

NEW BRUNSWICK ENERGY AND UTILITIES BOARD

**IN THE MATTER OF a Review of the
New Brunswick System Operator's
2011-2012 Revenue Requirement**

EVIDENCE

November 15, 2010

Volume 1 of 1

Board Reference: 2010-011



NEW BRUNSWICK ENERGY AND UTILITIES BOARD

IN THE MATTER OF the *Energy and Utilities Board Act*, Chapter E-9.18, R.S.N.B., 1973, as amended.

- and -

IN THE MATTER OF a Review of the New Brunswick System Operator's ("NBSO") 2011-2012 Revenue Requirement

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1 EXECUTIVE SUMMARY

2
3 The New Brunswick System Operator (“NBSO”) is applying to the New Brunswick
4 Energy and Utilities Board (the “Board”) pursuant to Section 111 of the *Electricity Act*,
5 Chapter E-4.6, R.S.N.B., 1973, for approval of:

- 6
- 7 a) A Schedule 1 (Scheduling, System Control and Dispatch Service) revenue
8 requirement of \$11.471 million to cover the cost of NBSO operations for the fiscal
9 year 2011-2012;
 - 10
 - 11 b) A Schedule 2 (Reactive Supply and Voltage Control) revenue requirement of
12 \$5.634 million for the fiscal year 2011-2012; and
 - 13
 - 14 c) Approval of a Schedule 3(c) (Automatic Generation Control and Load Following
15 for Non-Dispatchable Wind Power Generators) rate of \$0.50/MWh of Wind
16 Energy.
- 17

18 **Background**

19 Over the past two revenue requirement applications, the NBSO has placed a great deal
20 of emphasis on its efforts toward becoming a self-supporting organization, while at the
21 same time adapting to and meeting its evolving role in the electricity industry.
22 Accordingly, the NBSO has sought and received approval for revenue requirements
23 which have allowed the NBSO to add staff required to meet increasing demands in
24 virtually all areas of the organization, while at the same time providing some measure of
25 succession planning. The acquisition of additional office space was a key initiative in
26 the move to self-sufficiency, and this project was successfully completed in September
27 2009.

28
29 Perhaps the most fundamental element of the move toward becoming a self-supporting
30 organization was what came to be known as the “migration strategy”, and the lynch-pin
31 to that strategy was the need to have all NBSO work performed by direct-hire NBSO

1 employees. The NBSO is pleased to advise that, effective April 2, 2010, the
2 secondment arrangement between NBSO and NB Power Transmission Corporation
3 (“NB Power Transco”) came to an end. All previously seconded individuals (with one
4 exception, who took a position with NB Power Transco) accepted employment with the
5 NBSO. Additionally, the existing Collective Agreement between NB Power Transco and
6 the IBEW which covered most of the previously seconded employees will, pursuant to
7 an Order of the Public Service Labour Relations Board issued September 7, 2010,
8 continue, but the NBSO is now the “Employer” in respect of this relationship. The
9 virtually seamless direct-hiring of previously seconded employees and transfer of the
10 bargaining relationship are major milestones in the history of the NBSO and set the
11 stage for the future.

12 13 **Moving Forward in 2011/12**

14 Against this background, the Board of Directors of the NBSO at a meeting held October
15 19, 2010 approved an operating budget for the 2011/12 fiscal year of \$12.427 million
16 and a resulting Schedule 1 Revenue Requirement of \$11.471 million. This revenue
17 requirement amounts to an increase of 1.6% over the current year figure of \$11.288
18 million. This level of increase compares very favourably with those in the past three
19 years of 10.07%, 28.7% and 11.45% respectively. The revenue requirement does, of
20 course, take into account miscellaneous revenues, so an analysis of just the NBSO’s
21 operating costs (less the \$300 thousand contingency) indicates that budgeted costs for
22 2011/12 are \$12.127 million, a 4.8 % increase over the current year figure of \$11.569
23 million. Once again this increase compares favourably with the 8.2%, 25.6% and 12%
24 increases over the past three years. It should be noted as well that the difference
25 between the 4.8% increase in operating costs and the 1.6% increase in revenue
26 requirement is largely attributable to a \$375 thousand increase in miscellaneous
27 revenue. This matter is more fully discussed at Tab 3, Schedule 1.

28
29 The relatively stable nature of the NBSO’s costs and associated revenue requirement
30 for 2011/12 are reflective of the completion of many of the initiatives related to self-
31 sustainment and the completion of the hiring of new staff. There are, however, a few

1 items to be touched on in this summary, particularly in respect to Labour and Benefits.
2 While all significant line item variances are fully explained elsewhere in the evidence,
3 the \$916 thousand budget to budget increase in Labour and Benefits merits attention
4 here.

5
6 The full-year impact of the seven (7) new hires included in the 2009/10 revenue
7 requirement accounts for almost one third (\$287K) of the increase. Additionally, the
8 proposed 2011/12 revenue requirement provides for five (5) additional staff: Four (4)
9 Power System Operators-in-Training and one (1) Engineer. These new positions
10 account for another 30% (\$266K). All five (5) of these positions are required in
11 Operations. Earlier this year the Vice-President of Operations undertook a
12 comprehensive review of staffing in his area. Although two (2) Power System
13 Operators-in-Training positions were included in the 2009/10 revenue requirement for
14 purposes of succession planning, in the past year health issues have resulted in two (2)
15 members of the Operations staff being unable to continue in their current positions, and
16 four (4) individuals in Operations have now indicated they will retire in 2012.
17 Accordingly, an additional four (4) positions are required. In fact, given the training
18 required to become a fully qualified Power System Operator, it was determined that two
19 (2) of the in-training positions needed to be filled as soon as possible. Accordingly the
20 Board of Directors of NBSO approved the creation of two (2) new positions in the
21 current year. These two (2) salaries are included in the projection for the current year,
22 and the resulting full year impact is included in the 2011/12 revenue requirement.

23
24 The fifth new position, a Power System Engineer, will allow for the cross training of
25 three Engineers on all system operations engineering activities and the establishment of
26 an on-call roster to properly support control room operations on a 24/7 basis.
27 Additionally, the new Operator Training Simulator scheduled to come on line with
28 Supervisory Control and Data Acquisition (“SCADA”) in November, 2011 will require
29 engineering support.

1 As noted, the hiring of five (5) additional staff is a major initiative and cost driver in
2 2011/12. Other significant increases (amortization, training) are fully explained
3 elsewhere, as are a number of very significant reductions in cost (Service Agreement,
4 Data Communication, Consulting). In summary, however, the NBSO submits that the
5 completion of major initiatives related to the full establishment of the NBSO as a self-
6 supporting organization has brought us to a position of relative stability in terms of the
7 Schedule 1 revenue requirement. The major remaining piece is to ensure that the most
8 fundamental component of the NBSO, system operations, is appropriately staffed both
9 for today and the future.

10
11 With respect to Schedules 2 and 3(c), the Evidence filed at Tabs 4 and 5 fully describe
12 and support the requested Schedule 2 revenue requirement of \$ 5.634 million and a
13 Schedule 3(c) rate of \$0.50/MWh of wind energy. The evidence need not be elaborated
14 upon here.

15
16 A final point to bring forward relates to capital expenditures by the NBSO. As noted at
17 page 17 of the evidence, completion of the Supervisory Control and Data Acquisition
18 (“SCADA”) project will result in related amortization charges commencing in November,
19 2011. These charges will be in addition to existing costs related to capital expenditures
20 for furniture and improvements at the Energy Control Centre (“ECC”), as noted in the
21 chart on page 17 of the evidence.

22
23 The NBSO wishes to draw the Board’s attention as well to the last item listed on the
24 same chart, the Market Management System (“MMS”). Although this item does not
25 impact the 2011/12 revenue requirement, the NBSO wishes to advise the Board that the
26 need to replace the existing twenty-five year old MMS has been identified as a priority
27 item by Management, and the project has been approved by the NBSO Board of
28 Directors. Total capital expenditure for this acquisition is expected to be approximately
29 \$2 million and commissioning of the new system is scheduled to take place in late 2012.
30 Accordingly, amortization of these costs will commence in the 2012/13 fiscal year.
31 NBSO has retained the same consulting firm that assisted with the SCADA project to

1 scope the project, draw up the specifications, develop a Request for Proposals and
2 assist in the evaluation of submitted proposals. A more detailed explanation as to the
3 need for a new MMS system is found at Tab 5, Appendix E. While the expenditure
4 does not impact the 2011/12 revenue requirement, the NBSO believes it appropriate to
5 fully describe the project prior to the inclusion of related amortization charges in a future
6 revenue requirement.

1 **SCHEDULE 1**

2 **(Scheduling, System Control and Dispatch)**

3
4 Schedule 1 is a mandatory ancillary service provided by NBSO. This service is required
5 to schedule the movement of power through, out of, within, or into a control area in a
6 reliable manner.

7
8 The Revenue Requirement for Schedule 1 service for the fiscal year 2011/12 is
9 presented using the Minimum Filing Requirements (“MFR”) prescribed revenue and cost
10 categories shown in Table 1-1. The table, as prescribed in the MFR, also includes:

- 11
12 1. the audited results for the two most current fiscal years;
13 2. the approved budget for the 2010/11 fiscal year
14 3. the NBSO’s forecasted total revenues and costs for the 2010/11 fiscal year
15 4. variances, by each revenue and cost category, between the proposed 2011/12
16 budget and the forecast for fiscal 2010/11; and
17 5. variances, by each revenue and cost category, between the proposed 2011/12
18 budget and the approved budget for fiscal 2010/11.

19
20 The evidence further includes, by revenue and cost category, a written description
21 identifying in detail:

- 22
23 1. the types of revenues or costs that are included in the category
24 2. line item variances and reasons for change between the proposed 2011/12
25 budget and the 2010/11 budget and 2010/11 forecast
26 3. any included allowances for unknown costs, identifying the amount and basis
27 for the allowance
28 4. amounts, explanations and analysis for new and current year initiatives and
29 programs
30 5. reference to, and copies of, reports, reviews or studies supporting proposed
31 costs

1 The Revenue Requirement for Schedule 1 service for the fiscal year 2011/12 is
 2 highlighted in column 5.

Table 1-1
New Brunswick System Operator
Schedule 1 Revenue Requirement
 Fiscal Years Ending March 31
 (in thousands \$)

Explanation Page Ref.	(1) 2008/09 Actual	(2) 2009/10 Actual	(3) 2010/11 Budget	(4) 2010/11 Forecast	(5) 2011/12 Budget	(6) Variance 1 (5)-(3)	(7) Variance 2 (5)-(4)
(10) Labor and benefits	\$ 6,064	\$ 6,349	\$ 7,497	\$ 7,536	\$ 8,413	\$ 916	\$ 877
(13) Board costs	138	114	123	123	123	-	-
(13) EUB Assessments	406	276	400	400	370	(30)	(30)
(14) Energy Control Center	335	302	352	308	308	(44)	(0)
(16) Building O&M	352	608	600	600	633	33	33
(17) Amortization of capital costs	-	8	80	49	180	100	131
(18) Service agreement costs	399	410	409	256	256	(153)	-
(19) Computer software	114	171	244	244	156	(88)	(88)
(20) Data communications	108	101	313	163	190	(123)	27
(21) Insurance	132	144	145	145	145	(0)	(0)
(21) Consulting	437	333	498	698	393	(105)	(305)
(24) Travel	265	218	339	339	357	18	18
(28) Training	31	68	90	90	191	101	101
(29) Administration	104	170	267	192	251	(16)	59
(29) Finance charges	(108)	(12)	-	-	45	45	45
(30) EUB hearing	190	21	212	212	115	(97)	(97)
Subtotal - before contingency	\$ 8,967	\$ 9,282	\$ 11,569	\$ 11,355	\$ 12,127	\$ 558	\$ 772
Contingency	-	-	300	300	300	-	-
Subtotal - total expenses	\$ 8,967	\$ 9,282	\$ 11,869	\$ 11,655	\$ 12,427	\$ 558	\$ 772
Less: miscellaneous revenue							
(31) Schedule balancing service	\$ (267)	\$ (267)	\$ (267)	\$ (267)	\$ (267)	\$ -	\$ -
(31) Reliability coordinator service	(97)	(102)	(99)	(99)	(99)	-	-
(32) Oasis and etag service	(82)	(81)	(80)	(80)	(80)	-	-
(32) Transmission operator services	-	-	-	(375)	(375)	(375)	-
(33) Connection studies	(243)	(63)	(100)	(100)	(100)	-	-
(34) Conferences and workshops	(32)	(7)	(35)	(35)	(35)	-	-
Subtotal - miscellaneous revenue	\$ (721)	\$ (520)	\$ (581)	\$ (956)	\$ (956)	\$ (375)	\$ -
Schedule 1 Revenue Requirement	\$ 8,246	\$ 8,762	\$ 11,288	\$ 10,699	\$ 11,471	\$ 183	\$ 772

- 27 Column 1 - the audited results for fiscal 2008/09
- 28 Column 2 - the audited results for fiscal 2009/10
- 29 Column 3 - the approved budget for fiscal 2010/11
- 30 Column 4 - the forecast for fiscal 2010/11
- 31 Column 5 - the proposed budget for fiscal 2011/12
- 32 Column 6 - the variance between the proposed budget for 2011/12 (Column 5)
- 33 and the approved budget for 2010/11 (Column 3)
- 34 Column 7 - the variance between the proposed budget for 2011/12 (Column 5)
- 35 and the forecast for 2010/11 (Column 4)

1 **VARIANCE EXPLANATIONS**

2
3 **Labour and Benefits**

4 This category of costs includes salaries and wages of union and non-union regular
5 employees, casual or temporary employees, overtime, as well as the employer costs of
6 employee benefits including health, dental and life insurance, as well as pension
7 contributions and retirement payment allowances.

