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VIA EMAIL
bchydroregulatorygroup@bchydro.com

February 19, 2010

Ms. Joanna Sofield
Chief Regulatory Officer
British Columbia Hydro and Power Authority
333 Dunsmuir Street
Vancouver, BC V6B 5R3

Dear Ms. Sofield:

Re: British Columbia Hydro and Power Authority
Project No. 3698592
Fiscal 2011 Revenue Requirements Application

Further to your March 3, 2010 revenue requirements application, enclosed please find Commission Order G-180-10 with Reasons for Decision approving the Negotiated Settlement Agreement.

Yours truly,

for:
Erica M. Hamilton

cms
Enclosure
cc: Registered Interveners/Interested Parties

PF/BCH_F2011 RRA/ 2-02_Reasons-Settlement Agrmnt Released

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BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER G-180-10

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IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

An Application by British Columbia Hydro and Power Authority
for Review of its F2011 Revenue Requirements Application

BEFORE: D.A. Cote, Panel Chair/Commissioner
L.A. O'Hara, Commissioner
M.R. Harle, Commissioner

December 2, 2010

O R D E R

WHEREAS:

A. British Columbia Hydro and Power Authority (BC Hydro) filed on March 3, 2010 with the British Columbia Utilities Commission (Commission), pursuant to sections 44.2 and 58 to 61 of the *Utilities Commission Act* (the Act), its F2011 Revenue Requirements Application (the F11 RRA, or Application) for, among other things, final approval of an across-the-board rate increase of 6.11 percent, effective April 1, 2010, and final approval to increase the Deferral Account Rate Rider from 1.0 percent to 4.0 percent, effective April 1, 2010. For the residential inclining rate block Rate Schedules 1101 and 1121, BC Hydro proposes to apply the 6.11 percent increase equally to the Basic charge and Step 1 and Step 2 energy charges;

B. The Application also sought refundable interim relief, pursuant to sections 58 to 61, 89 and 90 of the Act and section 15 of the *Administrative Tribunals Act*, to allow BC Hydro to increase its rates by 6.11 percent on an across-the-board basis, and to increase its Deferral Account Rate Rider from 1.0 percent to 4.0 percent, both effective April 1, 2010, pending the hearing into the F11 RRA and orders subsequent to that hearing, on the basis that on April 1, 2010 BC Hydro's current rates would otherwise no longer be fair, just and not unduly discriminatory;

C. On March 15, 2010, Commission Order G-47-10 approved BC Hydro's request for interim rates subject to refund with interest at BC Hydro's weighted average cost of debt for its most recent fiscal year;

D. By Commission Order G-136-10 dated August 23, 2010, the Commission established a Further Amended Regulatory Timetable that provided in part for a Negotiated Settlement Process (NSP) to begin on September 22, 2010 and a Default Schedule in the event no agreement was reached as a result of the NSP;

E. In a letter dated October 13, 2010, BC Hydro advised the Commission that the NSP had failed;

F. By Order G-157-10 dated October 21, 2010, the Commission established a Revised Regulatory Timetable;

.../2

G. In a letter dated October 26, 2010, BC Hydro advised the Commission that it had continued informal discussions with NSP participants, despite BC Hydro's view that the NSP had failed. BC Hydro reported that the discussions had given it cause to believe that a settlement of the Application was both achievable and imminent; therefore, it sought a reinstatement of the NSP to allow the settlement process to continue, and a suspension of the regulatory schedule established by Order G-157-10;

H. By Order G-163-10 dated October 27, 2010, the Commission suspended the regulatory schedule established by Commission Order G-157-10 until further order of the Commission and reinstated the NSP;

I. A Negotiated Settlement Agreement (NSA) dated for reference November 18, 2010 was entered into by the majority of the participants to the NSP to settle all the issues arising from the F11 RRA. Two participants to the NSP, the Independent Power Producers of British Columbia (IPPBC) and the Line Contractors Association of BC (LCABC), were not parties to the NSA;

J. The NSA, together with Letters of Comment on the NSA that had been received, was made public on November 19, 2010, and circulated to all Interveners and the Commission. Interveners who had not participated in the NSP were requested to provide their comments on the Settlement Package to the Commission by November 26, 2010;

K. By letter dated November 19, 2010, the IPPBC filed a submission advising that it supported the NSA with the exception of section 9.xiv;

L. The Commission received four letters from Interveners who had not participated in the NSP;

M. On November 22, 2010, BC Hydro filed its comments in reply to the submission of the IPPBC;

N. The Commission has reviewed the proposed NSA and the Letters of Comments from the participants and, after due consideration considers that approval is warranted.

NOW THEREFORE for the reasons stated in the Reasons for Decision attached as Appendix A to this Order, the Commission orders that the NSA dated for reference November 18, 2010 and attached as Appendix B to this Order is approved.

DATED at the City of Vancouver, in the Province of British Columbia, this *Second* day of December 2010.

BY ORDER

D.A. Cote
Panel Chair/Commissioner

Attachment

IN THE MATTER OF

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

F2011 REVENUE REQUIREMENTS

REASONS FOR DECISION

December 2, 2010

BEFORE:

D.A. Cote, Panel Chair / Commissioner
L.A. O'Hara, Commissioner
M.R. Harle, Commissioner

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1.0 INTRODUCTION

On November 19, 2010, a proposed settlement package for British Columbia Hydro and Power Authority's (BC Hydro) F2011 Revenue Requirement Application (F11 RRA) was circulated to the British Columbia Utilities Commission (BCUC, the Commission) and all parties who intervened in the process. The package included the Negotiated Settlement Agreement (NSA) dated for reference November 18, 2010, along with a number of Letters of Comment in support of the NSA and two letters opposing it.

The Commission Panel approves the Negotiated Settlement Agreement for the reasons that follow.

2.0 BACKGROUND

On March 3, 2010, BC Hydro filed its F11 RRA pursuant to sections 44.2, and 58 to 61 of the *Utilities Commission Act* (the Act) seeking, among other things, an increase of 6.11 percent as well as approval to increase the rate schedule 1901 Deferral Account Rate Rider (DARR) from 1.0 percent to 4.0 percent. The increases were both to be effective April 1, 2010. BC Hydro sought approval to apply these rate increases on an across-the-board basis, but subject to specific rate designs such as the residential inclining block (RIB) rate schedules 1102 and 1121, and the transmission service rate schedule 1823. BC Hydro sought approval to apply the 6.11 percent increase equally to the Basic Charge and Step 1 and 2 Rates of the RIB 2 rate. BC Hydro also sought interim orders pursuant to sections 58 to 61, 89 and 90 of the Act and section 15 of the *Administrative Tribunals Act,* S.B.C. 2004, c.45 to allow it to increase these rates effective April 1, 2010, pending final determination of the F11 RRA. Finally, BC Hydro sought orders regarding both proposed new and existing regulatory accounts. (Exhibit B-1, pp. 1-9-1-12)

By Order G-136-10 dated March 15, 2010, the Commission approved BC Hydro's request for interim rates on a refundable basis and established an Initial Regulatory Timetable. A Procedural Conference took place on May 28 and by Order G-99-10 the Regulatory Timetable was amended to provide for a second Procedural Conference following the BC Hydro Evidentiary Update and responses to the second set of Information Requests (IRs). The second Procedural Conference took place on August 20, 2010 where it was agreed the Regulatory Timetable be further amended to go forward with a Negotiated Settlement Process (NSP) on September 22, 2010 following a third set of IRs. Following the second Procedural Conference the Commission, by Order G-136-10, issued a Further Amended Regulatory Timetable which provided, in part, for a third Procedural Conference to be held on October 14, 2010, and further process leading to an Oral Hearing to be held on December 13, 2010 in the event the NSP failed.

The NSP began on September 22, 2010 as scheduled. BCUC Staff tabled a written request from the Commission Panel detailing two items of concern which it requested be addressed by the participants: (i) the recovery of BC Hydro's deferral account balances, and (ii) the process and preparation for the next BC Hydro RRA .

By letter dated October 13, 2010, BC Hydro advised the Commission that the NSP had failed and stated that, in the absence of Intervener motions or Commission Panel questions, it did not believe the third Procedural Conference was necessary. On October 21, 2010, following further submissions from the parties with respect to proposed changes in dates up to and including the Oral Hearing, the Commission issued Order G-157-10 which included a Revised Regulatory Timetable outlining the process leading to an Oral Hearing scheduled for December 13, 2010.

On October 26, 2010, BC Hydro informed the Commission by letter that it had continued informal discussions with NSP participants which caused it to believe that a settlement of the Application was after all both achievable and imminent. Accordingly, BC Hydro sought a suspension of the Regulatory Timetable established by Order G-157-10 and reinstatement of the NSP to allow for the settlement process to continue. By Order G-163-10 dated October 27, 2010, the Commission accepted BC Hydro's proposal and suspended further regulatory process until further order and reinstated the NSP.

By letter dated November 2, 2010, BC Hydro advised the Commission that the NSP participants, with the possible exception of the Independent Power Producers of British Columbia (IPPBC) and the Line Contractors Association of BC (LCABC), had achieved an agreement on the substantive terms of a comprehensive settlement of all F11 RRA issues.

The NSA, together with Letters of Comment on the NSA that had been received, was made public on November 19, 2010, and circulated to all Interveners and the Commission. Interveners who had not participated in the NSP were requested to provide their comments on the Settlement Package to the Commission by November 26, 2010.

The Commission received a Letter of Comment from the Canadian Office and Professional Employees Union, Local 378 (COPE) stating that the proposed Settlement package was acceptable to it.

The Commission also received letters from FortisBC Inc., the City of New Westminster Electric Utility Commission, and the group of Terasen gas distribution companies including, Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc., and Terasen Gas (Whistler) Inc., all of whom had intervened in the proceedings but did not participate in the NSP. All advised that they had no comment on the Settlement package.

By letter dated November 19, 2010, the IPPBC filed a submission advising that it supported the NSA with the exception of section 9.xiv. On November 22, 2010, BC Hydro filed its comments in reply to the IPPBC submission.

The Commission Panel is not privy to the events of the NSP other than what is outlined in the NSA and Letters of Comment it has received from the participants.

3.0 NEGOTIATED SETTLEMENT AGREEMENT

A group consisting of BC Hydro, the Joint Industry Electricity Steering Committee (JIESC), the Commercial Energy Consumers of British Columbia (CEC), the British Columbia Old Age Pensioners Organization *et al.* (BCOAPO), the British Columbia Sustainable Energy Association and Sierra Club of British Columbia (BCSEA), Catalyst Paper, Teck Coal and Mr. Ruskin (the Parties) reached an agreement to settle all issues arising from the F11 RRA.

Full details of the Negotiated Settlement Agreement are provided in Appendix B to Order G-180-10 issued concurrently with these Reasons, but some of the highlights are as follows:

1) General

- The Parties expect the next RRA will be reviewed in an oral public hearing.
- None of the provisions of the NSA are severable.
- The NSA is a comprehensive settlement of all issues related to F11 RRA.

2) BC Hydro Commitments

- To provide, in the next RRA, an analysis of, and a proposal for, a DARR effective April 1, 2011, based on a 5 year amortization of the Trade Income Deferral Account and 10 year amortization of the Non-Heritage Deferral Account and Heritage Deferral Account.

- To meet with interested parties and BCUC staff prior to November 30, 2010, to try to agree on an approach to the next RRA, which will best allow for a comprehensive review conducted in a transparent, efficient and effective manner.

