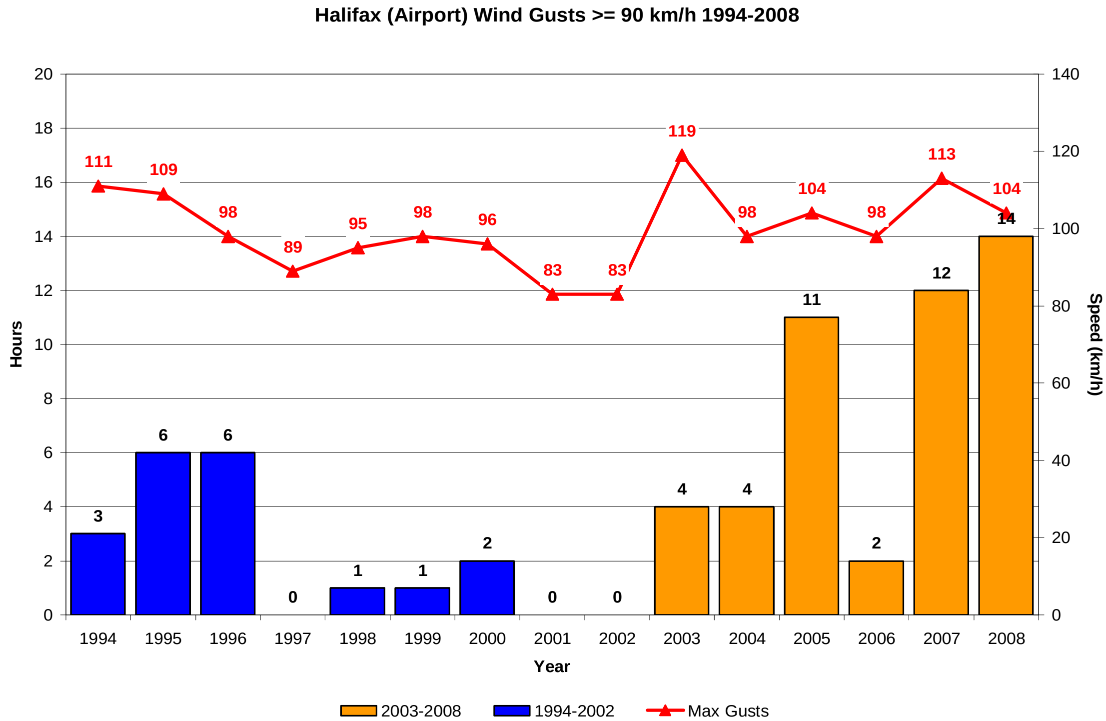

Fig. 2 Wind Gusts at Halifax Stanfield Airport 1994-2008

In terms of the yearly peak gusts, general variations with each station were noted, but no obvious overall trends were seen. In fact, outside of some occasional yearly spikes, the peaks seemed to remain relatively constant from year to year. However, going back to the Halifax Stanfield International Airport data we do note that along with the low number of high wind gust occurrences in 1997 to 2002, we see an associated diminishing of the peak winds. In fact, with the exception of the peak gust in 2003 due to Hurricane Juan, this observation appears valid through 2004.

Looking at the data for the sustained wind speeds for the same time period (1994-2008), we find very similar results. Generally, most locations show little to no trend, but what trend they do show was most frequently downwards. Again, the glaring exception to this is Halifax Stanfield International Airport (Fig. 3). The results are very similar to those of the wind gusts, with a period of light winds from 1994-2004 then a sharp increase of occurrences in 2005, 2007 and 2008. The trends, or lack thereof, of the yearly peak winds also follow those of the high wind gusts. Again, other than a few sharp peaks the peaks have remained generally constant from year to year over the past twelve years.

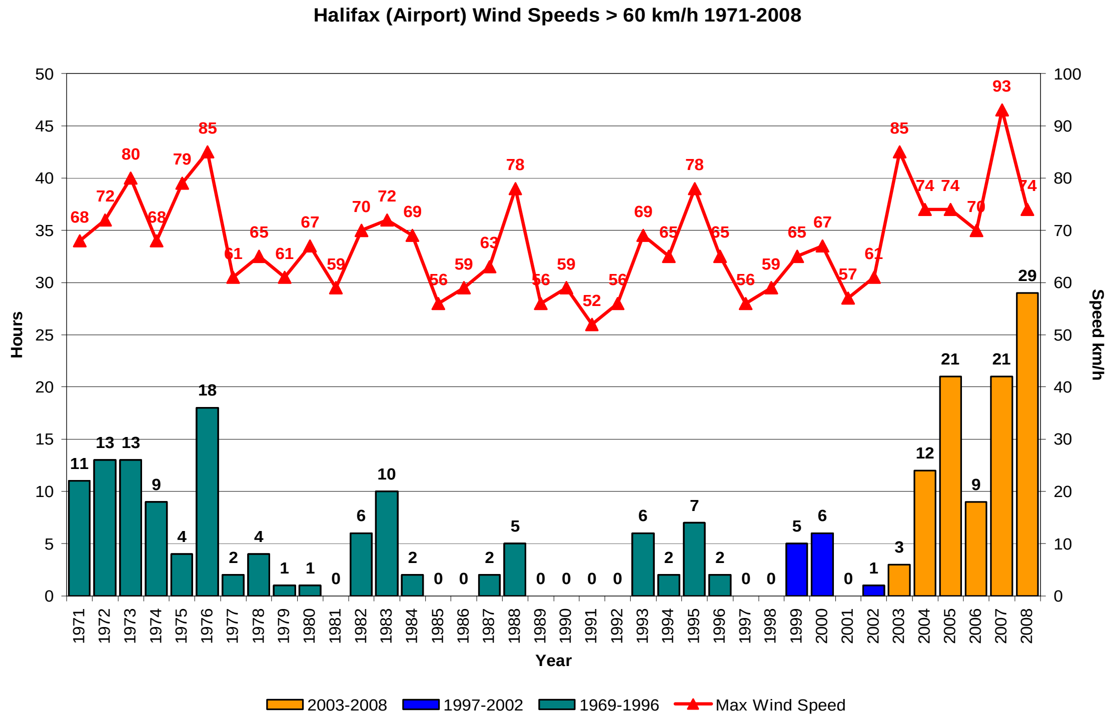

Fig. 3 Sustained Winds at Halifax Stanfield Airport 1971-2008

When we examined the long term data (1971-2008), we found for most stations that the last two decades have actually been (and continue to be) relatively quiet (Fig. 4 for Greenwood). In most cases we found that in the 1970's, there were far more occurrences of high winds than anything that has been seen since. Once more, Halifax Stanfield International Airport is a notable exception to this general observation, where although the 1970's did have more frequent occurrences of high winds than the 1980's and 1990's, the past 3 to 4 years saw a frequency of high winds unseen since 1971 (Fig. 3).

In terms of the annual peak winds, there was generally enough annual variation to hide specific trends, however, they did tend to mirror the trends of the occurrences, which for most areas has been generally downward. Again, the Halifax station is an exception in that it does not follow a downward trend, but does mirror the trend of the occurrences reasonably well, although the increase in peak winds over the past 3-4 years is not nearly as strong as the increase in the number of occurrences.

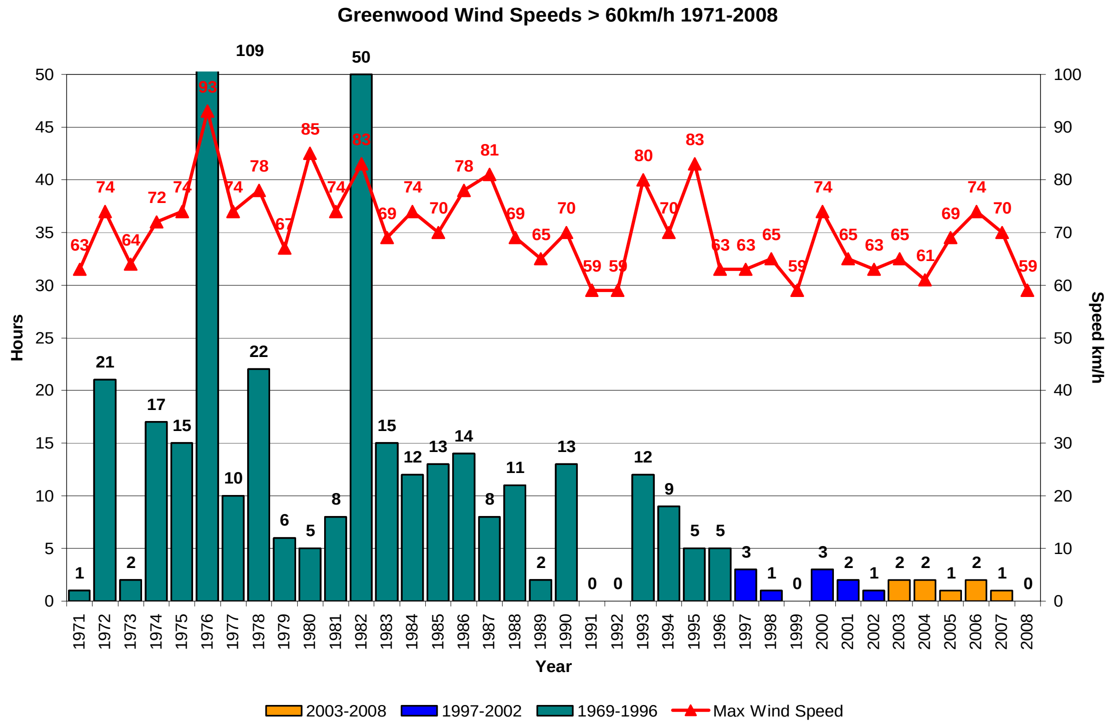

Fig. 4 **Sustained winds at CFB Greenwood 1971-2008**

When we expanded the comparison to New Brunswick, Prince Edward Island, and Newfoundland, the only increase we saw similar to that of Halifax, was in Moncton, although that station saw an increase starting around 1999, and has ebbed slightly in the past two years (Fig. 5). Otherwise, the region as whole has either trending downward or has been relatively quiet (Fig. 6) over the past 15 years. This result is further confirmed when we examined the 15-year dataset from Bangor, Maine. In summary, we see from looking at several stations across the region, that for the most part the 1990's, and to some degree the 2000's have been quiet relative to 1970's and early 1980's, with only a few stations showing some increases in the past few years (See Appendix A for the graphs for stations across the region).

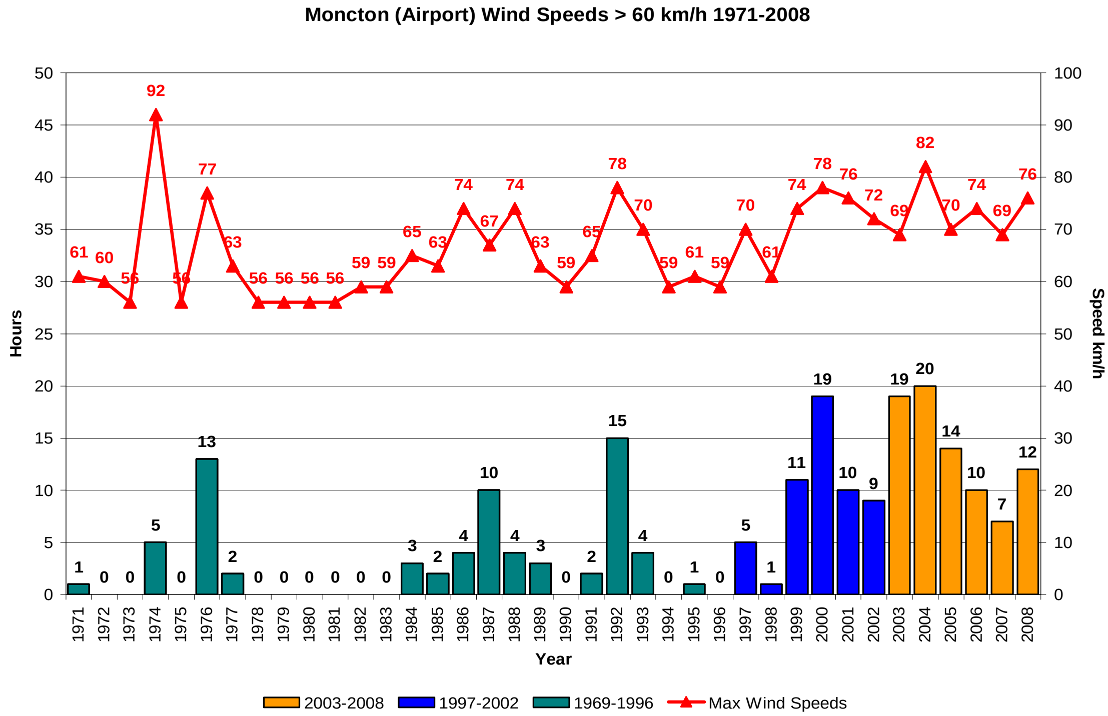

Fig. 5 Sustained winds at Moncton Airport 1971-2008

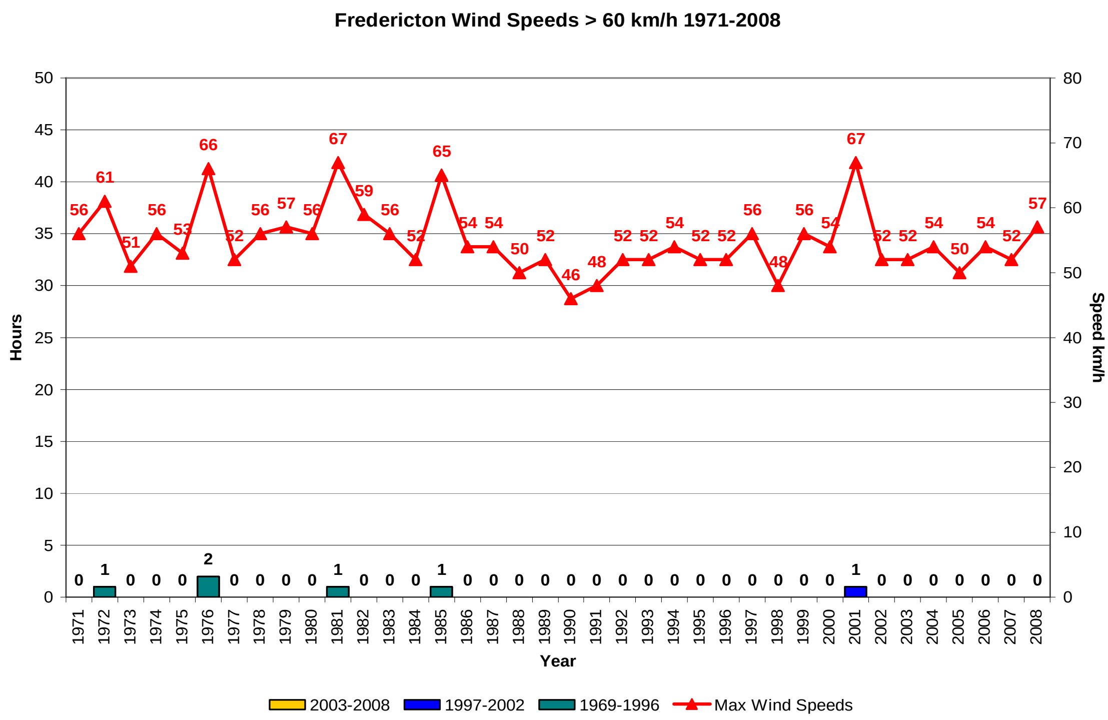

Fig. 6 Sustained winds at Fredericton Airport 1971-2008

When we compared an average of the values across each of the provinces, we found that, in general, Nova Scotia and New Brunswick experience similar sustained wind conditions (Fig. 7). However, Nova Scotia experiences stronger and more frequent wind gusts than New Brunswick (Fig. 8), in fact it does so by a significant margin with the frequency.

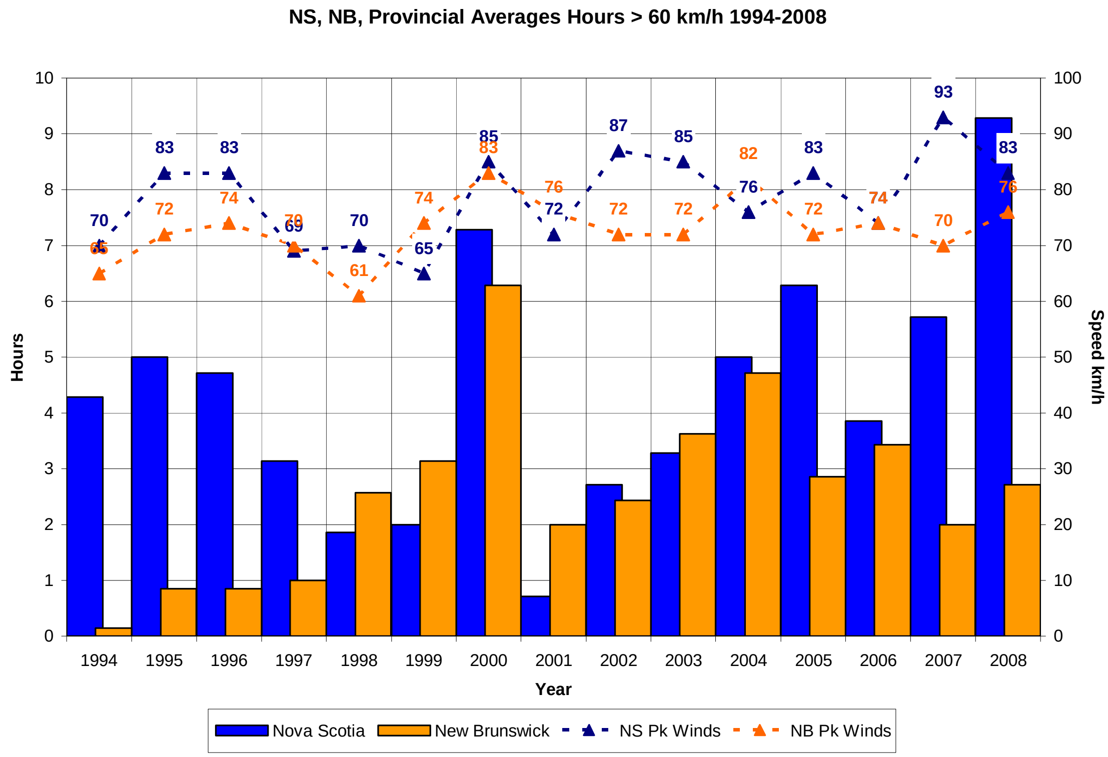

Fig. 7 **Comparison of provincial averages of sustained winds, 1994-2008**

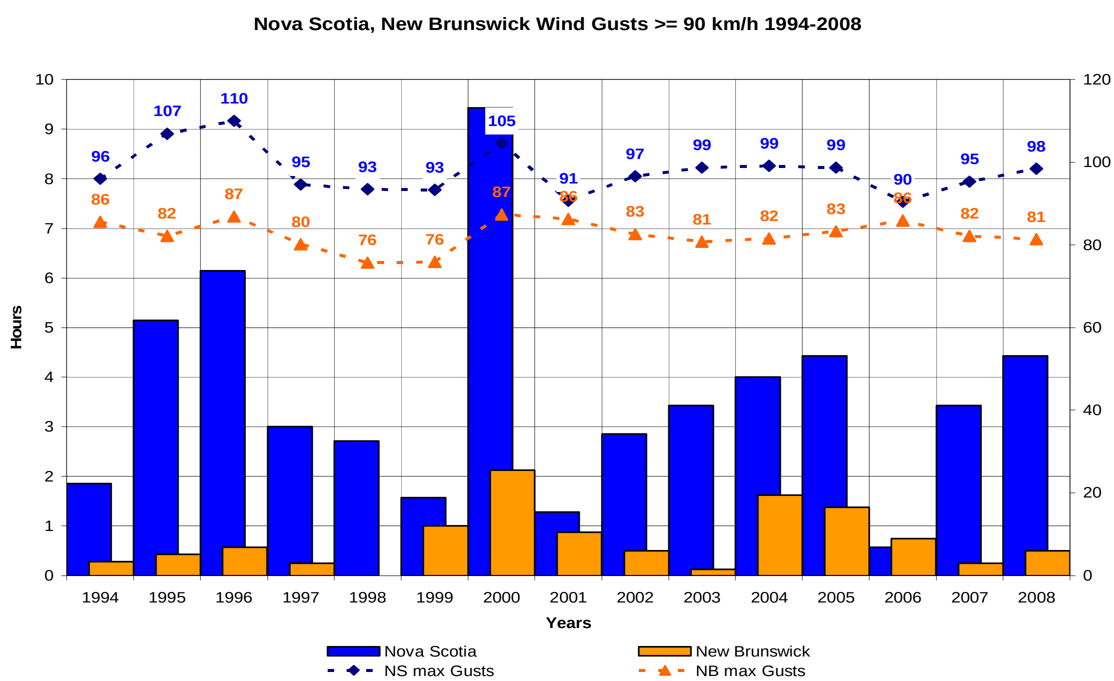

Fig. 8 **Comparison of provincial averages of wind gusts, 1994-2008**

Ice Accretion

We investigated two forms of possible ice accretion; 1) accumulation of ice from a sustained period of freezing rain, and 2) accumulation of ice from a sustained period of wet snow. Freezing rain is defined as rain that has formed in a layer of warm air aloft, which becomes super-cooled as it falls into a layer of cold air (below the freezing point of water) at the surface. The super-cooled rain then freezes to objects at the surface, which have been cooled below the freezing point by the layer of cold air. Wet snow is snow that is falling into a layer where the dew point temperature is above -1.0 C. Wet snow has a high liquid content and is, in fact, very near liquid itself. When it impacts objects on the surface, which, again have been cooled to near or just below the freezing point, it “sticks” to those objects, and accumulates in a similar manner as freezing rain.

The Data:

We used the same dataset from the High Winds comparisons, which included the hourly observations across Atlantic Canada back to when the individual stations started up. In this case weather is only reported at manned stations, so for these comparisons we did not have any data available from automatic stations. This turns out to be a very stringent criterion, as in the case for Nova Scotia it reduces our number of usable stations down to five (Yarmouth airport, CFB Greenwood, Halifax Stanfield International Airport, CFB Shearwater, and Sydney airport), when we add the condition that there be a relatively continuous period of observations throughout the time period for which we are comparing, we reduce it to four (CFB Shearwater has been reporting part time since the early 2000’s). However, the remaining stations are relatively spread out across Nova Scotia, so even with this reduced number, we still have a representative sample of what the province as a whole received.

In terms of the other provinces, we focused on New Brunswick alone. Simply because Prince Edward Island had only one useable station (Charlottetown airport), which would not necessarily be a representative sample of the province as a whole. Also, we did not compare data from Newfoundland, as it was determined from our wind analyses that Newfoundland has a very different climatology, as well as geography, and may not serve as a reasonable comparison when it comes to determining the effects of the weather on a power grid. Even for New Brunswick, we have only three usable stations (Saint John airport, Fredericton airport, and Moncton airport) for this study, all three of which are located in the southern half of the province, although all three represent a significant portion of that province’s population.

Finally, the dataset does not include precipitation totals, which is a key element to how ice accretion affects a system. A region may see 6-10 hours of freezing rain, but if only 2 mm falls it will have little effect, however, that same region may only see 2-3 hours of freezing rain, but if 15 mm falls, then it can have a significant effect on the system. Fortunately, we could obtain daily snowfall totals from a separate dataset, which we could correlate with our occurrences of wet snow, and thus determine the relative severity of a given event. Unfortunately, while all the stations we used have daily rainfall totals, none of these totals differentiate freezing rain and rain, so we could not determine the relative severity of the freezing rain events, or at least in terms of amounts of ice accretion.

The Analysis:

In terms of wet snow events, we were looking for cases where a significant amount of snow could adhere to the power lines and their supporting systems, in this case we set a threshold of 20 cm. While this is not to say that amounts under 20 cm can't produce power interruptions, however, like the wind speeds and gusts, we are focusing more on the severe events. As such, we removed any event that gave a total snowfall less than 20 cm, regardless of whether the snow was wet or not. We also eliminated cases where there were no more than 2 consecutive hours of wet snow, as these represented merely a transition period of snow to rain, and it was very unlikely that 20 cm could be accumulated in such a short period. Finally, we did note a few occasions where there were more than 2 consecutive hours of wet snow, and the snowfall total was 20 cm or more, but the heaviest precipitation occurred when the dew point temperature was -1.0C or lower, and the wet snow was mixed with rain, indicating that it likely did not contribute significantly to the total, and was thus rejected. This left us with occurrences at each station where there were 3 or more consecutive hours of wet snow, that the majority of the snowfall occurred as wet snow, and the total snowfall was at least 20 cm.

With the above criteria in place, we compared the number of hours of wet snow (producing 20cm or more), for each station across the province. We also did a comparison of snowfall amounts. As with the winds, we performed a comparison over the past fifteen years (1994 to 2008) to determine if there has been a trend of worsening weather over the past four to six years. We also did a long term comparison, (1971-2008) to establish a reference for the relative severity of the recent years. For the long term comparison we did not use the 20 cm filter, rather we simply compared the number of hours of wet snow per year for each station.

For the freezing rain, we followed a slightly different procedure than that of the wet snow. Primarily because we had no accumulation data to determine the relative severity of any given event. In this case our limitation was strong winds that followed an event within six hours. As we mentioned in the Introduction, the impact of ice accumulation on power lines is significantly magnified by the addition of a strong wind stress soon after the ice has accumulated, and before it could be melted off. In this case we counted hours of freezing rain that were followed by sustained winds of 40 km/h or stronger within six hours. This data was then compared for each station for the fifteen year period of 1994 to 2008.

For the long term comparison, we again went back to 1971, however, like the wet snow, we did not apply any limitation. We simply looked at the total number of hours of freezing rain for each station per year.