8

9 (in thousands \$)

	(1) 2008/09 Actual	(2) 2009/10 Actual	(3) 2010/11 Budget	(4) 2010/11 Forecast	(5) 2011/12 Budget	(6) Variance 1 (5)-(3)	(7) Variance 2 (5)-(4)
Labor and benefits	\$ 6,064	\$ 6,349	\$ 7,497	\$ 7,536	\$ 8,413	\$ 916	\$ 877

10
11
12

13 **Variance 1: Increase of \$916 thousand from 2010/11 budget to 2011/12 budget**

14 Labour and benefits are to increase by \$916 thousand from the approved budget for
15 2010/11 of \$7,497 thousand to a budget of \$8,413 thousand. The variances are
16 summarized as follows:

17

18 Labour and benefits, budget 2010/11	7,497
19 Full year effect of 7 new staff that started mid 2010/11	287
20 Five new positions in 2011/12	266
21 General increase in collective agreement	127
22 Reclassifications, merit, salary adjustments	166
23 <u>Benefits increase, from \$1,272 to \$1,341 thousand</u>	<u>69</u>
24 <u>Labour and benefits, budget 2011/12</u>	<u>8,413</u>

25

26 The number of employees was budgeted to increase by seven (7) positions in 2010/11
27 from fifty-six (56) to sixty-three (63) positions by the end of the fiscal year. Six (6) of the
28 seven (7) positions were scheduled to begin at mid fiscal year. Therefore, fiscal
29 2011/12 includes the additional half-year of salary for the six (6) new positions and two
30 months salary for the seventh position, amounting to \$287 thousand.

1 The number of employees increases by five (5) positions in 2011/12 from sixty-three
2 (63) to sixty-eight (68) positions. The five (5) positions include four (4) Power System
3 Operators-in-Training and one (1) Engineer. The incremental budget for these five (5)
4 positions amounts to \$266 thousand.

5
6 An organizational chart identifying the number of positions by department is included in
7 the Evidence at Tab 5, Appendix B.

8
9 The general cost of living wage increase for unionized NBSO employees is prescribed
10 in the five-year collective agreement ending December 31, 2012. An increase of 3.5%
11 on January 1, 2011 and 4.0% on January 1, 2012 result in a general increase averaging
12 3.6% for this group of employees from budget year 2010/11 to budget year 2011/12,
13 amounting to \$127 thousand. In accordance with the government directive of 2008,
14 NBSO non-bargaining staff received no cost of living increase in the 2009/10 fiscal year,
15 have not forecast a cost-of-living increase for 2010/11, nor is one included for 2011/12.

16
17 The increase in salaries and wages resulting from reclassifications, adjustments or merit
18 increases amount to \$256 thousand. A non-recurring initiative in the 2010/11 budget
19 amounts to an offset of \$90 thousand to cost increases. Together these variances
20 amount to \$166 thousand.

21
22 A copy of a Compensation Study is included in the Evidence at Tab 5, Appendix D.

23
24 The cost of employee benefits was budgeted at \$1,272 thousand in 2010/11 and is
25 budgeted in 2011/12 at \$1,341 thousand, an increase of \$69 thousand reflecting the
26 proportional increases in salaries and wages.

1 **Variance 2: Increase of \$877 thousand from 2010/11 forecast to 2011/12 budget**

2 Labour and benefits are to increase by \$877 thousand from the forecast of 2010/11 of
3 \$7,536 thousand to a budget of \$8,413 thousand. The variances are summarized as
4 follows:

5

6	Labour and benefits, forecast 2010/11	7,536
7	Full year effect of seven (7) new staff in 2010/11	392
8	Five (5) new positions in 2011/12, two (2) starting 2010	206
9	General increase in collective agreement	127
10	Reclassifications, merit, salary adjustments	75
11	<u>Benefits increase, from \$1,264 to \$1,341 thousand</u>	<u>77</u>
12	<u>Labour and benefits, budget 2011/12</u>	<u>8,413</u>

13

14 The number of new positions forecast to be added in 2010/11 is seven (7), as
15 budgeted, but the start dates, rather than mid-year, are in the fall and winter period.
16 Therefore, the full year effect of adding these positions is greater from forecast
17 2010/11 to budget 2011/12 than from budget 2010/11 to budget 2011/12,
18 amounting to \$392 thousand.

19
20 Of the five (5) new positions to be added from budget 2010/11 to budget 2011/12,
21 two (2) Power System Operators-in-Training are forecast to begin within 2010/11,
22 costing \$60 thousand in 2010/11, resulting in a variance from forecast 2010/11 to
23 budget 2011/12 of \$206 thousand.

24
25 The general increase as prescribed in the collective agreement amounts to \$127
26 thousand both from the 2010/11 budget and forecast.

27
28 The forecast for 2010/11 includes reclassification, merits and salary adjustments
29 amounting to \$91 thousand that were not in the budget for 2010/11. Therefore, the
30 variance from forecast 2010/11 to budget 2011/12 is lower than from budget
31 2010/11 to budget 2011/12, amounting to \$75 thousand.

1 Employee benefits expense is forecast at \$1,264 thousand for 2010/11 and is
 2 budgeted to increase to \$1,341 thousand in 2011/12, amounting to an increase from
 3 forecast of \$77 thousand.

4
 5 **Board Costs**

6 This category of costs includes annual stipends, per diems and travel expenses for the
 7 NBSO Board of Directors. A breakdown of the 2011/12 budget for this cost category is
 8 as follows:

- 9 • stipends \$39 thousand
- 10 • per diems \$40 thousand
- 11 • education and training \$20 thousand
- 12 • travel \$24 thousand

13
 14 (in thousands \$)

	(1) 2008/09 Actual	(2) 2009/10 Actual	(3) 2010/11 Budget	(4) 2010/11 Forecast	(5) 2011/12 Budget	(6) Variance 1 (5)-(3)	(7) Variance 2 (5)-(4)
Board costs	\$ 138	\$ 114	\$ 123	\$ 123	\$ 123	\$ -	\$ -

15
 16
 17
 18 **Variance 1 and Variance 2: No change from 2010/11 budget and forecast.**

19
 20 **NBEUB Assessments**

21 This category of costs includes the NBSO portion of EUB annual common expenses,
 22 EUB hearing expenses incurred associated with the NBSO and fees and expenses of
 23 the Public Intervenor.

24
 25 (in thousands \$)

	(1) 2008/09 Actual	(2) 2009/10 Actual	(3) 2010/11 Budget	(4) 2010/11 Forecast	(5) 2011/12 Budget	(6) Variance 1 (5)-(3)	(7) Variance 2 (5)-(4)
EUB Assessments	\$ 406	\$ 276	\$ 400	\$ 400	\$ 370	\$ (30)	\$ (30)

1 **Variance 1: \$30 thousand decrease from 2010/11 budget to 2011/12 budget**

2 The amounts budgeted for the EUB Assessment and Public Intervention costs are:

- 3 • \$245 thousand for the Schedule 1 revenue requirement, \$55 thousand less than
4 the \$300 thousand budgeted for 2010/11, and
- 5 • \$125 thousand for a Tariff hearing, \$25 thousand more than the \$100 thousand
6 budgeted for 2010/11.

7
8 **Variance 2: \$30 thousand decrease from 2010/11 forecast to 2011/12 budget**

9 The forecast total Assessment and Public Intervention costs are \$400 thousand for
10 2010/11. This includes the Tariff hearing, \$150 thousand, and the Revenue
11 Requirement hearing, \$250 thousand in 2010/11.

12
13 Therefore, the variance from 2010/11 forecast to 2011/12 budget is a decrease of \$30
14 thousand, including:

- 15 • A decrease of \$25 thousand in the Tariff hearing assessment; and
- 16 • A decrease of \$5 thousand in the Schedule 1 hearing.

17
18 **Energy Control Center**

19 This category of costs includes the lease costs of the Energy Control Center. The
20 NBSO leases approximately 70% of the building from NB Power Transmission
21 Corporation (“NB Power Transco”) with NB Power Distribution and Customer Service
22 Corporation (“NB Power Disco”) occupying the remaining portion of the building. Lease
23 charges have been calculated based on the NBSO portion of amortization and finance
24 charges.

25
26 A breakdown of the 2011/12 budgeted charges for amortization and finance charges
27 from NB Power Transco is as follows:

28 (in thousands \$)

	(1) 2008/09 Actual	(2) 2009/10 Actual	(3) 2010/11 Budget	(4) 2010/11 Forecast	(5) 2011/12 Budget	(6) Variance 1 (5)-(3)	(7) Variance 2 (5)-(4)
29 Energy Control Center	\$ 335	\$ 302	\$ 352	\$ 308	\$ 308	\$ (44)	\$ (0)

30
31
32

	Amortization	Finance	Total
Energy Control Center building	28	184	212
Key Dispatch	81	4	85
Security System	6	5	11
Provision for additions	-	-	-
<u>2011/12 budget</u>	<u>115</u>	<u>193</u>	<u>308</u>

Variance 1: \$44 thousand decrease from 2010/11 budget to 2011/12 budget

The 2010/11 budget included amortization and finance charges from NB Power Transco as follows:

	Amortization	Finance	Total
Energy Control Center building	26	186	212
Key Dispatch	75	10	85
Security System	6	5	11
Provision for additions	19	25	44
<u>2010/11 budget</u>	<u>126</u>	<u>226</u>	<u>352</u>

The variance from 2010/11 budget to 2011/12 budget, a decrease of \$44 thousand results from the exclusion of the provision for additions in 2011/12.

Variance 2: No change from 2010/11 forecast to 2011/12 budget

A breakdown of the 2010/11 forecast of charges for amortization and finance charges from NB Power Transco is as follows:

	Amortization	Finance	Total
Energy Control Center building	26	186	212
Key Dispatch	75	10	85
Security System	6	5	11
Provision for additions	-	-	-
<u>2010/11 forecast</u>	<u>107</u>	<u>201</u>	<u>308</u>

The amount of amortization increases by item, using a financing method of amortization, and the amount of finance charges decreases by item, resulting from a decreasing unamortized balance, but the total payment requirement is unchanged from forecast 2010/11 to budget 2011/12.

1 **Note: Finalization of Lease with NB Power Transco**

2 Although the payments of amortization and finance charges are being made based on a
3 schedule of leased assets, a formal lease agreement has not been finalized between
4 the two parties at the time of this submission. Upon completion of the lease the new
5 agreement and any adjustments to the revenue requirement will be submitted by the
6 NBSO prior to the commencement of the hearing.