- To apply for a minimum two-year and maximum three-year test period by March 2011.

- Not to object to a review of the efficacy of its F2009-2011 DSM expenditures in its F2012 section 44.2 DSM filing, that will be filed no later than July 31, 2011.

- To increase its focus on management and control of its cost structure and undertake to propose to government changes to government-related aspects of BC Hydro's revenue requirement. This is in recognition of customer concerns with currently projected future rate increases.

3) Changes to F2011 Revenue Requirement and Rate Relief

- Forecast capital expenditures shall be reduced for F2011 by $100 million and forecast capital additions shall be reduced by $50 million.

- BC Hydro F2011 operating costs shall be reduced by $35 million.

- The approved interim across-the-board 6.11 percent rate increase is confirmed as final.

- The final F2011 DARR will be 4.0 percent for the period of April 1 to December 31, 2010, and 2.5 percent thereafter.

- A 4.71 percent credit shall be applied to charges payable to other approved rates (not including DARR) for the period January 1 to March 31, 2011 inclusive. This represents the net impact of regulatory account write-offs, reductions in capital expenditures and additions and the reduction in operating costs.

The above changes result in an effective weighted average rate increase for F2011 of 4.67 percent.

4.0 ISSUES OF CONCERN TO PARTICIPANTS OPPOSING THE SETTLEMENT

4.1 IPPBC

The IPPBC, in its Letter of Comment dated November 19, 2010, submits that it supports the NSA with the exception of section 9.xiv, which is related to the review of the efficacy of BC Hydro's F2009-F2011 DSM Expenditures and anticipated F2012 section 44.2 DSM filing. In particular it cites the filing date of July 31, 2011 as a particular concern in this provision. IPPBC notes that from the outset it has made it clear it wished to pursue the issue of the efficacy of BC Hydro's DSM programs through a prudency review if required. It further notes that although DSM expenditures were previously approved by the Commission, the amortization of costs related to prior expenditures is included as a part of the F11 RRA and requires BCUC approval. The IPPBC points out that it is this retrospective approval by the Commission that provides the opportunity to review the efficacy of the prior expenditures by way of a prudency review. In its view, BC Hydro's response to BCUC IR 1.38.1 (Exhibit B-6) and 2.356.1 (Exhibit B-11) is indicative that the initial requirement for prudency review has been met and that "the efficacy of DSM should be fully reviewed" as soon as possible. It is IPPBC's position that delaying the start of this review until July 31, 2011 is not in the best interest of BC Hydro customers.

The IPPBC further comments that given that the forecast for the next 2-3 year period covered by the next RRA will include Power Smart expenditures, conducting a review following the July 31, 2011 submission date is hard to understand as it should coincide with BC Hydro's March 2011 RRA filing. On a final point the IPPBC raises concerns with respect to the anticipated filing of the Integrated Resource Plan (IRP) (prior to the end of December 2011). In its view it would benefit all concerned if the review of the efficacy of Power Smart is completed prior to the IRP being submitted to government.

The IPPBC in closing notes that no useful purpose would be served if the BCUC were to reject the F11 RRA in its entirety. Accordingly it requests that BCUC do one of two things:

1. Accept the NSA except for a nominal amount of the DSM amortization amounts described in the F11 RRA Evidentiary Update (Exhibit B-1, Appendix 1, Schedule 7) and conduct a prudency review of Power Smart on this basis.

2. Accept the NSA, but amend the date in Section 9.xiv from July 31, 2011 to March, 2011.

BC Hydro, in Reply dated November 22, 2010, notes that by the terms of the NSA, the Parties have agreed it is a comprehensive settlement of all issues arising from the F11 RRA and that none of the provisions are severable. BC Hydro states that if the BCUC does not accept and approve the entire NSA, there is no agreement. BC Hydro further submits that BCUC has no jurisdiction to order the filing of its F2012 DSM Expenditures by a certain date as section 44.2 filings are made at the option of the public utility.

4.2 LCABC

The LCABC, in its Letter of Comment of November 18, 2010, notes that its sole reservation concerning the NSA relates to the LCABC complaint only. The concern raised by the LCABC relates to the amount of time being taken by BC Hydro to resolve the LCABC complaint and BC Hydro's failure to follow through on commitments it has made with respect to setting up a meeting with the LCABC and BC Hydro senior management to review what progress has been made on the issues that form the basis of its complaint. Because of this, LCABC has stipulated that it requires a timeline and an end date for the resolution of its complaint before it is willing to sign off on the NSA.

5.0 COMMISSION DETERMINATION

The concerns which have been raised by the IPPBC with respect to the timing of BC Hydro's F2012 DSM filing have some validity. An earlier date for this filing would allow for a more complete review of it within the context of the next RRA in March 2011. Further, if a review of the F2012 DSM filing could be completed sufficiently early to allow BC Hydro to incorporate the results in its next IRP, it would be of benefit to all concerned. However, as BC Hydro points out, the terms of the NSA as signed off by the Parties are comprehensive and non-severable. The Commission Panel is in agreement with BC Hydro that if the BCUC accepted either of the options presented by the IPPBC it would, in effect, cancel the NSA which has been reached amongst the Parties.

Further, the Panel, not being a party to the process can only assume that the Parties agreed to the non severability and comprehensive settlement sections in the NSA with full knowledge of their implications. Put into different terms, the Panel accepts that the agreed upon dates were part of the negotiation process. **Accordingly, the Panel has determined that there is no way the options presented by the IPPBC can be considered without nullifying the agreement among the Parties. Therefore, the Panel does not consider it necessary to address BC Hydro's submission with respect to the Commission's jurisdiction to order a specific date for filing under section 44.2.**

With respect to the issues raised by LCABC, the Commission Panel, while concerned about the lack of progress on the LCABC complaint, is unwilling to accept that this should have a bearing upon the NSA. This proceeding is a rate setting review and disputes between participants cannot be allowed to impede the settlement process. However, we do encourage both BC Hydro and LCABC to work toward a timely resolution of the matter. Failing a satisfactory resolution to the complaint we note it can be resubmitted to the BCUC.

In considering section 44.2 (5.1) the Panel sees no reason the NSA should not be approved. The Parties, as part of the NSA, have agreed that the amounts BC Hydro has spent on energy conservation rates in F2009 and F2010 which total $10.3 million shall be written off in F2011. The $5.2 million for F2011 has been agreed to by the Parties and forms part of the NSP. The Panel notes that none of the expenditures for work on energy conservation rates for the period F2009 to F2011 have previously been accepted by the Commission. Therefore, the Panel views as reasonable the agreement among the Parties to write-off non-approved expenditures from previous years and approve the F2011 expenditures.

The Parties to the NSA have, through Letters of Comment, all supported the NSA. Moreover, both the IPPBC and the LCABC have indicated that they have no other concerns with the terms of the NSA other than those which have been stated. Overall, the Panel is satisfied the NSA, which has been agreed to by the Parties, represents a fair settlement considering the circumstances, results in rates that are fair, just and reasonable and not unduly discriminatory or unduly preferential and that the NSA is in the public interest. The alternative would have to been to go to an Oral Hearing process where, at best, a decision would not be reached until very late in the test period. This would serve no useful purpose as there would be little that could be done to effect change at that late date. **The Commission Panel approves the NSA as submitted**.

The Panel recognizes that this has been a lengthy and likely frustrating process for the participants. We would like to acknowledge and praise the efforts of the Applicant, the Interveners, the BCUC Staff and Facilitator who continued to work to resolve issues which had arisen in the NSP and threatened to derail the process permanently. Subjecting this to further process would have achieved no better result.

BRITISH COLUMBIA UTILITIES COMMISSION

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Log No. 32857

VIA EMAIL

November 19, 2010

TO: Registered Interveners (BCH-2011RR-RI)
BC Hydro - F2011 Revenue Requirements

Dear Registered Intervenors:

Re: British Columbia Hydro and Power Authority
Negotiated Settlement
Project No. 3698592
<u>Fiscal 2011 Revenue Requirements Application</u>

Enclosed with this letter is the proposed settlement package for BC Hydro's Fiscal 2011 Revenue Requirements Application. This settlement package is now public and is being submitted to the Commission and all Interveners. Also enclosed are Letters of Comment received to date from the participants in the negotiated settlement process.

Prior to consideration by the Commission, Interveners who did not participate in the settlement negotiations are requested to provide to the Commission with their comments on the settlement package by Friday, November 26, 2010. Thereafter, the Commission will consider the settlement package. A public hearing may not be required unless there is significant opposition to the proposed settlement.

Yours truly,

for William J. Grant

SPS/dg
Attachments
cc: Ms. Joanna Sofield
Chief Regulatory Officer
British Columbia Hydro and Power Authority

~~**CONFIDENTIAL – WITHOUT PREJUDICE**~~

IN THE MATTER OF THE

Utilities Commission Act, R.S.B.C. 1996, Chapter 473, as amended

and

British Columbia Hydro and Power Authority

F2011 Revenue Requirement Application (F11 RRA)

F11 RRA SETTLEMENT AGREEMENT

DATED FOR REFERENCE NOVEMBER 18, 2010

WHEREAS:

A. On March 3, 2010, British Columbia Hydro and Power Authority (BC Hydro) filed with the British Columbia Utilities Commission (BCUC), pursuant to sections 44.2 and 58 to 61 of the *Utilities Commission Act* (Act), its F11 RRA (Exhibit B-1) seeking, among other things, approval of an across-the-board rate increase of 6.11 per cent and approval to increase the rate schedule 1901 Deferral Account Rate Rider (DARR) from 1.0 per cent to 4.0 per cent, both effective April 1, 2010.

B. BC Hydro sought approval to apply the rate increase on an across-the-board basis, subject to specific rate designs such as the residential inclining block (RIB) rate schedules 1101 and 1121, and the transmission service rate schedule 1823. For the RIB rate, BC Hydro sought approval to apply the 6.11 percent increase equally to the Basic Charge and Step 1 and Step 2 Rates.

C. BC Hydro also sought interim orders pursuant to sections 58 to 61, 89 and 90 of the Act, and section 15 of the *Administrative Tribunals Act*, S.B.C. 2004, c.45 allowing it to increase its rates by 6.11 percent on an across-the-board basis, and to increase the DARR from 1.0 per cent to 4.0 per cent, both effective April 1, 2010, pending the final determination of the F11 RRA.

D. BC Hydro also sought orders regarding existing and proposed new regulatory accounts.

E. On March 10, 2010, BC Hydro filed evidence regarding its Procurement Enhancement Initiative (PEI) as Appendix A4 to the F11 RRA (Exhibit B-1-1).

F. By Order No. G-47-10 dated March 15, 2010 (Exhibit A-3), the BCUC approved for BC Hydro an across-the-board rate increase of 6.11 per cent, and an increase in the DARR from 1.0 per cent to 4.0 per cent, both on an interim and refundable basis effective April 1, 2010.

G. On July 5, 2010, sections 21 to 33 of the *Clean Energy Act*, S.B.C. 2010 c. 22 (CEA) came into force. By section 28 of the CEA, British Columbia Transmission Corporation (BCTC) employees became BC Hydro employees. By sections 22 and 23 of the CEA, BCTC's rights, property, assets, included contracts and included permits (as defined in the CEA), and its obligations and liabilities were transferred to BC Hydro.