The Results:

For the short term comparisons with wet snow events, giving 20 cm or more, we found that there was a significant annual variation, as well as variations from station to station. The variations, however, showed no significant identifiable trends over the past 15 years. There were years where there was a large number of occurrences of wet snow across the province of Nova Scotia, some years with large accumulations of wet snow, and some years with both (2004 was such a year, where in November a significant amount of wet snow fell across Nova Scotia, specifically in the southwest portion of the province, Fig. 9).

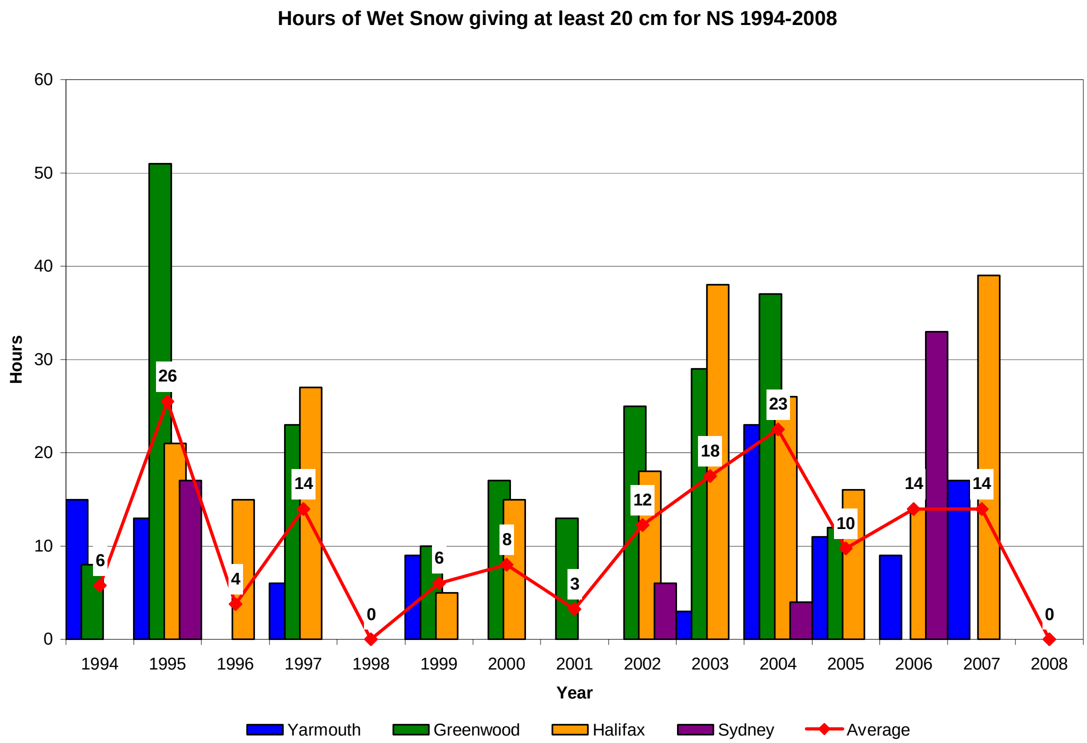

Fig. 9 Hours of wet snow giving at least 20 cm over Nova Scotia 1994-2008

In terms of the Freezing rain events, again, we found a certain degree of annual variation, as well as variations from station to station, but no significant trends. One slight trend was noted in the last two years (2007, and 2008) that each station saw more hours of severe freezing rain events than the previous four or five years. In fact, these peaks were on par with some of the peaks seen in the late 1990's (Fig. 10). The difference is that while in the 1990's the peaks typically occurred only over one station, the last two years saw a peak across more than one station, giving a slight overall increase across the province over previous years.

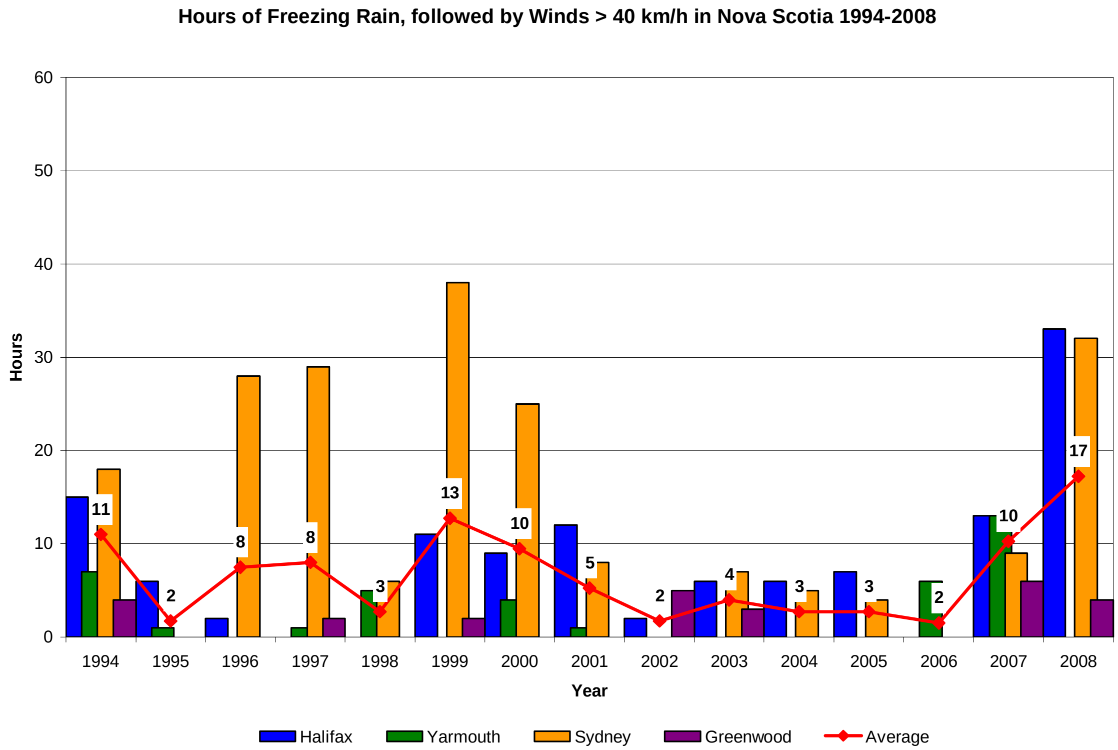

Fig. 10 Hours of freezing rain for stations across Nova Scotia, 1994-2008

When we looked at the long term comparisons, we saw that the past fifteen years showed no marked differences from the previous 23 years. Some stations have shown a slight upward trend in the past few years, while other stations appear to be on a slight downward trend. Overall, no station has shown a significant difference in number of occurrences over the past 6 years compared to the previous 32 years.

When we expand the comparisons beyond Nova Scotia, we found very little deviation from this pattern, or lack thereof, in New Brunswick. Overall, while there are some rough cycles in each station, there is little indication of a major shift in the weather patterns. However we did note that Saint John did see significantly more occurrences of wet snow in the 1980's, and 1990's than it has in recent years (Figs. 11 and 12). We also noted that, while similar, the numbers were lower in New Brunswick, both for wet snow and freezing rain events. Given the province's reputation for heavy snowfalls, this would indicate that the majority of snowfall events are not wet.

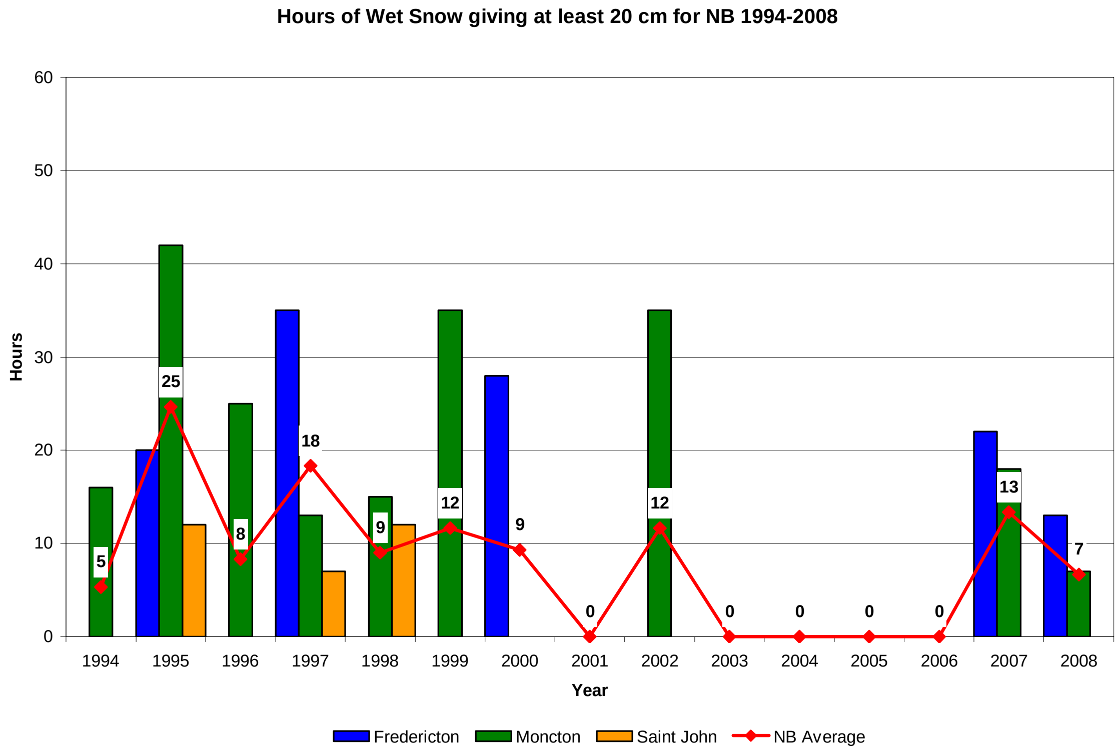

Fig. 11 Hours of wet snow over New Brunswick 1994-2008

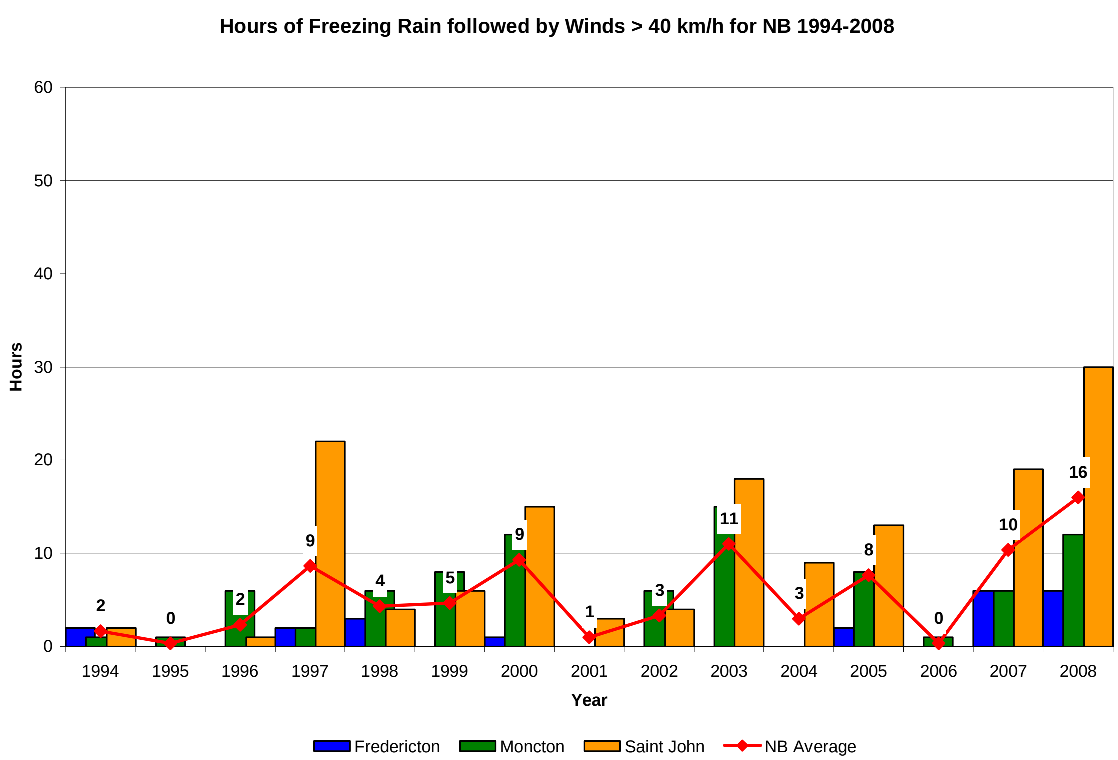

Fig. 12 Hours of freezing rain over New Brunswick 1994-2008

Combined Events

To this point we have isolated the weather events, and looked at both the long term and short term trends. However, since a power grid experiences all of the weather events over the course of a year, we needed to examine the combined effects of all the parameters.

The Analysis:

The simplest method of examining the combined effects of all the weather parameters would be to simply add each parameter for a given year, then plot the yearly totals. However, we had to be mindful of a few points. First, such a comparison could only be done for years where we have data for all elements, since we do not have wind gust data prior to 1994, nor have we filtered the wet snow events prior to 1994, we only performed the comparisons for the 1994 to 2008 time frame. Since the focus of this study has been to ascertain whether the decrease in reliability at NSPI over the past 3-4 years has been due to the weather, this 15 year time span should be a sufficient comparison.

Another issue to consider is that by adding the effects of each of the weather elements, we are essentially considering each to be a separate event. In other words, doing a straight summation would assume that there were no occasions where a station received over 60 km/h sustained winds, and had freezing rain or wet snow, or gusts over 90 km/h. This turns out to not be a bad assumption in terms of the freezing rain and wet snow combined with the high winds. When we looked at establishing thresholds, we found that there were very few cases when a station received either freezing rain or wet snow, along with winds over 60 km/h, or gusts over 90 km/h. In fact, for most stations this combination of events occurred at most 2-3 hours in one or two years, with most years having no such occurrences whatsoever. It was also noted that there were few cases where wet snow events gave 20 cm or more, and had significant periods of freezing rain as well. In some cases there were a few hours of freezing rain, but the overlap was generally small. On the other hand, we would expect a large number of cases where the sustained winds would be greater than 60 km/h, and the gusts would be 90 km/h or more. However, since we have already seen that the trends of these components are closely related, we would not expect to see major changes to the overall shape of the curve. It should also be considered that since we are examining trends, rather than specific relationships, the absolute values that we obtain are not as important, just the relative influence from year to year. Given this, we felt that simply adding the number of hours of each event was a reasonable approximation of the overall effect.

The Results:

After combining the hours of sustained winds, high wind gusts, freezing rain (followed by winds over 40 km/h), and wet snow, we found that while some of the stations had slightly different trends, the overall results were relatively unchanged from when we looked at the individual parameters. Essentially, in most cases there was little to no identifiable trend, in fact, for the most part we noted a rough cycle visible in most stations (Fig 14, Moncton example). The exception to this, as it was with the winds, was Halifax Stanfield International Airport. In the case of Halifax, the slight increase of wet snow and freezing rain over the past two years, combined with the strong increase in occurrences of high winds over the past four years, gave a significant upwards trend (Figs. 13).

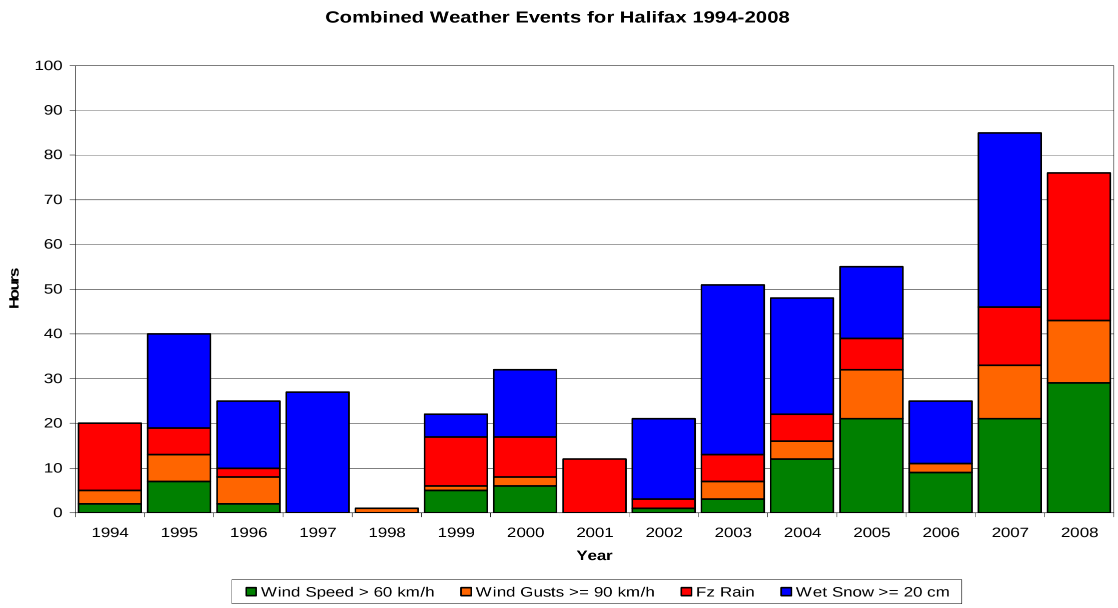

Fig. 13 Combined hours of Fz. rain, wet snow, high winds for Halifax, 1994-2008

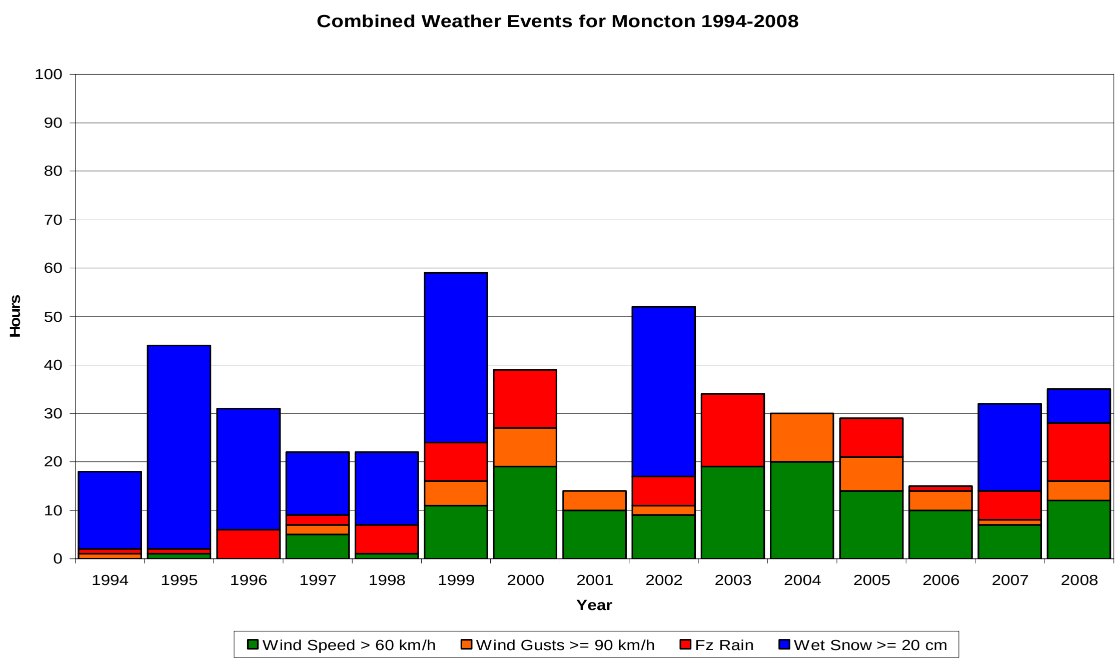

Fig. 14 Combined hours of Fz. rain, wet snow, high winds for Moncton, 1994-2008

Effects on Reliability

Analysis:

In terms of influence on the reliability of NSPI's power grid, we needed to compare our trends of combined weather and compare them to the reliability of NSPI over the same time frame. We were provided reliability data from NSPI covering the years 1988 to 2008, which included one of the metrics of reliability known as the System Average Interruption Frequency Index (SAIFI). This index is determined by dividing the total number of customer interruptions by the total number of customers, and is typically measured over the course of a year. A quick way to determine how much influence the weather has on a grid would be to compare the annual occurrences (i.e. frequency) of the combined weather parameters to the yearly values of the SAIFI. However, before attempting such a comparison we needed to take a couple of issues into account. First, the SAIFI data provided is a measure across the entire province, so an average of the occurrences across the province is needed. Second, since the SAIFI is determined from the total number of customers, the influence of any particular weather event will depend significantly on where it is located. For instance, if Hurricane Juan had tracked further east, say over Guysborough County, its influence would have been greatly reduced. It would have still been devastating to the infrastructure in the area, and customers in the affected areas would still lose their power, but given the low population density of the southeastern portion of the province, the total number of customers affected would have been much less. This change of influence by location suggests that rather than a straight average, a weighted average of the occurrences would be more representative of the influence on the power grid.

For this comparison we are not looking at the influence of intensity of any given event, just the frequency of the event. If this compared well with the SAIFI, then it would indicate that once the weather pattern crosses a specific threshold, the intensity is irrelevant. To do a weighted average, we gathered community population data (Nova Scotia Government, 2006), for several locations across the province that were obtained from the Statistics Canada 2006 census. With this information we calculated approximate populations near the available stations used for the different comparisons, and divided by the total population of the province, obtaining a percentage of the total population that is represented by a given station. Also, since there are portions of the population that are not represented by any station used (for instance there is no data in Guysborough County), the weighted sum of the hours is not divided by the number of stations, but the sum of the population percentages represented by the stations. This also means we can add the averages from the wind comparisons to those of the ice accretion, where we had fewer stations available, without biasing the influence of a weather element due to number of stations.

Finally, it may also be possible that the more an intense event is, may have a more devastating effect on a system, so we needed some manner of accounting for particularly intense storms by factoring the peak values. We did this in addition to the previous comparison where it is assumed that intensity is irrelevant other than the fact it crosses a threshold. To take this into account we simply divided the annual peak values at a given station by the threshold imposed, and multiply that by the number of hours for the station. We then applied our weighted averaging technique to these new numbers. This gives slightly more weight to events that are significantly higher than the thresholds we applied, and less weight to those that marginally cross the threshold, while still taking into account the duration of the events.

We should note at this point, that one of the elements we use in this comparison, freezing rain, did not have an intensity threshold applied to it. This meant that we could not weigh the particular events by their intensity, possible affecting the shape of the curve. To determine possible influences of this, we used both the weighted average of total hours of freezing rain, and the hours followed by winds of 40 km/h or more in our calculations. We also looked at the combined effects without the freezing rain factored in at all.

Finally, to measure the influence each event may have had on the SAIFI data, we applied a correlation calculation to the curves. This calculation provides a measure of how well two separate curves correlate with each other. The results of this calculation range from -1.0 to 1.0, where 1.0 means the two curves are perfectly correlated, -1.0 means they are negatively correlated (i.e. mirror images of each other), and a 0.0 means the curves are absolutely uncorrelated. Generally speaking, values that are over +0.5 or less than -0.5 indicate a good correlation between curves. In this case, if the weather has the influence on the system as we expect, we should obtain a positive correlation between weather events and the SAIFI curve. Also, we would expect that the individual elements would have a lower correlation than the combined elements, since the SAIFI would be influenced by all elements over the course of a year.

Results:

The first weather element we compared was the sustained wind speed. We first took just a straight average of the hours of high winds across Nova Scotia, and compared these to the SAIFI. We found that this did correlate reasonably well with the SAIFI data, with a correlation value of 0.70 for 1994-2008. When we limited the comparison to the past six years (2003-2008), where the frequency of high winds increased so dramatically in the Halifax area, the correlation improved to 0.79. When we applied the weighted averaging scheme, the correlations actually diminished somewhat, with a value of 0.65 for the entire fifteen year period, and 0.75 for the past six years (Fig. 15). When we applied the same comparison to the wind gusts, the straight average did not correlate well with the SAIFI curve over the entire fifteen year span, with a correlation value of 0.33. The correlation did improve for the last six years, with a value of 0.71. However, in this case the weighted average of the occurrences provided a dramatic difference, with a correlation value of 0.71 for the entire fifteen year period, and 0.84 for the past six years (Fig. 16).