7
8 **Building O&M**

9 This category of costs includes operating and maintenance costs of the Energy Control
10 Center (“ECC”). Operating and maintenance costs include electricity, property tax,
11 building maintenance, cleaning and grounds maintenance. Also included in this
12 category are the rent, and operating and maintenance costs at the second office
13 location at West Hills.

14
15

(in thousands \$)	(1) 2008/09 Actual	(2) 2009/10 Actual	(3) 2010/11 Budget	(4) 2010/11 Forecast	(5) 2011/12 Budget	(6) Variance 1 (5)-(3)	(7) Variance 2 (5)-(4)
Building O&M	\$ 352	\$ 608	\$ 600	\$ 600	\$ 633	\$ 33	\$ 33

16
17
18

19
20 **Variance 1: \$33 thousand increase from 2010/11 budget to 2011/12 budget**

21 Addition of a security service at the office entrance at ECC is a new cost in 2011/12
22 amounting to \$35 thousand. This is the primary cause of the variance of \$33 thousand
23 from 2010/11 budget to 2011/12 budget.

24
25 NBSO proposes to retain the services of a security firm to provide Monday-to-Friday
26 daytime security to control access to the ECC, maintain security logs, coordinate day
27 time delivery of materials, escort contractors within the facility, etc. Retention of the
28 services will enhance the security profile of a provincially designated Level 1 critical
29 infrastructure facility, while at the same time freeing up NBSO staff for their core
30 functions.

1

	2010/11	2011/12	Variance
Energy Control Center building O&M	371	400	30
West Hills lease	99	100	1
West Hills building O&M	68	71	2
Computer equipment maintenance	62	62	-
Building O&M	600	633	33

2

3

4 **Variance 2: \$33 thousand increase from 2010/11 forecast to 2011/12 budget**

5 The planned new security service in 2011/12 at ECC is the primary cause of the
6 variance of \$33 thousand from 2010/11 forecast to 2011/12 budget.

7

8 **Amortization of Capital Costs**

9 This category of costs includes amortization of non-leased, NBSO owned, capitalized
10 assets. The NBSO purchased and capitalized furniture in fiscal 2009/10, the first year
11 of the lease of office space at the West Hills location. The NBSO also purchased and
12 capitalized improvements at the ECC, including new carpeting and new consoles in the
13 Control Room and has commenced a capital project to replace one of its operating
14 systems called Supervisory Control and Data Acquisition/Energy Management System
15 (“SCADA/EMS”) that will be in service in 2011/12.

16

17

18

19

20

(in thousands \$)							
	(1) 2008/09 Actual	(2) 2009/10 Actual	(3) 2010/11 Budget	(4) 2010/11 Forecast	(5) 2011/12 Budget	(6) Variance 1 (5)-(3)	(7) Variance 2 (5)-(4)
Amortization of capital costs	\$ -	\$ 8	\$ 80	\$ 49	\$ 180	\$ 100	\$ 131

21 The following table lists the capital expenditure items purchased and planned to be purchased
22 by the NBSO and the corresponding amortization amounts:

23

24

25

26

27

28

29

Capital Item to amortize	Capital Expenditure			In Service Date	Amortization			
	2009/10 Actual	2010/11 Forecast	2011/12 Budget		2009/10 Actual	2010/11 Budget	2010/11 Forecast	2011/12 Budget
West Hills furniture	143	-	-	Oct-10	8	14	14	14
ECC Improvements - carpet	53	-	-	Apr-10	-	10	5	5
ECC Improvements - control room	240	62	-	Jul-10	-	56	30	30
Computer system - SCADA/EMS	53	1,564	1,519	Nov-11	-	-	-	131
Computer system - MMS	-	-	227	Nov-12	-	-	-	-
					8	80	49	180

1 **Variance 1: \$100 thousand increase from 2010/11 budget to 2011/12 budget**

2 The increase of \$100 thousand from budget 2010/11 to budget 2011/12, is primarily the
3 result of the November 2011 start of the amortization of the SCADA/EMS computer
4 system multi-year capital expenditure, forecast to cost \$3,136 thousand and to be
5 amortized over a 10-year period. The SCADA amortization amount of five months of
6 \$131 thousand is partially offset by a difference between budget and forecast for the
7 ECC control room improvements of \$26 thousand.

8
9 **Variance 2: \$131 thousand increase from 2010/11 forecast to 2011/12 budget**

10 The commencement of amortization in November 2011 of the SCADA/EMS system is
11 the reason for the increase from 2010/11 forecast to 2011/12 budget of \$131 thousand.

12
13 **Service Agreement Costs**

14 This category of costs includes costs related to an agreement with NB Power for
15 Information Technology services, including network, internet and e-mail services as well
16 as Human Resource services including payroll and benefit administration.

17
18 (in thousands \$)

	(1) 2008/09 Actual	(2) 2009/10 Actual	(3) 2010/11 Budget	(4) 2010/11 Forecast	(5) 2011/12 Budget	(6) Variance 1 (5)-(3)	(7) Variance 2 (5)-(4)
Service agreement costs	\$ 399	\$ 410	\$ 409	\$ 256	\$ 256	\$ (153)	\$ -

19
20
21

22 The NBSO and NB Power Holding Corporation completed a service agreement in
23 2010/11 and a copy is included in the Evidence at Tab 5, Appendix C. This new
24 agreement reflects the fact that the Secondment Agreement has terminated and
25 replaces the Service Agreement which previously existed between NBSO and NB
26 Power Transco (filed with each of the previous revenue requirement applications).
27 Services being provided and budgeted costs are as follows:

- 28 • Information Technology services budgeted at \$196 thousand
 - 29 • Human Resources services budgeted at \$60 thousand
- 30

1 **Variance 1: \$153 thousand decrease from 2010/11 budget to 2011/12 budget**

2 The new service agreement has resulted in a cost reduction of \$153 thousand
 3 compared to the 2010/11 budget. Most of these savings (\$120 thousand) relate to the
 4 Human Resources portion of the new agreement. With the ending of the secondment of
 5 employees, NBSO no longer pays for their portion of NB Power corporate overhead
 6 charges for services such as employment, health and safety, etc.

7
 8 **Variance 2: No change from 2010/11 forecast to 2011/12 budget**

9 The new service agreement with NB Power was effective April 2010 and is not subject
 10 to automatic escalation so there is no change from the 2010/11 forecast to the 2011/12
 11 budget.

12
 13 **Computer Software**

14 This category of costs includes license and support payments to various operational
 15 computer application providers such as PI and ITRON, as well as hosted services for
 16 operating applications such as OATI and MV-90.

17

(in thousands \$)	(1) 2008/09 Actual	(2) 2009/10 Actual	(3) 2010/11 Budget	(4) 2010/11 Forecast	(5) 2011/12 Budget	(6) Variance 1 (5)-(3)	(7) Variance 2 (5)-(4)
Computer software	\$ 114	\$ 171	\$ 244	\$ 244	\$ 156	\$ (88)	\$ (88)

21
 22 The cost estimates for the items included in this category are as follows:

23

	2010/11	2011/12	Variance
License and maintenance support - operating software	103	70	(33)
Hosted services - operating software	37	42	5
2010/11 initiative - reliability & compliance	104	4	(100)
Market optimization and modelling software	-	40	40
Computer software	244	156	(88)

24
 25
 26
 27
 28 **Variance 1: \$88 thousand decrease from 2010/11 budget to 2011/12 budget**

29 Computer software is budgeted to decrease by \$88 thousand largely due to a non-
 30 recurring budgeted purchase of software in 2010/11 required to meet compliance

standards, resulting in a decrease of \$100 thousand after providing \$4 thousand in 2011/12 for reoccurring support payments.

A decrease of \$33 thousand in operating software license and support is primarily attributable to the termination of a cost sharing arrangement for MV90 software with NB Power whereby each party alternated payment. NB Power Transco is now fully responsible for costs associated with MV-90.

In 2011/12, the NBSO has budgeted to purchase software to model the electrical system to provide optimal electrical system planning. This \$40 thousand item partially offsets other decreases, resulting in the overall \$88 thousand decrease.

Variance 2: \$88 thousand decrease from 2010/11 forecast to 2011/12 budget

Variances from 2010/11 forecast to 2011/12 budget are the same as outlined above in Variance 1.

Data Communications

This category of costs includes the costs of various data services providing the NBSO with information on operating requirements including wind and other weather data and exchange with other system operating entities and electric system participants.

(in thousands \$)							
	(1) 2008/09 Actual	(2) 2009/10 Actual	(3) 2010/11 Budget	(4) 2010/11 Forecast	(5) 2011/12 Budget	(6) Variance 1 (5)-(3)	(7) Variance 2 (5)-(4)
Data communications	\$ 108	\$ 101	\$ 313	\$ 163	\$ 190	\$ (123)	\$ 27

The cost estimates for the items included in this category are as follows:

	2010/11 Budget	2010/11 Forecast	2011/12 Budget
Data services, NERCnet, Scotia weather, etc	98	98	92
2010/11 initiative - wind forecasting	115	15	-
Wind forecasting data service	100	50	98
Computer software	313	163	190

1 **Variance1: \$123 thousand decrease from 2010/11 budget**

2 The \$123 thousand decrease in data communications is primarily related to the 2010/11
3 initiative to procure a wind power production forecasting service. The 2010/11 budget
4 provided an allowance of \$215 thousand, including \$115 thousand to procure or build
5 the capability to provide the service and \$100 thousand for supply of the wind forecast
6 data for the year. The 2010/11 forecast reflects a lower cost in the year to procure the
7 service and a mid fiscal year start for the supply of the wind forecast data.

8
9 **Variance 2: \$27 thousand increase from 2010/11 forecast to 2011/12 budget**

10 The \$27 thousand increase from 2010/11 forecast to 2011/12 budget is primarily due to
11 the increase to a full year of wind forecast data service of \$98 thousand from a part-year
12 in 2010/11 of \$50 thousand, less the \$15 thousand external cost of creating the wind
13 forecasting service in 2010/11.

14
15 **Insurance**

16 This category of costs includes premiums for general liability and directors and officers'
17 liability insurance.

18 (in thousands \$)

	(1) 2008/09 Actual	(2) 2009/10 Actual	(3) 2010/11 Budget	(4) 2010/11 Forecast	(5) 2011/12 Budget	(6) Variance 1 (5)-(3)	(7) Variance 2 (5)-(4)
Insurance	\$ 132	\$ 144	\$ 145	\$ 145	\$ 145	\$ (0)	\$ (0)

22
23 **Variance 1: No change from 2010/11 budget to 2011/12 budget**

24
25 **Variance 2: No change from 2010/11 forecast to 2011/12 budget**

26
27 **Consulting Services**

28 This category of costs includes the cost of external professional services. These
29 services include annual recurring costs of external audit of the financial statements,
30 independent actuarial reviews supporting notes to the financial statements for
31 retirement and pension liabilities, internal audit related to mandatory operational

1 requirements as well as normal legal, market development and employee benefit
 2 related business. As well, non-recurring professional services may be included.

(in thousands \$)							
	(1) 2008/09 Actual	(2) 2009/10 Actual	(3) 2010/11 Budget	(4) 2010/11 Forecast	(5) 2011/12 Budget	(6) Variance 1 (5)-(3)	(7) Variance 2 (5)-(4)
Consulting	\$ 437	\$ 333	\$ 498	\$ 698	\$ 393	\$ (105)	\$ (305)

8 The following provides the description and cost of consulting items for 2010/11 and
 9 2011/12.

	2010/11 Budget	2010/11 Forecast	2011/12 Budget	
Financial services	153	153	153	Annual audits, external & internal
Market Development and Renewables	50	50	50	Ongoing market assessments
Tariff hearing preparation	40	40	40	Annual tariff hearing preparation
Information Technology/ Operations	75	75	30	Cyber vulnerability assessment
Legal services	25	25	25	Independent legal services
Human Resources	15	15	10	External assessments
Operations	5	5	5	Provision for external reviews
Procurement	-	-	5	RFP assistance
Recurring	363	363	318	
Market Opt. & Modelling reqmts.	75	75	-	New software RFP preparation
Organizational development	60	60	-	New business processes development
IT Governance	-	-	25	Readiness for independence
Compliance	-	100	50	Transmission compliance/ Operations
One facility study	-	100	-	Initial building scoping for business case
Consulting	498	698	393	

19 **Variance 1: \$105 thousand decrease from 2010/11 budget to 2011/12 budget**

20 The decrease from 2010/11 budget of \$105 thousand includes a decrease of \$45
 21 thousand in recurring professional services; specifically the provision for the Cyber
 22 Vulnerability Assessment has decreased from \$75 thousand to \$30 thousand.