H. On July 9, 2010, BC Hydro filed an evidentiary update to the F11 RRA (Evidentiary Update, Exhibit B-8) to reflect changes to BC Hydro's F2011 revenue requirement since the F11 RRA was filed on March 3, 2010, including actual F2010 results and updates on forecasts of energy sales and revenues and the cost of energy. In addition, the Evidentiary Update addressed the F2011 revenue requirement implications of the CEA, and in particular the cost implications arising from the integration of BCTC with BC Hydro; the cost implications arising from the CEA provisions regarding Burrard Thermal; the CEA provisions that require the BCUC, in setting rates for BC Hydro, to ensure that the rates do not allow BC Hydro to recover "expenditures for export"; and the implications of the CEA for BCTC's F2011 revenue requirement application.

I. On August 16, 2010, BC Hydro submitted a revised F2010 Demand-Side Management (DSM) Report as Revised Appendix 8 of its Evidentiary Update (Exhibit B-8-1).

J. By Order No. G-136-10 dated August 23, 2010 (Exhibit A-13), the BCUC ordered that a negotiated settlement process (NSP) be held for the F11 RRA.

K. The NSP commenced on September 22, 2010, and participants met in the BCUC hearing room on September 22, 24, 27, 28, 30 and October 5, 2010. BCUC Staff tabled a written request from the BCUC Panel regarding two items of particular concern to the Panel, namely that recovery of BC Hydro's deferral account balances and preparation for its next RRA be addressed by participants in the NSP discussions. By letter dated October 13, 2010 BC Hydro advised the BCUC that the NSP had failed. However, by letter dated October 26, 2010, BC Hydro advised the BCUC that it had continued informal discussions with NSP participants and these discussions had given cause to BC Hydro to believe that a settlement of the F11 RRA was achievable. BC Hydro requested the BCUC to reinstate the NSP, and by Order No. G-163-10 dated October 27, 2010, the BCUC reinstated the NSP.

L. By letter dated November 2, 2010, BC Hydro advised the BCUC that NSP participants achieved agreement on the substantive terms of a comprehensive settlement of all issues arising from the F11 RRA, with the possible exception of the Independent Power Producers Association of British Columbia (IPPBC) and the Line Contractors Association of BC (LCABC).

M. The following individuals participated in the NSP:

W. J. Grant	BCUC facilitator
R. Bishop	BCUC Staff
Y. Domingo	BCUC Staff
D. Flintoff	BCUC Staff
P. Nakoneshny	BCUC Staff
S. Sue	BCUC Staff
J. Tran	BCUC Staff
G.A. Fulton, Q.C.	Counsel to the BCUC
P. Miller	Counsel to the BCUC
F. Metcalfe	Consultant to the BCUC
R. Stout	Joint Industry Electricity Steering Committee (JIESC)
B. Wallace	Counsel to the JIESC
L. Guenther	Consultant to the JIESC
C. Dal Monte	Catalyst Paper
C. Weafer	Counsel to the Commercial Energy Consumers of British Columbia (CEC)
D. Craig	Consultant to the CEC
J. Quail	Counsel to the British Columbia Old Age Pensioners Organization *et al* (BCOAPO)
R. Salvador	Counsel to the BCOAPO

C. Fussell	Consultant to the BCOAPO
W. Andrews	Counsel to the British Columbia Sustainable Energy Association and the Sierra Club of British Columbia (BCSEA)
C. O'Riley	BC Hydro
C. Reid	BC Hydro
G. Reimer	BC Hydro
J. Sofield	BC Hydro
C. Yaremko	BC Hydro
W. Kassam	BC Hydro
G. Leroux	BC Hydro
J. Christian	Counsel to BC Hydro
I. Webb	Counsel to BC Hydro
W. Taylor	Consultant to BC Hydro
D. Newlands	Teck Coal
V. Ruskin	VW Ruskin & Associates
P. Kariya	Independent Power Producers of BC (IPPBC)
D. Austin	Counsel to the IPPBC
J. Weimer	Consultant to the IPPBC
J. Skosnik	LCABC

N. BC Hydro, JIESC, CEC, BCOAPO, BCSEA, Catalyst Paper, Teck Coal, and Mr. Ruskin came to an agreement to settle all issues arising from the F11 RRA, as described further below, and are collectively referred to in this agreement (Settlement Agreement) as the "Parties", or individually as a "Party".

NOW THEREFORE THE PARTIES AGREE AS FOLLOWS:

<u>General</u>

1. The Parties shall maintain in confidence all confidential discussions that they had in the course of negotiating this Settlement Agreement, unless disclosure is agreed to by all Parties.

2. Neither this Settlement Agreement, nor the positions taken and the statements made by the Parties in the course of negotiating this Settlement Agreement, shall restrict in any way the positions that may be taken by any of the Parties in any future proceedings. A Party shall not, in this or any other proceeding, cross-examine witnesses or make submissions in relation to the reasons why any other Party entered into this Settlement Agreement or agreed to any of its provisions.

3. The Parties expect that BC Hydro's next revenue requirement application (RRA) will be reviewed in an oral public hearing. BC Hydro agrees that it will not support a NSP for its next RRA if one or more of the BCOAPO, CEC, JIESC, or BCSEA are opposed to a NSP.

4. This Settlement Agreement represents a compromise of the positions taken by the Parties during the NSP. None of the provisions of this Settlement Agreement are severable. If the BCUC does not accept and approve this Settlement Agreement in its entirety, there is no agreement.

5. When used in this Settlement Agreement, terms with initial capitalization shall have the meanings specified for them in this Settlement Agreement or, if not specified in this Settlement Agreement, in the F11 RRA.

<u>Scope and Effective Date of Settlement</u>

6. This Settlement Agreement is a comprehensive settlement of all issues arising from the F11 RRA.

7. This Settlement Agreement shall be effective on the date of the BCUC order approving it.

8. The relief sought by BC Hydro in the F11 RRA, as amended by the Evidentiary Update, including the relief requested in section 1.2 of the Evidentiary Update, is accepted subject to the provisions that follow.

<u>BC Hydro Commitments</u>

9. BC Hydro shall:

i. provide an analysis of, and propose in its next RRA, a DARR effective April 1, 2011, based on a 5 year amortization of the Trade Income Deferral Account (TIDA) and 10 year amortization of the Non-Heritage Deferral Account (NHDA) and Heritage Deferral Account (HDA), all based on the Deferral Account balances as of September 30, 2010 ($766.8 million). In that context, and to address the first item of particular concern to the BCUC Panel, BC Hydro shall address the recent significant increase in its Deferral Account balances, the experience with the current DARR adjustment mechanism including the potential for shorter amortization periods as BC Hydro's rates increase, and the concerns of some Parties that the current DARR adjustment mechanism does not reflect the multi-year variations in water inflows to BC Hydro's reservoirs. As part of that analysis, BC Hydro shall also address how the NHDA and HDA amortization could be optimized to lower the long term average cost of energy to current and future ratepayers. Other parties in the next RRA proceeding are not precluded from advancing other analysis and views of the Deferral Account balances and clearing mechanisms;

ii. meet with interested parties and BCUC staff prior to November 30, 2010 to address the second item of particular concern to the BCUC Panel, and in particular to try and agree on an approach to BC Hydro's next RRA that best allows for a comprehensive review in a transparent, efficient and effective manner, including provision of data in electronic format and the provision of assumptions as well as the identification of major issues. Such issues may include the process to determine the dividing-line between utility costs recoverable from ratepayers and those properly associated with "expenditures for export" (as defined in the CEA), and the process to provide a longer-term perspective on the management of projected escalations in utility costs and rates;

iii. not enter into any forward market electricity purchase arrangements (energy hedges) without the approval of the BCUC;

iv. apply by March 2011 for at least a two year test period, and no more than a three year test period, in its next RRA, and Parties shall work towards a timely review of the RRA;

v. address in its next RRA the merits of using the competitiveness of BC Hydro's rates as a metric in determining variable pay;

vi. propose in its next RRA a transfer pricing mechanism for renewable energy credits (RECs) sold to Powerex, with the benefits from REC sales going to ratepayers (subject to the $200 million cap on Trade Income);

vii. apply in its next RRA for a determination that the balance in the GMS3 Regulatory Account ought to be recovered in BC Hydro's rates, or if BC Hydro chooses to not include such an application in its next RRA, then BC Hydro shall write off the balance in the GMS3 Regulatory Account;

viii. provide a full and complete explanation of the activities and benefits of the Office of the Chief Technology Officer in its next RRA;

ix. consider "rate smoothing" mechanisms of the type it applied for in the F11 RRA regarding the Waneta Transaction on a case-by-case basis and, in addition, address in its next RRA (a) the pros and cons of "smoothing" the revenue requirement impacts of large projects on a levelized cost basis (i.e., over the life of the asset); and (b) different ways to bring BC Hydro's cost of capital into rates;

x. report to the BCUC IEEE 2.5 Beta and CEMI reliability metrics;

xi. report in its next RRA on customer reliability initiatives;

xii. report in its next RRA on the management of overtime and, in that context, address service levels and cost effectiveness;

xiii. copy RRA interveners on BC Hydro's section 71 filings with the BCUC of amended electricity purchase agreements;

xiv. not object to a review of the efficacy of its F2009-F2011 DSM expenditures in its F2012 section 44.2 DSM filing, which would be filed no later than July 31, 2011 and pursue a timely review process, and address, if timely, the BCUC decision on that filing in its Integrated Resource Plan to be submitted to government pursuant to the CEA. Nothing shall prevent parties from leading evidence with respect to additional cost-effective DSM available to mitigate future energy costs;

xv. engage with government regarding informing customers of future rate increases beyond those which are currently published. The 5 year rate increase forecast provided in the response to JIESC IR 3.40.3 (Exhibit B-13-1), as amended to reflect this settlement and the assumption that the DARR will be set throughout the 5-year period in accordance with the amortization proposal in item #9.i., above, and the net bill impacts are shown in the following table.

	F2011	F2012	F2013	F2014	F2015
Projected Rate Increase	4.67%	17.44%	5.42%	9.72%	8.37%
Projected Deferral Account Rate Rider	3.53%	2.50%	2.20%	2.00%	1.70%
Projected Net Bill Impact	7.29%	16.27%	5.11%	9.51%	8.05%
Projected Cumulative Net Bill Impact	7%	25%	31%	44%	55%

Note 1: For F2011 the percentages are annualized weighted averages, reflecting the impact of the changes to the DARR and the F11 RRA settlement credit, as described in items #21 and #22 of this Settlement Agreement.

Note 2: For F2012 the projected annualized rate increase (17.44 per cent) represents the combined effect of a forecast 15.85 per cent rate increase effective April 1, 2011, and the termination of the F11 RRA settlement credit (item #22) also effective April 1, 2011.

Note 3: For F2012 to F2015 the projected DARR is based on the assumptions stated above and the assumption that there are no further increases or decreases in the Deferral Account balances other than due to DARR recoveries and interest.

In its communications with respect to relative rate increases involving F2011 rates, and in particular regarding its next RRA, BC Hydro shall disclose the net bill impact of its applied-for rate increase for F2012 and subsequent years relative to the annualized weighted average rates for F2011 that reflect the 7.29% increase shown in the table above.

BC Hydro acknowledges the concern of customers regarding the currently projected future rate increases, and shares this concern. In recognition of this, BC Hydro shall increase its focus on the management and control of its cost structure with the objective of reducing potential future rate increases, and undertakes to propose to government changes to government-related aspects of BC Hydro's revenue requirement, also with the objective of mitigating potential future rate increases;

xvi. meet with interested parties and BCUC staff to examine mitigation strategies to help safeguard the most vulnerable customers from the impact of the current and anticipated rate increases; and

xvii. include in the main body of its 2010 Load Forecast document an up-to-date and comprehensive review of the electricity demand of the oil and gas industry and related facilities in British Columbia.