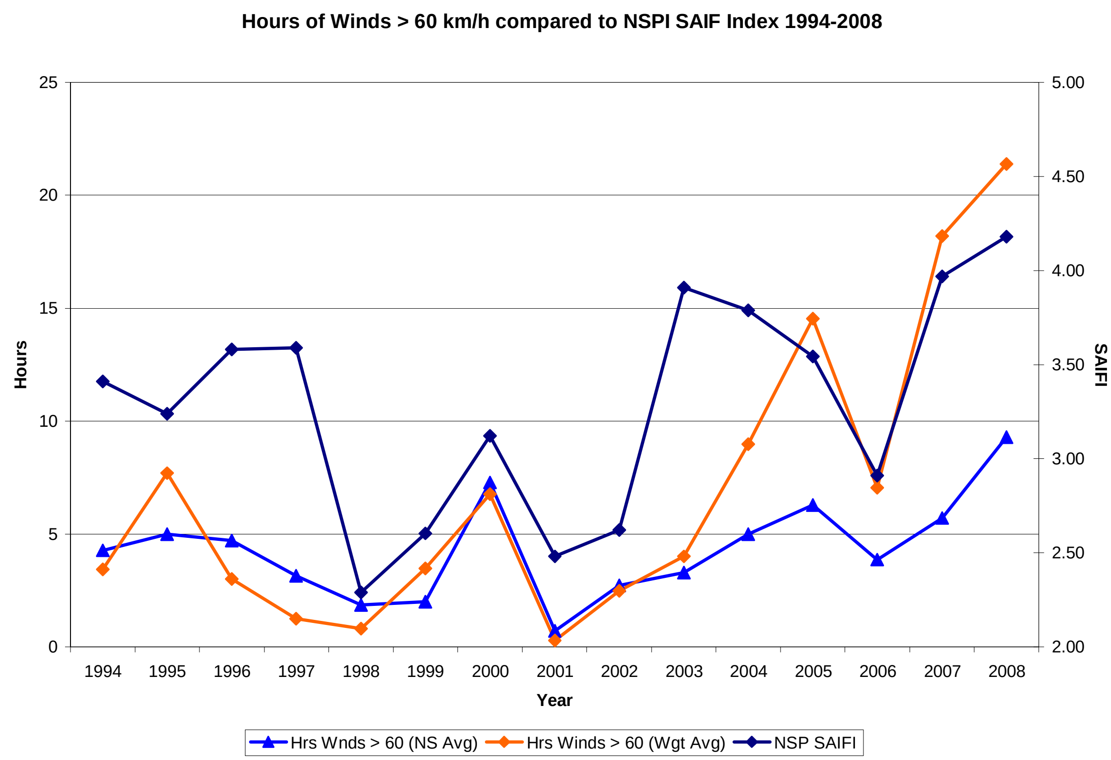

Fig. 15 **NSPI SAFI compared to average occurrences of winds > 60 km/h 1994-2008**

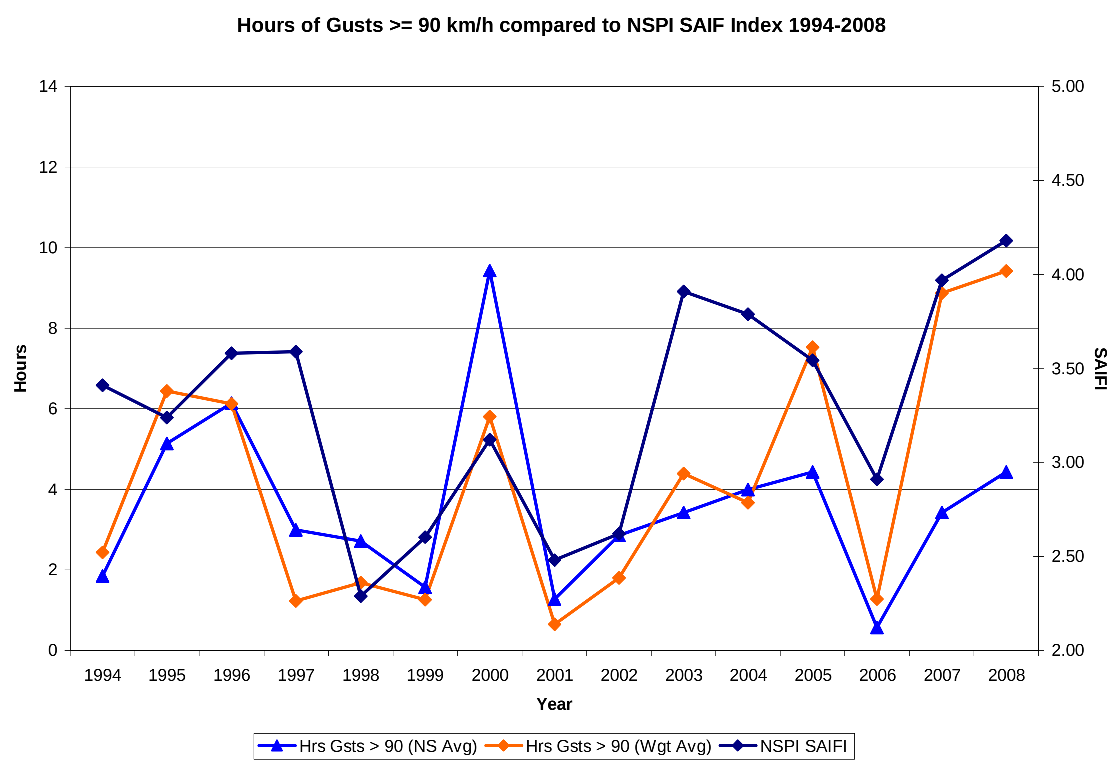

Fig. 16 **NSPI SAFI compared to average occurrences of wind gusts >= 90 km/h 1994-2008**

The results for the wet snow and freezing rain events were not so well correlated. In fact, the best correlation across the fifteen year period was the weighted average of wet snow occurrences, without factoring in the intensity, which gave a correlation of 0.44. Factoring in the intensity dropped the correlation to 0.40. Similarly, the occurrences of freezing rain, followed by winds 40 km/h or higher, gave a value 0.41. The straight average of wet snow occurrences gave a value of 0.29, and the freezing rain without the wind constraint was essentially uncorrelated with a value of -0.17. For the past six years, the occurrences of wet snow, giving more than 20 cm, was essentially uncorrelated with the SAIFI, with values of -0.26, -0.07, and -0.03 for the straight average, weighted average, and weighted average with Intensity factored in. However, the correlation improved for the freezing rain, with values of 0.90, and 0.74 for the freezing rain events, and freezing rain with wind limitation. When we combined the values of the freezing rain events (with wind restriction), and the weighted average of wet snow (without intensity factored in), we found that the correlation with the SAIFI improved to 0.78 for the fifteen year time span, and to 0.76 for the past six years. When we factored in the intensity of the wet snow events, the correlations dropped to 0.68 for the fifteen year period, and to 0.53 for the past six years.

Finally, all four elements, sustained winds, wind gusts, freezing rain, and wet snow, were combined, giving a total number hours of severe weather. We first looked at the total with the weighted averages, without factoring in the intensity of the events, and the freezing rain events with the wind restriction. When compared with the SAIFI data, we found that the two curves were well correlated with a value of 0.85 for the entire fifteen year period, and a near perfect 0.95 for the past six years. For completeness we also combined the values with the intensities factored in, and found that the correlation values dropped to 0.82 for the fifteen year period, and to 0.90 for the past six years (Fig. 17).

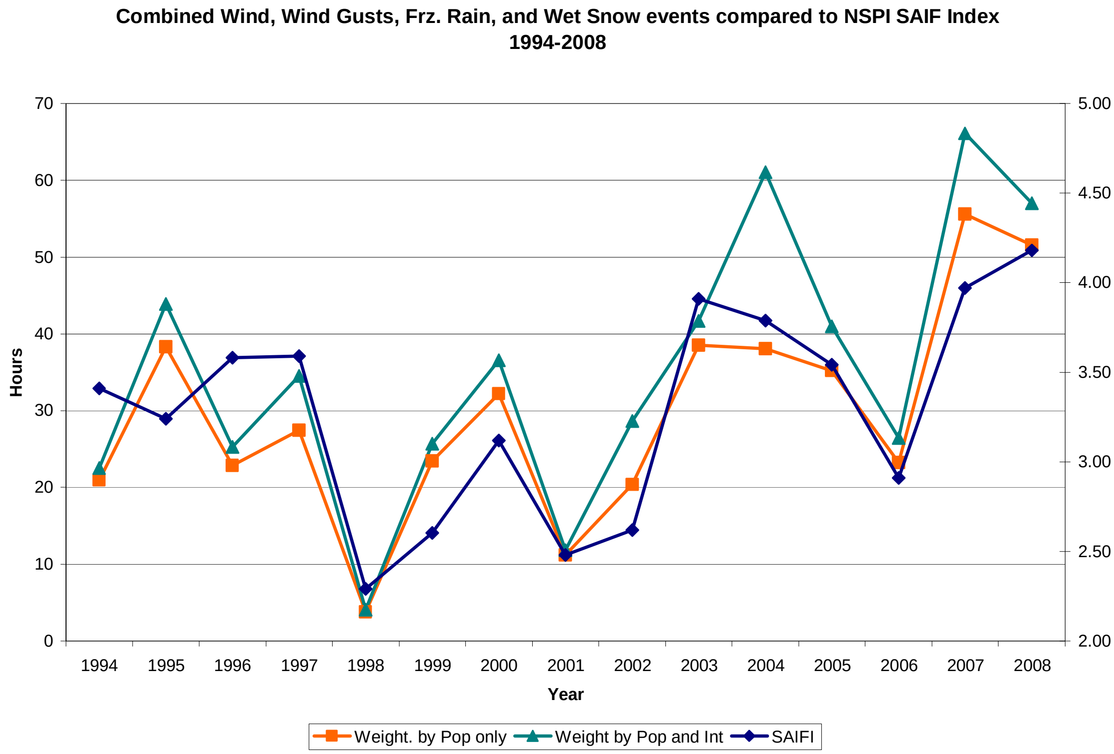

Fig. 17 **NSPI SAIFI compared to hours of all weather events, 1994-2008**

Conclusions

There are several conclusions that can be drawn from the results we obtained from the various analyses performed on the data.

Trends:

As we noted in the results of each of the parameters, for many of the stations we noted little to no trend in the weather over the past six years that would correspond to a decrease in reliability within that same time frame. In fact some stations have shown a trend downwards, and when we examined the long term data, the past 15-20 years have actually been generally very quiet. There were a couple of exceptions to this, with the most obvious being the station at Halifax Stanfield International Airport. As was discussed in the results sections, Halifax had a sharp increase in occurrences of strong winds over the past 3-5 years, and a slight increase in the occurrences of freezing rain and wet snow over the past 2 years. The recent increase was emphasized when we combined all the weather elements into one chart. This was significant in that the location that did experience the dramatic increase also happened to be in the vicinity of the highest population density of the province, and thus a large portion of the NSPI network.

We also examined the intensities of each of the weather parameters (with the exception of the freezing rain events), and as noted in the results sections, they did appear to mirror the trends of the frequencies to some degree. Although, the strength of the intensity trends was much weaker than those of the frequencies, and in cases where the trends in the frequency were already weak, they disappeared entirely in the intensity. A good example of this is the data from Halifax, where although the frequency of high winds (speed and gusts) showed a strong increase over the past 3-5 years, the intensity increased only slightly. This indicates that the strongest issue for Halifax has been the increased number of storms, rather than their strength, although there has been a slight increase in their strength on average.

Long term Trends:

Given that most of the stations we examined showed little difference from the 30 year climatology, the 5, 10, and 30 year return periods as calculated from Gumbel distributions of the peaks should remain relatively unchanged. In fact, when such a distribution is done for Halifax, there is only an increase of 1-3 km/h for each of the winds in the return periods (Fig. 18 and Table 1). This would suggest that Halifax may be in a windy portion of its cycle, and may see similar weather over the next few years. More importantly, the past few years have shown that although the region around Halifax may not have seen very windy years since 1971, the conditions are certainly possible, and may even be quite likely over the expected lifetime of a given system.

Return Period	30 yr climatology	38 yr climatology
5	78 km/h	77 km/h
10	83 km/h	81 km/h
30	91 km/h	89 km/h

Table 1: Comparison of return period for peak winds at Halifax Stanfield International Airport, using 30 year (1971-2000) and 38 year (1971 to 2008) climatologies.

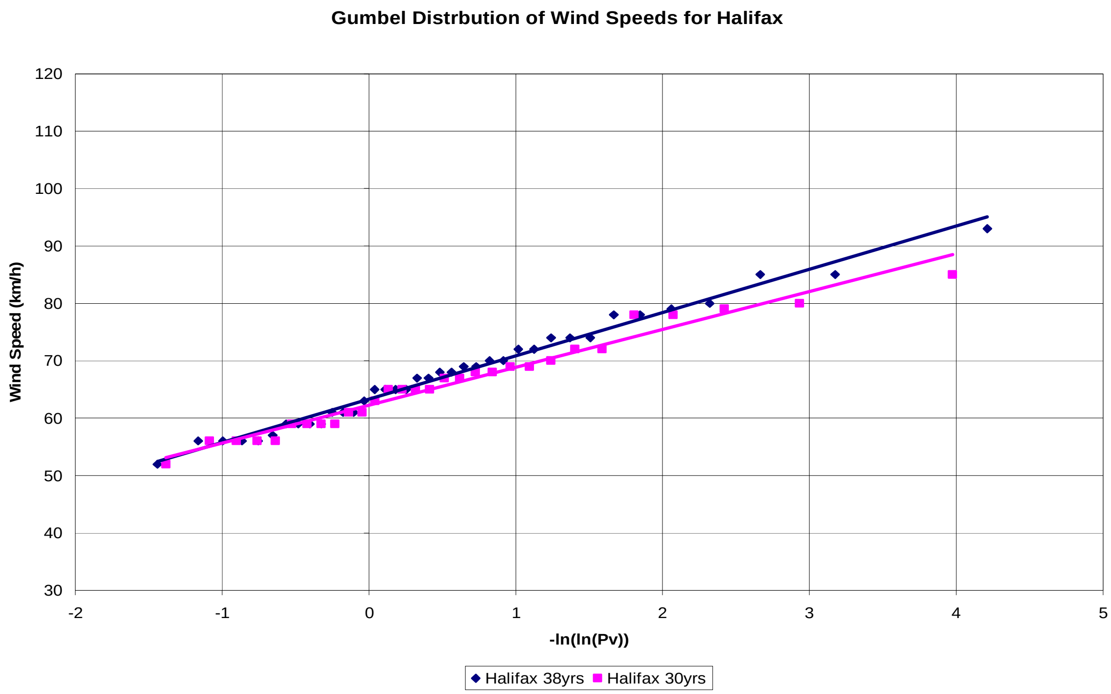

Fig. 18 Gumbel distribution of peak winds for Halifax, 30yr and 38 year climatologies

Overall Effect:

When we looked at each of the weather elements averaged across the province, and weighted according to the population, we found generally good correlations between the occurrences of high winds and the SAIFI data. There was some correlation between the SAIFI data and the wet snow and freezing rain events, (followed by strong winds) however, these were not nearly as strong as the correlations with the wind events. These results suggest that the influence of the wind has had a much stronger effect on the reliability of the NSPI system, although the influence of the freezing rain events had increased over the past six years.

When we combined all of the weather events, without taking intensity of the events into account, we found a very strong correlation with the SAIFI data. A correlation that became nearly perfect in the past six years. This result strongly suggests that the largest influence on the reliability of NSPI's system, especially over the past six years, has been the weather.

When we factored in the intensity of each of the elements (with the exception of freezing rain), we found that the individual correlations remained either relatively unchanged, or were actually less correlated with the SAIFI data. When the elements were combined, the curves were slightly less correlated, although, the correlation values were still relatively strong. This makes a degree of sense when one takes into account that the SAIFI is a measure of number of interruptions per customer, and does not relate to duration. So all that matters is that the system has failed once the weather has crossed a threshold, and any further failures are due to the persistence above the given threshold, and not necessarily due to an increase in intensity.

In summary, we found that although Nova Scotia as a whole has not necessarily seen an increase in severe weather, and has, in fact, seen a decrease in some locations. However, we did find that the region with the highest population density has seen a dramatic increase in strong wind events over the past six years. We also found that in terms of overall severe weather, as defined by its influence on power lines and their supporting systems, Nova Scotia is slightly more susceptible than New Brunswick, especially in terms of high wind gusts. When we combined the number of events of high winds and ice accumulation over the past fifteen years, we found that there was a strong correlation between the trends of the weather and reliability of the NSPI power system. This correlation became stronger when we took into account the percentage of the population influence by the recent changes. This means that while the overall occurrences of severe weather have not increased across the province, they have over the heavily populated areas, which in turn has had a strong effect on the overall reliability of the system. Finally, since the increase was primarily in the frequency of the events, and not the intensity, the current return periods calculated for the region, based on the 30 year climatology from 1971-2008 remain valid design specifications. Although, given the history of the frequency of strong events across the province, perhaps a design that would harden the system to withstand a slightly higher threshold would be advisable.

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Richards, Abuamer, and Hasan, "Atmospheric Hazards: Snowstorms, Blizzards, Blowing Snow, Extreme Cold, Windchill, Freezing Precipitation, and Winter Rainfall in Atlantic Canada", Meteorological Service of Canada – Atlantic Science Report Series, http://www.hazards.ca, December 2006.

Simpson and Van Bossuyt, "Tree-Caused Electric Outages", Journal of Aboriculture, Vol 22, No. 6, 1996.

Appendix A
Charts and Tables

High Winds:

Stations available, used, and rejected for the sustained winds and wind gusts comparisons. Some notes; a large portion of these stations have either been recently installed, or the data has not yet been completely incorporated into Environment Canada's quality controlled digital, or online, data set. As such, several stations only have data for the past few years, not long enough to determine what the trends have been prior to the past 5-6 years. Other stations, while sufficient data is available, have not been used in the study, as they have been deemed "not representative". A station was deemed not representative when the hours of high winds were at least an order of magnitude greater than a significant number of stations within the inland regions. For example, at Beaver Island the wind speeds typically exceed 60 km/h 100 to 300 hours per year, where the typical values of inland stations during that time were no higher than 29 hours per year. This would have an effect of significantly biasing provincial averages or totals towards the extreme values, losing the signal from any inland stations. Add to this, that many of these stations have been purposely located on exposed islands, points, or right on a coastline in order to minimize the frictional effect of the land, and give a representation of marine conditions in that area.

Nova Scotia:

Station	Years of Data	Used/Not Used	Reason for Rejection
Debert	1994-2008	Used (partial)	Used after 2005 when Truro stopped
Amherst	1994-2006	Used (partial)	stopped in 2005 replaced by Nappan
SHEARWATER AUTO	1996-2004	Not Used	Insufficient Data
McNab's Island	1999-2008	Not Used	Insufficient Data
CARIBOU POINT	1994-2008	Not Used	Very coastal, not representative
HART ISLAND	1994-2008	Not Used	Very coastal, not representative
Tracadie	2002-2008	Not Used	Insufficient Data
Western Head	1988-2008	Used	Coastal, but representative of area
Kentville CDA	1999-2008	Not Used	Insufficient Data
Beaver Island	1994-2008	Not Used	Very coastal, not representative
Baccaro Point	1994-2008	Not Used	Very coastal, not representative
Grand Etang	1994-2008	Not Used	Located in an extreme wind location
HALIFAX INT'L A, NS	1961-2008	Used	
YARMOUTH A, NS	1953-2008	Used	
SYDNEY A, NS	1953-2008	Used	
SHEARWATER A, NS	1953-2005	Not Used	Only partial information since 2002
GREENWOOD A, NS	1953-2008	Used	
ABERCROMBIE POINT, N	1954-197	Not Used	Insufficient data, not representative
BEDFORD BASIN, NS	2004-2008	Not Used	Insufficient data
BEDFORD RANGE, NS	2004-2008	Not Used	Insufficient data

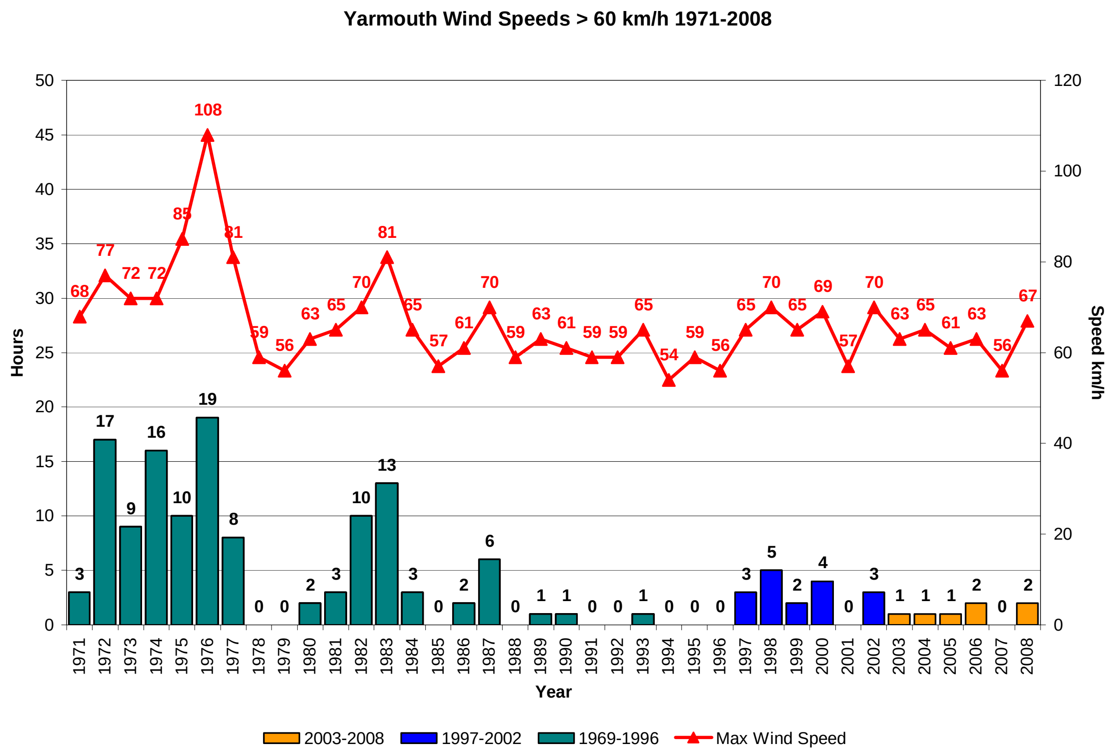
BRIER ISLAND, NS	1994-2008	Not Used	Very coastal, not representative
CAPE GEORGE, NS	1994-2002	Not Used	Insufficient data, not representative
CHETICAMP CS, NS	1994-2008	Not Used	No wind data available
DIGBY AIRPORT, NS	1994-1997	Not Used	Insufficient Data
HALIFAX DOCKYARD, NS	2004-2008	Not Used	Insufficient Data
HALIFAX KOOTENAY, NS	2004-2008	Not Used	Insufficient Data
HALIFAX WINDSOR PARK	2004-2008	Not Used	Insufficient Data
INGONISH BEACH CS, N	2000-2008	Not Used	Insufficient Data
KEJIMKUJIK 1, NS	1994-2008	Not Used	Not representative, very sheltered
LUNENBURG, NS	2002-2008	Not Used	Insufficient Data
MALAY FALLS, NS	1994-2008	Not Used	No Wind data available
NAPPAN AUTO, NS	2003-2008	Used (Partial)	Replaced Amherst
NORTH MOUNTAIN CS, N	1998-2008	Not Used	Insufficient Data
OSBORNE HEAD DND	2004-2008	Not Used	Insufficient Data
UPPER STEWIACKE RCS,	2005-2008	Not Used	Insufficient Data
PARRSBORO, NS	2004-2008	Not Used	Insufficient Data
ST PAUL ISLAND (AUT)	1994-2008	Not Used	Very coastal, not representative
SHEARWATER RCS, NS	2008	Not Used	Insufficient Data
SHEARWATER JETTY, NS	1994-2008	Not Used	Missing data 2002 and 2003
SYDNEY CS, NS	2006-2008	Not Used	Insufficient Data
TRENTON MUNICIPAL A,	1999-2000	Not Used	Insufficient Data

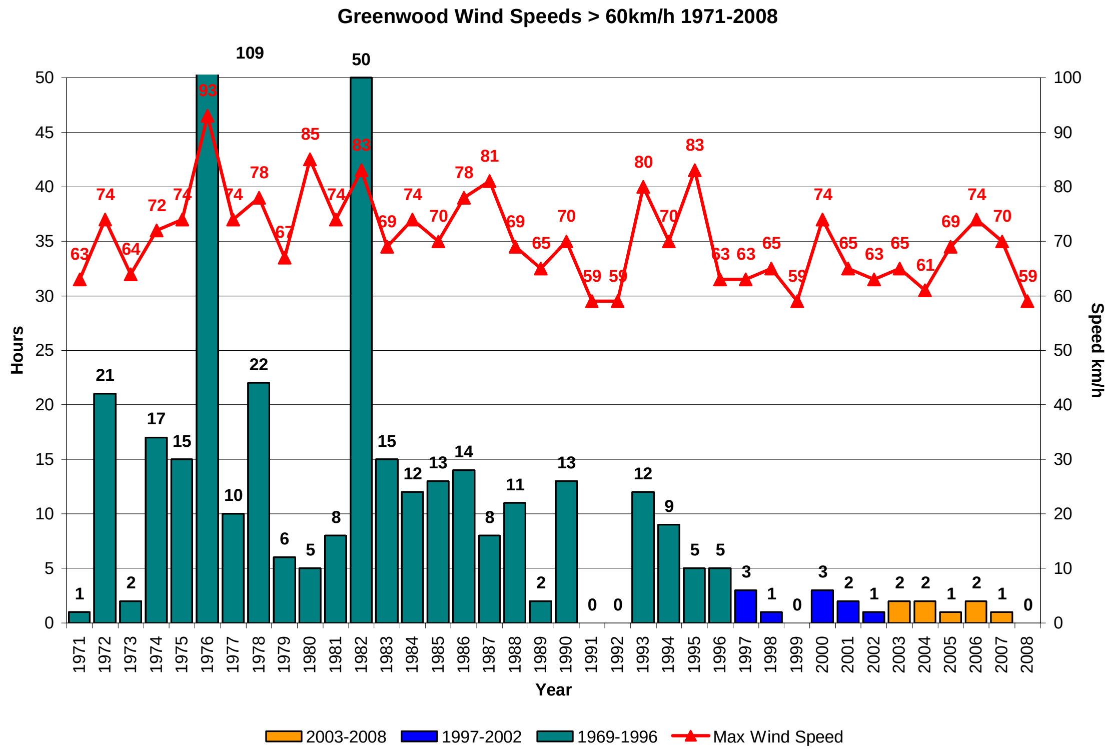
New Brunswick:

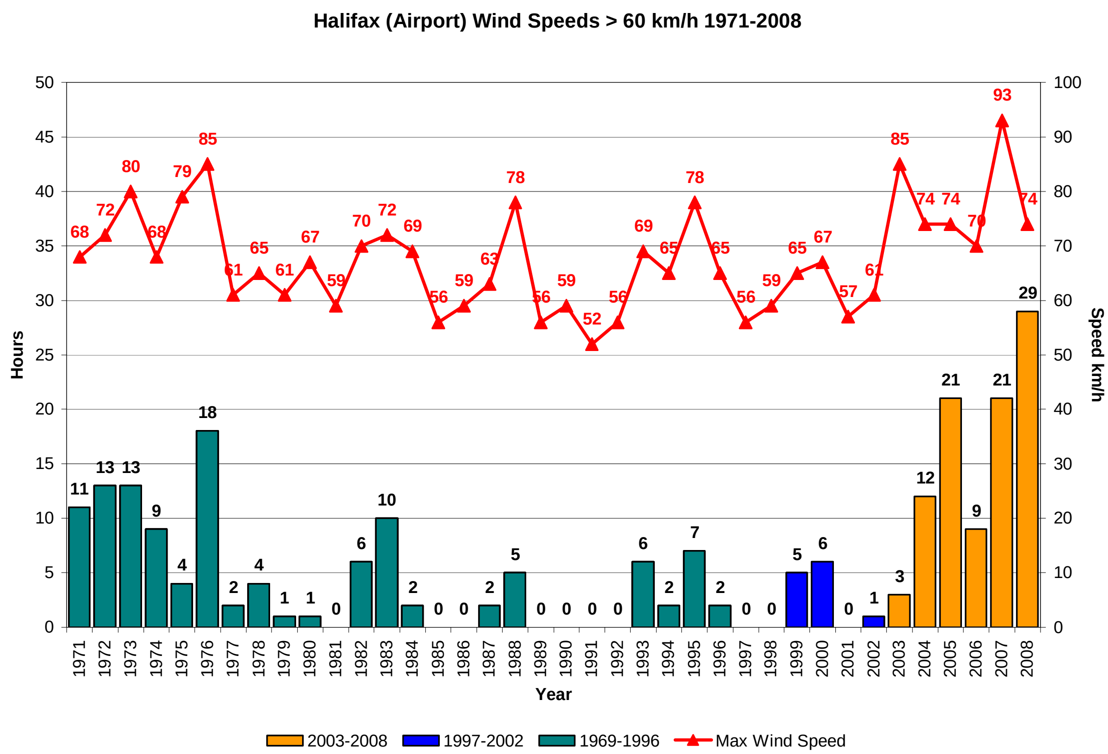
Station	Years of Data	Used/Not Used	Reason for Rejection
BAS CARAQUET, NB	1994-2008	Not Used	Coastal, not representative
BATHURST A, NB	1994-2008	Used	
BUCTOUCHE CDA CS, NB	2005-2008	Not Used	Insufficient Data
CHARLO A, NB	1966-2003	Used (Partial)	Replaced by Charlo Auto in 2004
CHARLO AUTO, NB	2004-2008	Used (Partial)	Replaced Charlo A in 2004
MIRAMICHI RCS, NB	1994-2008		
EDMUNDSTON, NB	2004-2008	Not Used	Insufficient Data
FREDERICTON A, NB	1953-2008	Used	
FREDERICTON AQUATIC	2005-2008	Not Used	Insufficient Data
FREDERICTON CDA CS,	2005-2008	Not Used	Insufficient Data
FUNDY PARK (ALMA) CS	2005-2008	Not Used	Insufficient Data
GAGETOWN A, NB	1976-2008	Used	
GRAND MANAN SAR CS,	2000-2008	Not Used	Insufficient Data
KOUCHIBOUGUAC CS, NB	2005-2008	Not Used	Insufficient Data

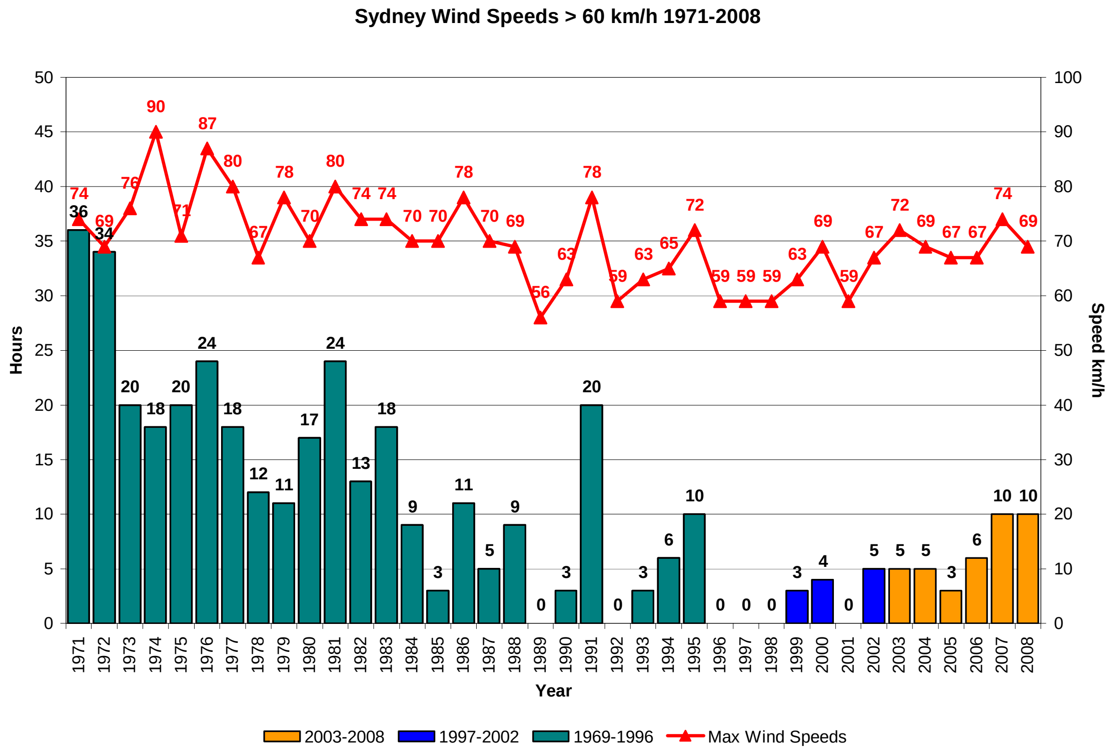
MECHANIC SETTLEMENT,	2006-2008	Not Used	Insufficient Data
MISCOU ISLAND (AUT),	1987-2008	Not Used	Coastal, not representative
POINT ESCUMINAC (AUT	1987-2001	Not Used	Coastal, not representative
POINT LEPREAU CS, NB	1994-2008	Used	
SAINT JOHN A, NB	1953-2008	Used	
ST LEONARD A, NB	1985-2008	Used	
ST. STEPHEN, NB	1986-2008	Used	

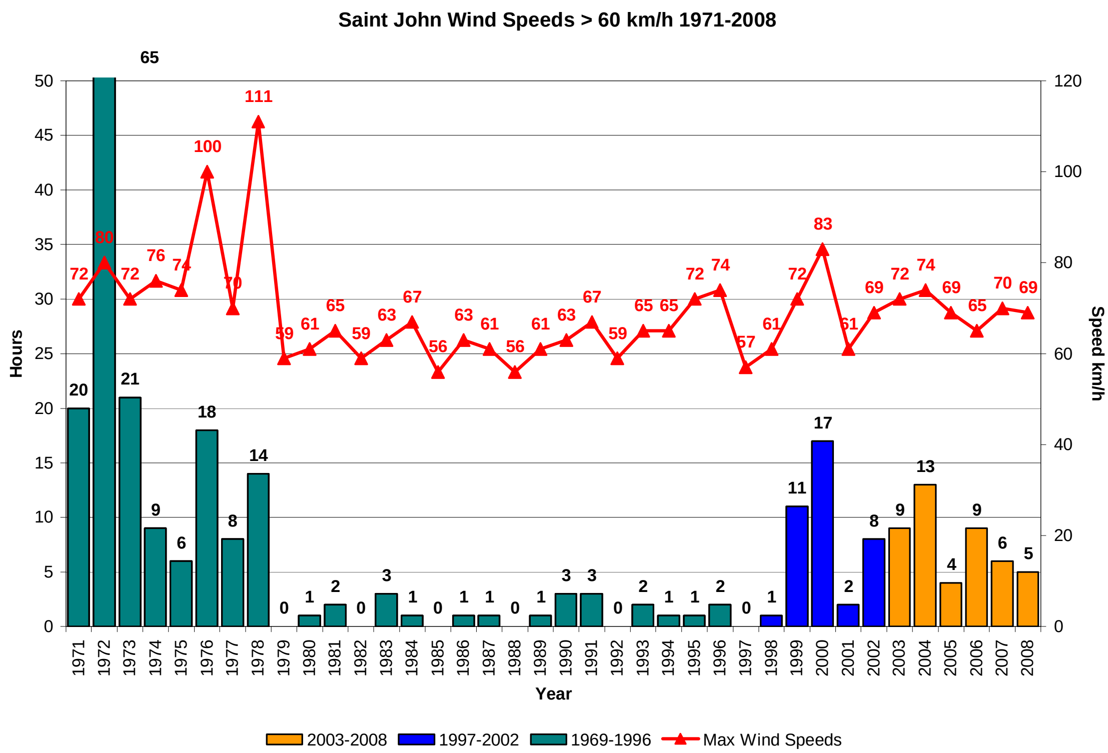
Charts of long term occurrences of strong winds at stations in the study:

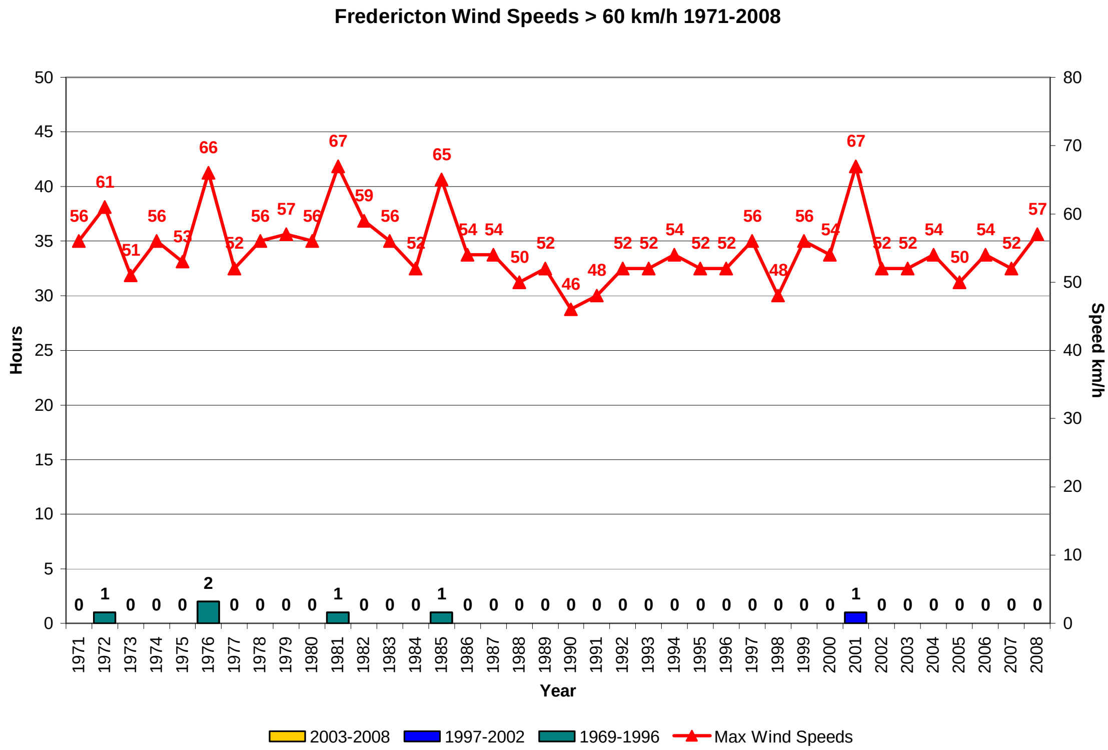


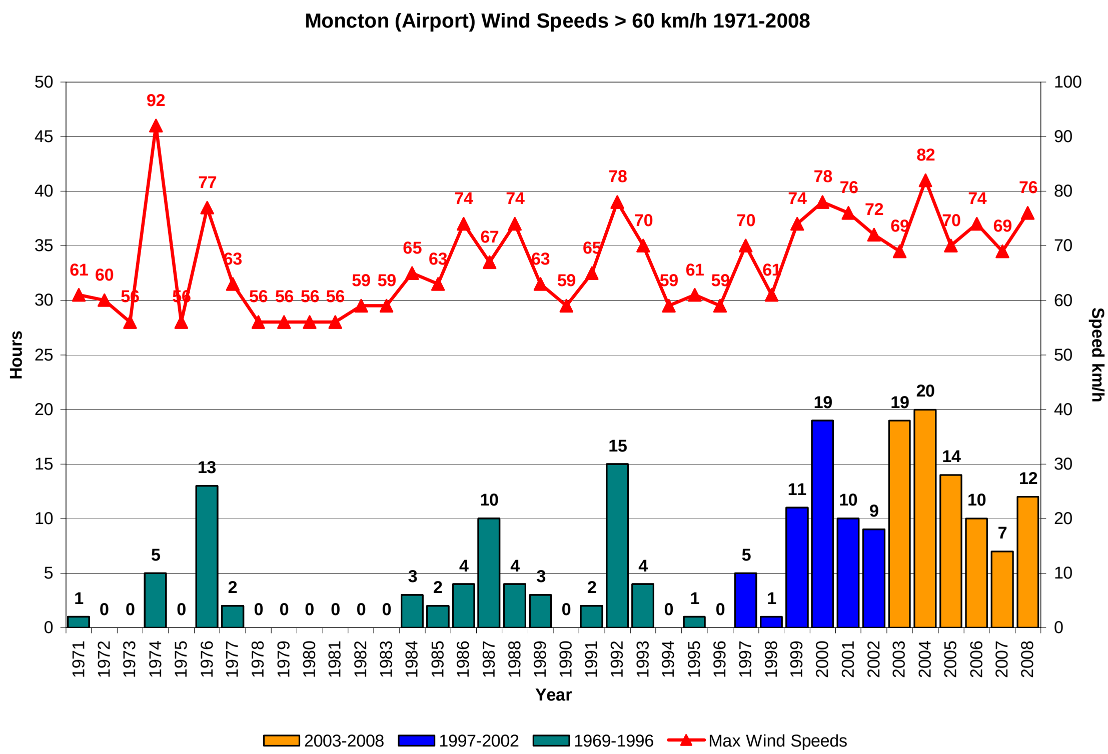

Greenwood Wind Speeds > 60km/h 1971-2008
Hours
Speed km/h
Year
2003-2008
1997-2002
1969-1996
Max Wind Speed

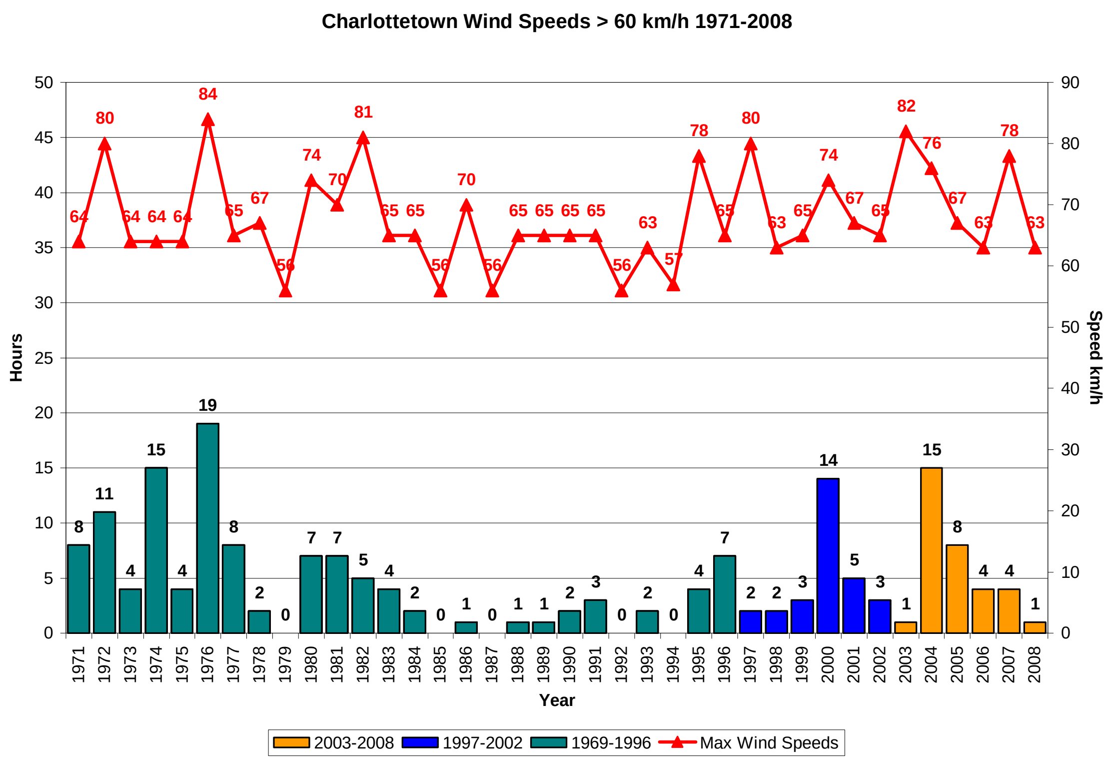

Halifax (Airport) Wind Speeds > 60 km/h 1971-2008
Hours
Speed km/h
Year
2003-2008
1997-2002
1969-1996
Max Wind Speed

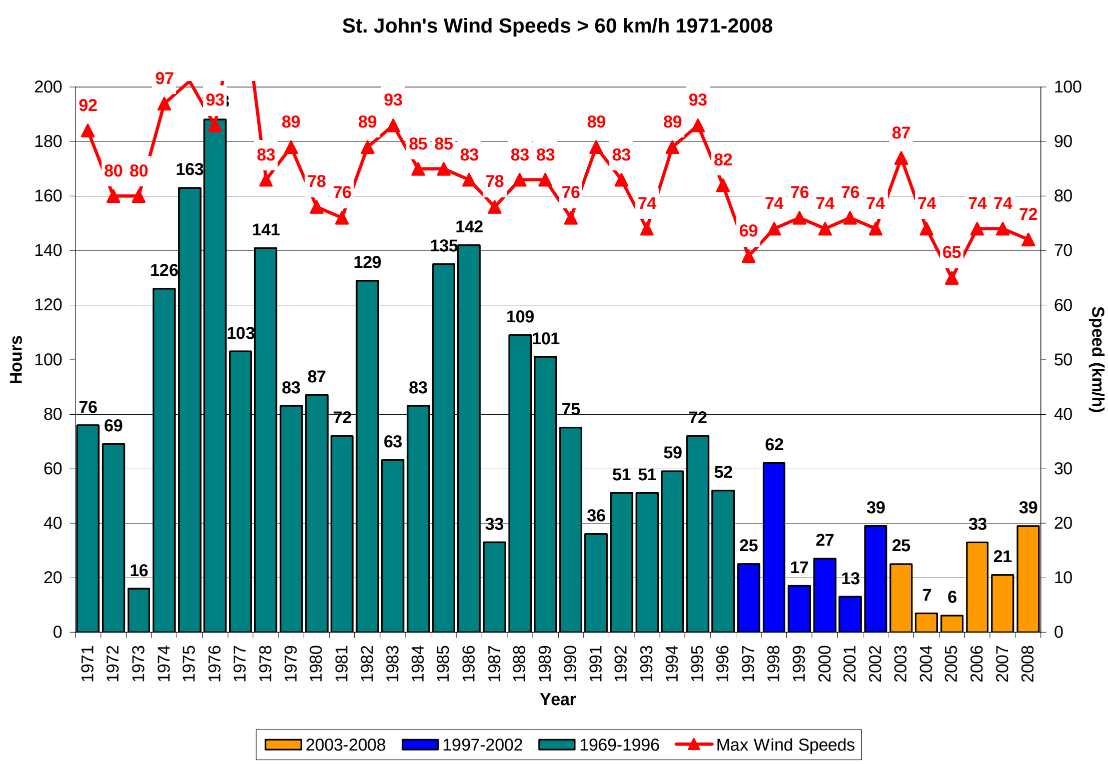

Sydney Wind Speeds > 60 km/h 1971-2008
Hours
Speed km/h
Year
2003-2008
1997-2002
1969-1996
Max Wind Speeds

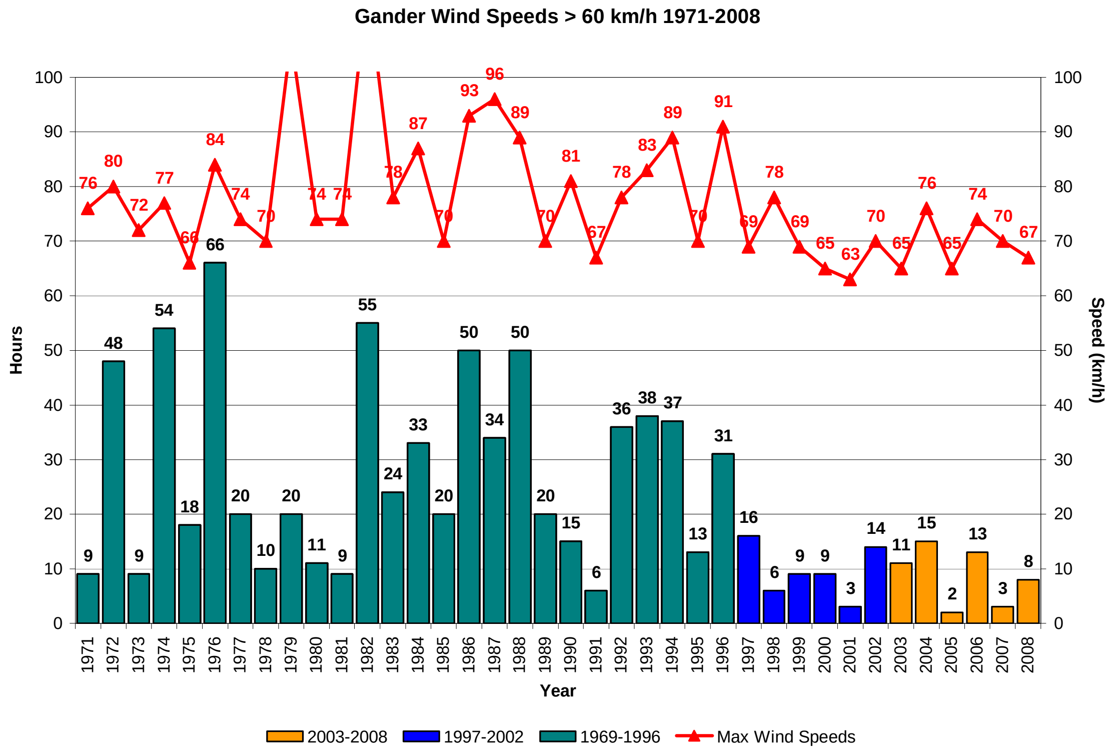

Saint John Wind Speeds > 60 km/h 1971-2008
Hours
Speed km/h
Year
2003-2008
1997-2002
1969-1996
Max Wind Speeds

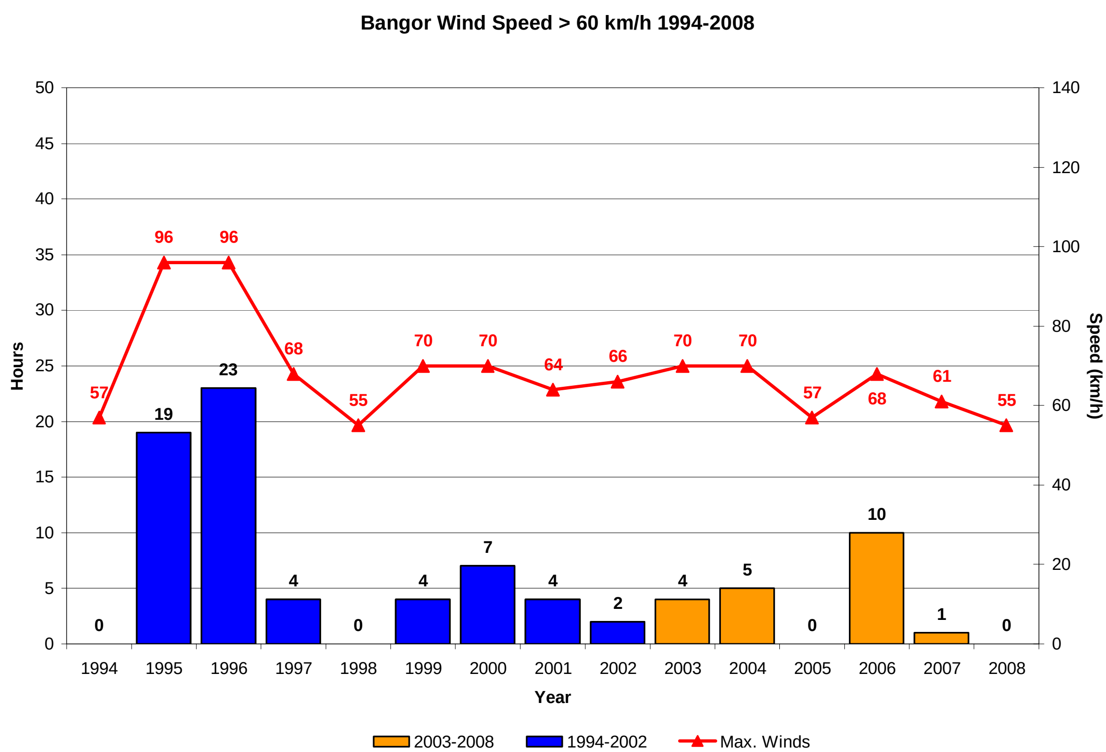

Fredericton Wind Speeds > 60 km/h 1971-2008
Hours
Speed km/h
Year
2003-2008
1997-2002
1969-1996
Max Wind Speeds