24 Non-recurring items have decreased overall by \$60 thousand as the two items from
 25 2010/11, \$75 thousand for development of the requirements for a Market Optimization
 26 and Modeling System and \$60 thousand for development of business processes and
 27 organizational development are not repeating in 2011/12 but two new items totaling \$75
 28 thousand are budgeted.

30 To prepare the NBSO for independence in the Information Technology functions, \$25
 31 thousand is budgeted to provide advice and develop an outline of the structure, both
 32 organizational and infrastructure, and to provide a plan for migration from the NB Power

1 Information Technology services. NBSO staff will provide the existing shared
2 technology and services structure and the initial assessment of how the NBSO might be
3 structured. The external expertise will suggest a roadmap for migration and advice on
4 the IT structure, policies and governance requirements.

5
6 NBSO Operations will be audited by the North American Electric Reliability Corporation
7 (“NERC”) and the NBSO has provided \$50 thousand for an independent assessment of
8 NBSO operations in preparation for the formal audit to ensure all operating
9 requirements are being met.

10
11 **Variance 2: \$305 thousand decrease from 2010/11 forecast to 2011/12 budget**

12 The \$305 thousand decrease from 2010/11 forecast to 2011/12 budget is comprised of
13 items in variance 1 above of \$105 thousand and \$200 thousand related to 2 items in the
14 2010/11 forecast.

15
16 The two items in the 2010/11 forecast totaling \$200 thousand are as follows:

- 17 a. \$100 thousand to engage an independent audit service related to transmission
18 system vegetation concerns. Transmission system outages attributed to
19 vegetation have increased in 2010/11 and, given the NBSO’s obligations with
20 respect to compliance and reliability assurance, the NBSO has initiated an
21 independent assessment with recommendations.
- 22
23 b. \$100 thousand to obtain budget estimates and conceptual designs for Control
24 Center and building alternatives to allow the NBSO to prepare a business case
25 and obtain approval to address the issues related to the location of NBSO
26 Operations. The professional services engaged have expertise in design of
27 Control Centers for other System Operators in Canada and the United States.

1 **Travel**

2 This category of costs includes travel required due to membership in industry
 3 organizations and required participation in committees and task forces. This includes
 4 organizations such as AEWG, CAMPUT, CANWEA, IRC, NERC, NERCnet, NICE, and
 5 NPCC (please refer to descriptions below). Also included in this category is travel
 6 associated with projects/studies supported by regional governments such as the Atlantic
 7 Energy Gateway initiative, as well as travel related to training and conferences.

8
 9
 10
 11
 12

(in thousands \$)							
	(1) 2008/09 Actual	(2) 2009/10 Actual	(3) 2010/11 Budget	(4) 2010/11 Forecast	(5) 2011/12 Budget	(6) Variance 1 (5)-(3)	(7) Variance 2 (5)-(4)
Travel	\$ 265	\$ 218	\$ 339	\$ 339	\$ 357	\$ 18	\$ 18

AEWG	<p><u>Atlantic Electricity Working Group</u> AEWG advocates regional co-operation on electricity, oil and gas, renewables and other energy initiatives and collaborates on matters such as resource adequacy in Atlantic Canada, climate change, and economic development impacts of the electricity industry.</p>
CAMPUT	<p><u>Canadian Association of Members of Public Utility Tribunals</u> CAMPUT is a self-supporting, non-profit organization of federal, provincial, and territorial boards and commissions which are responsible for the regulation of the electric, water, gas, and pipeline utilities in Canada. Some CAMPUT members are also responsible for the regulation of matters such as automobile insurance. The Canadian Nuclear Safety Commission (CNSC), the Canadian Environmental Assessment Agency (CEAA), the Québec Bureau d'audiences publiques sur l'environnement (BAPE), the British Columbia Oil and Gas Commission (BCOGC), the Alberta Energy Resources Conservation Board (ERCB), the Canada-Nova Scotia Offshore Petroleum Board (CNSOPB), the Canada-Newfoundland and Labrador Offshore Petroleum Board (CNLOPB), Efficiency NB and the Comisión Reguladora de Energía (CRE) in Mexico are associate members of CAMPUT.</p> <p>The purpose of CAMPUT is to improve public utility regulation in Canada and the education and training of commissioners and staff of public utility tribunals.</p>

13
 14

<p>CANWEA</p>	<p><u>Canadian Wind Energy Association</u></p> <p>The Canadian Wind Energy Association (CanWea) is a non-profit trade association that promotes the appropriate development and application of all aspects of wind energy in Canada, including the creation of a suitable policy environment.</p> <p>CanWea represents the wind energy community; organizations and individuals who are directly involved in the development and application of wind energy technology, products and services.</p> <p>Members are Canada's wind energy leaders. They are wind energy owners, operators, manufacturers, project developers, consultants, service providers, and other organizations and individuals interested in supporting Canada's wind energy industry.</p>
<p>IRC</p>	<p><u>ISO-RTO Council (IRC)</u></p> <p>The IRC is an industry organization that includes 10 Independent System Operators and Regional Transmission Organizations that serve two-thirds of electricity consumers in the United States and just over 50% of Canada's population. The members are:</p> <ul style="list-style-type: none"> • Alberta Electric System Operator (AESO) • California Independent System Operator (CAISO) • Electric Reliability Council of Texas (ERCOT) • Independent Electricity System Operator, Ontario (IESO) • ISO New England (ISO-NE) • Midwest Independent Transmission System Operator (Midwest ISO) • New Brunswick System Operator • New York Independent System Operator (NYISO) • PJM Interconnection (PJM) • Southwest Power Pool, Inc. (SPP) <p>The IRC works collaboratively to develop effective processes, tools, and standard methods for improving competitive electricity markets across North America. The goal of IRC is to balance reliability considerations with market practices resulting in efficient, robust markets that provide competitive and reliable service to electricity users.</p>

NERC	<p><u>North American Electric Reliability Corporation</u> NERC ensures the reliability of the bulk power system in North America. They develop and enforce reliability standards; assess reliability annually via 10-year and seasonal forecasts; monitor the bulk power system; evaluate users, owners, and operators for preparedness; and educate, train, and certify industry personnel. NERC is a self-regulatory organization subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada.</p>
NERCnet	<p><u>North American Electric Reliability Corporation (NERCnet)</u> NERCnet is a communications network that ties together all participants in the electric power industry to enable business to be conducted “reliably and securely”. Reliability and security refers to the telecommunications requisite to meet all commercial and operating needs. NERCnet is impervious to outside “attack”, but open to all interested users. This network is the communications system which provides the following services:</p> <ul style="list-style-type: none"> • Information transfer among Security Coordinators (real or near real-time data) • All transmission scheduling information • Outage planning information • The Transaction Information System (known as the “Tag” System) • The Transmission Reservation and Scheduling System • Open Access Same-Time Information System (OASIS)
NICE	<p><u>Northeast International Committee on Energy</u> NICE was established by the Conference of New England Governors and Eastern Canadian Premiers in 1978, to monitor and act upon common energy issues in the New England-Eastern Canadian region. Since its establishment, NICE has hosted more than a dozen roundtables and conferences on energy and published numerous energy reports. In recent years, NICE has been paying particular attention to significant developments in the areas of energy restructuring, natural Gas developments, climate change and resource and infrastructure development.</p>

1

NPCC	<p><u>Northeast Power Coordinating Council, Inc.</u> NPCC is the cross-border regional entity and criteria services corporation for Northeastern North America. NPCC promotes and enhances the reliable and efficient bulk power system in Northeastern North America. The geographic area covered by NPCC includes New York State, the six New England States, and the Ontario, Québec, and the Maritime Provinces.</p>
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2

3 Below is a table that provides insight into the development of the budget for travel, as
4 well as highlights of the types of costs and events included in this category.

5

	2010/11 Budget	2011/12 Budget	Includes:		
			NPCC	NERC	IRC,etc
6 President and CEO	37	37	5	2	30
7 Legal and Regulatory	18	18	-	-	5
8 Executive VP	33	33	2	-	10
9 Facilities Manager	-	1	-	-	-
10 Power Sys. Planning & Compliance	80	80	66	-	-
11 Market Dev. & Renewables	30	30	-	-	11
12 Finance	5	5	-	-	-
13 Human Resources	23	27	12	-	-
14 VP Operations	8	8	2	-	-
15 Information Technology	33	21	10	10	-
16 Market Ops. & Settlement	16	17	-	-	-
17 Power System Operations	56	80	48	8	8
18 Travel costs	339	357	145	20	64

14

15 **Variance 1: \$18 thousand increase from 2010/11 budget to 2011/12 budget**

16 The increase of \$18 thousand from 2010/11 budget is primarily due to an increase in
17 Power System Operations travel budget by \$23 thousand which includes NPCC
18 requirements, NERC and operating seminars.

19

20 **Variance 2: \$18 thousand increase from 2010/11 forecast to 2011/12 budget**

21 The reasons for the \$18 thousand increase from 2010/11 forecast to 2011/12 budget
22 are the same as in variance 1 above.

23

24

25

26

1 **Training**

2 This category of costs includes course fees related to meeting job requirements,
 3 professional development or continuing education requirements in power system
 4 operations, engineering, administrative or management roles.

5 (in thousands \$)

	(1) 2008/09 Actual	(2) 2009/10 Actual	(3) 2010/11 Budget	(4) 2010/11 Forecast	(5) 2011/12 Budget	(6) Variance 1 (5)-(3)	(7) Variance 2 (5)-(4)
6 Training	\$ 31	\$ 68	\$ 90	\$ 90	\$ 191	\$ 101	\$ 101

7
8

9
 10 Below is a table that provides insight into the development of the budget for training, as
 11 well as reasons for increase in costs in this category.

12

	2010/11 Budget	2011/12 Budget	
President and CEO	10	10	
Legal and Regulatory	5	5	
Executive VP	-	-	
Facilities Manager	-	1	
Power Sys. Planning & Compliance	20	70	Compliance audit training +\$50k
Market Dev. & Renewables	5	5	
Finance	5	5	
Human Resources	10	15	
VP Operations	-	2	
Information Technology	25	10	
Market Ops. & Settlement	-	6	
Power System Operations	10	62	new engineers and PSOs training
13 Training costs	90	191	- - -

14

15 **Variance 1: \$101 thousand increase from 2010/11 budget to 2011/12 budget**

16 The increase of \$101 thousand in training costs from the 2010/11 budget to the 2011/12
 17 budget is due to a \$50 thousand increase in compliance audit training and \$52
 18 thousand for training for new engineering staff and Power System Operator staff in the
 19 Operations department.

20
 21 **Variance 2: \$101 thousand increase from 2010/11 forecast to 2011/12 budget**

22 The increase of \$101 thousand from the 2010/11 forecast to the 2011/12 budget is the
 23 same as listed in variance 1 above.

1 **Administration**

2 This category of costs includes corporate business expenses such as corporate
3 memberships, dues, an annual energy conference, production of the annual report, and
4 costs associated with other corporate and business reports and events.

5

6

(in thousands \$)	(1) 2008/09 Actual	(2) 2009/10 Actual	(3) 2010/11 Budget	(4) 2010/11 Forecast	(5) 2011/12 Budget	(6) Variance 1 (5)-(3)	(7) Variance 2 (5)-(4)
Administration	\$ 104	\$ 170	\$ 267	\$ 192	\$ 251	\$ (16)	\$ 59

7

8

9

10

11 **Variance 1: \$16 thousand decrease from 2010/11 budget to 2011/12 budget**

12 The \$16 thousand decrease from 2010/11 budget to 2011/12 budget is largely due to a
13 decrease in the budget for recruitment costs, decreasing by \$20 thousand from \$40
14 thousand to reflect fewer planned position vacancies to fill in 2011/12.