Changes and Commitments re Regulatory Accounts and Deferred Costs

10. Capital Project Investigation Costs Regulatory Account: This account shall continue for F2011. Starting in F2012 BC Hydro shall expense its capital project investigation (CPI) costs. The closing F2011 balance of this account shall be amortized commencing in F2012. BC Hydro shall address the amortization period in its next RRA. BC Hydro may apply for regulatory accounting treatment for investigation costs for large projects.

11. Home Purchase Option Plan Regulatory Account: This account shall continue for F2011.

12. Amortization of Capital Additions Regulatory Account: This account shall not be eliminated as proposed in the F11 RRA, and shall continue for F2011.

13. Export Market Development, and Economic and Business Development Costs (E&E) Regulatory Account: BC Hydro withdraws its request for this account. BC Hydro reserves the right to seek recovery of F2012 and future costs of its Export Market Development, and Economic and Business Development business units.

14. BC Hydro shall describe the activities and expenditures associated with its forecast deferred operating costs in its next RRA, as well as the basis for deferring those costs.

Changes to F2011 Revenue Requirement and Rate Relief

15. The F2011 point-to-point (PTP) transmission charge allocation methodology described in section 4.4 of the Evidentiary Update shall be reversed. BC Hydro reserves the right to bring forward, in its next RRA, changes to the PTP transmission charge allocation methodology.

16. Given the reversal of the proposed allocation of PTP transmission charges, the forecast F2011 Trade Income shall be reduced by $23 million to $152 million and the forecast F2011 cost of energy shall also be reduced by $23 million.

17. $5.5 million of the PEI Regulatory Account balance shall be written off in F2011, and the closing F2011 balance of this account shall be amortized over 10 years beginning in F2012. There shall be no amortization of the balance of this account in F2011.

18. $10.3 million (for the amounts BC Hydro spent on energy conservation rates in F2009 and F2010) of the DSM Regulatory Account balance shall be written off in F2011, which results in a $1 million reduction in F2011 DSM amortization.

19. The forecast of F2011 capital expenditures shall be reduced by $100 million, and the forecast of F2011 capital additions shall be reduced by $50 million.

20. The Parties are unable to agree on the appropriate level of operating expenditures for F2011, but recognize that an oral hearing late in F2011 will not resolve F2011 rates prior to the end of the fiscal year. To avoid this outcome, and to advance other NSP determinations, the Parties have agreed, among other settlement terms, that BC Hydro's F2011 current operating costs shall be reduced by $35 million. For greater certainty, the parties agree that this operating cost reduction does not preclude a full review of BC Hydro's operating costs in its next RRA, nor does it imply acceptance by any Party of what an appropriate level of "base" operating expenditures should be.

21. The across-the-board 6.11 per cent rate increase approved, on an interim basis, by Order No. G-47-10 (Exhibit A-3) is confirmed as final.

22. The final F2011 DARR shall be 4.0 per cent for the period from April 1, 2010 to December 31, 2010, inclusive, and 2.5 per cent thereafter (2.5 per cent being approximately what the amortization proposal in item #9.i., above, is currently expected to yield).

23. The net impact on BC Hydro's F2011 revenue requirement of items 17 to 20, above, is $43.8 million, which shall be reflected in BC Hydro's rates as a 4.71 per cent credit applied to the

charges payable under all other approved rates, except for the DARR, for the period from January 1, 2011 to March 31, 2011, inclusive.

24. The combination of the final F2011 rate increase of 6.11 per cent and the 4.71 per cent credit applied to charges payable for the period from January to March, 2011 results in an effective weighted average rate increase for F2011 of 4.67 per cent. The overall annual bill impact of the 6.11 per cent rate increase, the 4.71 per cent credit applied to bills for the period January to March, and the changes in the DARR is 7.29 per cent. The changes to the F2011 revenue requirement and the adjustments to the regulatory account balances are summarized as follows.

	Total NSP Reduction ($ million)	**Settlement Reference**	**F2011**
	F11 Settlement Adjustment		
1	Impacts of Capital & Reg Acct Adjustments	17-19	(8.8)
2	Operating Cost Reduction	20	(35.0)
3	Powerex Net Income (PTP Allocation)	23	23.0
4	Cost of Energy (PTP Allocation)	23	(23.0)
5	Subtotal		(43.8)
6	**DSM Regulatory Account**	18	(10.3)
7	**PEI Regulatory Account**	17	(5.5)
8	**Total**		(59.6)

25. The forecasts of costs and revenues subject to deferral shall be as follows:

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	($ million)	Appendix 1 Reference	F2011 Update	F2011 NSP	Difference
			1	2	3 = 2 - 1
	Heritage Deferral Account				
1	Heritage Payment Obligation	4.0 L73	512.1	510.9	(1.2)
	Non-Heritage Deferral Account				
2	Non-Heritage COE Subject to Deferral	4.0 L83	572.4	572.3	(0.0)
3	Total Rate Revenue	1.0 L22	(3,227.3)	(3,183.6)	43.8
	Trade Income Deferral Account				
4	Trade Income	1.0 L17	175.0	152.0	(23.0)
	Other Regulatory Accounts				
5	Non-Current PEB - Pension	5.0 L18	21.2	21.2	0.0
6	Storm Restoration Costs		4.2	4.2	0.0
7	Taxes (Grants in Lieu and School Taxes)	1.0 L3	182.3	182.3	0.0
8	Total Finance Charges	1.0 L5	500.2	500.9	0.7
9	Amortization of Capital Additions		N/A	28.4	N/A

Appendix 1 - Revenue Requirement Schedules

F11 RRA Settlement
Schedules.xls

Revenue Requirements Model
Version: 2010-11-02 (Negotiated Settlement)

BC Hydro
F11 RRA
Revenue Requirement Summary
($ million)

Line	Column	Reference	F2007 Actual	F2008 Actual	F2009 RRA	F2009 Actual	F2009 Difference	F2010 RRA	F2010 Actual	F2010 Difference	F2011 Update	F2011 Increase
			1	2	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10 = 9 - 7
1	**Cost of Energy**	3.0 L12	1,091.2	970.4	1,141.6	1,282.8	141.3	1,225.5	1,209.9	(15.6)	1,415.1	205.2
2	**Operating Costs**	3.0 L17	645.7	885.6	801.2	831.1	29.9	814.8	1,186.6	371.8	981.2	(205.4)
	F11 Settlement Adjustment										**(35.0)**	
3	**Taxes**	3.0 L21	147.1	158.6	168.4	166.7	(1.7)	178.1	172.6	(5.5)	182.3	9.7
4	**Amortization**	3.0 L25	378.5	363.4	390.7	388.0	(2.7)	422.5	437.4	14.9	519.4	82.0
5	**Finance Charges**	3.0 L30	456.0	434.5	448.1	495.1	47.0	498.5	384.0	(114.5)	500.9	116.9
6	**Return on Equity**	3.0 L34	407.0	369.0	359.4	365.6	6.2	451.5	447.0	(4.5)	602.3	155.3
	F11 Settlement Adjustment										**(15.8)**	
7	**Non-Tariff Revenue**	3.0 L35	(45.2)	(31.4)	(40.9)	(44.0)	(3.1)	(39.9)	(55.2)	(15.3)	(44.6)	10.6
8	**Inter-Segment Revenue**	3.0 L41	(42.6)	(68.7)	(60.9)	30.5	91.4	(64.8)	(60.9)	3.9	(50.8)	10.1
	Deferral Accounts											
9	Deferral Account Additions	2.1 L28	22.4	96.3	0.0	(239.6)	(239.6)	0.0	(249.1)	(249.1)	(245.6)	3.5
10	Interest on Deferral Accounts	2.1 L29	(13.8)	(4.7)	(5.5)	(16.0)	(10.5)	(4.7)	(32.2)	(27.5)	(29.1)	3.1
11	Deferral Account Recoveries	2.1 L30	50.2	55.9	14.1	14.0	(0.0)	15.3	29.7	14.5	113.9	84.1
12	Total		58.8	147.5	8.6	(241.6)	(250.1)	10.6	(251.5)	(262.1)	(160.8)	90.7
	Other Regulatory Accounts											
13	Regulatory Account Additions	2.2 L133	(115.6)	(314.2)	(213.1)	(271.3)	(58.2)	(244.6)	(542.1)	(297.5)	(331.7)	210.4
14	Interest on Regulatory Accounts	2.2 L134	0.0	(3.3)	(3.6)	(3.9)	(0.2)	(5.7)	(9.9)	(4.2)	(11.2)	(1.3)
15	Regulatory Account Recoveries	2.2 L135	28.6	28.3	47.7	79.0	31.3	40.5	107.9	67.5	(83.2)	(191.1)
16	Total		(87.0)	(289.2)	(169.0)	(196.2)	(27.2)	(209.8)	(444.1)	(234.2)	(426.1)	18.0
	Subsidiary Net Income											
17	Powerex Net Income		(259.2)	(82.7)	(199.0)	(243.9)	(44.9)	(199.0)	**(7.5)**	191.5	**(152.0)**	(144.5)
18	Powertech Net Income		(1.2)	(0.5)	(1.7)	(1.2)	0.5	(1.9)	**(0.7)**	1.2	**(1.0)**	(0.4)
19	Total		(260.4)	(83.2)	(200.7)	(245.1)	(44.4)	(200.9)	(8.2)	192.7	(153.0)	(144.8)
20	**Less Other Utilities Revenue**	14.0 L17	(18.4)	(15.4)	(15.2)	(22.1)	(7.0)	(16.6)	(16.4)	0.3	(17.6)	(1.2)
21	**Less Deferral Rider**	14.0 L19	(10.1)	(55.7)	(14.1)	(14.0)	0.1	(15.3)	(29.7)	(14.4)	(113.9)	(84.2)
22	**Total Rate Revenue Requirement**		2,720.6	2,785.5	2,817.2	2,796.8	(20.4)	3,054.2	2,971.5	(82.6)	3,183.6	212.0
	Rate Revenue at Current Rates											
23	Total Domestic Revenue	14.0 L20	2,749.1	2,856.5	2,846.4	2,833.0	(13.5)	3,086.0	3,017.6	(68.4)	3,358.8	341.2
24	Less Other Utilities	Line 20	(18.4)	(15.4)	(15.2)	(22.1)	(7.0)	(16.6)	(16.4)	0.3	(17.6)	(1.2)
25	Less Deferral Rider	Line 21	(10.1)	(55.7)	(14.1)	(14.0)	0.1	(15.3)	(29.7)	(14.4)	(113.9)	(84.2)
26	Revenue Subject to Rate Increase		2,720.6	2,785.5	2,817.2	2,796.8	(20.4)	3,054.1	2,971.5	(82.6)	3,227.3	255.8
27	**Revenue Shortfall**	Line 22 - 26									(43.8)	
	Refund Jan-Mar 2011										**4.71%**	
	Rate Increase											
28	April 1, 2010 Interim Rate Increase										**6.11%**	
29	Balance										-1.36%	
30	Annualized Rate Increase					2.34%			8.74%		4.67%	
31	**Deferral Account Rate Rider**			2.00%		0.50%			1.00%		3.53%	
32	**Net Bill Impact**					0.83%			9.28%		7.29%	