Moncton (Airport) Wind Speeds > 60 km/h 1971-2008
Hours
Speed km/h
Year
2003-2008
1997-2002
1969-1996
Max Wind Speeds


Charlottetown Wind Speeds > 60 km/h 1971-2008
Hours
Speed km/h
Year
2003-2008
1997-2002
1969-1996
Max Wind Speeds

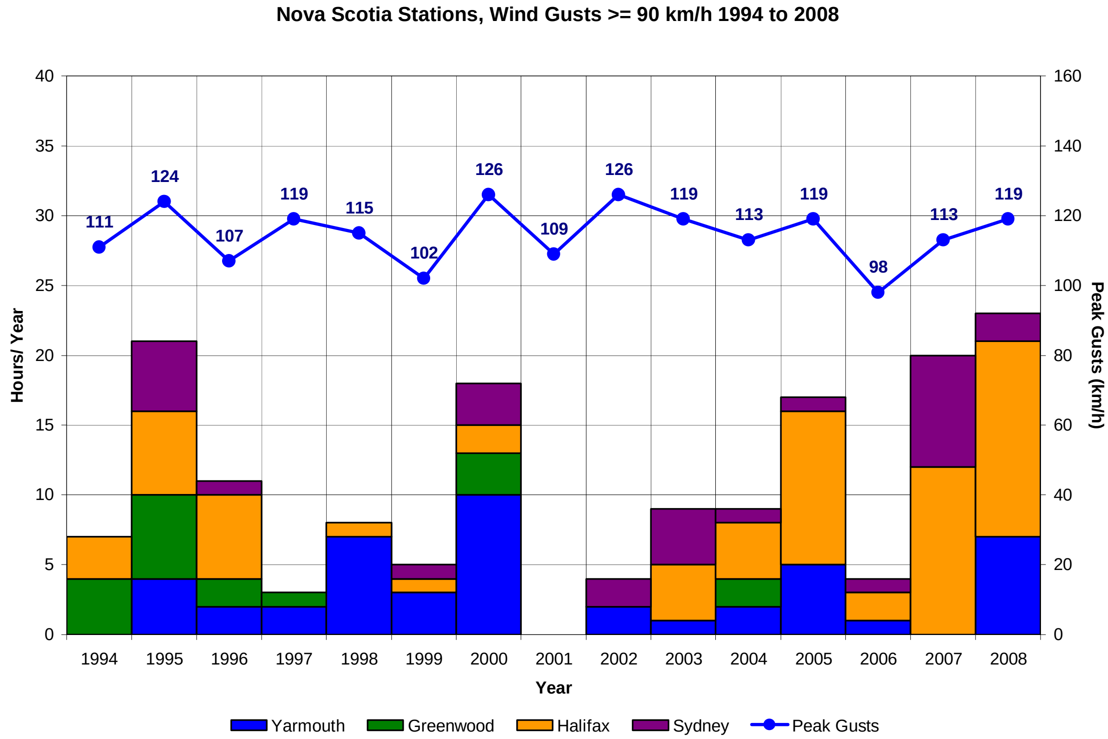

St. John's Wind Speeds > 60 km/h 1971-2008
Hours
Speed (km/h)
Year
2003-2008
1997-2002
1969-1996
Max Wind Speeds

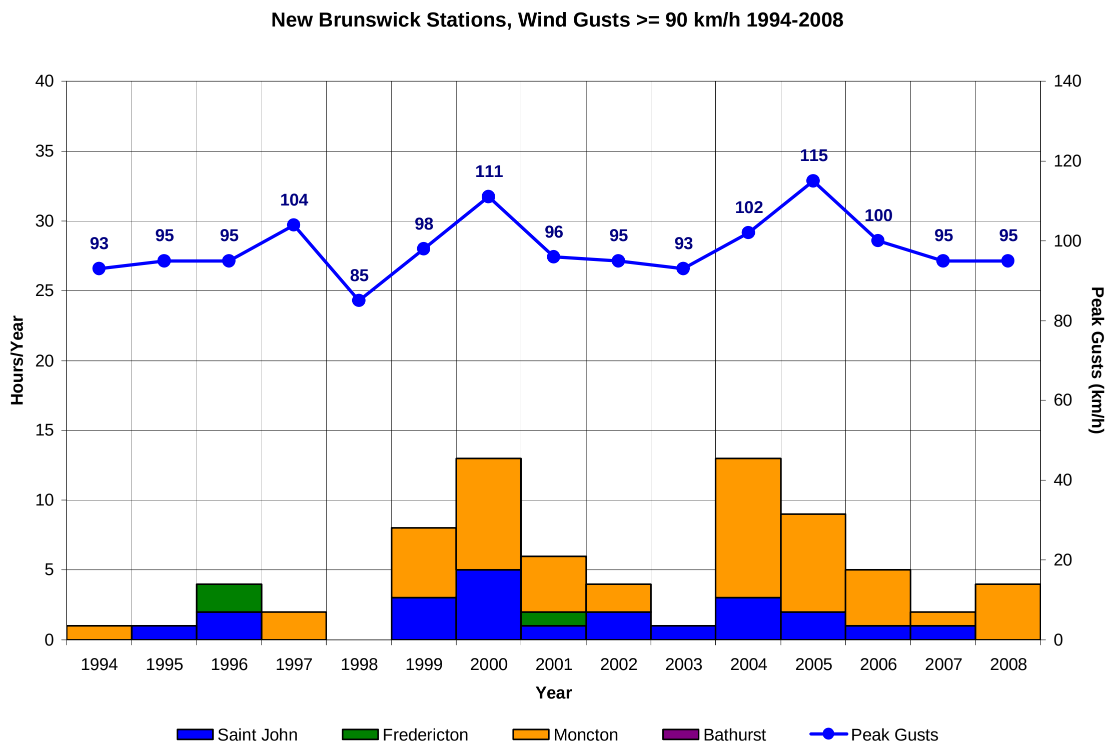


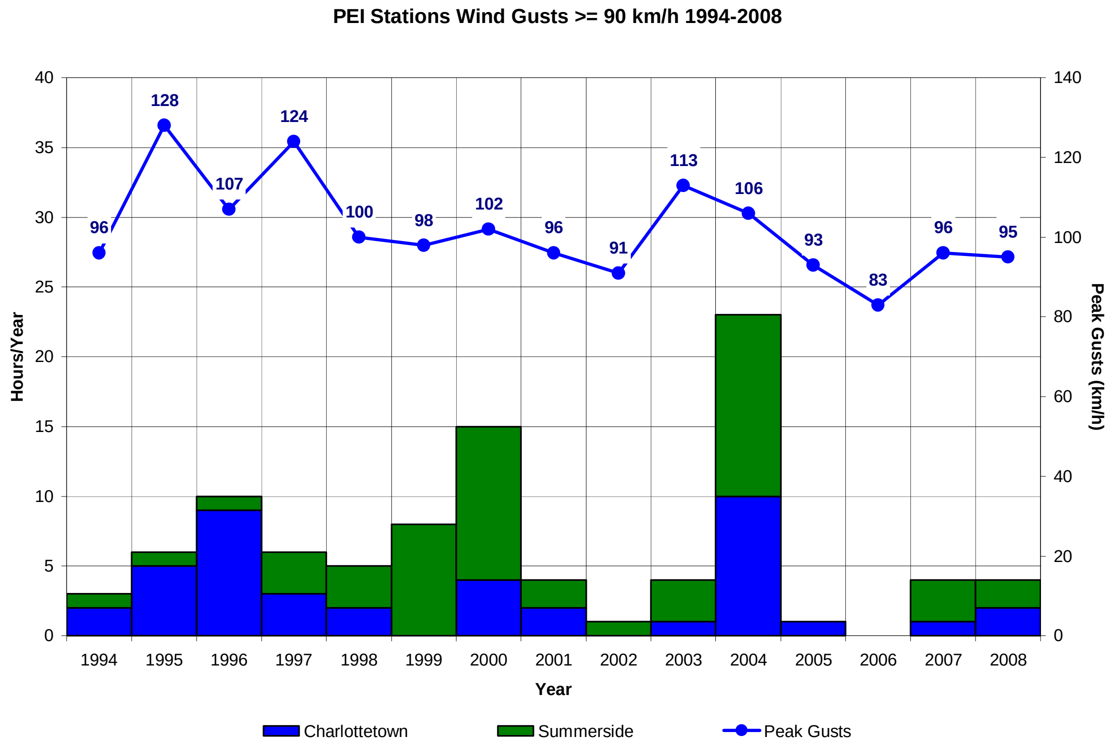


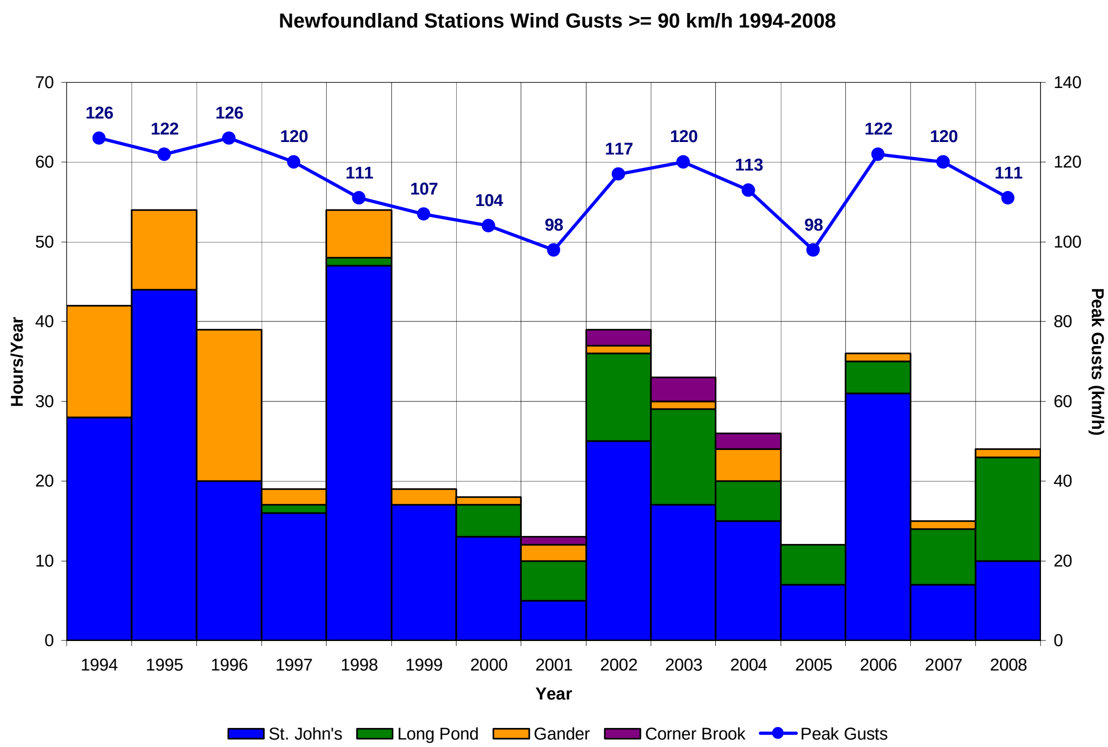
Bangor data is not available prior to 1994, however, data available indicates no major trend in the past 15 years, other than a two-year peak of winds in 1995 and 1996.

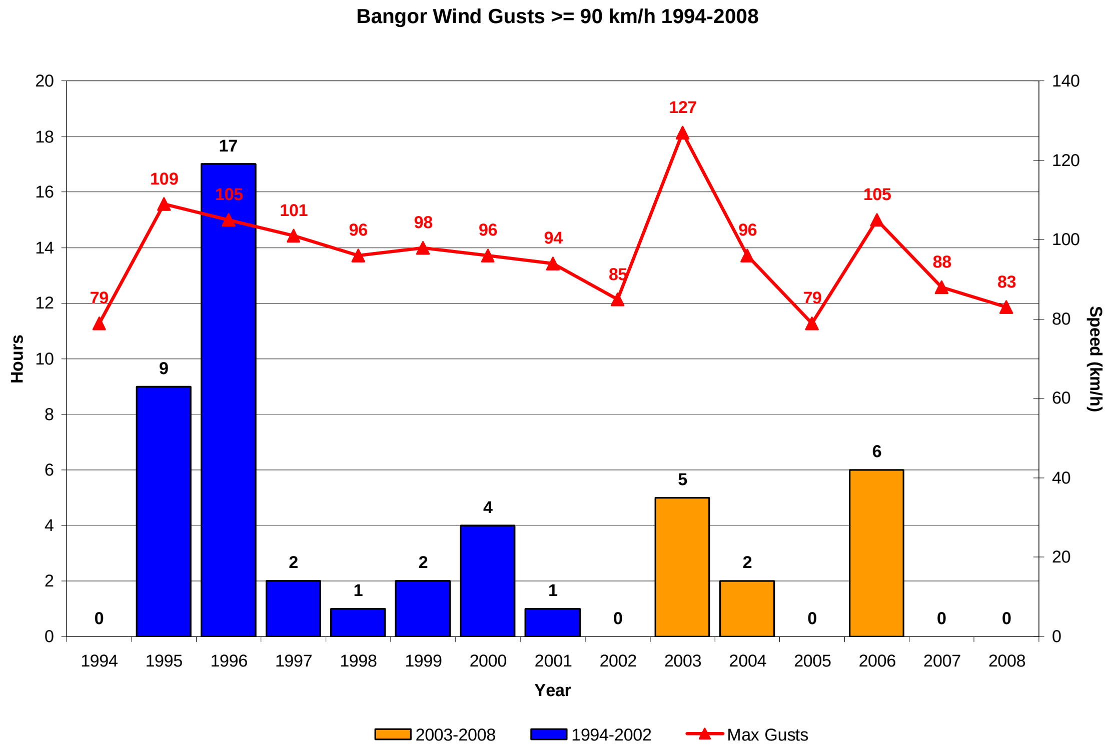
Provincial charts for Wind Gusts:



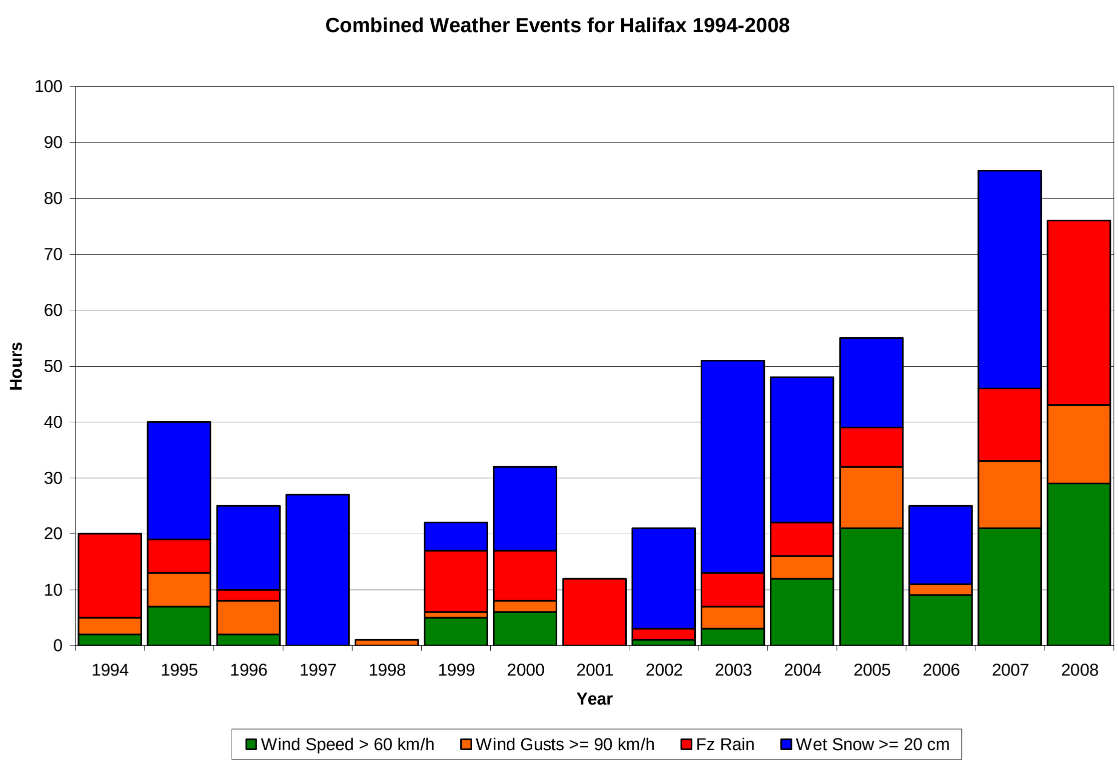


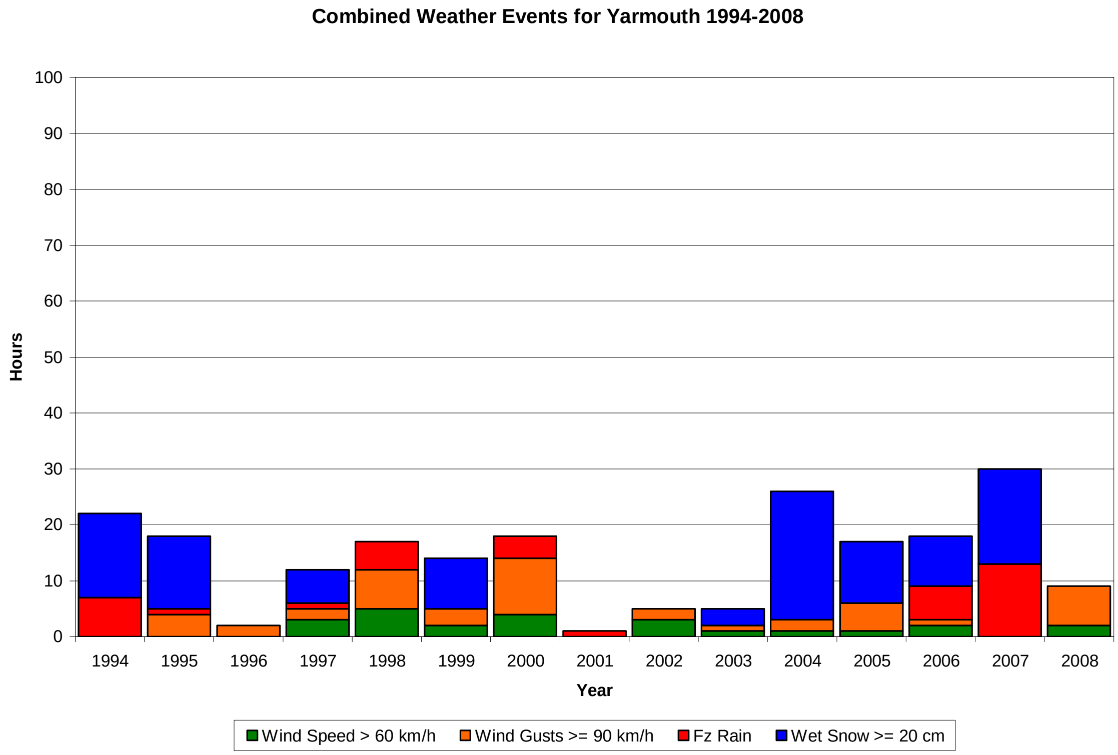

PEI Stations Wind Gusts >= 90 km/h 1994-2008
Hours/Year
Peak Gusts (km/h)
Year
128
124
107
96
100
98
102
96
91
113
106
93
83
96
95
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
Charlottetown
Summerside
Peak Gusts

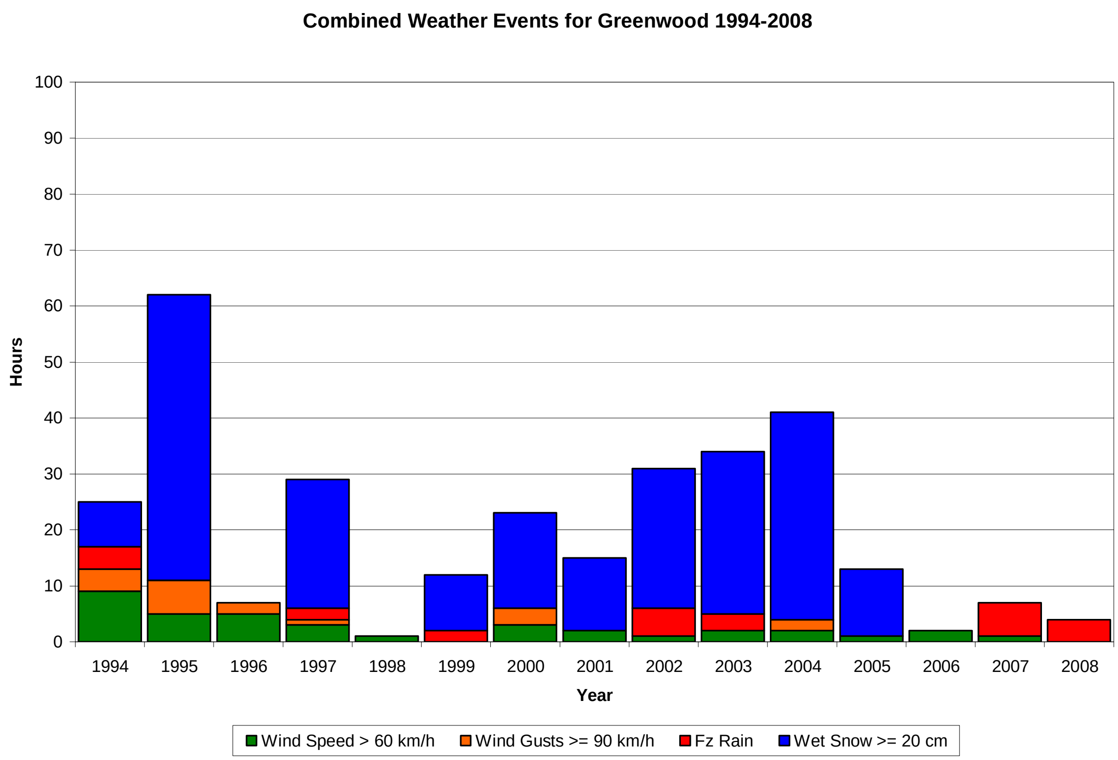

Newfoundland Stations Wind Gusts >= 90 km/h 1994-2008
Hours/Year
Peak Gusts (km/h)
Year
126
122
126
120
111
107
104
98
117
120
113
98
122
120
111
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
St. John's
Long Pond
Gander
Corner Brook
Peak Gusts



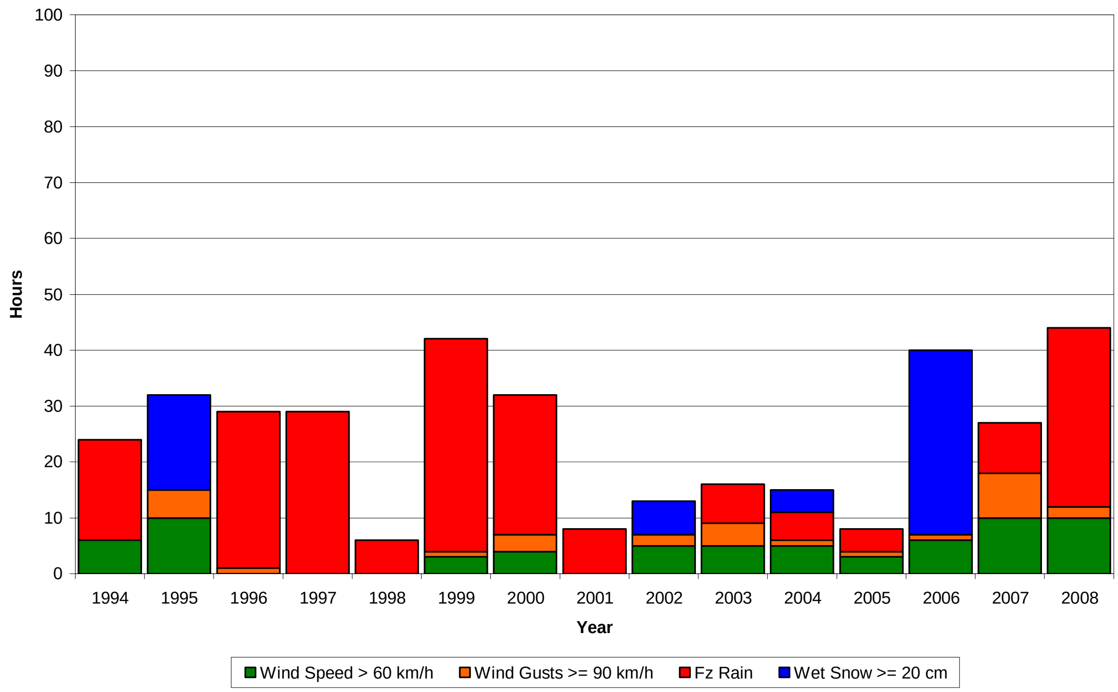
Combined Weather Events by Station:



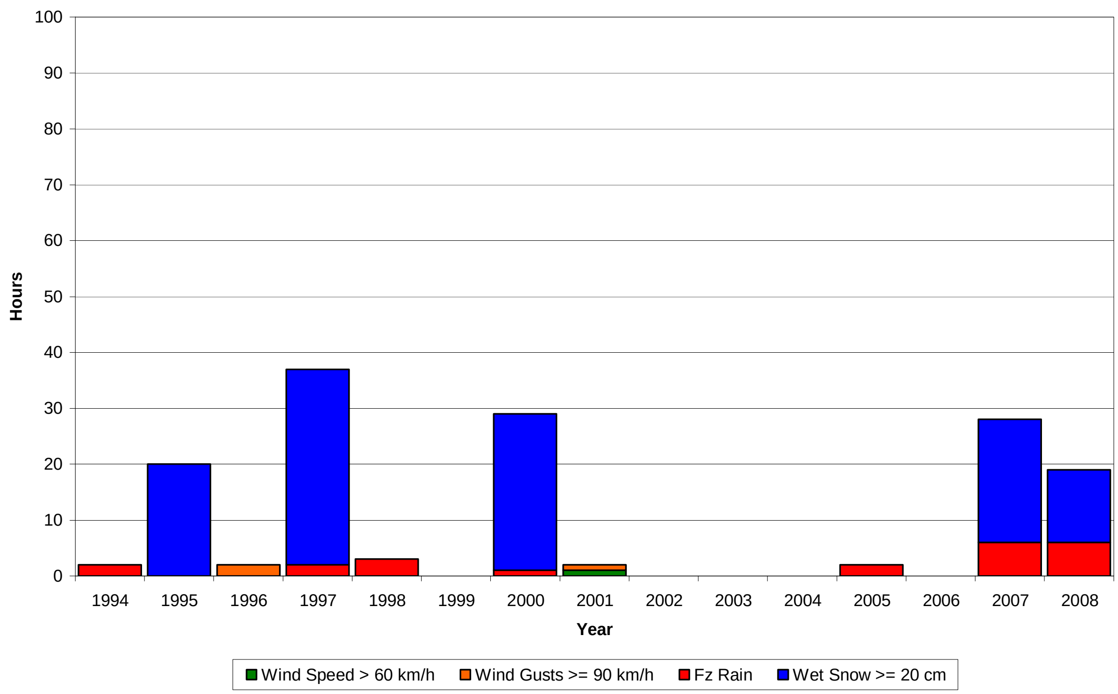

Combined Weather Events for Yarmouth 1994-2008
Hours
100
90
80
70
60
50
40
30
20
10
0
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
Year
Wind Speed > 60 km/h
Wind Gusts >= 90 km/h
Fz Rain
Wet Snow >= 20 cm

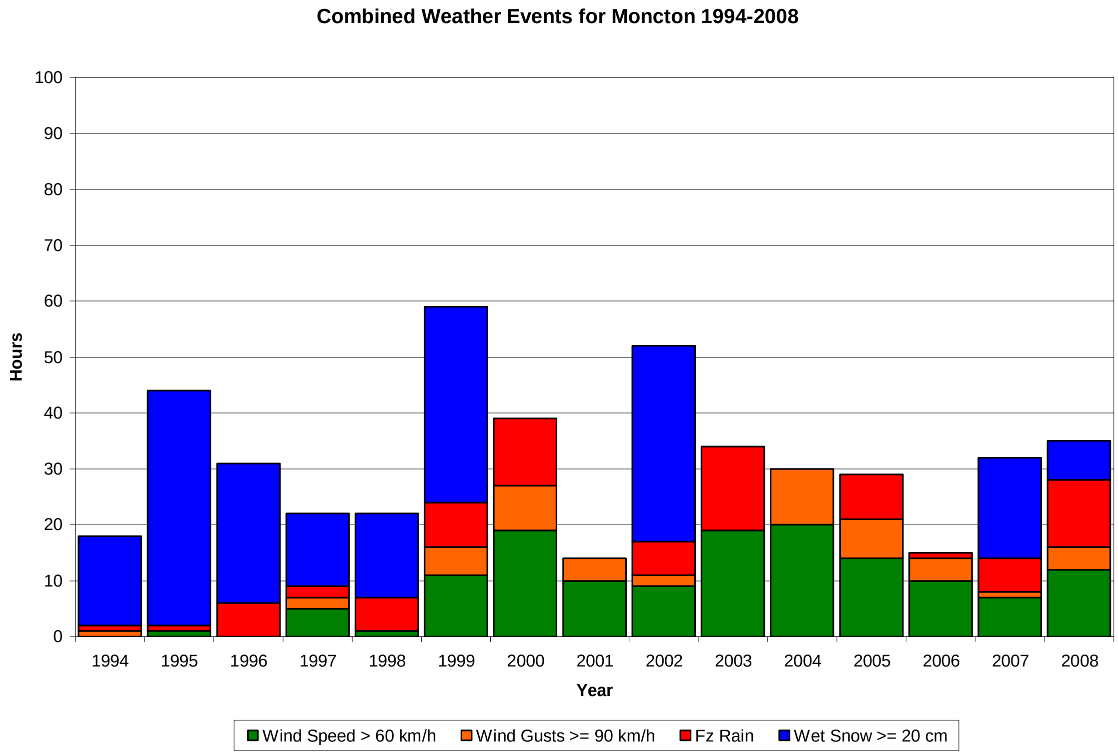

Combined Weather Events for Greenwood 1994-2008
Hours
100
90
80
70
60
50
40
30
20
10
0
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
Year
Wind Speed > 60 km/h
Wind Gusts >= 90 km/h
Fz Rain
Wet Snow >= 20 cm

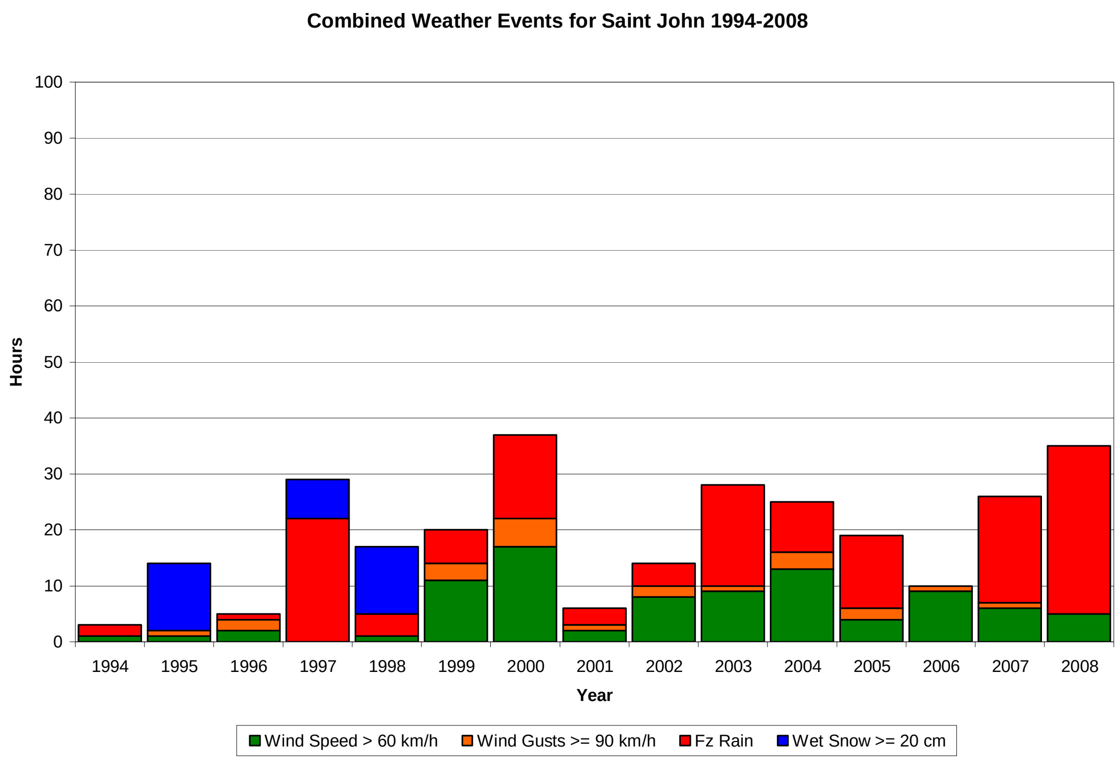
Combined Weather Events for Sydney 1994-2008



Combined Weather Events for Fredericton 1994-2008




Combined Weather Events for Moncton 1994-2008
Hours
100
90
80
70
60
50
40
30
20
10
0
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
Year
Wind Speed > 60 km/h
Wind Gusts >= 90 km/h
Fz Rain
Wet Snow >= 20 cm


Combined Weather Events for Saint John 1994-2008
Hours
100
90
80
70
60
50
40
30
20
10
0
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
Year
Wind Speed > 60 km/h
Wind Gusts >= 90 km/h
Fz Rain
Wet Snow >= 20 cm

Appendix B
Hurricanes, Tropical Storms, and Post-Tropical systems

While not specifically mentioned in this report, other than by example, tropical systems, or former tropical systems have had an increased effect on the Maritimes over the past six years, compared to the mid to late 1990's. Since the primary impact from these systems (in terms of the power systems) is in the form of high winds, they are included in the data used for the high wind and wind gusts comparisons. However, we have listed in the tables below, the storms that made landfall in the Canadian Maritimes for the periods of 1997 to 2002, and 2003 to 2008. The maximum wind speeds quoted are the best estimate of the maximum sustained wind speed of the storm at landfall, and the location is based on the best track calculated following the Hurricane season. We also include charts of the more severe storms, including stations that were close to the track.

Tropical Systems making landfall, by province: 1997-2002

Nova Scotia storm names and characteristics						
Name	**Date**	**Storm #**	**Max Wind (km/h)**	**SS Scale**	**Pres (mb)**	**Comment**
Unamed Sub Trop	October 29, 2000	15	83	STS	992	Extra-Tropical
Karen	October 15, 2001	11	74	TS	997	
Gustav	September 12, 2002	7	139	SS1	960	

New Brunswick storm names and characteristics						
Name	**Date**	**Storm #**	**Max Wind (km/h)**	**SS Scale**	**Pres (mb)**	**Comment**
Floyd	September 18, 1999	6	74	TS	987	Extra-Tropical

Prince Edward Island storm names and characteristics						
Name	**Date**	**Storm #**	**Max Wind (km/h)**	**SS Scale**	**Pres (mb)**	**Comment**
Floyd	September 18, 1999	6	65	TS	990	Extra-Tropical
Karen	October 15, 2001	11	74	TS	1002	Extra-Tropical

Tropical Systems making landfall, by province: 2003-2008

Nova Scotia storm names and characteristics						
Name	**Date**	**Storm #**	**Max Wind (km/h)**	**SS Scale**	**Pres (mb)**	**Comment**
Juan	September 28, 2003	10	157	SS2	972	
Ophelia	September 18, 2005	15	83	TS	1000	Extra-Tropical
Beryl	Friday, July 21, 2006	3	65	TS	1000	Extra-Tropical
Noel	November 04, 2007	14	120	SS1	961	Extra-Tropical
Hanna	September 07, 2008	8	83	TS	995	Extra-Tropical
Kyle	September 28, 2008	11	120	SS1	985	

New Brunswick storm names and characteristics						
Name	**Date**	**Storm #**	**Max Wind (km/h)**	**SS Scale**	**Pres (mb)**	**Comment**
Noel	November 04, 2007	14	111	TS	966	Extra-Tropical
Kyle	September 29, 2008	11	93	TS	990	Extra-Tropical

Prince Edward Island storm names and characteristics						
Name	**Date**	**Storm #**	**Max Wind (km/h)**	**SS Scale**	**Pres (mb)**	**Comment**
Juan	September 28, 2003	10	120	SS1	1002	
Hanna	September 07, 2008	8	74	TS	996	

SS Scale: Refers to category on the Saffir-Simpson scale of Hurricanes. SS1 is category one, TS is Tropical Storm, and STS is a sub-tropical storm, a label typically given to a tropical system that developed within an extra-tropical storm, and is typically categorized after a re-analysis of the data.

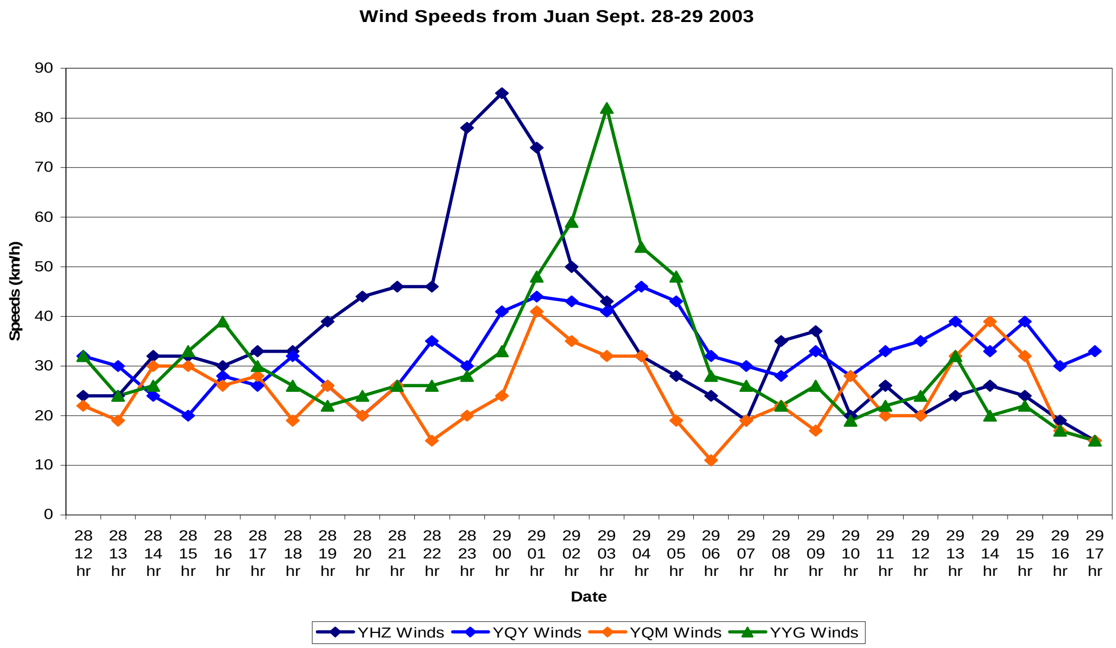
Also, some storms had changed into extra-tropical storms by the time they made landfall. The importance of this distinction has to do with the distribution of the highest winds (and therefore the strongest impact), relative to the storm centre, or eye. In a tropical system, the highest winds are concentrated in a band around the eye of the storm, with the strongest of these located on the right side (relative to the track) of the storm. As the storm transitions to an extra-tropical storm (a storm we would typically see in the mid-latitudes), the strongest winds actually separate from the centre of the storm, to a broader band to the right side of the track. What this means, is that for a Hurricane, the highest winds, thus the worst damage will be near where the centre of the storm passes, and will typically be confined to a relatively narrow area around the centre. However, as it transitions, the worst damage will occur further away from the centre, and to the right side of the track, and will be somewhat more wide-spread.

Wind Profiles of Tropical, and Post-Tropical Storms

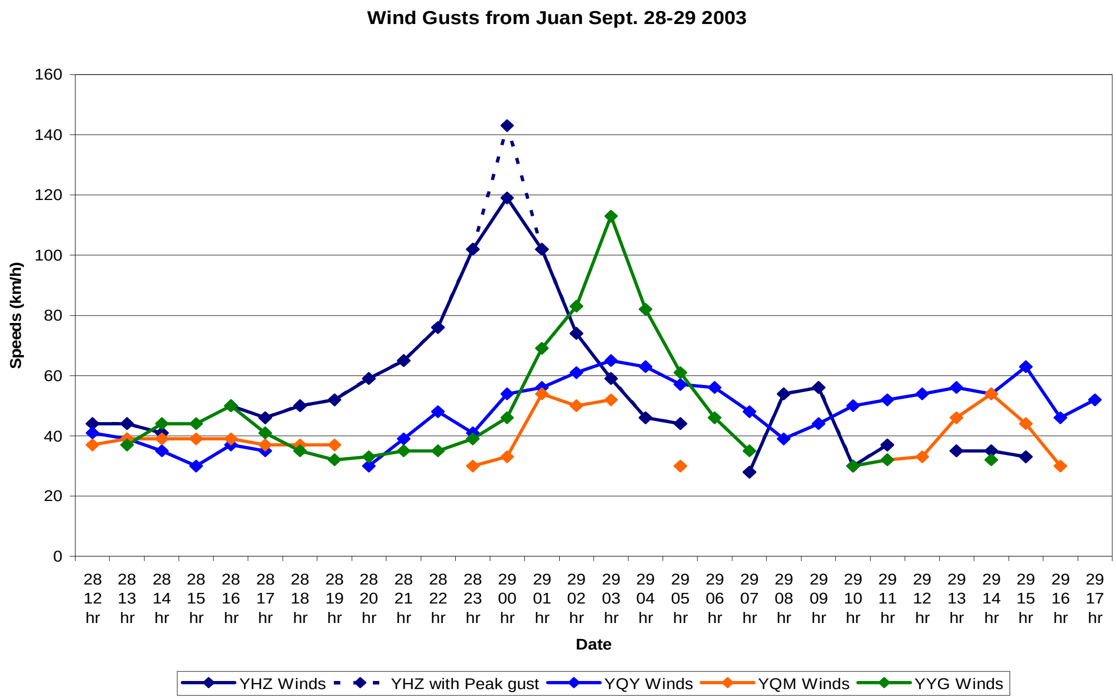
Station list:

YHZ – Halifax Stanfield International Airport
YQY – Sydney Airport
YQM – Moncton Airport
YYG – Charlottetown Airport
YSJ – Saint John Airport
YQI – Yarmouth Airport

Hurricane Juan, Sept. 2003

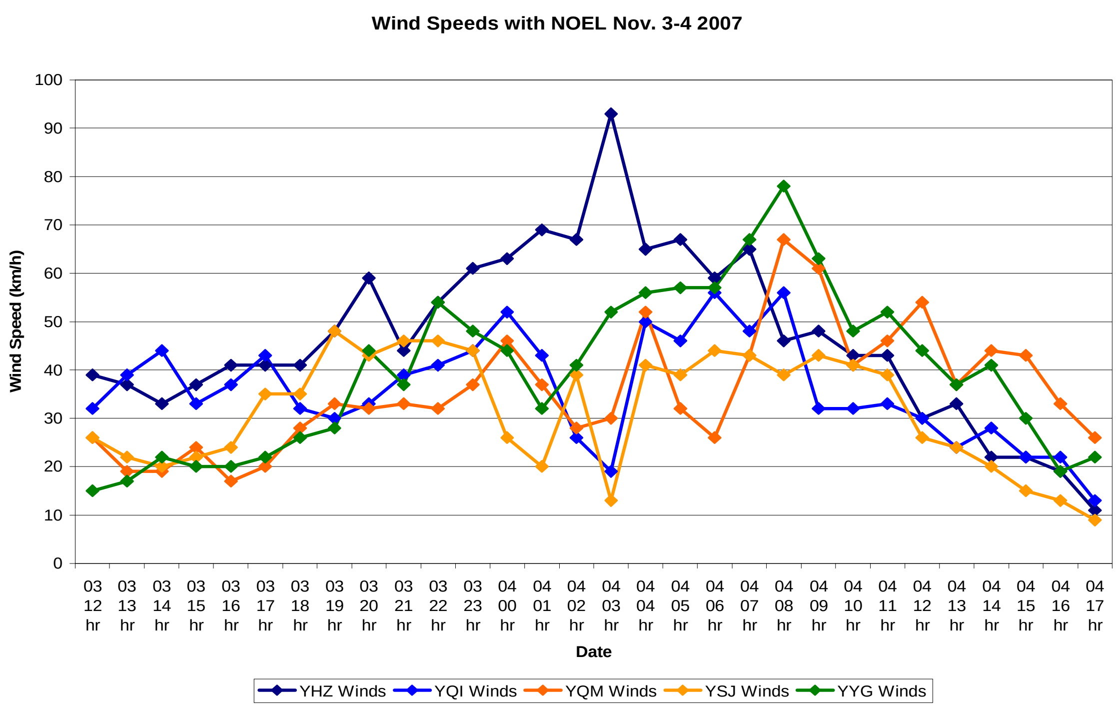


While this graph shows that the peak hourly winds at Charlottetown were nearly as strong as the peak at Halifax, bear in mind that the wind profile of a Hurricane is usually a very sharp peak, and that the peak winds occurred at Halifax in between the hourly observations. This argument is further strengthened with the wind gust profile:

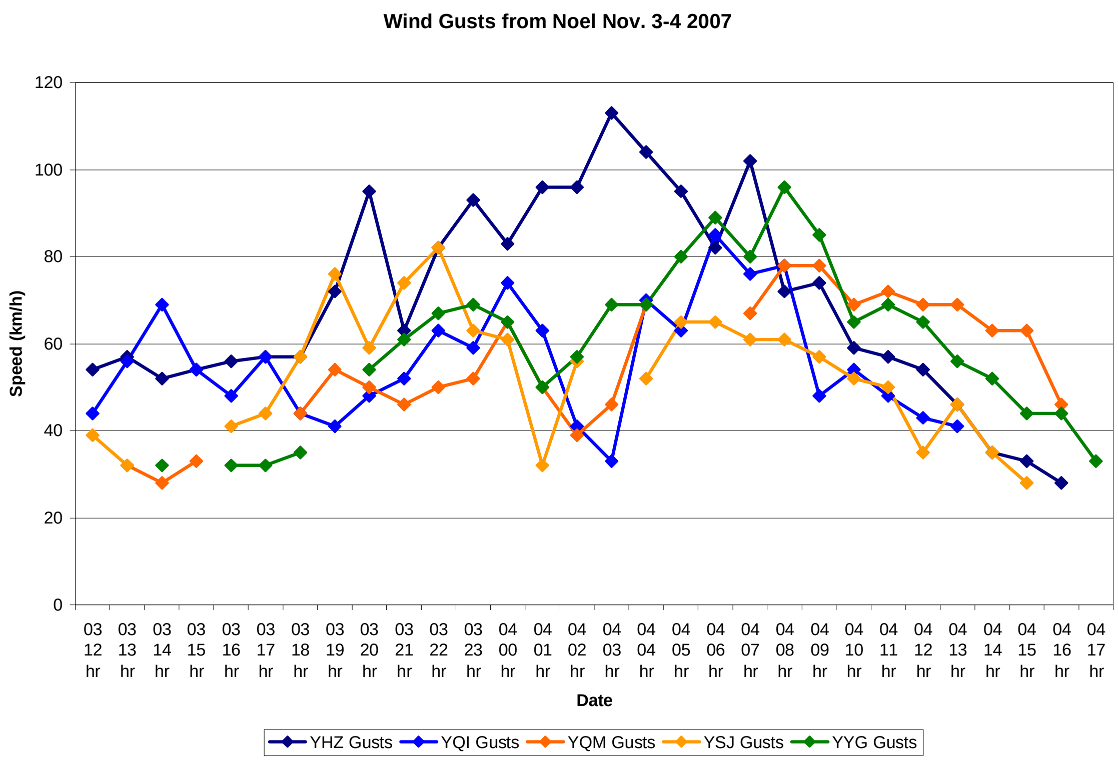


The dashed line represents the profile based on the maximum reported wind gust at the Halifax Stanfield International Airport, which occurred in between the hourly observations. Note how the profile at Halifax resembles that of Charlottetown, once the peak gust has been added.

Extra-Tropical Storm Noel, Nov. 2007

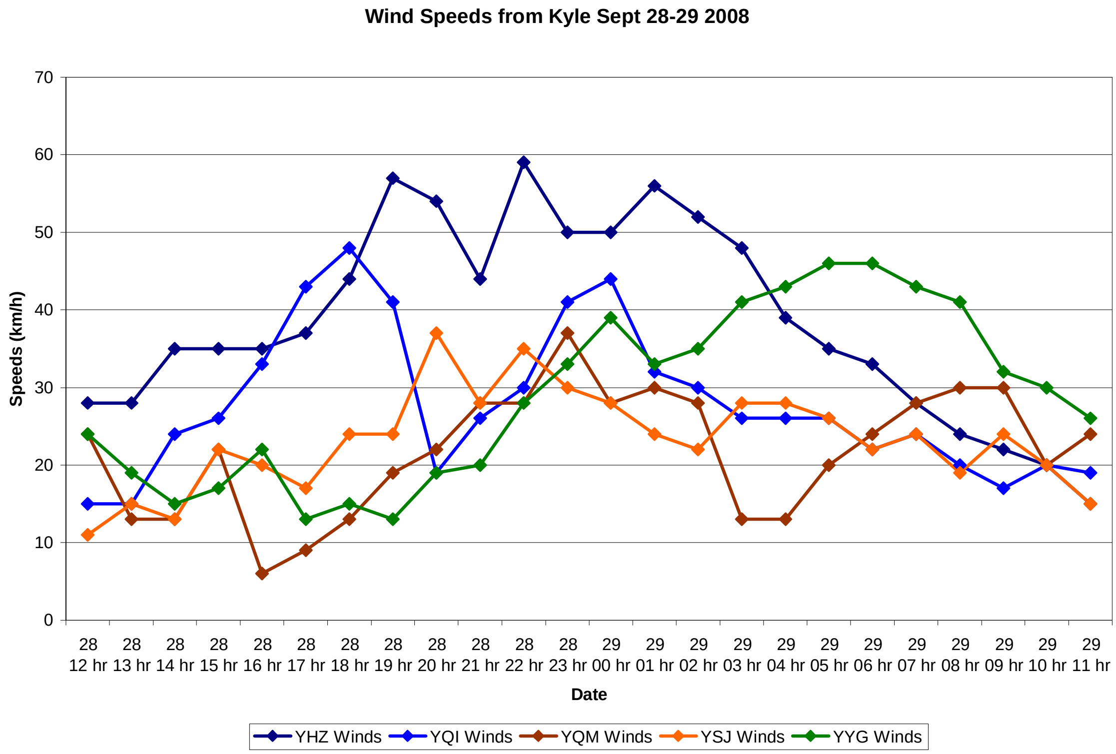


Wind profile of Extra-Tropical storm Noel, over stations in Nova Scotia, New Brunswick and Prince Edward Island. Note the peak winds from the storm occurred near Halifax, whereas the centre of the storm passed over Yarmouth at approximately the same time. The centre then tracked over eastern New Brunswick, while the peak winds tracked over eastern PEI.