15

16 **Variance 2: \$59 thousand increase from 2010/11 forecast to 2011/12 budget**

17 The \$59 thousand increase from forecast 2010/11 to budget 2011/12 is due to a
18 decreased forecast in 2010/11 compared to budget as the annual spring energy
19 conference was cancelled for 2010 but will be re-instated for spring 2011, costing \$75
20 thousand. This together with the recruitment variance of \$16 thousand noted above in
21 Variance 1, accounts for the \$59 thousand increase.

22

23 **Finance Charges**

24 This category of costs include borrowing costs for loans to finance capital additions
25 once they are in service, foreign exchange costs, offset by any interest earned on bank
26 balances or short term investments. Borrowing costs during capital projects, until
27 placed in service, are capitalized as interest during construction.

28

(in thousands \$)	(1) 2008/09 Actual	(2) 2009/10 Actual	(3) 2010/11 Budget	(4) 2010/11 Forecast	(5) 2011/12 Budget	(6) Variance 1 (5)-(3)	(7) Variance 2 (5)-(4)
Finance charges	\$ (108)	\$ (12)	\$ -	\$ -	\$ 45	\$ 45	\$ 45

29

30

31

1 **Variance 1: \$45 thousand increase from 2010/11 budget to 2011/12 budget**

2 The \$45 thousand cost in 2011/12 reflects the in-service of the SCADA/EMS in
3 November 2011 and the associated borrowing costs. Borrowing costs up to the in-
4 service date are capital costs and not expensed.

5
6 **Variance 2: \$45 thousand increase from 2010/11 forecast to 2011/12 budget**

7 The variance from forecast 2010/11 to budget 2011/12 of \$45 thousand is the same as
8 above in Variance 1.

9
10 **NBEUB Hearing Costs**

11 This category of costs includes all NBSO direct costs associated with an EUB hearing
12 including facility costs, legal fees, translation, printing and notice publications.

13

(in thousands \$)	(1) 2008/09 Actual	(2) 2009/10 Actual	(3) 2010/11 Budget	(4) 2010/11 Forecast	(5) 2011/12 Budget	(6) Variance 1 (5)-(3)	(7) Variance 2 (5)-(4)
EUB hearing	\$ 190	\$ 21	\$ 212	\$ 212	\$ 115	\$ (97)	\$ (97)

14
15 **Variance 1: \$97 thousand decrease from 2010/11 budget to 2011/12 budget**

16 See Variance 2 explanation below.

17
18 **Variance 2: \$97 thousand decrease from 2010/11 forecast to 2011/12 budget**

19 The 2010/11 budget provided for both a Revenue Requirement Hearing and a major
20 Tariff Hearing. The \$97 thousand reduction from both the 2010/11 budget and forecast
21 reflects the fact that NBSO expects each Revenue Requirement Hearing to become
22 more efficient/less expensive as all parties become more familiar with the process.
23 Additionally, while provision has been made for a Tariff Hearing in 2011/12, it would not
24 cover as broad a range of topics as the one to be completed in the current year.

1 **Miscellaneous Revenue - Schedule Balancing Service**

2 This category of miscellaneous revenue includes revenue for an automatic updating of
 3 hourly energy schedules service on behalf of Market Participants using NBSO computer
 4 software.

5
 6 The 2011/12 budget for schedule balancing service revenue is determined from the
 7 amount of 2010/11 billings for this service, pursuant to a contract between NBSO and
 8 NB Power Generation Corporation which has existed since 2005.

9
 10 (in thousands \$)

	(1) 2008/09 Actual	(2) 2009/10 Actual	(3) 2010/11 Budget	(4) 2010/11 Forecast	(5) 2011/12 Budget	(6) Variance 1 (5)-(3)	(7) Variance 2 (5)-(4)
Schedule balancing service	\$ (267)	\$ (267)	\$ (267)	\$ (267)	\$ (267)	\$ -	\$ -

11
 12
 13
 14 **Variance 1: No change from 2010/11 budget to 2011/12 budget**

15
 16 **Variance 2: No change from 2010/11 forecast to 2011/12 budget**

17
 18 **Miscellaneous Revenue – Reliability Coordinator Service**

19 This category of miscellaneous revenue includes revenue earned by the NBSO as a
 20 result of provision of the “Reliability Coordinator” role for the Maritimes Control Area.
 21 Revenues include services to Nova Scotia, Prince Edward Island and Northern Maine
 22 and are based on peak load information for the prior year.

23
 24 The 2011/12 budget for reliability coordinator service revenue is determined from the
 25 amount of 2010/11 billings for this service pursuant to existing agreements.

26
 27 (in thousands \$)

	(1) 2008/09 Actual	(2) 2009/10 Actual	(3) 2010/11 Budget	(4) 2010/11 Forecast	(5) 2011/12 Budget	(6) Variance 1 (5)-(3)	(7) Variance 2 (5)-(4)
Reliability coordinator service	\$ (97)	\$ (102)	\$ (99)	\$ (99)	\$ (99)	\$ -	\$ -

1 **Variance 1: No change from 2010/11 budget to 2011/12 budget**

2
3 **Variance 2: No change from 2010/11 forecast to 2011/12 budget**

4
5 **Miscellaneous Revenue - Oasis and E-tag Service**

6 This category of miscellaneous revenue includes revenue earned by the NBSO as a
7 result of providing host services for the Open Access Same-Time Information System
8 (“OASIS”) and Electronic Tagging (“E-tagging”) on the NBSO network to entities in the
9 Control Area.

10
11 The 2011/12 budget for oasis and e-tag service revenue is determined from the amount
12 of 2010/11 billings for this service, pursuant to existing agreements.

13

(in thousands \$)	(1) 2008/09 Actual	(2) 2009/10 Actual	(3) 2010/11 Budget	(4) 2010/11 Forecast	(5) 2011/12 Budget	(6) Variance 1 (5)-(3)	(7) Variance 2 (5)-(4)
Oasis and etag service	\$ (82)	\$ (81)	\$ (80)	\$ (80)	\$ (80)	\$ -	\$ -

14
15
16
17

18 **Variance 1: No change from 2010/11 budget to 2011/12 budget**

19
20 **Variance 2: No change from 2010/11 forecast to 2011/12 budget**

21
22 **Miscellaneous Revenue - Transmission Operator Services**

23 This new category of miscellaneous revenue includes revenue from NB Power Transco
24 resulting from the NBSO performing transmission role functions on behalf of NB Power
25 Transco. The NBSO's undertaking of these functions is a direct result of the termination
26 of the Secondment Agreement.

27
28 The 2011/12 budget for this new NBSO revenue item was determined from draft but
29 agreed upon terms for a new agreement to be formalized in 2010/11 that compensates
30 the NBSO for transmission operator service performed by the NBSO on behalf of NB
31 Power Transco.

(in thousands \$)							
	(1) 2008/09 Actual	(2) 2009/10 Actual	(3) 2010/11 Budget	(4) 2010/11 Forecast	(5) 2011/12 Budget	(6) Variance 1 (5)-(3)	(7) Variance 2 (5)-(4)
Transmission operator services	\$ -	\$ -	\$ -	\$ (375)	\$ (375)	\$ (375)	\$ -

Variance 1: \$375 thousand revenue increase from 2010/11 budget to 2011/12 budget

The \$375 thousand revenue increase is caused by the introduction of this new agreement effective April 1 2010.

Variance 2: No change from 2010/11 forecast to 2011/12 budget

The forecast for 2010/11 reflects the effective date of April 1, 2010 for this new agreement and the 2011/12 revenue for this service is unchanged from 2010/11 forecast.

Miscellaneous Revenue - Connection Studies

This category of miscellaneous revenue includes revenue earned to provide technical studies related to requests for new transmission service. Such service is provided by the NBSO in accordance with the Tariff. The portion of revenue earned from NBSO staff provided service is included in the category. The remaining portion of revenue earned from connection studies, resulting from externally provided services are accounted for as “flow through revenues and expenses”.

The 2011/12 budget for connection studies service revenue resulting from NBSO staff provided service is estimated based on prior year experience.

(in thousands \$)							
	(1) 2008/09 Actual	(2) 2009/10 Actual	(3) 2010/11 Budget	(4) 2010/11 Forecast	(5) 2011/12 Budget	(6) Variance 1 (5)-(3)	(7) Variance 2 (5)-(4)
Connection studies	\$ (243)	\$ (63)	\$ (100)	\$ (100)	\$ (100)	\$ -	\$ -

1 **Variance 1: No change from 2010/11 budget to 2011/12 budget**

2
3 **Variance 2: No change from 2010/11 forecast to 2011/12 budget**

4
5 **Miscellaneous Revenue - Conferences and Workshops**

6 This category of miscellaneous revenue is the result of collection by the NBSO of
7 registration fees for workshops and conferences to educate and inform industry
8 stakeholders.

9
10 The 2011/12 budget for conference and workshop service revenue is estimated based
11 on prior year experience.

12

(in thousands \$)	(1) 2008/09 Actual	(2) 2009/10 Actual	(3) 2010/11 Budget	(4) 2010/11 Forecast	(5) 2011/12 Budget	(6) Variance 1 (5)-(3)	(7) Variance 2 (5)-(4)
Conferences and workshops	\$ (32)	\$ (7)	\$ (35)	\$ (35)	\$ (35)	\$ -	\$ -

13
14
15
16

17 **Variance 1: No change from 2010/11 budget to 2011/12 budget**

18
19 **Variance 2: No change from 2010/11 forecast to 2011/12 budget**

20
21 **CONCLUSION**

22 As noted in the Executive Summary, the proposed revenue requirement for the 2011/12
23 fiscal year amounts to 1.6% over the current year. The NBSO has achieved savings in
24 many areas, most notably with respect to service contracts and consulting, and has
25 increased miscellaneous revenues substantially. The most notable increase in costs
26 relates to the need to add five positions to Operations to meet current and succession
27 planning needs. Accordingly, the NBSO submits that the evidence provided in support
28 of its application fully justifies all elements of its 2011/12 revenue requirement and
29 respectfully requests its approval.

1 **SCHEDULE 2**

2 **(Reactive Supply and Voltage Control)**

3

4 NBSO seeks approval of a Schedule 2 revenue requirement for the fiscal year 2011/12
5 of \$5.634 million, subject to an adjustment to reflect the actual 2010 NB CPI which is to
6 be published late in January 2012.

7

8 **Background**

9 Schedule 2 is a mandatory ancillary service provided by generators or loads through the
10 System Operator in order to maintain transmission voltages on the transmission
11 facilities in New Brunswick within acceptable limits. The System Operator, through
12 contracts with suppliers, directs their operation to produce (or absorb) reactive power or
13 to operate at a voltage set-point.

14

15 In its Decision of November 26, 2008 the Energy and Utilities Board (the "Board")
16 ordered the NBSO to annually apply for approval of its revenue requirement for
17 Schedule 1 and 2 services of the Tariff.

18

19 The applicable ancillary service contracts are in the form of Appendix 5A of the New
20 Brunswick Electricity Market Rules. All contracts for the NBSO procurement of
21 Schedule 2 services were filed with the Board in previous proceedings. The most
22 recent such filing was IN THE MATTER OF a Hearing to Review the New Brunswick
23 System Operator's 2010/2011 Revenue Requirement (Appendices C, D and E of the
24 NBSO responses to Interrogatories).

25

26 In its Decision of July 16, 2010 the Board approved the NBSO's proposed \$5.709
27 Million Schedule 2 Revenue Requirement for 2010/11. The Board indicated in that
28 Decision that it had reviewed the Ancillary Services Contracts and the support for

1 revenue requirement provided in NBSO's response to Interrogatory NBSO (NBEUB) IR-
2 39, and found the rates to be reasonable (page 11).