BC Hydro
F11 RRA
Deferral Accounts
($ million)

Line	Column	Reference	F2007 Actual	F2008 Actual	F2009 RRA	F2009 Actual	F2009 Difference	F2010 RRA	F2010 Actual	F2010 Difference	F2011 Update	F2011 Increase
			1	2	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10 = 9 - 7
	Heritage Deferral Account											
1	Beginning of Year		240.7	178.1	78.0	78.0	0.0	70.7	328.9	258.2	324.9	(4.0)
2	Adjustment to Opening Balance		0.0	(2.0)	0.0	(0.1)	(0.1)	0.0	(0.0)	(0.0)	0.0	0.0
3	Additions	Line 35	(23.4)	(54.3)	0.0	259.8	259.8	0.0	3.1	3.1	0.0	(3.1)
4	Interest		14.1	6.3	4.7	13.9	9.2	4.0	**22.2**	18.2	13.1	(9.1)
5	Recovery		(53.3)	(50.2)	(12.0)	(22.6)	(10.6)	(13.0)	**(29.3)**	(16.3)	(63.3)	(34.0)
6	End of Year		178.1	78.0	70.7	328.9	258.2	61.7	324.9	263.2	274.7	(50.2)
	Non-Heritage Deferral Account											
7	Beginning of Year		204.6	208.8	51.6	51.6	(0.0)	86.0	74.4	(11.5)	119.5	45.1
8	Additions	Line 36	35.5	(107.1)	0.0	(12.9)	(12.9)	0.0	44.9	44.9	**222.5**	177.6
9	Interest		14.0	8.8	5.7	7.4	1.7	4.8	**6.8**	2.0	9.8	3.0
10	Recovery		(45.3)	(58.9)	(14.6)	(14.9)	(0.3)	(15.8)	**(6.6)**	9.2	(23.3)	(16.6)
11	Transfer of Storm Restoration	2.2 L44	0.0	0.0	43.2	43.2	0.0	0.0	0.0	0.0	0.0	0.0
11.1	Transfer from BCTCDA		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**39.4**	39.4
12	End of Year		208.8	51.6	86.0	74.4	(11.5)	75.0	119.5	44.5	367.9	248.4
	Trade Income Deferral Account											
13	Beginning of Year		(213.3)	(202.2)	(102.6)	(102.6)	0.0	(93.0)	(79.9)	13.2	121.7	201.5
14	Additions	Line 37	(20.2)	54.2	0.0	(1.0)	(1.0)	0.0	191.5	191.5	0.0	(191.5)
15	Interest		(15.9)	(11.5)	(6.2)	(5.9)	0.3	(5.2)	**3.0**	8.2	4.9	1.9
16	Recovery		47.2	56.9	15.8	29.6	13.9	17.1	**7.1**	(10.0)	(23.7)	(30.8)
17	End of Year		(202.2)	(102.6)	(93.0)	(79.9)	13.2	(81.2)	121.7	202.8	102.9	(18.8)
	BCTC Deferral Account											
18	Beginning of Year		24.9	13.3	21.5	21.5	(0.0)	19.5	9.7	(9.8)	18.6	9.0
19	Additions	Line 45	(14.4)	10.9	0.0	(6.2)	(6.2)	0.0	9.6	9.6	**23.1**	13.5
20	Interest		1.6	1.1	1.3	0.6	(0.7)	1.1	**0.2**	(0.9)	1.3	1.1
21	Recovery		1.2	(3.7)	(3.3)	(6.2)	(2.9)	(3.6)	**(0.9)**	2.7	(3.6)	(2.8)
21.1	Transfer to NHDA		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**(39.4)**	(39.4)
22	End of Year		13.3	21.5	19.5	9.7	(9.8)	17.0	18.6	1.6	0.0	(18.6)
	End of Year Balances											
23	Heritage	Line 6	178.1	78.0	70.7	328.9	258.2	61.7	324.9	263.2	274.7	(50.2)
24	Non-Heritage	Line 12	208.8	51.6	86.0	74.4	(11.5)	75.0	119.5	44.5	367.9	248.4
25	Trade Income	Line 17	(202.2)	(102.6)	(93.0)	(79.9)	13.2	(81.2)	121.7	202.8	102.9	(18.8)
26	BCTC	Line 22	13.3	21.5	19.5	9.7	(9.8)	17.0	18.6	1.6	0.0	(18.6)
27	Total		198.1	48.5	83.2	333.2	250.0	72.6	584.7	512.1	745.5	160.8
	Summary											
28	Deferral Account Additions		(22.4)	(96.3)	0.0	239.6	239.6	0.0	249.1	249.1	245.6	(3.5)
29	Interest on Deferral Accounts		13.8	4.7	5.5	16.0	10.5	4.7	32.2	27.5	29.1	(3.1)
30	Deferral Account Recoveries		(50.2)	(55.9)	(14.1)	(14.0)	0.0	(15.3)	(29.7)	(14.5)	(113.9)	(84.1)
31	Transfer of Storm Restoration	Line 11	0.0	0.0	43.2	43.2	0.0	0.0	0.0	0.0	0.0	0.0
32	Adjustment to Opening Balance	Line 2	0.0	(2.0)	0.0	(0.1)	(0.1)	0.0	(0.0)	(0.0)	0.0	0.0
33	Deferral Account Net Transfers		(58.8)	(149.5)	34.6	284.7	250.1	(10.6)	251.5	262.1	160.8	(90.7)
34	**Interest Rate (One Year Lag)**	8.0 L80		6.88%	6.52%	6.52%		6.20%	6.55%		4.47%	

Deferral Accounts
($ million)

Line	Column	Reference	F2007 Actual	F2008 Actual	F2009 RRA	F2009 Actual	F2009 Difference	F2010 RRA	F2010 Actual	F2010 Difference	F2011 Update	F2011 Increase
			1	2	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10 = 9 - 7
	Summary of Items Subject to Deferral											
35	Heritage Payment Obligation	4.0 L72	440.3	333.8	406.4	666.1	259.8	432.2	435.3	3.1	510.9	75.6
36	Cost of Non-Heritage Energy	4.0 L83	605.5	525.2	628.0	615.1	(12.9)	688.5	733.4	44.9	572.3	(161.1)
37	Trade Income	1.0 L17	200.0	82.7	199.0	200.0	1.0	199.0	7.5	(191.5)	152.0	144.5
	BCTC Costs:											
38	Transmission Asset Mgmt Fee	3.4 L17	87.3	87.3	90.9	90.9	0.0	92.4	92.4	0.0	N/A	N/A
39	GRTA Asset Mgmt Fee	3.4 L28	5.4	5.4	8.3	8.3	0.0	8.2	8.2	0.0	N/A	N/A
40	SDA Asset Mgmt Fee	3.4 L29	12.7	16.2	15.0	15.6	0.6	14.7	16.8	2.1	N/A	N/A
41	Domestic Transmission Cost	4.0 L16	36.8	75.7	91.9	92.0	0.1	88.9	87.9	(1.0)	N/A	N/A
42	Intersegment Revenues - PTP	3.4 L14	(54.3)	(54.4)	(56.6)	(55.9)	0.7	(60.5)	(60.0)	0.5	N/A	N/A
43	External PTP Revenues	3.4 L18	(8.5)	(8.5)	(8.4)	(8.2)	0.2	(8.3)	(8.1)	0.2	N/A	N/A
44	Adjustment		0.0	0.0	0.0	(7.9)	(7.9)	0.0	7.8	7.8	N/A	N/A
45	Total		79.4	121.7	141.1	134.9	(6.2)	135.4	145.0	9.6	N/A	N/A

Other Regulatory Accounts
($ million)

Line	Column	Reference	F2007 Actual	F2008 Actual	F2009 RRA	F2009 Actual	F2009 Difference	F2010 RRA	F2010 Actual	F2010 Difference	F2011 Update	F2011 Increase
			1	2	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10 = 9 - 7
	Demand-Side Management											
1	Beginning of Year		269.3	282.1	309.3	309.3	0.0	379.8	362.4	(17.4)	442.9	80.5
2	Adjustment to Opening Balance	CICA 3064	0.0	0.0	0.0	0.0	0.0	0.0	2.1	2.1	0.0	(2.1)
3	Additions	5.0 L32	46.4	63.3	112.1	94.9	(17.2)	138.2	130.4	(7.8)	184.4	54.0
3.1	F11 Settlement Adjustment	5.0 L21.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(10.3)	(10.3)
4	Amortization on Existing		(33.6)	(36.1)	(41.6)	(41.8)	(0.2)	(52.5)	**(51.9)**	0.6	**(63.1)**	(11.2)
5	Amortization on Additions	13.0 L72	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	End of Year		282.1	309.3	379.8	362.4	(17.4)	465.5	442.9	(22.6)	553.9	111.0
	First Nations Costs											
7	Beginning of Year		31.7	36.3	40.9	40.9	0.0	60.4	62.4	2.0	91.2	28.8
8	Adjustment to Opening Balance		0.0	0.0	0.0	2.6	2.6	0.0	**0.2**	0.2	0.0	(0.2)
9	Additions	5.0 L33	4.4	5.7	7.7	5.5	(2.2)	1.9	4.1	2.2	3.6	(0.5)
10	Transfer from Provision	Line 15	4.4	1.8	17.7	19.4	1.7	73.8	30.2	(43.6)	3.7	(26.5)
11	Recovery	5.0 L22	(4.2)	(2.9)	(5.9)	(6.0)	(0.1)	(6.7)	(5.7)	1.0	(6.5)	(0.8)
12	End of Year		36.3	40.9	60.4	62.4	2.0	129.4	91.2	(38.2)	92.1	0.8
	First Nations Settlement Provisions											
13	Beginning of Year		87.7	89.9	319.4	319.4	0.0	322.2	326.2	4.0	308.1	(18.1)
14	Additions	5.0 L34	6.6	231.3	20.5	26.2	5.7	19.0	12.2	(6.8)	16.4	4.2
15	Transfer to Negotiation Costs		(4.4)	(1.8)	(17.7)	(19.4)	(1.7)	(73.8)	**(30.2)**	43.6	**(3.7)**	26.5
16	End of Year		89.9	319.4	322.2	326.2	4.0	267.4	308.1	40.7	320.8	12.7
	F07/F08 RRA Depreciation Study											
17	Beginning of Year		0.0	19.2	14.4	14.4	0.0	9.6	9.6	0.0	4.8	(4.8)
18	Additions	7.0 L23	24.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
19	Recovery	7.0 L36	(4.8)	(4.8)	(4.8)	(4.8)	0.0	(4.8)	(4.8)	0.0	(4.8)	0.0
20	End of Year		19.2	14.4	9.6	9.6	0.0	4.8	4.8	0.0	0.0	(4.8)
	Site C											
21	Beginning of Year		0.0	3.7	8.7	8.7	0.0	27.3	34.7	7.3	59.4	24.8
22	Additions	5.0 L35	3.7	4.6	17.5	24.8	7.3	14.6	22.1	7.5	40.0	17.9
23	Interest		0.0	0.4	1.1	1.2	0.0	2.1	**2.7**	0.5	3.5	0.9
24	Recovery	5.0 L23	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
25	End of Year		3.7	8.7	27.3	34.7	7.3	44.1	59.4	15.3	103.0	43.5
	Future Removal and Site Restoration											
26	Beginning of Year		(226.9)	(210.9)	(192.2)	(192.2)	0.0	(175.2)	(172.2)	3.0	(159.4)	12.8
27	Adjustment to Opening Balance		0.0	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
28	Additions	N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
29	Recovery	7.0 L43	16.0	18.1	17.0	20.0	3.0	21.0	12.8	(8.3)	33.9	21.2
30	End of Year		(210.9)	(192.2)	(175.2)	(172.2)	3.0	(154.2)	(159.4)	(5.3)	(125.5)	33.9
	Foreign Exchange Gains/Losses											
31	Beginning of Year		2.6	(15.8)	(66.0)	(66.0)	0.0	(92.8)	(57.0)	35.8	(100.8)	(43.8)
32	Adjustment to Opening Balance		0.0	(17.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
33	Additions	8.0 L62	(2.4)	(17.6)	(2.8)	32.9	35.7	6.0	(33.8)	(39.8)	0.4	34.2
34	Recovery	8.0 L58	(16.0)	(15.3)	(24.0)	(23.9)	0.1	(8.3)	(10.0)	(1.7)	(0.2)	9.8
35	End of Year		(15.8)	(66.0)	(92.8)	(57.0)	35.8	(95.1)	(100.8)	(5.7)	(100.7)	0.2