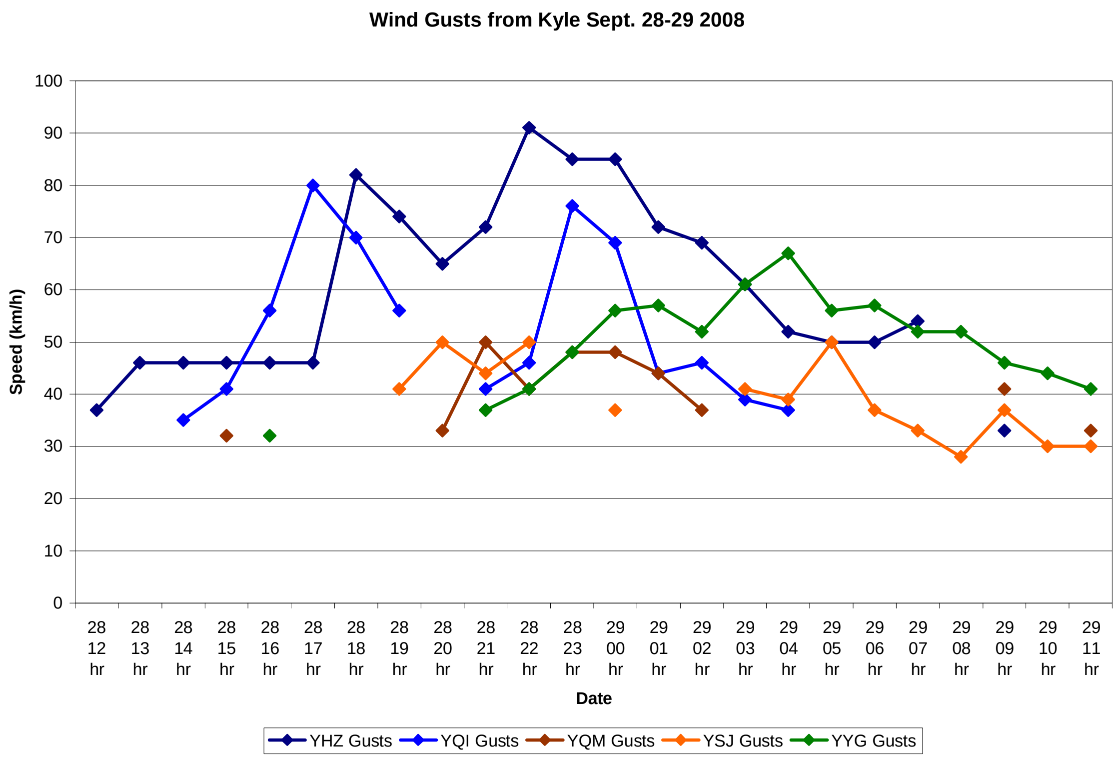


Wind gust profile for Noel, over Nova Scotia, New Brunswick and Prince Edward Island.

Hurricane/Extra-Tropical storm Kyle, Sep. 2008



Wind Profile for Kyle.



Wind Gust profile from Kyle. The storm was technically still a Hurricane when it made landfall at the western edge of Nova Scotia, however, it quickly transitioned to an extra-tropical storm by the time it reached southeastern New Brunswick. This storm was significantly weaker than Noel from the previous year, and the profiles over the region are noticeably different.

REDACTED

Request IR-163:

Reference: NPB IR-3(b)

(a) Please identify the counter-party for this contracted freight price, and provide the last two contracted freight prices for petroleum coke.

(b) Please indicate why NSPI appears to have contracted for freight for petroleum coke prior to purchasing petroleum coke in 2012.

(c) Please indicate whether this contract for freight covers the entire open portion of petroleum coke. If the contract does not cover the entire open portion, please provide the forecast market price for freight used in the forecast for the remaining open tonnage.

Response IR-163:

(a) [redacted]. The last two contracted freight prices were [redacted] in 2011 and [redacted] in 2010. These prices do not include bunker adjustment or demurrage estimate.

(b) [redacted] provides a listing of load ports and pricing and NSPI designates the load ports required throughout the year. As open petcoke positions are closed, transportation may be included in the bidder's price and NSPI may designate the tonnage to another load port. [redacted] also deliver coal for NSPI, freight is contracted with a view to total requirements.

(c) [redacted].

REDACTED

Request IR-164:

Reference: NPB IR-8.

Please explain why NSPI's forecast USD requirement changed by $[redacted] from the time the GRA forecast process was started to the time it was completed, and provide an updated OE-12, Attachment 1 using the updated average unhedged rate as of June 17, 2011 shown in NPB IR-8(b).

Response IR-164:

The original estimate of $[redacted] million was based on the USD requirements for the 2011 BCF. 2012 GRA was the first FAM compliant, detailed forecast of 2012.

OE-12, Attachment 1 details the FX contracts in place at the time of the forecast. This information would not change. The following chart provides the summary information that would change if the unhedged portion was updated to June 17, 2011 information.

	Buy USD	**Rate**	**Sell CAD**
Hedged	[redacted]	[redacted]	[redacted]
Unhedged	[redacted]	.99000	[redacted]
Total	[redacted]	[redacted]	[redacted]

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Request IR-165:

Reference: NPB IR-11.

Please update Attachment 2 to show the items that have been approved as a result of the Board's Decision in the 2011 ACE Plan. In this update, please identify any additions that are no longer forecast to be in-service in 2012.

Response IR-165:

Upon further review it was determined that the projects listed in NPB IR-11 Attachment 2 were not all correct. An ERRATA NPB IR-11 Attachment 2 has been filed. Please see Attachment 1, that includes all projects as well as identifies those items approved as part of the 2011 ACE Decision, designated "Y (2011 ACE)".

2011 - 2012 Additions

Project #	Project Title	Addition ($)	Approved (Y/N)
29131-P772	FAC Space 2011	57,428,836	Y
39566-S679	LIN2-LSB Replacement	2,691,987	N
36902-S614	LIN1- ESP Gas Flow Modification	1,540,413	Y
36882-W107	Nuttby Mountain Wind Project Dev	281,219	Y
35742-P789	Connectivity Upgrade	2,650,314	Y
34242-S432	TRE Unit #6 Mercury Abatement	472,909	Y
34223-S430	POT Mercury Abatement Project	458,637	Y
34222-S429	LIN Unit #4 Mercury Abatement	386,401	Y
34202-S427	LIN Unit #2 Mercury Abatement	331,174	Y
34182-S426	LIN Unit #1 Mercury Abatement	344,731	Y
33624-T639	Spare Generator Transformer	8,721,928	Y
31244-H574	HYD Paradise Wood Stave Pipeline R	11,020,417	Y
31142-S399	LIN PF Line Upgrades	276,090	Y
30954-S613	LIN3-ESP Gas Flow Modification	1,608,606	Y
30283-S665	POT - Tupper Vessel Access	301,417	Y
29009-P833	Right of Way Purchase Northern NS	3,916,683	Y
28098-S353	TUC 6 Waste Heat Recovery	557,435	Y
22467-S587	POT - Condenser Waterbox Replacemen	323,448	Y
16374-H517	HYD Gaspereau Dam Safety	2,131,001	Y
40657	LIN CW Pump Refurbishment	503,894	N
40655	LIN 2012 Mill Refurbishment	752,409	N
40652	Nucleus	562,440	N
40651	Fuelworx (Fuel Management)	335,269	N
40650	PowerPlant (Capital Mgt)	281,204	N
40649	PeopleSpft (Human Resource Mgt)	506,189	N
40648	Field Mobility System	1,714,880	N
40647	Service Hub (CDS)	279,382	N
40646	GIS Functionality Enhancements	1,709,307	N
40643	CIS	3,315,434	N
40563	2012 RTU Replacement Program	382,017	N
40557	Baghouse #2	29,999,909	N
40555	Baghouse #1	29,999,906	N
40365	MS Sharepoint Platform Upgrade	908,174	N
40363	LIN3 HVB Refurbishment	612,225	Y (2011 ACE)
40330	LIN2 HT Fastener Replacement	865,699	N
40321	Canaan Rd to Prospect Rd Tx Line	2,024,763	N
40320	LED Street Light Conversion	16,182,441	N
40311	50MVA Mobile Substation Transformer	2,640,974	N
40310	Circuit Switcher Additions	680,990	N
40231	2011 Protection Upgrades LAK	1,569,973	Y (2011 ACE)
39934	TRE5 - Conveyor System Upgrades	335,921	N
39933	TRE - Siding Replacement	603,707	Y (2011 ACE)
39803	POT Unit 2 Generator Major Refurbis	2,086,097	N
39502	TRE - Stack Coating	1,206,513	N
39306	Radio & Communication Replacements	989,905	N
39276	Bedford 4 kV Conversion	1,617,199	N
39275	Halifax UG Cable Replacement	4,765,354	N
39274	Distribution Replacements	3,853,696	N
39272	2011 Distribution Feeder Ties	347,147	Y (2011 ACE)

2011 - 2012 Additions

Project #	Project Title	Addition ($)	Approved (Y/N)
39271	Dist. Reliability Replacements	10,369,424	N
39270	2011 Dist. Cutout Replacements	1,176,075	N
39269	2011 Recloser Additions	1,379,482	Y (2011 ACE)
39267	Transmission Replacements	12,695,814	N
39266	Transmission Reinforcements	7,487,020	N
39265	Transmission Reliablity Replacement	17,962,443	N
39264	FAC Space 2011 Placecard	5,036,203	N/A
39263	Biomass Placecard	21,927,101	N
38947	Co-Firing Biomass	10,000,231	N
38945	LIN2 #8 Nozzle Replacement	695,448	Y
38944	LIN - Unit 2 Rotor Rewind	5,396,198	N
38868	HYD Marshall Falls Hydro Station	13,380,533	N
38826	POT - DCS upgrade	725,025	Y (2011 ACE)
38824	2011 Protection Upgrades	3,349,299	N
38823	2012 Protection Upgrades	2,445,359	N
38819	51V Tremont Circuit Breaker & Bus	6,628,453	Y
38817	TRE6 - Primary Air Fan Shaft	663,904	N
38816	Kempt/Lakeside Protection Upgrades	567,495	N
38732	1H Water St Replace 138 kV GIS	8,368,588	Y
38603	TRE6 - LP Turbine Gland Replacement	800,000	N
38242	TRE - Fire Pump and Water Storage	800,000	N
38182	2010 Backup Control Centre	2,856,185	Y
38102	POT - Utilization of Heavy Biofuel	306,008	N
38043	TRE6 - Turbine Gland Replacement	805,276	N
38042	TRE6 - Steam Coil Airheater Upgrade	1,023,194	N
38002	CT'S Refurbish Bsd #4 Engine	990,318	N
37828	TRE - Fire Water Storage Bunker	401,327	N
37607	LIN - DCS Equipment Upgrades	822,905	N
36962	TUC East Tunnel Cable Re-routing	262,761	N
36862	HYD - Wreck Cove Unit # 1 Overhaul	6,348,087	N
36603	LIN2- DAS Upgrades	461,298	N
36565	POA ID Fan Motor Upgrade	503,279	N/A
36562	POA PE Turbine Cont. Sys Repl.	2,013,267	N/A
35022	POA Front End Loader Replacement	802,623	N/A
34703	Lin CW Pump Rebuild	485,000	N
34622	Upgrade L-8002	1,926,888	Y
34565	HYD- ANNAPOLIS CONTROLS PLC	600,000	N
34544	POT TURBINE MAJOR REBUILD	1,293,745	N
34386	POA Cell 4 Stage 1 Residue Mangemen	2,549,001	N
33625	Mobile 138kV Circuit Switcher	268,685	N
33525	Canaan Rd 43V to Tremont 51V Line	7,901,434	Y
33504	Upgrade 69 kV Circuit - Pleasant St	993,896	N
33282	LIN Super Heater Header Vestibule	318,904	N
33142	CT-U&U #4 Restoration And Upgrade	1,111,234	N
32522	LIN - CW TRENCH CTRL CABLE UPGRADE	297,570	N
32304	AMI Hardware & Software Installatio	12,909,472	N
31729	POA SH3 TUBE BENDS REPLACEMENT	376,845	N/A
31602	LIN2-REFURBISH GENERATOR HYDROGEN	563,808	N
31583	LIN2 - L-1 BLADING REPLACEMENT	3,199,465	N

2011 - 2012 Additions

Project #	Project Title	Addition ($)	Approved (Y/N)
31545	LIN3-Replace Screens on Backpass	804,422	N
31442	LIN2-REPLACE HIGH VOLTAGE BUSHINGS	307,532	N
31246	HYD Methals Intake Refurbishment	520,548	N
31243	LIN-REPLACE BOILER HOUSE LOUVERS	311,061	N
30924	LIN REPLACE CRUSHERs	261,232	N
30911	LIN1- STACK BREACHING EXPAN	260,895	N
30909	LIN C/W INLET CANAL WALL SEALING	300,967	N
30624	LIN HEAVY PARTS STORAGE	254,855	N
29065	CT'S -Replace Halon Fire Protection	1,642,214	N
28921	LIN3-REPLACE STACK BREECH EXPANSION	283,000	N
28907	LIN-CW Organic Sea Debris Capture U	2,111,280	N
28849	TRE5 - CONDENSER PIPE REPLACEMENTS	809,948	N
28793	POA- PE- COAL CONVEYOR SUPPORT REF.	408,052	N/A
28790	POA Ash Cell Capping Cell 3 Stage 1	326,533	N/A
28674	TRE6 HMI Upgrades	871,216	N
28645	TRE6 - Turbine Controls Power Suppl	687,896	Y
28641	ROSEWAY UNIT REFURBISHMENT	584,067	N
28554	POT - ANALYTICAL PANEL AND ANALYZER	324,709	Y (2011 ACE)
28424	DEPOT & SUBSTATION SECURITY SYSTEM	706,771	N
28393	POT 2A Mill and Feeder Refurbishmen	416,666	Y (2011 ACE)
28347	LIN- STACK PAINTING 0-300 FT LEVEL	330,047	N
28289	POT - TURBINE ELECTRO HYDRAULIC GOV	581,502	Y (2011 ACE)
28288	POT - TURBINE SUPERVISORY EQUIPMENT	837,167	N
28131	POT - BURNER CORNER TUBE NEST PHASE	398,917	N
28080	88S-LINGAN - REPLACE BREAKER 714	2,760,679	N
28079	88S-LINGAN - SWAP NODES L-7012 & GT	1,511,695	N
28063	87S-LINGAN - PROCURE SPARE FOR GT4	2,210,206	N
27850	LIN-ENGINEERING MODIFICATIONS FOR C	918,910	N
27507	RUTH FALLS BUTTERFLY VALVE REPLACEM	550,199	N
27150	TUC - REPLACE UNIT #1 AIR HEATER	4,177,215	N
27149	TUC - REPL. CONDENSATE POLISHERS &	1,474,869	N
27088	POA ST2 TRANSFORMER REPLACEMENT	475,421	N/A
26904	GULCH WS PENSTOCK REPLACEMENT	1,269,143	N
26472	TRE - 6A CW Pump Refurbishment	262,674	Y (2011 ACE)
25385	LIN-REPLACE WASTEWATER FORCE MAIN	269,118	N
25182	TUC - UNIT 2 LOW LOAD CAPABILITY IM	385,267	N
25171	L5532 RE-INSULATION	634,810	N
24923	REPLACE BREAKERS 17V-503 AND 17V-40	277,589	N
23602	STM - WRIGHTS LAKE DAM	888,963	N
23341	CDS COMPUTER DISPATCH SYSTEM UPGRAD	597,890	N
23123	MER - LLF#3 RUNNER REPLACEMENT	300,000	N
23122	MER LLF RUNNER #4	553,607	N
23093	EMPLOYEE SELF-SERVICE TECHNOLOGY	387,289	N
21266	LIN, UNIT 1-2 2003 DIVISION WALL RE	296,159	N
21168	TRE5 - CONVERT COAL FEEDERS TO GRAV	1,158,555	N
20758	NIC - PIPELINE REPLACEMENT	2,682,506	N
20741	TUC - UNIT 1 BOILER IMPROVEMENTS (1	3,714,209	N
20718	TUC - UNIT 2 CHIMNEY LINER RESTORA	600,338	N
20512	CT'S - Re-insulate Vj Generator Rot	327,110	N

2011 - 2012 Additions

Project #	Project Title	Addition ($)	Approved (Y/N)
20511	CT'S -Replace Halon Fire Protection	797,068	N
18991	LIN, ONLINE VIBRATION MONITORING EQ	660,952	N
18907	GENERATOR REWIND ?	430,441	N
18469	TUC - UNIT 2 CONDENSER TUBE RESTORA	558,647	N
18448	TUC-CW SYSTEM BIOFOULING CONTROL	1,955,599	N
18175	MER-LLF RUNNER REPLACEMENT	634,653	N
18174	MER-ULF GENERATOR REWIND	281,714	N
17853	HYD - STM-SAL #4 Runner	270,824	Y
17830	HYD - STM Big Indian Lake Dam Safet	3,703,458	N
17583	HYD - BER-GUL - Electrical Refurbis	662,935	Y (2011 ACE)
17581	WEY - ELECTRICAL REFURBISHMENT	910,528	N
17368	MER-COF DAM SAFETY REMEDIAL WORKS	565,571	N
16416	BLR-HEG UNIT 2 GENERATOR REWIND	323,725	N
16415	BLR-MET GENERATOR REWIND	648,904	N
16387	HYD- Ruth Falls #3 Runner Replmt	414,557	Y
16003	LINGAN - REPLACE UNIT 1-2 DUPLEX AC	512,408	N
14371	HYD - AVO #2 PIPELINE REPLACE	4,733,409	N
12419	STM - TID PIPELINE REPLACEMENT	5,934,085	N
12079	SHH - RUF 1&2 RUNNER REPLACEMENT	831,591	Y (2011 ACE)
11948	POT - REHEATER ORIFICING	439,534	N
11610	STM- COON POND DAM SAFETY	1,797,801	N
11554	WRC DAM SAFETY REMEDIAL WORKS	1,175,367	N
10898	TUS - GENERATOR REWIND UNITS 1, 2	820,987	N
10796	TUC - U#3 BOILER FD PUMPS VARIABLE	1,305,268	N
10772	WRC- T2 Tunnel Adit Replacement	258,147	N
Projects less than $250K		26,327,430	
Distribution Routines		81,008,949	
Transmission Routines		19,978,317	
General Plant Routines		10,062,064	
	Total	**602,354,079**	

REDACTED

Request IR-166:

Reference: NPB IR-14(c).

NSPI's response did not indicate whether NSPI had assumed the carry-over of any excess earnings from 2010 into 2011 in preparing these statements. Please confirm whether or not any carry-over was assumed in the preparation of FOR-01 and CS-01-CS-03.

Response IR-166:

The response to this request is confidential.

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Request IR-167:

Reference: NPB IR-22.

Please provide any documentation, prior to 2011, in which NSPI previously indicated to NPB that import energy would be excluded from the 20-minute ahead marginal cost for ELI 2P-RTP purposes.

Response IR-167:

The setting of marginal costs was discussed during the ELIIR-2 Hearing, the Application having been filed in June 2006.[1] Please refer to Attachment 1.

Energy contracts entered into by NSPI more than two hours before setting the 20-minute ahead marginal price do not affect the 20-minute ahead marginal costs. Imported energy, on the basis of such contracts, cannot be avoided and is no longer at the discretion of the scheduler.

[1] NSPI ELIIR-2 Hearing Transcripts, NSUARB-NSPI-P-883, Sept 5, 2006, page 158 at 406 (Mr. Cooper cross-exam of NSPI Panel).

BY MR. COOPER

406. Q. And then at page 2 of the exhibit, there's a heading towards the bottom, "Marginal Cost"?

A. (Boutilier) Yes, I see it.

407. Q. And it reads:

> "The marginal cost will be the 20-minute ahead forecast of hourly marginal fuel and variable O&M excluding any impacts of exports but including imports when they impact marginal cost, and the MC forecast will be calculated based on in-province load."

Underline added

And then the sentence reads:

> "The load levels assumed for NSPI's largest customers will be the pre-shifted CBL value."

Correct?

A. (Boutilier) Yes, that's correct.

408. Q. And that tariff was put forward by NSPI.

A. (Boutilier) Yes, in the context -- if I could turn your attention back to the first page under "Availability," this rate was approved for use with customers who take ELIIR, and as a result of that, it is only available to those who take ELIIR and only for energy above the UET. And NSPI made very certain that

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Request IR-168:

Reference: NPB IR-63.

Please identify and justify the source of the costs for "Other Non-Labour" and "Contracts" for each of the Nuttby Wind Project, the Digby Wind Project, and the Point Tupper Wind Project, and indicate whether NSPI anticipates that these costs will recur annually.

Response IR-168:

The OM&G costs reported in 'Other Non-Labour' include insurance, land leases, and tax assessments.

The OM&G costs reported in 'Contracts' are related to inspections, and Operating and Maintenance Service agreements.

NSPI anticipates each of these costs will recur annually.

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Request IR-169:

Reference: NPB IR-101(b).

Please indicate whether the 2012 test year forecast assumed [redacted]. If not, please provide NSPI's current forecast freight price [redacted], and identify the freight savings NSPI expects to realize in 2011 [redacted].

Response IR-169:

The GRA 2012 forecast assumed the [redacted] for the full tonnage. The opportunity for usage of bulkers, which potentially could have prices competitive with contracted self-unloaders, will be part of the 2012 reforecast calculation. The 2011 ending inventory, plus [redacted], will be used to forecast the incoming shipping requirements for the International Pier, which can only accept belted self-unloaders. The [redacted] will then be estimated. [redacted].

NON-CONFIDENTIAL

Request IR-170:

Reference: NPB IR-102.

(a) Please indicate what NSPI means by "short time frames" in this response.

(b) Please provide the test results at Point Aconi.

Response IR-170:

(a) Please refer to Avon IR-19. "Short time frames" refers to the test duration of varying blends of the test coal, which ranged from several days to three weeks at each blend, within an overall five-week period.

(b) Please refer to Avon IR-19. The 2011 test results will be available in report form by October 31, 2011.

REDACTED

Request IR-171:

Reference: NPB IR-106.

(a) [redacted].

(b) [redacted].

Response IR-171:

(a) The 2012 GRA is based upon the understanding that [redacted] will be online and producing. The [redacted] has been optimized in the filing.

(b) The lower priced annual and monthly volumes are included the forecast. Please refer to FAM Data Room confidential binder GE0022, available for viewing at NSPI offices for the calculations.

REDACTED

Request IR-172:

Reference: NPB IR-109.

(a) With respect to the responses to NPB IR-109(a) and (d), please describe the activities undertaken by NSPI to determine there was no opportunity in this period. Specifically, indicate the parties that were contacted and whether non-firm transmission was considered.

(b) The FAM Forecasting Methodology forecasts the price of power imports using forward prices for the New England Power Pool's Hub, located in western Massachusetts, USA, adjusted for the difference in price between that location and the location on the New Brunswick/Nova Scotia border. Please indicate whether NSPI's [redacted].

Response IR-172:

(a) No follow up was made in regards to this offer. As stated in NPB IR-109(a) there was no firm transmission available from through New Brunswick (Hydro Quebec to Nova Scotia). [redacted]. This would be needed to offset [redacted].

(b) In the case of the April 2011 monthly power purchase, the forecasted [redacted] giving price of [redacted] at the Nova Scotia interface (including

REDACTED

transmission, losses and fees). The actual Salisbury price for was [redacted] giving a price of [redacted] at the Nova Scotia interface (including transmission, losses and fees). The price of the transacted power purchase was [redacted] at the Nova Scotia interface (including transmission and losses). In this case the power purchased was more economic than the forecast and actuals Salisbury values.

In the case of the May 2011 monthly power purchase, the forecasted Salisbury was [redacted] giving price of [redacted] at the Nova Scotia interface (including transmission, losses and fees). The actual Salisbury price for was [redacted] giving a price of [redacted] at the Nova Scotia interface (including transmission, losses and fees). The price of the transacted power purchase was [redacted] at the Nova Scotia interface (including transmission and losses). In this case the power purchased was more economic than the forecast and actuals Salisbury value.

CONFIDENTIAL (Attachment Only)

Request IR-173:

In the Original Pension IR, the Applicable Years include 2011. However, no documents have been produced dated in 2011. Please review the Original Pension IR again and provide any documents that are dated in or relate to 2011 concerning the NSPI RPPs, NSPI SERPS or NSPI OPEB including, but not limited to, any predictions in respect of any future liabilities for any of the NSPI RPP's, NSPI SERPS, or NSPI OPEB.

Response IR-173:

Please refer to the following documents which were produced in 2011 and referenced or provided in the response to NPB IR-99. Please refer to Liberty IR-80 Attachment 1, and the Application, RB-02-RB-16, Attachment 2. Please refer to NPB IR-99 Attachment 13 and Attachment 16.

Please refer to Confidential Attachment 1 for letters dated April 14, 2011 to NSPI's auditors regarding draft results of NSPI RPPs' going concern financial position at December 31, 2010, along with an estimate of the minimum contribution requirements for 2011. The going concern results are now considered final, but the minimum contribution requirement for 2011 should still be considered an estimate.

Please refer to Confidential Attachment 2 for the letter of credit valuations for the SERP performed in each of 2008 through 2011. NSPI has modified the valuations to remove personal information.

In addition to the work referenced above, substantial work was completed in the recent past on projections of future liabilities for the NSPI RPPs as documented in NPB IR-099 Attachment 4, and Attachment 6 and NPB IR-177.

Request IR-174:

With reference to Part (b) of the Original Pension IR, please provide the final or draft actuarial report in respect of December 31, 2010. If still not yet prepared, we note that the 2009 valuation was prepared in April 2010 and the 2008 valuation was prepared in May 2009. If no report is available, why has the 2010 valuation not yet been prepared, either in draft or as an extrapolation, or any other informal estimate?