3
4 **Detailed Discussion**

5 NBSO is seeking approval of a Schedule 2 revenue requirement for the fiscal year
6 2010/11 of \$5.634 million, based on estimated expenses arising from the administration
7 of the contracts that NBSO has for the supply of Ancillary Services. There has been no
8 change to those contracts since they were filed with the EUB IN THE MATTER OF a
9 Hearing to Review the New Brunswick System Operator's 2010/2011 Revenue
10 Requirement. Escalation and retirement of assets in accordance with the contract result
11 in a net reduction of the proposed revenue requirement from that which was approved
12 by the Board for the current fiscal year.

13
14 The unit prices to be paid in 2011/12 will be escalated from the current prices in
15 accordance with the escalation clauses in the relevant contracts. The estimated
16 relevant escalation is 2.1% as noted in Table 2-1. NBSO will provide the actual
17 escalation figure and an adjusted Schedule 2 revenue requirement early in 2011 after
18 Statistics Canada releases the required data.

19
20 Courtenay Bay #4 and Grand Lake #8 generation facilities have been retired as of
21 February 1, 2009 and June 1, 2010 respectively. NBSO will not be making payments for
22 Schedule 2 services to the applicable Market Participant with respect to those two
23 facilities in 2011/12. The calculation of the proposed revenue requirement for 2011/12
24 takes the termination of payments for services from those two facilities into account.
25 The requested revenue requirement is therefore less than what it would otherwise have
26 been.

27
28 The calculation of the requested revenue requirement is as shown in Table 2-2 based
29 on contracts and estimated escalation as noted above.

1 Although none is anticipated, any surplus (or deficit) at the end of the fiscal year will be
 2 credited to (or collected from) Transmission Customers in accordance with the Tariff's
 3 Schedule 2 which states that, *"The actual amount of a surplus or deficit for any given*
 4 *fiscal year, as approved by the Board, is to be rebated or billed to Transmission*
 5 *Customers in proportion to their respective Schedule 2 charges for that fiscal year."*
 6

Table 2-1					
History of Schedule 2 Expenses					
Fiscal Year	Amount (in thousands \$)	Percentage Increase (%)	Compounded Increase (%)	Prior Year NB CPI (%)	Compounded NB CPI (%)
2005/06	\$5,241	n/a	n/a	1.5%	1.50%
2006/07	\$5,327	1.6%	1.64%	2.4%	3.94%
2007/08	\$5,534	3.9%	5.59%	1.7%	5.70%
2008/09	\$5,645	2.0%	7.71%	1.9%	7.71%
2009/10	\$5,692	0.8%	8.61%	1.7%	9.54%
2010/11	\$5,709	0.3%	8.93%	0.3%	9.87%
2011/12	\$5,634	-1.3%	7.50%	2.1%	12.18%

7

1 **Table 2-2 Supporting Documentation for 2011/12 Budget**

2

Generator	MVARs	2008/09		2009/10		2010/11		2011/12	
		\$/MVAR-m	(\$000)	\$/MVAR-m	(\$000)	\$/MVAR-m	(\$000)	\$/MVAR-m	(\$000)
Coleson Cove #1	160	\$ 223	\$ 428	\$ 227	\$ 435	\$ 227	\$ 437	\$ 232	\$ 446
Coleson Cove #2	160	\$ 223	\$ 428	\$ 227	\$ 435	\$ 227	\$ 437	\$ 232	\$ 446
Coleson Cove #3	160	\$ 223	\$ 428	\$ 227	\$ 435	\$ 227	\$ 437	\$ 232	\$ 446
Mactaquac #1	52	\$ 223	\$ 139	\$ 227	\$ 141	\$ 227	\$ 142	\$ 232	\$ 145
Mactaquac #2	52	\$ 223	\$ 139	\$ 227	\$ 141	\$ 227	\$ 142	\$ 232	\$ 145
Mactaquac #3	52	\$ 223	\$ 139	\$ 227	\$ 141	\$ 227	\$ 142	\$ 232	\$ 145
Mactaquac #4	52	\$ 223	\$ 139	\$ 227	\$ 141	\$ 227	\$ 142	\$ 232	\$ 145
Mactaquac #5	54	\$ 223	\$ 144	\$ 227	\$ 147	\$ 227	\$ 147	\$ 232	\$ 150
Mactaquac #6	54	\$ 223	\$ 144	\$ 227	\$ 147	\$ 227	\$ 147	\$ 232	\$ 150
Beechwood #1	18	\$ 223	\$ 48	\$ 227	\$ 49	\$ 227	\$ 49	\$ 232	\$ 50
Beechwood #2	18	\$ 223	\$ 48	\$ 227	\$ 49	\$ 227	\$ 49	\$ 232	\$ 50
Beechwood #3	20	\$ 223	\$ 54	\$ 227	\$ 54	\$ 227	\$ 55	\$ 232	\$ 56
Tobique #1	7.5	\$ 223	\$ 20	\$ 227	\$ 20	\$ 227	\$ 20	\$ 232	\$ 21
Tobique #2	7.5	\$ 223	\$ 20	\$ 227	\$ 20	\$ 227	\$ 20	\$ 232	\$ 21
Grand Falls #1	7.7	\$ 223	\$ 21	\$ 227	\$ 21	\$ 227	\$ 21	\$ 232	\$ 21
Grand Falls #2	7.7	\$ 223	\$ 21	\$ 227	\$ 21	\$ 227	\$ 21	\$ 232	\$ 21
Grand Falls #3	7.7	\$ 223	\$ 21	\$ 227	\$ 21	\$ 227	\$ 21	\$ 232	\$ 21
Grand Falls #4	7.7	\$ 223	\$ 21	\$ 227	\$ 21	\$ 227	\$ 21	\$ 232	\$ 21
Sisson #1	4.6	\$ 223	\$ 12	\$ 227	\$ 13	\$ 227	\$ 13	\$ 232	\$ 13
Ste-Rose #1	82	\$ 111	\$ 110	\$ 113	\$ 112	\$ 114	\$ 112	\$ 116	\$ 114
Millbank #1	82	\$ 111	\$ 110	\$ 113	\$ 112	\$ 114	\$ 112	\$ 116	\$ 114
Millbank #2	82	\$ 111	\$ 110	\$ 113	\$ 112	\$ 114	\$ 112	\$ 116	\$ 114
Millbank #3	82	\$ 111	\$ 110	\$ 113	\$ 112	\$ 114	\$ 112	\$ 116	\$ 114
Millbank #4	82	\$ 111	\$ 110	\$ 113	\$ 112	\$ 114	\$ 112	\$ 116	\$ 114
Belledune #2	315	\$ 223	\$ 843	\$ 227	\$ 857	\$ 227	\$ 860	\$ 232	\$ 878
Courtenay Bay #4	66	\$ 111	\$ 88	\$ 113	\$ 90	\$ 114	\$ 90	n/a	n/a
Dalhousie #1	66	\$ 223	\$ 177	\$ 227	\$ 180	\$ 227	\$ 180	\$ 232	\$ 184
Dalhousie #2	100	\$ 223	\$ 268	\$ 227	\$ 272	\$ 227	\$ 273	\$ 232	\$ 279
Grand Lake #8	37	\$ 331	\$ 147	\$ 227	\$ 101	\$ 227	\$ 101	n/a	n/a
Grand Manan #3	37	\$ 111	\$ 49	\$ 113	\$ 50	\$ 114	\$ 50	\$ 116	\$ 52
Point Lepreau	415	\$ 223	\$ 1,110	\$ 227	\$ 1,129	\$ 227	\$ 1,133	\$ 232	\$ 1,156
Total	2348		\$ 5,645		\$ 5,692		\$ 5,709		\$ 5,634

3

- 1 The quantity of Schedule 2 services to be purchased by NBSO in 2011/12 is dictated by
 2 the contractual obligations as noted above. The quantity purchased is based on
 3 capabilities and the calculation is as follows:

Generator	Peakers (MVARs)	Others (MVARs)
Coleson Cove #1	n/a	160
Coleson Cove #2	n/a	160
Coleson Cove #3	n/a	160
Mactaquac #1	n/a	52
Mactaquac #2	n/a	52
Mactaquac #3	n/a	52
Mactaquac #4	n/a	52
Mactaquac #5	n/a	54
Mactaquac #6	n/a	54
Beechwood #1	n/a	18
Beechwood #2	n/a	18
Beechwood #3	n/a	20
Tobique #1	n/a	7.5
Tobique #2	n/a	7.5
Grand Falls #1	n/a	7.7
Grand Falls #2	n/a	7.7
Grand Falls #3	n/a	7.7
Grand Falls #4	n/a	7.7
Sisson #1	n/a	4.6
Ste-Rose #1	82	n/a
Millbank #1	82	n/a
Millbank #2	82	n/a
Millbank #3	82	n/a
Millbank #4	82	n/a
Belledune #2	n/a	315
Courtenay Bay #4	n/a	n/a
Dalhousie #1	n/a	66
Dalhousie #2	n/a	100
Grand Lake #8	n/a	n/a
Grand Manan #3	37	n/a
Point Lepreau	n/a	415
Totals	447	1798.4



Consumer Price Index, by province (monthly)
(New Brunswick)

	September 2009	August 2010	September 2010	August 2010 to September 2010	September 2009 to September 2010
	2002=100			% change	
N.B.					
All items	114.2	116.0	116.0	0.0	1.6
Food	124.3	127.9	127.9	0.0	2.9
Shelter	120.8	122.8	122.6	-0.2	1.5
Household operations, furnishings and equipment	107.4	110.2	110.6	0.4	3.0
Clothing and footwear	97.4	94.4	94.5	0.1	-3.0
Transportation	108.0	110.3	109.9	-0.4	1.8
Health and personal care	110.8	111.4	111.4	0.0	0.5
Recreation, education and reading	106.8	107.6	107.7	0.1	0.8
Alcoholic beverages and tobacco products	133.3	134.1	134.1	0.0	0.6
Special aggregates					
All items excluding food	112.1	113.6	113.5	-0.1	1.2
All items excluding energy	111.5	113.3	113.5	0.2	1.8
Energy	135.0	137.8	135.8	-1.5	0.6

Source: Statistics Canada, CANSIM, table (for fee) [326-0020](#) and Catalogue nos. [62-001-X](#) and [62-010-X](#).

Last modified: 2010-10-22.

1 **CONCLUSION**

2 NBSO seeks approval of a Schedule 2 revenue requirement of \$5.634 million for the
3 fiscal year 2011/12 subject to an adjustment to reflect the actual New Brunswick CPI for
4 2010 which is scheduled for publication in late January 2011.

1 **SCHEDULE 3(c)**

2 **(Automatic Generation Control (“AGC”) and Load Following for Non-Dispatchable**
3 **Wind Power Generators)**

4
5 The additional months of history that NBSO now has with the revenues and expenses
6 associated with Schedule 3(c) warrant a deviation from the original NBSO proposal of
7 2008. In that proposal, which was not fully adopted by the Energy and Utilities Board
8 (the “Board”), the plan was to increase the Schedule 3(c) rate from \$0.25/MWh to \$0.50
9 as of April 2010, \$0.75 as of April 2011, and \$1.00 as of April 2012. Not to increase the
10 rate on April 1, 2011 as proposed in 2008, does increase the probability of a deficit with
11 respect to Schedule 3(c). Nonetheless, given the current cost estimates, this risk is
12 offset by the possibility of a surplus. Accordingly, NBSO seeks Board approval to
13 maintain the current rate for Schedule 3(c) at \$0.50/MWh beyond March 31, 2011.

14
15 **Background**

16 In May 2008, NBSO filed an application with the Board for changes to the Open Access
17 Transmission Tariff (the “Tariff”). One of the requested changes dealt with a proposal to
18 add a new section to the Tariff, Schedule 3(c), Automatic Generation Control and Load
19 following for Non-Dispatchable Wind Power Generators (“AGC”). The new service was
20 intended to address potential cost shifting; coupled with the fact that NBSO did not have
21 access to unlimited balancing resources. In NBSO’s application, it was noted that
22 absent these charges, cost shifting could arise from wind power integration costs
23 incurred by NB Power Generation and passed on to New Brunswick ratepayers through
24 standard service rates, due to the integration of wind power production that is not
25 supplying load in New Brunswick. The intent was to establish a rate with which the
26 incremental cost of AGC and Load Following could be recovered from the Market
27 Participants that are responsible for the generation.