Other Regulatory Accounts
($ million)

Line	Column	Reference	F2007 Actual	F2008 Actual	F2009 RRA	F2009 Actual	F2009 Difference	F2010 RRA	F2010 Actual	F2010 Difference	F2011 Update	F2011 Increase
			1	2	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10 = 9 - 7
	Pre-1996 Customer Contributions											
36	Beginning of Year		0.0	14.0	26.7	26.7	0.0	38.3	38.3	(0.0)	49.0	10.7
37	Additions	N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
38	Recovery	7.0 L44	14.0	12.7	11.6	11.6	(0.0)	10.8	10.7	(0.1)	9.7	(1.0)
39	End of Year		14.0	26.7	38.3	38.3	(0.0)	49.1	49.0	(0.1)	58.7	9.7
	Storm Restoration Costs											
40	Beginning of Year		0.0	32.9	43.2	43.2	0.0	0.0	(2.0)	(2.0)	(4.8)	(2.8)
41	Additions	5.0 L36	32.9	7.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
42	Interest		0.0	2.5	0.0	0.0	0.0	0.0	**(0.3)**	(0.3)	(0.2)	0.1
43	Recovery	5.0 L24	0.0	0.0	0.0	(2.0)	(2.0)	0.0	(2.5)	(2.5)	0.0	2.5
44	Transfer to NHDA		0.0	0.0	(43.2)	(43.2)	0.0	0.0	0.0	0.0	0.0	0.0
45	End of Year		32.9	43.2	0.0	(2.0)	(2.0)	0.0	(4.8)	(4.8)	(5.0)	(0.2)
	Procurement Enhancement											
46	Beginning of Year		0.0	0.0	7.3	7.3	0.0	30.0	29.2	(0.8)	40.3	11.1
47	Additions - Operating	5.0 L37	0.0	7.3	20.9	21.0	0.1	3.8	8.9	5.1	2.0	(6.9)
48	Additions - Amortization	7.0 L25	0.0	0.0	0.6	0.0	(0.6)	1.1	0.0	(1.1)	0.0	0.0
49	Interest		0.0	0.0	1.2	0.9	(0.3)	2.0	**2.2**	0.2	1.7	(0.5)
49.1	F11 Settlement Adjustment	5.0 L25.1	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**	0.0	(5.5)	(5.5)
50	Recovery	5.0 L25	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
51	End of Year		0.0	7.3	30.0	29.2	(0.8)	36.9	40.3	3.4	38.5	(1.8)
	Capital Project Investigation											
52	Beginning of Year		0.0	0.0	12.2	12.2	0.0	27.4	32.0	4.6	42.8	10.8
53	Adjustment to Opening Balance		0.0	0.0	0.0	3.1	3.1	0.0	**(0.8)**	(0.8)	0.0	0.8
54	Additions	5.0 L38	0.0	11.8	14.6	15.7	1.1	8.6	9.2	0.6	8.2	(1.0)
55	Interest		0.0	0.4	0.6	1.0	0.4	0.3	**2.3**	2.0	**1.5**	(0.8)
56	Recovery	5.0 L26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	(0.0)
57	End of Year		0.0	12.2	27.4	32.0	4.6	36.3	42.8	6.5	52.4	9.7
	GM Shrum 3											
58	Beginning of Year		0.0	0.0	0.0	0.0	0.0	22.7	42.4	19.7	41.5	(1.0)
59	Additions - Deferred Operating	5.0 L39	0.0	0.0	0.0	19.9	19.9	0.0	(1.6)	(1.6)	0.0	1.6
60	Additions - COE	4.0 L50	0.0	0.0	22.0	21.2	(0.8)	(5.0)	8.3	13.3	0.0	(8.3)
61	Interest		0.0	0.0	0.7	1.3	0.6	1.3	**2.8**	1.6	1.9	(1.0)
62	Insurance Proceeds	4.0 L51	0.0	0.0	0.0	0.0	0.0	0.0	(10.5)	(10.5)	0.0	10.5
63	End of Year		0.0	0.0	22.7	42.4	19.7	19.0	41.5	22.5	43.3	1.9
	ROE Adjustment											
64	Beginning of Year		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	56.4	56.4
65	Additions	9.0 L41	0.0	0.0	0.0	0.0	0.0	56.4	56.4	0.0	0.0	(56.4)
66	Interest		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
67	Recovery	9.0 L42	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(11.3)	(11.3)
68	End of Year		0.0	0.0	0.0	0.0	0.0	56.4	56.4	0.0	45.1	(11.3)

Other Regulatory Accounts
($ million)

Line		Reference	F2007 Actual	F2008 Actual	F2009 RRA	F2009 Actual	F2009 Difference	F2010 RRA	F2010 Actual	F2010 Difference	F2011 Update	F2011 Increase
	Column		1	2	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10 = 9 - 7
	Net Employment Costs											
69	Beginning of Year		0.0	0.0	0.0	0.0	0.0	0.0	(29.1)	(29.1)	(61.6)	(32.5)
70	Additions		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
71	Interest		0.0	0.0	0.0	(0.9)	(0.9)	0.0	**(3.0)**	(3.0)	(1.3)	1.7
72	Recovery	5.0 L27	0.0	0.0	0.0	(28.2)	(28.2)	0.0	(29.5)	(29.5)	62.9	92.5
73	End of Year		0.0	0.0	0.0	(29.1)	(29.1)	0.0	(61.6)	(61.6)	0.0	61.6
	Total Taxes											
74	Beginning of Year		0.0	0.0	0.0	0.0	0.0	0.0	(1.7)	(1.7)	(7.4)	(5.7)
75	Additions		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
76	Interest		0.0	0.0	0.0	0.0	0.0	0.0	**(0.3)**	(0.3)	(0.3)	(0.0)
77	Recovery	6.0 L24	0.0	0.0	0.0	(1.7)	(1.7)	0.0	**(5.4)**	(5.4)	0.0	5.4
78	End of Year		0.0	0.0	0.0	(1.7)	(1.7)	0.0	(7.4)	(7.4)	(7.7)	(0.3)
	Amortization on Capital Additions											
79	Beginning of Year		0.0	0.0	0.0	0.0	0.0	0.0	(2.8)	(2.8)	(5.7)	(2.9)
80	Additions		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
81	Interest		0.0	0.0	0.0	0.0	0.0	0.0	**(0.5)**	(0.5)	(0.1)	0.4
82	Recovery	7.0 L50	0.0	0.0	0.0	(2.8)	(2.8)	0.0	(2.4)	(2.4)	5.8	8.2
83	End of Year		0.0	0.0	0.0	(2.8)	(2.8)	0.0	(5.7)	(5.7)	0.0	5.7
	Total Finance Charges											
84	Beginning of Year		0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.6	(104.1)	(104.7)
85	Additions		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
86	Interest		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
87	Recovery	8.0 L59	0.0	0.0	0.0	0.6	0.6	0.0	(104.7)	(104.7)	104.1	208.9
88	End of Year		0.0	0.0	0.0	0.6	0.6	0.0	(104.1)	(104.1)	0.0	104.1
	Smart Metering & Infrastructure											
89	Beginning of Year		0.0	0.0	0.0	0.0	0.0	0.0	8.9	8.9	18.5	9.6
90	Additions - Deferred Operating	5.0 L40	0.0	0.0	0.0	8.6	8.6	0.0	8.8	8.8	19.7	10.9
91	Additions - Amortization	7.0 L26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.9	8.9
92	Additions - Interest		0.0	0.0	0.0	0.0	0.0	0.0	**0.0**	0.0	1.2	1.2
93	Interest		0.0	0.0	0.0	0.3	0.3	0.0	**0.8**	0.8	1.5	0.7
94	Recovery		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
95	End of Year		0.0	0.0	0.0	8.9	8.9	0.0	18.5	18.5	49.8	31.3
	Home Purchase Option Plan											
96	Beginning of Year		0.0	0.0	0.0	0.0	0.0	0.0	0.7	0.7	11.0	10.3
97	Additions - Deferred Operating	5.0 L41	0.0	0.0	0.0	0.7	0.7	0.0	7.1	7.1	4.9	(2.2)
98	Additions - Interest		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**1.3**	1.3
99	Interest		0.0	0.0	0.0	0.0	0.0	0.0	**3.2**	3.2	0.6	(2.6)
100	Recovery		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
101	End of Year		0.0	0.0	0.0	0.7	0.7	0.0	11.0	11.0	17.8	6.8
	Non-Current Pension Cost											
102	Beginning of Year		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	85.6	85.6
103	Additions		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
104	Interest		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
105	Recovery	5.0 L28	0.0	0.0	0.0	0.0	0.0	0.0	85.6	85.6	(17.1)	(102.7)
106	End of Year		0.0	0.0	0.0	0.0	0.0	0.0	85.6	85.6	68.5	(17.1)
	Waneta											
107	Beginning of Year		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
108	Additions		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30.0	30.0
109	Recovery		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
110	End of Year		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30.0	30.0
	Environmental Provisions											
110.1	Beginning of Year		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	320.5	320.5
110.2	Additions - Deferred Operating	5.0 L41.1	0.0	0.0	0.0	0.0	0.0	0.0	289.5	289.5	13.2	(276.3)
110.3	Additions - Amortization	7.0 L26.1	0.0	0.0	0.0	0.0	0.0	0.0	31.0	31.0	0.0	(31.0)
110.4	Recovery	5.0 L28.1-28.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(14.6)	(14.6)
110.5	End of Year		0.0	0.0	0.0	0.0	0.0	0.0	320.5	320.5	319.2	(1.3)

Other Regulatory Accounts
($ million)