Response IR-174:

A draft December 31, 2010, actuarial report does not exist at this time. The professional standards of the Canadian Institute of Actuaries (CIA) were recently updated for actuarial funding valuations dated December 31, 2010, or later. These changes require significant additional technical analysis, projections and professional disclosures to be included in the actuary's valuation reports. Furthermore, the CIA issued an Educational Note to actuaries on May 10, 2011, (Assumptions for Hypothetical Wind-up and Solvency valuations with effective dates between December 31, 2010, and December 30, 2011) which impacts the results of our December 31, 2010, valuation. However, this change is not anticipated to have a significant impact on projected pension expense.

While our actuary has indicated that most of the valuation figures required under the new professional standards are completed, their practice is to prepare the valuation report after all the required figures are finalized.

Please refer to NPB IR-173 Attachment 1 for a summary of the going concern valuation results as at December 31, 2010, and estimated minimum contribution requirements for 2011.

CONFIDENTIAL (Attachment Only)

Request IR-175:

Please provide the best estimate available of the funded position of the NSPI RPP's as calculated under the PBR (not accounting report) as at December 31, 2010.

Response IR-175:

Please refer to NPB IR-173 Attachment 1 filed electronically for the going concern financial position at December 31, 2010.

Please refer to Confidential Attachment 1 for a summary of the draft solvency financial position at December 31, 2010 for the NSPI RPPs. This was determined using December 31, 2010 data and solvency assumptions and the same general methodology as used for prior solvency valuations. Non NSPI content has been removed.

REDACTED

Request IR-176:

With reference to Part (b) of the Original Pension IR, why does NSPI file annual valuation reports with the Superintendent of Pensions, when, under the PBR, reports usually only need to be filed every three years?

Response IR-176:

The response to this request is confidential.

NON-CONFIDENTIAL

Request IR-177:

With reference to Part (c) (iii) of the original Pension IR please provide a copy of the Towers Watson Asset Liability Study.

Response IR-177:

This confidential Study is available for viewing at NSPI Offices. These large documents are available electronically upon request.

CONFIDENTIAL (Attachment Only)

Request IR-178:

Please provide a copy of the most recent Asset Liability study completed prior to the Towers Watson study referenced above.

Response IR-178:

Please refer Confidential Attachment 1. NSPI has not retained any additional information pertaining to this request. Non NSPI content has been removed from the attachment.

CONFIDENTIAL (Attachment Only)

Request IR-179:

In respect of Part (h) of the Original Pension IR, please provide copies of the communications identified in the Original Pension IR Response Part (h)(ii) – information requested on plan amendments and additional information on Annual Information Returns.

Response IR-179:

Please refer to Confidential Attachment 1 for copies of communications with the Pension Superintendent for the Applicable Years. The memos of June 9, 2010, and June 22, 2009, to the Pension Superintendent were summaries of the information contained in the actuarial report to assist with the review of the Annual Information Returns.

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Request IR-180:

Please provide a copy of the 1992 pension plan text for the Pension Plan for Employees of Nova Scotia Power Incorporated (the "NSPI Employees Plan") (not the current consolidated text) as well as the valuation report filed in connection with the time of the establishment of the pension plan.

Response IR-180:

Copies of the original plan text and initial actuarial valuation report for the NSPI Employees Plan as well as a revised plan text dated September 1993 and accompanying actuarial cost certificate can be viewed at NSPI offices. This large confidential document is available electronically upon request.

NON-CONFIDENTIAL

Request IR-181:

Please provide a copy of each amendment (on an unconsolidated basis, not the consolidated text) to the NSPI Employees Plan, and a copy of the cost certificate or subsequent actuarial valuation that sets out the cost of each amendment.

Response IR-181:

Copies of all filed amendments to the NSPI Employees Plan as well as accompanying cost certificates can be viewed at NSPI offices. This large confidential document is available electronically upon request. We note that not all amendments have an associated actuarial cost certificate as some are of a housekeeping nature that do not impact plan costs.

Please also refer to NPB IR-180, Attachment 1 Appendix A of the original plan text and actuarial cost certificate dated September 20, 1993 for details on the 1993 Early Retirement Incentive Program ("ERIP").

NON-CONFIDENTIAL

Request IR-182:

With reference to Original Pension IR Response Attachment 15, page 15 of 36, section entitled "Chief Financial Officer" provide any funding policy related to the NSPI RPPs in place in respect of any of the Applicable Years.

Response IR-182:

NSPIs funding policy is to contribute the amount as required by pension legislation and the Plan terms. Nova Scotia Power Inc., from time to time, may decide to contribute additional amounts over and above the required amount.

Please refer to NPB IR-183 Attachment 1.

CONFIDENTIAL (Attachment Only)

Request IR-183:

With reference to Original Pension IR Response Attachment 15, page 15 of 36, section beginning “The Treasurer...”, 6th bullet point, and Attachment 23, page 16 of 32, Section 5, 6th bullet point, please provide copies of the audited financial statements in respect of the NSPI RPPs for each of the Applicable Years.

Response IR-183:

Please refer to Confidential Attachment 1.

CONFIDENTIAL (Attachment Only)

Request IR-184:

With reference to Original Pension IR Response Attachment 15, page 16 of 36, 1st bullet point, please provide all documents and correspondence to and from the actuary related to the accounting assumptions referenced therein.

Response IR-184:

NSPIs meets with the actuary in early January of each calendar year to set the assumptions (including the discount rate) at December 31 of the prior fiscal year and to set the asset return assumption for the pension expense calculation for the upcoming year. The following relevant information is provided by our actuary:

- Discount rate on AA and A corporate bonds at various durations. Please refer to Liberty IR-83.

- Most recently available Morneau Shepell surveys of economic assumptions, along with information on recent trends in asset return assumptions. Please refer to Liberty IR-80 Attachment's 4-6 and Liberty IR-162 Attachment 1 for documentation. Please also refer to Attachment 1.

Additional information related to the discount rate and asset return assumption may be provided from time to time. Over the period 2008 to 2011, the following relevant information was provided by our actuaries:

(a) For the January 2011 meeting the best estimate asset returns by asset class was also provided by our actuaries, Morneau Shepell (formerly Morneau Sobeco). Please refer to Woodridge IR-5.

CONFIDENTIAL (Attachment Only)

(b) In January 2010, a graph of monthly discount rates of corporate AA bonds for a 14 year duration. Please refer to Confidential Attachment 2.

(c) In December 2009, a discussion of the methodology used to determine the discount rate. Please refer to Confidential Attachment 3.

Survey of Economic Assumptions - Expected Long-Term Return on Plan Assets

	31-Dec-09	31-Dec-08	31-Dec-07	31-Dec-06	31-Dec-05	31-Dec-04
8.25% and higher	1%	1%	1%	2%	3%	5%
8.00%	1%	6%	6%	11%	9%	8%
7.75%	3%	2%	6%	1%	3%	7%
7.50%	12%	12%	14%	18%	19%	22%
7.25%	18%	13%	11%	13%	19%	16%
7.00%	31%	32%	28%	30%	29%	31%
6.75%	10%	5%	14%	7%	6%	3%
6.50%	9%	11%	8%	4%	6%	3%
6.25% and lower	15%	18%	12%	14%	6%	5%
Median	7.00%	7.00%	7.00%	7.00%	7.25%	7.25%
Total	100%	100%	100%	100%	100%	100%

Fiscal Year	6.75% or lower	7% or lower	7.25% or lowe	7.50% or low	7.75% or lowe	8% or lower
2004	11%	42%	58%	80%	87%	95%
2005	18%	47%	66%	85%	88%	97%
2006	25%	55%	68%	86%	87%	98%
2007	34%	62%	73%	87%	93%	99%
2008	34%	66%	79%	91%	93%	99%
2009	34%	65%	83%	95%	98%	99%

CONFIDENTIAL (Attachment Only)

Request IR-185:

In respect of Original Pension IR Response Attachment 24, please provide the report or document to which the contents of confidential Attachment 24 were appended. There are references to Towers Watson at pp 9, 10, 12, 13, 24 and 25 of 27.

Response IR-185:

Please refer to Confidential Attachments 1-6.

CONFIDENTIAL (Attachment Only)

Request IR-186:

Please provide copies of all correspondence to or from Towers Watson, including reports by Towers Watson, final or in draft if no final report was completed, in relation to the NSPI RPPs, NSPI SERPs and NSPI OPEB.

Response IR-186:

Please refer to Confidential Attachments 1 and 2, NPB IR-177 and NPB IR-185.

NON-CONFIDENTIAL

Request IR-187:

In reference to Original Pension IR Response, part (q), Attachment 26, please provide copies of the Management Pension Committee Minutes in respect of 2011 and copies of any documents circulated to the Management Pension Committee in advance of any 2011 meetings or presented at the 2011 meetings of the Management Pension Committee.

Response IR-187:

A sub-committee of the MPC has had ongoing work through 2011. There have been no meetings of the MPC to date in 2011 (and therefore no Minutes have been created or documents issued).

Request IR-188:

Please provide asset allocation reports or SIP&P compliance reports for the period ending December 31, 2007 showing the asset allocation for NSPI RPPs as of December 31, 2007, and how this allocation compares to the asset allocation provided for in the SIP&P.

Response IR-188:

The confidential reports can be viewed at NSPI offices. These large documents are available electronically upon request.

The December 31, 2007 asset allocations compared to the asset allocations in the SIP&P are as follows:

Main Pension Plan

	Main	SIP&P
Cash	2.45%	0.00%
Canadian Equities	30.61%	27.50%
Global Equities	35.96%	37.50%
Domestic Fixed Income	30.77%	35.00%
US Fixed Income	0.20%	0.00%
	99.99%	100.00%

Acquired Plans

	Acquired I	Acquired II	SIP&P
Cash	2.29%	2.60%	3.00%
Canadian Equities	32.31%	33.59%	32.00%
Global Equities	25.86%	26.10%	28.00%
Domestic Fixed Income	39.24%	37.42%	37.00%
US Bonds	0.31%	0.29%	0.00%
	100.01%	100.00%	100.00%

Figures may not add due to rounding

NON-CONFIDENTIAL

Request IR-189:

With respect to Board Minutes and Board Committee Minutes sought in Original Pension IR, part (q), we note that the Management Pension Committee Minutes (Original Pension IR Response Attachment 26, pp. 21 and 30 of 35) refer to the Audit Committee of the Board, that the governance policy (Attachment 23, pp 9, 10, 14 and 17 of 32) identifies responsibilities of the Board or Committee of the Board relating to the NSPI RPPs and the Statement of Investment Policies and Procedures, (Attachment 15, pp 8, and 35 of 36) identifies that the Audit Committee, Management Resources & Compensation Committee, and the Board have responsibility for the pension funds.

(a) **We repeat our request to be provided with Relevant Minutes (NSPI RPP, NSPI SERP, and NSPI OPEB related extracts only for the Applicable Years) for the Board, Audit Committee and Management Resources & Compensation Committee in respect of the sponsorship or administration of the NSPI RPPs and NSPI SERPs, and NSPI OPEB.**

(b) **Please also provide any reports from the Management Pension Committee or any other source to the Board, Audit Committee and Management Resources & Compensation Committee in respect of the sponsorship or administration of the NSPI RPPs and NSPI SERPs, and NSPI OPEB that are referenced in the Relevant Minutes.**

(c) **We also note reference to an Executive Committee of NSPI and request copies of the Relevant Minutes and any reports from the Management Pension Committee or any other source to the Executive Committee in respect of the sponsorship or administration of the NSPI RPPs and NSPI SERPs, and NSPI OPEB that are referenced in the Relevant Minutes for the Executive Committee of NSPI.**

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Response IR-189:

(a) NSPI will provide this information to the UARB upon request.

(b) NSPI will provide this information to the UARB upon request.

(c) There are no such documents to provide.

NON-CONFIDENTIAL

Request IR-190:

With reference to Original Pension IR Response Attachment 22, page 2 of 3, paragraph 2 - Amendments, provide copies of all documents provided by NSPI in respect of the NSPI RPPs in respect of the Applicable Years.

Response IR-190:

There are no such documents to provide.

REDACTED

Request IR-191:

With reference to Original Pension IR Response Attachment 23, page 1 of 32, provide a copy of the [redacted] referenced in paragraph 1 of the resolution.

Response IR-191:

Please refer to Confidential Attachment 1.

NON-CONFIDENTIAL

Request IR-192:

With reference to Original Pension IR Response Attachment 23, page 16 of 32, Section 5, 8th bullet point, please provide copies of the reports and required information provided to the Audit Committee for the Applicable Years.

Response IR-192:

NSPI will provide this information to the UARB upon request.

CONFIDENTIAL (Attachment Only)

Request IR-193:

With reference to Original Pension IR Response Attachment 23, page 16 of 32, Section 6, 7th bullet point, please provide copies of the annual budget for the Applicable Years.

Response IR-193:

Please refer to Confidential Attachment 1.

NON-CONFIDENTIAL

Request IR-194:

With reference to Original Pension IR Response Attachment 23, page 16 of 32, Section 7, 2nd bullet point, identify all action taken as a result of receipt of the actuarial valuations during the Applicable Years.

Response IR-194:

The VP of Human Resources ensures that the following actions are taken after receiving the valuation report:

(a) Meets with the actuary to review the report and financial and demographic implications.

(b) Discusses any issues identified by the actuary during the valuation process and follow-up as necessary.

(c) Signs the employer's confirmation certificate which forms part of the valuation report.

(d) Arranges for the actuary to make a presentation to the pension committee regarding the results of the valuation report and financial projections for upcoming years (Note: this sometimes occurs prior to receiving the final valuation report).

(e) Arranges for the actuary to meet with the union executive board to review the report.

(f) Distributes the report to internal stakeholders (union, finance, HR staff, and others as necessary).

(g) Ensures that the valuation report is filed with the pension regulator.

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(h) Updates the employer contribution remittance requirements and ensure that updated contribution requirements are met.

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Request IR-195:

With reference to Original Pension IR Response Attachment 26, page 8 of 35, Item 4.0 – NSPI and Acquired Plan Amendments please provide a copy of the document before the Management Pension Committee related to this item.

Response IR-195:

Please refer to Confidential Attachment 1 for a copy of the pension plan amendment no. 13 and Confidential Attachment 2 for a copy of the Acquired pension plan amendment no. 8 as provided to the Management Pension Committee.

NON CONFIDENTIAL

Request IR-196:

With reference to Original Pension IR Response Attachment 26, page 17 of 35, Item 4.0 - Pension Governance, please provide a copy of the memo dated November 26, 2009.

Response IR-196:

NSPI will provide this information to the UARB upon request.

REDACTED

Request IR-197:

With reference to Original Pension IR Response Attachment 26, page 23 of 35, Item 13.0, please provide a copy of [redacted]

Response IR-197:

Please refer to Confidential Attachment 1 for a letter dated January 15, 2010, to NSPI pensioners and a letter dated January 21, 2010, to NSPI employees.

NON-CONFIDENTIAL

Request IR-198:

With reference to Original Pension IR Response Attachment 26, page 26 of 35, Item 9.0, page 30 of 35, Item 7.0 and page 33 of 35, Item 7.0, please provide a copy of all reports to the Audit, Nominating and Corporate Governance Committee related to the NSPI RPPs, SERPs, NSPI and OPEB for the Applicable Years.

Response IR-198:

NSPI will provide this information to the UARB upon request.

REDACTED

Request IR-199:

(a) With reference to Original Pension IR Response Part (d) was the question of whether to seek solvency relief discussed internally and/or with consultants?

(b) If not, why not?

(c) If so, are these discussions recorded in notes or minutes of these individuals and/or committees?

(d) If not, why not?

(e) If so, please provide all notes and/or committee minutes recording these discussions.

(f) When was the decision made not to seek solvency relief?

(g) Was the decision not to pursue solvency relief made by the Board of NSPI, the Audit Committee of NSPI, the Pension Management Committee or other group or body? If other group or body, please identify.

(h) Was the question of whether to seek an increase in employee contributions discussed internally and/or with consultants?

(i) If not, why not?

(j) If so, are these discussions recorded in notes or minutes of these individuals and/or committees?

(k) If not, why not?

REDACTED

(l) If so, please provide all notes and/or committee minutes recording these discussions.

(m) When was the decision made [redacted]

(n) Was the decision [redacted] made by the Board of NSPI, the Audit Committee of NSPI, the Pension Management Committee or other group or body? If other group or body, please identify.

Response IR-199:

(a) [redacted]. Please refer to Confidential Attachment 1 for correspondence from our pension consultants in May 2009 when solvency relief was initially proposed by the government. [redacted]. Please refer to Attachment 2 for general correspondence from our pension consultants regarding the solvency relief. [redacted]:

- [redacted].

- [redacted].

[redacted]:

REDACTED

- [redacted].

- [redacted].

- [redacted].

(b) [redacted].

(c) [redacted].

(d) [redacted].

(e) [redacted].

(f) [redacted].

REDACTED

(g) [redacted].

(h) [redacted].

(i) [redacted].

(j) [redacted].

(k) [redacted].

(l) [redacted].

(m) [redacted].

(n) [redacted].

within a fairly narrow range. This started to change 18 months ago with rates diverging significantly. The main reason is that the market for long-term corporate bonds in Canada is relatively thin and has been undergoing gyrations during the financial crisis. The Canadian Institute of Actuaries (CIA) is looking at alternative methodologies and we may receive fresh direction from both the CIA and CICA in 2010.

Why Plan Sponsors Should Care

The sponsors of either DB pension plans or post-retirement (non-pension) benefit programs may be required to change their method for selecting the discount rate, most likely downwards. The net effect could be a jump in costs on an accounting basis.

Flexible Benefits Strongly Endorsed

Global studies by two major consulting firms find that offering more choice, in the form of flexible benefits, garners a positive employee response (83% were happy in one study) while keeping employer costs the same or even reducing them.

Why Plan Sponsors Should Care

Win-win situations are hard to come by. Mid-sized employers in particular who previously thought flexible benefits were too costly to implement may want to reconsider. ■

Nova Scotia Grants Solvency Funding Relief

Nova Scotia is the most recent Canadian jurisdiction to ease the burden on pension plan sponsors by temporarily extending the period to fund solvency deficiencies in the wake of the recent economic downturn. Effective November 3, 2009, the Nova Scotia Pension Benefits Regulations were amended to change the period over which solvency deficiencies must be funded from five to ten years.

The extension applies to plans that prepare valuation reports between December 30, 2008 and January 2, 2011. To make use of the solvency funding relief, the plan administrator must send out a notice to plan members, retirees, and unions representing members detailing certain information about the plan, the impact of the extension if granted, and advising that they have 30 days to object to the extension. If fewer than one-third of those individuals object (if a union objects, each member it represents is deemed to vote against the extension), then the Superintendent of Pensions will grant the solvency relief. Both existing deficiencies and newly arising deficiencies are available for the funding extension. However, plan sponsors that make use of the extension will not be permitted to amend their pension plans in a way that will decrease employee contributions or increase benefits (unless the cost of those benefits is fully funded) for the first five years of the amortization period. ■

FSCO's Draft Policy on Management and Retention of Pension Records

On December 22, 2009, the Financial Services Commission of Ontario (FSCO) released a Consultation Policy on Management and Retention of Pension Records by the Administrator. The draft policy is intended to provide plan administrators with information on their obligations and responsibilities related to the management and retention of pension plan records. It provides guidelines and instructions on record keeping practices. FSCO expects the administrator to establish a formal and comprehensive written policy addressing such issues as how long records are to be retained and which individuals are responsible for those records. As part of its consultation, FSCO is accepting public comments until February 26, 2010. ■

CONFIDENTIAL (Attachment Only)

Request IR-200:

With reference to Liberty IR-24, Attachment 2, Pages 73-76 of 110, Article 20 – Retirement and Pensions, please provide copies of all predecessor articles from prior collective agreements (1992 to 2007) that address pensions.

Response IR-200:

Please refer to Confidential Attachment 1 which includes Article 20 – Retirement and Pensions from Collective Agreements dating April 1, 1993, to July 31, 2007.

CONFIDENTIAL (Attachment Only)

Request IR-201:

(a) With reference to Liberty IR-24, Attachment 2, Pages 73-76 of 110, Article 20 – Retirement and Pensions, please provide copies of any proposals made by NSPI management to seek changes to the language in this Article during the last round of collective bargaining.

(b) Please provide copies of any proposals made by NSPI management during prior rounds of collective bargaining to seek changes to the predecessor articles to Article 20-Retirement and Pensions from prior collective agreements.

Response IR-201:

(a) Please refer to Confidential Attachment 1 for 2007 NSPI Proposals.

(b) Please refer to Confidential Attachment 2 for Previous NSPI Proposals.

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Request IR-202:

(a) Has there been any consideration to establishing a separate pension plan for non-unionized employees?

(b) If yes, please provide all documents related to that consideration?

(c) If not, why not?

Response IR-202:

(a) There has been no consideration to establishing a separate pension plan for non-unionized employees.

(b) N/A.

(c) Please refer to NBP IR-205.

NON-CONFIDENTIAL

Request IR-203:

Why has NSPI not closed the DB Plan for non unionized employees for future service in order to reduce pension costs?

Response IR-203:

NSPI active employees accrue benefits under the NSPI Employees pension plan. Please refer to NPB IR-99 Attachment 24 for internal NSPI discussions and analysis regarding the NSPI Employees pension plan.

NSPI has traditionally provided the identical pension plan and health benefit plan to union and non-union employees. To the extent possible, any amendment to the plan terms are made at the same time for all plan members. Any substantive changes to the pension for union members would have to be negotiated with NSPIs unionized employees represented by IBEW Local 1928.

The most recent negotiations with the union occurred late 2007/early 2008 and resulted in an agreement signed in May 2008 covering the period August 2007 to March 31, 2012. NSPI rarely approaches the union to negotiate substantive changes during the period covered by an existing collective agreement. Based on prior discussions with the union, the union opposes any changes which would reduce benefits or increase employee contributions to the defined benefit pension plan. Furthermore, even if the union were to agree to any pension changes, it is likely that the union would want concessions in exchange for the pension plan changes – these concessions would likely be comparable in value to the pension plan changes and so there would be no net savings to NSPI.

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Request IR-204:

Please identify the funding, if any, that is being undertaken by NSPI beyond the minimum funding requirements of the PBR, the amounts of that funding, and why NSPI is funding beyond the minimum PBR requirements?

Response IR-204:

Under the Pension Benefits Act and Regulations, the value of escalated adjustments may be excluded from the solvency valuation calculation. This has the effect of minimizing solvency special funding payments. If a plan sponsor chooses to exclude the value of escalated adjustments from the valuation, the plan cannot include the value of the escalated adjustments in commuted value payments from the pension fund until an amount equal to the value of the escalated adjustments in respect of such payment is paid into the fund (Regulation 19(12)). The plan sponsor has up to five years to contribute the value of the escalated adjustments into the fund (Regulation 19(10)). NSPI chooses to contribute the value of the escalated adjustment immediately, rather than deferring up to five years. This simplifies recordkeeping and enables full settlement of the pension entitlement.

When the transfer ratio is less than one, the plan may transfer the full commuted value only if the plan sponsor has remitted the amount of the transfer deficiency (generally: (1 – transfer ratio) x commuted value) into the pension fund (Regulation 19(9)). While there are some specific exclusions to this rule, many terminating NSPI members are affected by this rule. The plan sponsor has up to five years to contribute the value of the transfer deficiency into the fund (Regulation 19(10)). NSPI chooses to contribute the value of the deficiency immediately, rather than deferring up to five years. This simplifies recordkeeping and enables full settlement of the pension entitlement.

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The approximate amount of the additional contribution in respect of the above items made immediately, rather than waiting for up to five years, has been approximately $1 million per year over the last few years

Other than the above, NSPI usually contributes at the minimum level required by the Pension Benefits Act and regulations, and has no current plans of contributing more than the minimum required.

REDACTED

Request IR-205:

During the Applicable Years, considering the financial crisis of 2008, and resulting substantial changes to pension plans in the private sector and public sector, please identify all steps taken by NSPI to reduce the funding requirements in respect of the NSPI RPPs both during the Applicable Years and for future years.

Response IR-205:

Please refer to NPB IR-203.

[redacted].

REDACTED

Request IR-206:

There are references to the NSPI SERPs being [redacted] (e.g., Original Pension IR, Attachment 21, page 3 of 16) [redacted]. Please provide a copy of each [redacted], a copy of the [redacted], and a description of the [redacted].

Response IR-206:

NSPI has established one Retirement Compensation Arrangement (RCA) in respect of the SERP.

Please refer to Confidential Attachment 1 for the original RCA agreement dated May 31, 2002.

Please refer to Confidential Attachment 2 for the original Letter of Credit. Please refer to Confidential Attachment 3 for the revised Letters of Credit for 2008 – 2011.

The following are the costs for the letters of credit from 2008 to 2011. Amounts shown are the true cost of the letter of credit – excluding the matching amount of refundable tax which must be remitted to CRA.

[redacted]

[redacted]

[redacted]

[redacted]

REDACTED

Request IR-207:

(a) Original Pension IR, Attachment 15, page 35 of 36, contains an [redacted]. This was approved in March, 2008 – have there been any changes since?

(b) Is there any distinction between [redacted]? If so, please provide a copy of the latter.

Response IR-207:

(a) No.

(b) No.

REDACTED

Request IR-208:

In the response to Liberty IR-107, NSPI provides as Attachment 1 the Milliken study offering [redacted]. In making [redacted], has NSPI distinguished wage increases for those in final average, indexed DB pension plans from those without such plans? If so, please provide all related documents. If not, why not?

Response IR-208:

The wage benchmarking information does not enable comparison at that level of detail.

In our experience, detailed wage benchmarking databases are not usually integrated with detailed defined benefit pension plan benchmarking databases. The comparison suggested in this IR would be more in line with a total compensation benchmarking, and even in such a study, the focus would be on total amounts, rather than detailed plan specific benefits.