28
29 NBSO proposed a phased-in approach to rates over a four year period to avoid rate
30 shock for existing wind power facilities. As well, it would better align with the
31 progressive increase in costs per MWh as the penetration of wind power production

1 increased.

2

3 The following table (Table 10) is an **excerpt** taken from the Evidence filed by NBSO on
4 May 1, 2008 (IN THE MATTER of an Application Dated May 1, 2008 by New Brunswick
5 System Operator for Changes to the Open Access Transmission Tariff, Volume 1 of 1,
6 Page 17, Board Reference: 2008-007).

7

Table 10 Proposed Rates		
	Schedule 3(c) Start Date	Rate (\$/MWh of Wind Energy)
1	April 1, 2009	0.25
2	April 1, 2010	0.50
3	April 1, 2011	0.75
4	April 1, 2012	1.00

8

9 NBSO would track its cost of providing these services to wind power producers and
10 require self-supply by new wind facilities once the costs reached the 4-year rate of
11 \$1.00 MWh. This approach would provide greater certainty to purchasers of these
12 services. The proposed rate was \$1.00 per MWh of wind power production based only
13 on the facilities that were purchasing and not those that were self-supplying. The \$1.00
14 rate was based on cost estimates arising from the Maritimes Area Wind Integration
15 Study; and the projected rate was also based nominally on 400 MW of wind power
16 production capacity in the Balancing Area.

17

18 The Board decided on this matter in its Decision of November 26, 2008 (pages 17 and
19 18) as follows:

20

21 *“The Board approves the initial rate of \$0.25 per MWh of Wind Energy, effective*
22 *April 1, 2009. The Board approves, in principle, the escalation of the rate as*

1 *proposed by the SO. The SO is ordered to file with the Board, beginning in 2010, as*
2 *part of the review of the annual revenue requirement, information on the actual*
3 *revenues, the actual expenses and the expected expenses for the 3(c) service.*

4
5 *The OATT wording for Schedule 3(c) services, as found in Attachment "A", is*
6 *approved.*

7
8 *The SO is ordered to provide information, as part of the review for the 2010/2011*
9 *fiscal year, on whether or not there should be a limit on the amount of wind power*
10 *energy that will be eligible to receive 3(c) service".*

11
12 On March 15th, 2010 the NBSO filed evidence in support of the Revenue Requirements
13 for Schedules 1 and 2 of the Tariff. The evidence included a proposal to increase the
14 Schedule 3(c) rate as of April 1, 2010 to \$0.50/MWh from the \$0.25/MWh rate that went
15 into effect on April 1, 2009. In its Evidence NBSO restated it's rationale for capping the
16 quantity of service available from the NBSO at the Tariff rate.

17
18 The Board accepted the proposed rate of \$0.50/MWh for 2010/11 in its Decision of July
19 16, 2010 (page 13). With respect to the proposed cap, in that same Decision the Board
20 indicated that NBSO had not provided information or applied for a specific limit on the
21 supply of this service. The Board ordered NBSO to provide detailed information on
22 whether or not there should be a specific limit on the supply of Schedule 3(c) service at
23 the time of its next application.

24
25 **Discussion of Historical Costs**

26 NBSO has tracked the costs of incremental Regulation and Load Following required
27 due to the variability of wind power production at wind farms that are not electing to
28 self-supply these services. These costs are shown in the following Table 3-1, Schedule
29 3 (c) Revenues and Expenses:

1

Table 3-1				
Schedule 3(c) Revenues and Expenses				
		09/10 Actuals	10/11 Budget	11/12 Budget
a	Revenue (\$000)	105,405	111,000	95,700
b	Expenses (\$000)	178,215	79,584	65,100
c	Energy Produced (MWh)	390,356	221,000	191,716
d=b/c	Cost (\$/MWh)	0.42	0.36	0.34
e=a/b	Revenue/Cost Ratio	0.59	1.40	1.47
f	Regulation (MW)	1.6	1.8	2.8
g	Load Following (MW)	2.0	2.3	4.6

2

3 Forecasting revenues and expenses for Schedule 3(c) services is complicated by the
4 fact that each wind farm can elect to purchase the service from NBSO, self-supply, or
5 purchase from a third party. Forecasting the unit cost (i.e., per MWh of energy
6 produced by wind farms in the Balancing Area that are purchasing the service from
7 NBSO) is less affected by the elections of the wind farms than are the absolute
8 Schedule 3(c) revenues and expenses.

9

10 The following report indicates the calculation of the actual revenues and expenses for
11 Schedule 3(c) in fiscal year 2009/10. The average cost for the year was \$0.42/MWh of
12 wind power production corresponding to Schedule 3(c) purchases.¹

13

14

¹ \$178,215/(390,356.055 + 31,266) MWh = \$0.42 /MWh

CBAS for Wind System Costs & Totals

From Month: April-2009
To Month: April-2010

Procurement Costs (Incremental)

	Monthly		Hourly	
	MW	\$	MW	\$
Regulation	10.9	82,157.88	715.9	730.09
Load Following	13.1	82,650.60	-2,592.7	-2,204.67
Spinning Reserve	0.0	0.00	-387.9	-295.17
Supplemental OR - 10 min.	0.0	0.00	-3,947.6	-2,711.23
Supplemental OR - 30 min.	0.0	0.00	-546.5	-333.62
		164,808.48		-4,814.60

Re-dispatch Costs

Total ASRC	76,691.57
Incremental ASRC	0.00
Load ASRC	58,470.21
Wind ASRC	18,221.36

Tariff Charges

Total Metered MWh	800,599.127
Total Charge Determinant	390,356.055
Total Tariff Charges	97,588.99

Self-Supply Shortfall Charges

Total Charge Determinant	31,266.000
Total Charges	7,816.50

Summary

Total Charges	105,405.49
Total Costs	178,215.24
Variance	-72,809.75

1 An explanation of the components of the report follows.

2
3 **“Procurement Costs (Incremental)”**

4 The costs incurred reflect NBSO’s total cost of ancillary services capacity less the cost
5 that NBSO would have incurred if there had not been wind farms purchasing Schedule
6 3(c) services. NBSO purchases Capacity-Based Ancillary Services (“CBAS”) each
7 month based on the projected monthly needs and then selects the resources hourly for
8 the purpose of meeting real-time operational needs. The total projected Regulation and
9 Load Following needs for each month are increased to accommodate wind farm
10 production in the Balancing Area. The same is true with respect to hourly Regulation
11 needs. In the case of hourly Load following, the wind farm production may increase or
12 decrease the total Load Following requirements. For example, if the wind power
13 production is expected to decrease and the load is expected to increase over the course
14 of an hour, then the wind production increases the net hourly Load Following
15 requirement. Conversely, if the wind power production is expected to increase and the
16 load is expected to increase over the course of an hour, then the wind production
17 decreases the net hourly Load Following requirement. Therefore, in any given hour
18 there may be an increase or a decrease in the Load Following requirement as a
19 consequence of wind power production. The hourly procurement of Load Following is
20 also impacted by the fact that self-supply quantities are established at the start of each
21 month and then scheduled in each hour within the month. Actual requirements for wind
22 farms in any given hour may exceed self-supply (or be less than self-supply). The
23 incremental cost (or savings) is charged (or credited) to the Schedule 3(c) account.
24 Also, Regulation and Load Following purchased hourly for Schedule 3(c) are counted
25 toward total reserves and thus an increase in either of those products reduces the
26 purchases of reserves. This approach results in a credit to Schedule 3(c) for those
27 services.

28
29 NBSO’s average costs of procuring the services for the fiscal year 2009/10 are as
30 shown in the following Table 3-3 and arise from NBSO buying the required quantities in
31 accordance with the applicable contract prices.

1
2
3

Table 3-3
Procurement Costs

Service	Monthly Purchases		
	Average Capacity (MW)	Average Expense (\$)	Average Price (\$/MW-m)
Regulation	0.91	6,846.49	7,537.42
Load Following	1.09	6,887.55	6,309.21

4
5

6 **“Re-dispatch Costs”**

7 Ancillary Service Re-dispatch Costs (“ASRC”) are calculated by comparing costs with
8 (“Total ASRC”) and without (“Load ASRC”) the CBAS requirements associated with
9 wind farms that are not purchasing Schedule 3c services from NBSO. The difference is
10 the ancillary services re-dispatch cost attributable to wind farms that are not purchasing
11 Schedule 3(c) services from NBSO (“Wind ASRC”). The calculation is as follows:

12

$$\text{\$76,691.57} - \text{\$58,470.21} = \text{\$18,221.36}$$

13
14
15

16 **“Tariff Charges”**

17 Wind farms in the Balancing Area that were not self-supplying Schedule 3(c) services
18 were charged at the Tariff rate multiplied by the production. The total production from
19 wind farms was 800,599 MWh and the production from those not self-supplying

1 Schedule 3(c) was 390,356 MWh. The calculation of the charge is as follows:

$$390,356 \text{ MWh} \times \$0.25/\text{MWh} = \$97,589.01$$

2 3 4 5 **“Self-Supply Shortfall Charges”**

6 To the extent that customers choose to self-supply but fall short on their hourly
7 scheduling, NBSO charges those customers so as to avoid cost shifting. The charges
8 are calculated by charging the Tariff Schedule 3(c) rate to the production corresponding
9 to the shortfall. The calculation of the charge is as follows:

$$31,266 \text{ MWh} \times \$0.25/\text{MWh} = \$7,816.50$$

10 11 12 13 14 **“Summary”**

15	Total Charges = \$97,589.01 + \$7,816.50	= \$105,405.51
16	Total Costs = \$164,808.48 - \$4,814.6 + \$18,221.36	= \$178,215.24
17	Variance = \$105,405.51 - \$178,215.24	= -\$72,809.75

18 19 **Information Related to the Need for a Limit on Schedule 3(c) Purchases**

20 The question of whether or not there should be a limit on the amount of Schedule 3(c)
21 service available at the Tariff rate prompts an analysis of the following considerations:

- 22
- 23 1. The **current quantities** of the underlying services (Regulation and Load
24 Following) that can be acquired by NBSO from sources that are subject to
25 existing ancillary services contracts;
- 26 2. The potential for acquisition of these services from **new sources** in the future;
- 27 3. The **supplier’s cost** of providing these services;
- 28 4. **NBSO’s cost** of purchasing these services;
- 29 5. The **allocation of NBSO’s costs** of purchasing these services;
- 30 6. The various applicable cost allocation and **rate design** principles including
31 stability of rates.

1 **Current Quantities**

2 The quantities of Regulation and Load Following that NBSO has under contract at this
3 time are as noted in Table 3-4. The two products are mutually exclusive in that the
4 same capacity cannot be counted as providing both services at the same time.
5 Accordingly the availability of either service for scheduling from a particular facility is
6 diminished by the scheduling of the other service from that facility.