Line	Column	Reference	F2007 Actual	F2008 Actual	F2009 RRA	F2009 Actual	F2009 Difference	F2010 RRA	F2010 Actual	F2010 Difference	F2011 Update	F2011 Increase
			1	2	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10 = 9 - 7
	End of Year Balances											
111	Demand-Side Management	Line 6	282.1	309.3	379.8	362.4	(17.4)	465.5	442.9	(22.6)	553.9	111.0
112	First Nations Costs	Line 12	36.3	40.9	60.4	62.4	2.0	129.4	91.2	(38.2)	92.1	0.8
113	First Nations Provisions	Line 16	89.9	319.4	322.2	326.2	4.0	267.4	308.1	40.7	320.8	12.7
114	F07/F08 RRA Depn Study	Line 20	19.2	14.4	9.6	9.6	0.0	4.8	4.8	0.0	0.0	(4.8)
115	Site C	Line 25	3.7	8.7	27.3	34.7	7.3	44.1	59.4	15.3	103.0	43.5
116	Future Removal	Line 30	(210.9)	(192.2)	(175.2)	(172.2)	3.0	(154.2)	(159.4)	(5.3)	(125.5)	33.9
117	Foreign Exchange	Line 35	(15.8)	(66.0)	(92.8)	(57.0)	35.8	(95.1)	(100.8)	(5.7)	(100.7)	0.2
118	Pre-1996 Contributions	Line 39	14.0	26.7	38.3	38.3	(0.0)	49.1	49.0	(0.1)	58.7	9.7
119	Storm Restoration	Line 45	32.9	43.2	0.0	(2.0)	(2.0)	0.0	(4.8)	(4.8)	(5.0)	(0.2)
120	Procurement Enhancement	Line 51	0.0	7.3	30.0	29.2	(0.8)	36.9	40.3	3.4	38.5	(1.8)
121	Capital Project Investigation	Line 57	0.0	12.2	27.4	32.0	4.6	36.3	42.8	6.5	52.4	9.7
122	GM Shrum 3	Line 63	0.0	0.0	22.7	42.4	19.7	19.0	41.5	22.5	43.3	1.9
123	ROE Adjustment	Line 68	0.0	0.0	0.0	0.0	0.0	56.4	56.4	0.0	45.1	(11.3)
124	Net Employment Costs	Line 73	0.0	0.0	0.0	(29.1)	(29.1)	0.0	(61.6)	(61.6)	0.0	61.6
125	Total Taxes	Line 78	0.0	0.0	0.0	(1.7)	(1.7)	0.0	(7.4)	(7.4)	(7.7)	(0.3)
126	Amortization - Capital Additions	Line 83	0.0	0.0	0.0	(2.8)	(2.8)	0.0	(5.7)	(5.7)	0.0	5.7
127	Total Finance Charges	Line 88	0.0	0.0	0.0	0.6	0.6	0.0	(104.1)	(104.1)	0.0	104.1
128	Smart Metering & Infrastructure	Line 95	0.0	0.0	0.0	8.9	8.9	0.0	18.5	18.5	49.8	31.3
129	Home Option Purchase Plan	Line 101	0.0	0.0	0.0	0.7	0.7	0.0	11.0	11.0	17.8	6.8
130	Non-Current Pension Cost	Line 106	0.0	0.0	0.0	0.0	0.0	0.0	85.6	85.6	68.5	(17.1)
131	Waneta	Line 110	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30.0	30.0
131.1	Environmental Provisions	Line 110.5	0.0	0.0	0.0	0.0	0.0	0.0	320.5	320.5	319.2	(1.3)
132	Total		251.4	523.9	649.7	682.6	32.9	859.6	1,128.1	268.5	1,554.2	426.1
	Summary											
133	Regulatory Account Additions		115.6	314.2	213.1	271.3	58.2	244.6	542.1	297.5	331.7	(210.4)
134	Interest on Regulatory Accounts		0.0	3.3	3.6	3.9	0.2	5.7	9.9	4.2	11.2	1.3
135	Regulatory Account Recoveries		(28.6)	(28.3)	(47.7)	(79.0)	(31.3)	(40.5)	(107.9)	(67.5)	83.2	191.1
136	Transfer of Storm Restoration	Line 44	0.0	0.0	(43.2)	(43.2)	0.0	0.0	0.0	0.0	0.0	0.0
137	Adjustments to Opening Balances		0.0	(16.7)	0.0	5.7	5.7	0.0	1.4	1.4	0.0	(1.4)
138	Regulatory Account Net Transfers		87.0	272.5	125.8	158.7	32.9	209.8	445.5	235.7	426.1	(19.4)
139	**Interest Rate (One Year Lag)**	8.0 L80		6.88%	6.52%	6.52%		6.20%	6.55%		4.47%	

Total Revenue Requirement - Reconcilation of GAAP View and Current Rates View
($ million)

Line	Column	Reference	F2007 Actual	F2008 Actual	F2009 RRA	F2009 Actual	F2009 Difference	F2010 RRA	F2010 Actual	F2010 Difference	F2011 Update	F2011 Increase
			1	2	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10 = 9 - 7
	Cost of Energy											
1	Total Current	4.0 L57	1,190.8	1,239.8	1,149.4	1,066.2	(83.2)	1,262.9	1,193.3	(69.5)	1,229.6	36.3
2	HDA Additions	4.0 L47	(23.4)	(54.3)	0.0	259.8	259.8	0.0	3.1	3.1	0.0	(3.1)
3	NHDA Additions	4.0 L48	35.5	(107.1)	0.0	(12.9)	(12.9)	0.0	44.9	44.9	222.5	177.6
4	BCTCDA Additions	4.0 L49	(14.4)	10.9	0.0	(6.2)	(6.2)	0.0	9.6	9.6	23.1	13.5
5	Deferred GMS 3 COE	4.0 L50	0.0	0.0	22.0	21.2	(0.8)	(5.0)	8.3	13.3	0.0	(8.3)
6	GMS 3 Insurance Proceeds	4.0 L51	0.0	0.0	0.0	0.0	0.0	0.0	(10.5)	(10.5)	0.0	10.5
7	Deferred Operating Expenses	4.0 L52	0.0	(6.0)	0.0	(1.5)	(1.5)	0.0	(2.1)	(2.1)	0.0	2.1
8	Deferred Waneta Costs	4.0 L53	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30.0	30.0
9	HDA Recoveries	4.0 L54	(53.3)	(50.2)	(12.0)	(22.6)	(10.6)	(13.0)	(29.3)	(16.3)	(63.3)	(34.0)
10	NHDA Recoveries	4.0 L55	(45.3)	(58.9)	(14.6)	(14.9)	(0.3)	(15.8)	(6.6)	9.2	(23.3)	(16.6)
11	BCTCDA Recoveries	4.0 L56	1.2	(3.7)	(3.3)	(6.2)	(2.9)	(3.6)	(0.9)	2.7	(3.6)	(2.8)
12	Total GAAP		1,091.2	970.4	1,141.6	1,282.8	141.3	1,225.5	1,209.9	(15.6)	1,415.1	205.2
	Operating Costs											
13	Total Current	5.0 L30	556.0	550.7	613.8	648.6	34.8	635.4	645.9	10.5	679.7	33.8
14	Deferral Account Additions	5.0 L31	0.0	6.0	0.0	1.5	1.5	0.0	2.1	2.1	0.0	(2.1)
15	Regulatory Account Additions	5.0 L42	93.9	331.8	193.3	217.3	24.0	186.1	490.7	304.6	292.4	(198.3)
16	Regulatory Account Recoveries	5.0 L29	(4.2)	(2.9)	(5.9)	(36.2)	(30.3)	(6.7)	47.9	54.6	9.0	(38.9)
17	Total GAAP		645.7	885.6	801.2	831.1	29.9	814.8	1,186.6	371.8	981.2	(205.4)
	Taxes											
18	Total Current	6.0 L25	147.1	158.6	168.4	168.4	0.0	178.1	178.1	0.0	182.3	4.2
19	Regulatory Account Additions	N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
20	Regulatory Account Recoveries	6.0 L24	0.0	0.0	0.0	(1.7)	(1.7)	0.0	(5.5)	(5.5)	0.0	5.5
21	Total GAAP		147.1	158.6	168.4	166.7	(1.7)	178.1	172.6	(5.5)	182.3	9.7
	Amortization											
22	Total Current	7.0 L52	362.9	373.4	407.9	405.9	(2.1)	446.8	442.1	(4.8)	529.0	86.9
23	Regulatory Account Additions	7.0 L23+27	24.0	0.0	0.6	0.0	(0.6)	1.1	31.0	29.9	8.9	(22.1)
24	Regulatory Account Recoveries	7.0 L51	(8.4)	(10.1)	(17.8)	(17.8)	0.0	(25.5)	(35.7)	(10.2)	(18.5)	17.1
25	Total GAAP		378.5	363.4	390.7	388.0	(2.7)	422.5	437.4	14.9	519.4	82.0
	Finance Charges											
26	Total Current	8.0 L61	460.6	459.4	465.7	465.7	(0.1)	490.4	490.4	0.0	356.3	(134.1)
27	Interest on Regulatory Accounts	8.0 L57	13.8	8.0	9.2	19.9	10.7	10.4	42.1	31.7	40.2	(1.9)
28	Regulatory Account Additions	8.0 L62	(2.4)	(17.6)	(2.8)	32.9	35.7	6.0	(33.8)	(39.8)	0.4	34.2
29	Regulatory Account Recoveries	8.0 L60	(16.0)	(15.3)	(24.0)	(23.3)	0.7	(8.3)	(114.7)	(106.4)	103.9	218.7
30	Total GAAP		456.0	434.5	448.1	495.1	47.0	498.5	384.0	(114.5)	500.9	116.9
	Return on Equity											
31	Total Current	9.0 L44	407.0	369.0	359.4	365.6	6.2	395.1	390.6	(4.5)	613.6	223.0
32	Regulatory Account Additions	9.0 L41	0.0	0.0	0.0	0.0	0.0	56.4	56.4	0.0	0.0	(56.4)
33	Regulatory Account Recoveries	9.0 L42	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(11.3)	(11.3)
34	Total GAAP		407.0	369.0	359.4	365.6	6.2	451.5	447.0	(4.5)	602.3	155.3
35	**Non-Tariff Revenue**	15.0 L19	(45.2)	(31.4)	(40.9)	(44.0)	(3.1)	(39.9)	(55.2)	(15.3)	(44.6)	10.6

BC Hydro
F11 RRA Total Revenue Requirement - Reconcilation of GAAP View and Current Rates View
($ million)