7

8

1
2

**Table 3-4
Contracted Quantities**

Facility	From MW	To MW	MW Per Minute	REG (MW)	LF (MW)
BEECHWD	0	36	115	0	36
BEECHWD	36	113	115	77	77
BELLDN 2	0	200	2	0	60
BELLDN 2	200	466	3	0	90
C.COVE 1	0	43	3	0	43
C.COVE 1	43	63	3	0	20
C.COVE 1	63	133	3	30	70
C.COVE 1	133	140	0.25	2.5	7
C.COVE 1	140	283	6	60	143
C.COVE 1	283	333	3	30	50
C.COVE 2	0	43	3	0	43
C.COVE 2	43	63	3	0	20
C.COVE 2	63	133	3	30	70
C.COVE 2	133	140	0.25	2.5	7
C.COVE 2	140	283	6	60	143
C.COVE 2	283	333	3	30	50
C.COVE 3	0	40	3	0	40
C.COVE 3	40	60	3	0	20
C.COVE 3	60	130	3	30	70
C.COVE 3	130	137	0.25	2.5	7
C.COVE 3	137	280	6	60	143
C.COVE 3	280	330	3	30	50
DALH 1	0	24	2	0	24
DALH 1	24	97	2	0	60
DALH 2	0	90	3	0	90
DALH 2	90	150	6	60	60
DALH 2	150	200	3	30	50
DALH 2	200	203	2	3	3
G.FALLS	0	4	66	0	4
G.FALLS	4	20	66	0	16
G.FALLS	20	36	66	0	16
G.FALLS	36	64	66	0	28
G.MANAN 3	0	2	2	0	2
G.MANAN 3	2	29	2	0	27
MACTAQ	0	216	672	216	216
MACTAQ	216	468	672	252	252
MACTAQ	468	672	672	204	204
MBANK 1	0	20	3.9	0	20
MBANK 1	20	35	3.9	0	15
MBANK 1	35	99	3.9	0	64
MBANK 2	0	20	3.9	0	20
MBANK 2	20	35	3.9	0	15
MBANK 2	35	99	3.9	0	64
MBANK 3	0	20	3.9	0	20
MBANK 3	20	35	3.9	0	15
MBANK 3	35	99	3.9	0	64
MBANK 4	0	20	5	0	20
MBANK 4	20	35	5	0	15
MBANK 4	35	99	5	0	64
SISSON	0	2	9	0	2
SISSON	2	8	9	0	6
SISSON	8	9	9	0	1
STE.ROSE	0	20	3.9	0	20
STE.ROSE	20	35	3.9	0	15
STE.ROSE	35	99	3.9	0	64
TOBIQUE	0	4	20	0	4
TOBIQUE	4	20	20	0	16

1 **New Sources**

2 Examples of potential new sources to NBSO for contracted Regulation and Load
3 Following include the Bayside combined cycle gas turbine in Saint John, New
4 Brunswick, imports, wind farms, and future power plants in New Brunswick.

5

6 **Supplier's Costs**

7 The supplier's cost of providing the service is a combination of capacity costs and out-
8 of-order dispatch costs. Out-of-order dispatch costs are incurred when generation
9 capacity that could economically produce energy (i.e. the incremental cost of production
10 is equal to or less than the value of the energy) is instead used to provide a capacity-
11 based ancillary service such as Regulation or Load Following. The out-of-order
12 dispatch cost is the cost of replacement energy from a different source less the savings
13 realized by not producing energy from the ancillary service source (i.e. the resource that
14 is re-dispatched so that it can provide the ancillary service).

15

16 **NBSO's Costs**

17 The capacity costs for NBSO are a matter of contracted price, or in some cases bid
18 prices. Out-of-order dispatch costs are effectively a pass through of the supplier's out-
19 of-order dispatch costs. These costs are calculated by NBSO based on the difference
20 between the cost of dispatching energy and the cost of dispatching energy if the
21 capacity-based ancillary services had not been required.

22

23 **Allocation of Costs**

24 The supporting evidence for the Schedule 3(c) rate assumes that all of the NBSO's
25 costs with respect to Regulation and Load Following for wind are allocated to the
26 Schedule 3(c) service.

27

28 **Rate Design**

29 The rate design originally proposed by NBSO had the rate capped at \$1/MWh, avoiding
30 exposing the early wind farm developers to the risk that subsequent developments
31 would lead to significant increases in Schedule 3(c) rates. The subsequent developers

1 would be required to source out their own supply of these services and would not have
2 the option of purchasing them from the NBSO.

4 **Case Studies on the Availability of Regulation and Load Following**

6 The availability and cost of Regulation and Load Following services are dependent on
7 the commitment and dispatch of generation and load resources for energy purposes.
8 The following discussion explains the availability of Regulation and Load Following
9 under the basic cases that can exist.

11 **Case “A” Hydro Sufficient**

12 In Case “A” the availability of hydro capacity to provide Regulation and Load Following
13 is high because hydro production can be increased or decreased rapidly over a
14 relatively wide range. Regulation and Load Following capabilities may or may not also
15 be available from thermal facilities.

17 Example:

18 If loaded at mid operating range, the Mactaquac facility could provide a couple of
19 hundred MW of capacity for Regulation and Load Following.

21 **Case “B” Hydro and Thermal, No Out-of-Order Dispatch**

22 In Case “B” the availability of hydro is more limited than in Case “A” and needs to be
23 supplemented by Regulation and Load Following capabilities from thermal facilities.
24 The combination of hydro and thermal capabilities provides the required quantities of
25 Regulation and Load Following without out-of-order dispatch. The thermal generation
26 may provide as much as 100% of the needs. However, the use of thermal generation to
27 provide Regulation and Load Following can pose a risk to system reliability. Thermal
28 generation is typically susceptible to performance issues when required to vary output.

1 Example:

2 High water flows indicate economic dispatch of hydro facilities at close to 100%
3 of capacity. This dispatch leaves enough capacity for Regulation, but not for
4 Load Following. A marginal cost thermal unit which was committed to be on-line
5 for energy provides Load Following from otherwise unscheduled capacity.

6
7 **Case “C” Out-of-Order Dispatch**

8 This case is the same as Case “B” other than with respect to Out-of-Order Dispatch.
9 Out-of-Order Dispatch is required and leads to increased costs to NBSO of procuring
10 the service.

11
12 Example:

13 High water flows indicate economic dispatch of hydro facilities at 100% of
14 capacity. There is insufficient capacity on the marginal cost thermal unit to
15 provide the required Regulation and Load Following. A generator with higher
16 production costs is committed to produce energy, freeing up capacity that can
17 provide Regulation and Load Following.

18
19 **Discussion of Marginal Cost Units and Out-of-Order Dispatch Costs**

20 For some combinations of dispatch a Coleson Cove unit on the margin would
21 technically be able to provide Regulation and Load Following as shown in Chart 3-1
22 (Regulation and Load Following Requirements and Availabilities, page 57). However,
23 given the relativity of current prices for oil and wholesale electricity, Coleson Cove is
24 rarely a marginal cost resource. Belledune is a coal plant that currently has production
25 costs that are competitive with wholesale electricity prices. Belledune can provide Load
26 Following, but is not able to provide Regulation. Dalhousie 2 can provide some
27 Regulation and Load Following, but is moving to production costs that are presumably
28 similar to those of Coleson Cove. None of the other non-hydro facilities are contracted
29 to provide regulation. Those other non-hydro facilities also have high production costs
30 and therefore would very rarely be the marginal cost facility. Furthermore, the potential
31 closure of the Dalhousie plant means that it would be imprudent for the NBSO to count

1 on that resource in its ancillary services planning for periods beyond this upcoming
2 winter.

3

4 The following calculations are for illustration purposes only, and all figures are rough
5 approximations. The first calculation is based on running a thermal generator out of
6 merit order and the second one is based on spilling water at a hydro facility.

7

8 Redispatch of Thermal Generator Having \$90/MWh Production Costs

Hydro fully dispatched for energy	10%
Hours in a year	8760
Hours hydro fully dispatched	876
Marginal cost of energy	\$50/MWh
Production cost of energy dispatched to free up regulation	\$90/MWh
Difference	\$40/MWh
Regulation required for wind	2.2 MW
Annual costs of out-of-order dispatch (876x40x2.2)	\$77,000

9

10 The out-of-order dispatch costs noted above reflect differences in energy costs only.
11 Bringing thermal units on-line costs tens of thousands of dollars. If units are committed
12 for Regulation and Load Following that would not otherwise be committed, then those
13 start-up costs are an additional out-of-order dispatch cost attributable to Regulation and
14 Load Following. In addition, thermal units typically have minimum run quantities which
15 would require out-of-order dispatch in excess of the quantities that was to be required to
16 provide Regulation and Load Following.

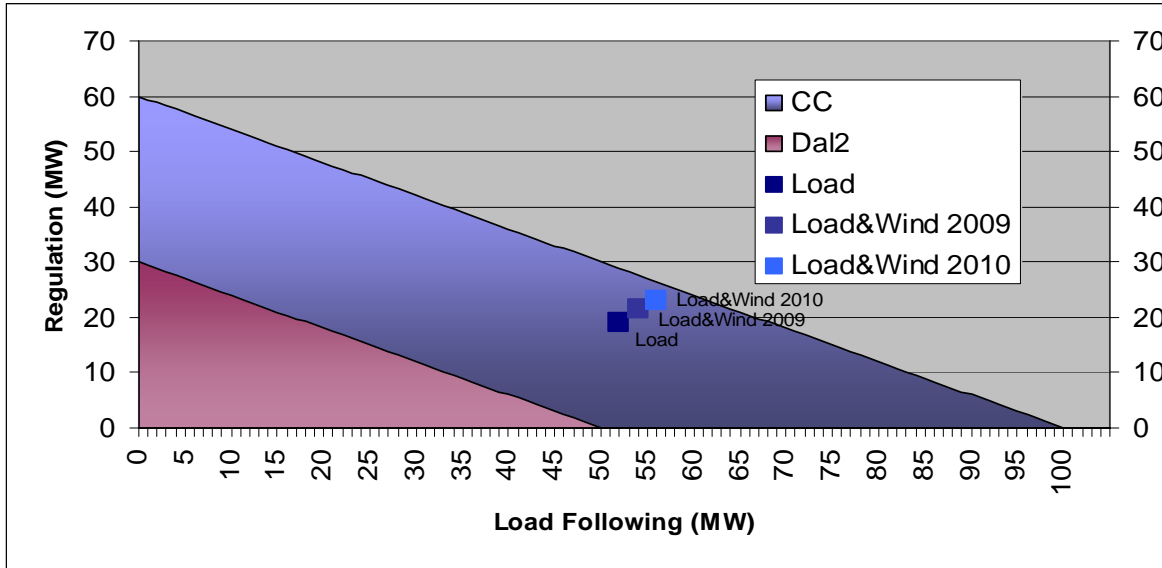
17

18 Spilling of Water

19 Hours hydro spilled	876
20 Cost of replacement energy	\$50/MWh
21 Regulation required for wind	2.2MW
22 Annual costs (876 x 50 x 2.2)	\$96,000

1 As shown in Chart 3-1, the nominal requirements for Regulation and Load Following are
2 greater than they would be with no wind generation and are increasing as more wind
3 farms are added to the Balancing Area.

4
5 **Chart 3-1**
6 **Regulation and Load Following Requirements and Availabilities**



7
8
9
10 **CONCLUSION**

11 The expenses incurred to date do not suggest a need to change from the current rate
12 for the Schedule 3(c) service.

13
14 Accordingly, NBSO seeks Board approval to maintain the Schedule 3(c) rate at
15 \$0.50/MWh beyond March 31, 2011.

16
17 As noted by NBSO in its application of 2008, the "...service is intended to address
18 potential cost shifting and the fact that NBSO does not have access to unlimited
19 balancing resources". NBSO's procurement of Regulation and Load Following services,
20 regardless of the purpose, is restricted to those quantities which NBSO can purchase
21 from generators and loads. Those suppliers must have the technical capability to

1 provide these services to NBSO, and must be willing to do so at a reasonable price and
2 under the terms and conditions of the Market Rules. NBSO does not have unlimited
3 contractual rights to such services, nor have there been strong signals from the
4 marketplace of interest in additional provision of such services. Only one new supplier
5 has executed an agreement for the provision of Capacity-Based Ancillary Services
6 since NBSO conducted a Request for Proposals in 2006, and this supplier has not
7 contracted to provide Regulation or Load Following. Accordingly, NBSO continues to
8 believe that it is appropriate to establish a limit on the amount of wind power energy that
9 will be eligible to receive Schedule 3(c) service. NBSO continues to be of the opinion
10 that to establish this limit before the Regulation and Load Following resources are
11 exhausted provides greater certainty to all and thus reduces regulatory risk in the
12 marketplace.

13

14 Nonetheless, NBSO has a limited history of procurement of Regulation and Load
15 Following to address the characteristics of wind power generation. In addition, the only
16 new wind farm capacities within the balancing area expected to be in production in the
17 2011/12 fiscal year are the 54 MW Kent Hills wind farm expansion and the Lameque 45
18 MW wind farm. These additions represent approximately a 25% increase in the
19 balancing area capacity. While more substantial development has been contemplated
20 in the past and may still be under consideration, NBSO has no firm indication of
21 developers imminently committing to construct those projects.

22

23 Accordingly, NBSO believes it is appropriate that the Board continue to seek information
24 as to why a limit should be adopted in the future, but NBSO is not applying for a limit at
25 this time.

26