Line	Column	Reference	F2007 Actual	F2008 Actual	F2009 RRA	F2009 Actual	F2009 Difference	F2010 RRA	F2010 Actual	F2010 Difference	F2011 Update	F2011 Increase
			1	2	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10 = 9 - 7
	Inter-Segment Revenue											
36	Powerex - Corporate Allocation	3.1 L9	(4.6)	(4.0)	(4.3)	(4.3)	0.0	(4.3)	(4.3)	0.0	(2.8)	1.5
37	Mark to Market Losses (Gains)	3.1 L10	17.6	(10.3)	0.0	90.2	90.2	0.0	3.8	3.8	0.0	(3.8)
38	Other	3.1 L11	(1.3)	0.0	0.0	0.5	0.5	0.0	(0.4)	(0.4)	0.0	0.4
39	Powerex PTP Charges	3.4 L12	(33.8)	(33.0)	(28.3)	(34.6)	(6.3)	(29.5)	(35.2)	(5.7)	(15.1)	20.1
40	BC Hydro PTP Charges	3.4 L13	(20.5)	(21.3)	(28.3)	(21.3)	7.0	(31.0)	(24.8)	6.2	(32.8)	(8.0)
41	Total		(42.6)	(68.7)	(60.9)	30.5	91.4	(64.8)	(60.9)	3.9	(50.8)	10.1
	Regulatory Account Transfers											
42	Deferral Accounts	1.0 L12	58.8	147.5	8.6	(241.6)	(250.1)	10.6	(251.5)	(262.1)	(160.8)	90.7
43	Other Regulatory Accounts	1.0 L16	(87.0)	(289.2)	(169.0)	(196.2)	(27.2)	(209.8)	(444.1)	(234.2)	(426.1)	18.0
44	Total		(28.2)	(141.7)	(160.4)	(437.8)	(277.3)	(199.2)	(695.6)	(496.4)	(586.9)	108.7
	Powerex Net Income											
45	Total Current		(286.2)	(193.8)	(214.8)	(272.5)	(57.8)	(216.1)	(206.1)	10.0	(128.3)	77.8
46	TIDA Additions	2.1 L14	(20.2)	54.2	0.0	(1.0)	(1.0)	0.0	191.5	191.5	0.0	(191.5)
47	TIDA Recoveries	2.1 L16	47.2	56.9	15.8	29.6	13.9	17.1	7.1	(10.0)	(23.7)	(30.8)
48	Total GAAP		(259.2)	(82.7)	(199.0)	(243.9)	(44.9)	(199.0)	(7.5)	191.5	(152.0)	(144.5)
49	**Powertech Net Income**	1.0 L18	(1.2)	(0.5)	(1.7)	(1.2)	0.5	(1.9)	(0.7)	1.2	(1.0)	(0.4)
50	**Other Utilities Revenue**	14.0 L17	(18.4)	(15.4)	(15.2)	(22.1)	(7.0)	(16.6)	(16.4)	0.3	(17.6)	(1.2)
51	**Deferral Rider Revenue**	14.0 L19	(10.1)	(55.7)	(14.1)	(14.0)	0.1	(15.3)	(29.7)	(14.4)	(113.9)	(84.2)
	F11 Settlement Adjustment										(50.8)	
52	**Total Rate Revenue Requirement**		2,720.6	2,785.5	2,817.2	2,796.8	(20.4)	3,054.2	2,971.5	(82.6)	3,183.6	212.0
	Summary - Current Rates View											
53	Cost of Energy	Line 1	1,190.8	1,239.8	1,149.4	1,066.2	(83.2)	1,262.9	1,193.3	(69.5)	1,229.6	36.3
54	Operating Costs	Line 13	556.0	550.7	613.8	648.6	34.8	635.4	645.9	10.5	679.7	33.8
55	Taxes	Line 18	147.1	158.6	168.4	168.4	0.0	178.1	178.1	0.0	182.3	4.2
56	Amortization	Line 22	362.9	373.4	407.9	405.9	(2.1)	446.8	442.1	(4.8)	529.0	86.9
57	Finance Charges	Line 26	460.6	459.4	465.7	465.7	(0.1)	490.4	490.4	0.0	356.3	(134.1)
58	Return on Equity	Line 31	407.0	369.0	359.4	365.6	6.2	395.1	390.6	(4.5)	613.6	223.0
59	Non-Tariff Revenue	Line 35	(45.2)	(31.4)	(40.9)	(44.0)	(3.1)	(39.9)	(55.2)	(15.3)	(44.6)	10.6
60	Inter-Segment Revenue	Line 41	(42.6)	(68.7)	(60.9)	30.5	91.4	(64.8)	(60.9)	3.9	(50.8)	10.1
61	Subsididary Net Income	Lines 45+49	(287.4)	(194.3)	(216.5)	(273.7)	(57.2)	(218.0)	(206.7)	11.3	(129.3)	77.4
62	Other Utilities Revenue	Line 50	(18.4)	(15.4)	(15.2)	(22.1)	(7.0)	(16.6)	(16.4)	0.3	(17.6)	(1.2)
63	Deferral Rider Revenue	Line 51	(10.1)	(55.7)	(14.1)	(14.0)	0.1	(15.3)	(29.7)	(14.4)	(113.9)	(84.2)
	F11 Settlement Adjustment										(50.8)	
64	Total Rate Revenue Requirement		2,720.7	2,785.5	2,817.2	2,796.8	(20.4)	3,054.2	2,971.5	(82.6)	3,183.6	212.0
	Current Costs by Business Group											
65	Corporate	3.1 L13	69.2	23.1	14.0	134.5	120.5	(6.2)	28.4	34.6	0.0	(28.4)
66	EARG	3.2 L10	1,279.7	1,227.2	1,192.9	1,138.7	(54.2)	1,285.7	1,306.1	20.4	1,529.2	223.1
67	CC&C	3.3 L9	730.4	838.3	845.2	821.4	(23.8)	911.7	816.2	(95.5)	799.5	(16.8)
68	Transmission	3.4 L15	385.3	389.3	406.0	403.5	(2.5)	440.9	438.4	(2.5)	459.9	21.5
69	Field Operations	3.5 L10	572.0	572.9	604.8	608.6	3.7	671.9	635.1	(36.8)	706.5	71.4
70	Subsididary Net Income	Line 61	(287.4)	(194.3)	(216.5)	(273.7)	(57.2)	(218.0)	(206.7)	11.3	(129.3)	77.4
71	Other Utilities Revenue	Line 62	(18.4)	(15.4)	(15.2)	(22.1)	(7.0)	(16.6)	(16.4)	0.3	(17.6)	(1.2)
72	Deferral Rider Revenue	Line 63	(10.1)	(55.7)	(14.1)	(14.0)	0.1	(15.3)	(29.7)	(14.4)	(113.9)	(84.2)
	F11 Settlement Adjustment										(50.8)	
73	Total Rate Revenue Requirement		2,720.7	2,785.5	2,817.2	2,796.8	(20.4)	3,054.2	2,971.5	(82.6)	3,183.6	212.0

Total Costs - Corporate
($ million)

			F2007	F2008	F2009			F2010			F2011	F2011
		Reference	Actual	Actual	RRA	Actual	Difference	RRA	Actual	Difference	Update	Increase
Line	Column		1	2	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10 = 9 - 7
1	**Cost of Energy**	N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	**Current Operating Costs**	5.0 L44,49-51.1	160.1	124.8	148.1	176.7	28.6	136.3	165.4	29.1	178.8	13.4
3	**Taxes**	6.0 L27	7.8	8.1	9.0	9.0	0.0	9.5	9.5	0.0	10.0	0.5
4	**Current Amortization**	7.0 L53	40.7	44.2	49.2	50.9	1.7	52.1	54.9	2.8	50.1	(4.8)
5	**Current Finance Charges**	N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	**Return on Equity**	N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
										0.0		
7	**Corporate Allocation**	Line 58	(140.2)	(134.9)	(181.2)	(181.2)	0.0	(193.0)	(193.0)	0.0	(229.1)	(36.1)
8	**Non-Tariff Revenue**	15.0 L4	(10.9)	(4.7)	(6.8)	(7.3)	(0.5)	(6.8)	(7.5)	(0.7)	(7.0)	0.5
	Inter-Segment Revenue											
9	Powerex - Corporate Allocation		(4.6)	(4.0)	(4.3)	(4.3)	0.0	(4.3)	**(4.3)**	0.0	**(2.8)**	1.5
10	Mark to Market Losses (Gains)		17.6	(10.3)	0.0	90.2	90.2	0.0	**3.8**	3.8	**0.0**	(3.8)
11	Other		(1.3)	0.0	0.0	0.5	0.5	0.0	(0.4)	(0.4)	**0.0**	0.4
12	Total		11.7	(14.3)	(4.3)	86.4	90.7	(4.3)	(0.9)	3.4	(2.8)	(1.9)
13	**Total**		69.2	23.1	14.0	134.5	120.5	(6.2)	28.4	34.6	0.0	(28.4)

Corporate Allocation:

Line		F2011 Update
	Building Operations	
14	EARG	**3.4**
15	CC&C	**1.6**
16	Transmission	**0.0**
17	Field Operations	**10.5**
18	Total	15.5
	ABS Costs	
19	EARG	**28.9**
20	CC&C	**5.3**
21	Transmission	**0.0**
22	Field Operations	**32.8**
23	Total	67.0
	Insurance	
24	EARG	**5.0**
25	CC&C	**0.3**
26	Transmission	**1.2**
27	Field Operations	**1.5**
28	Total	8.0

Total Costs - Corporate
($ million)

Line		Reference	F2007 Actual	F2008 Actual	F2009 RRA	F2009 Actual	F2009 Difference	F2010 RRA	F2010 Actual	F2010 Difference	F2011 Update	F2011 Increase
	Column		1	2	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10 = 9 - 7
	Customer Care Support and Billing System Amortization											
29	EARG										0.0	
30	CC&C										13.0	
31	Transmission										0.0	
32	Field Operations										0.0	
33	Total										13.0	
	Non-Current Pension Costs											
34	EARG										19.8	
35	CC&C										5.0	
36	Transmission										0.0	
37	Field Operations										23.6	
38	Total										48.4	
	Total Direct Assigments											
39	EARG										57.2	
40	CC&C										25.2	
41	Transmission										1.2	
42	Field Operations										68.4	
43	Total										152.0	
	Allocators for Balance - %											
44	EARG										38.3%	
45	CC&C										12.5%	
46	Transmission										13.0%	
47	Field Operations										36.2%	
48	Total										100.0%	
	Allocation of Balance											
49	EARG										29.5	
50	CC&C										9.7	
51	Transmission										10.0	
52	Field Operations										27.9	
53	Total										77.1	
	Total Corporate Allocation											
54	EARG		51.4	49.5	57.5	57.5	0.0	61.5	61.5	0.0	86.7	25.3
55	CC&C		0.0	0.0	31.4	31.4	0.0	32.9	32.9	0.0	34.9	2.0
56	Transmission		11.2	10.8	19.2	19.2	0.0	20.8	20.8	0.0	11.1	(9.6)
57	Field Operations		77.6	74.6	73.0	73.0	0.0	77.9	77.9	0.0	96.3	18.5
58	Total		140.2	134.9	181.2	181.2	0.0	193.0	193.0	0.0	229.1	36.1

Total Costs - Engineering, Aboriginal Relations & Generation
($ million)

Line	Column	Reference	F2007 Actual	F2008 Actual	F2009 RRA	F2009 Actual	F2009 Difference	F2010 RRA	F2010 Actual	F2010 Difference	F2011 Update	F2011 Increase
			1	2	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10 = 9 - 7
1	**Cost of Energy**	4.0 L59	534.7	474.2	412.7	358.5	(54.2)	464.6	485.2	20.7	582.3	97.0
2	**Current Operating Costs**	5.0 L45	104.1	112.1	145.7	142.0	(3.7)	154.1	139.8	(14.3)	138.6	(1.2)
3	**Taxes**	6.0 L28	29.9	33.9	35.5	35.5	0.0	36.7	36.7	0.0	38.4	1.7
4	**Current Amortization**	7.0 L54	141.9	145.6	149.7	150.7	0.9	163.4	167.0	3.6	203.7	36.7
5	**Current Finance Charges**	8.0 L69	205.3	209.1	205.7	206.0	0.3	209.3	221.3	12.0	165.5	(55.8)
6	**Return on Equity**	9.0 L50	181.4	167.9	158.8	161.7	3.0	168.6	176.3	7.6	285.0	108.8
7	**Corporate Allocation**	3.1 L54	51.4	49.5	57.5	57.5	0.0	61.5	61.5	0.0	86.7	25.3
8	**Non-Tariff Revenue**	15.0 L8	(6.8)	(3.0)	(7.7)	(8.2)	(0.5)	(7.6)	(16.8)	(9.2)	(6.2)	10.6
	Internal Allocations											
9	GRTA Asset Charges	3.4 L9	37.9	37.9	35.0	35.0	0.0	35.1	35.1	0.0	35.1	0.0
10	**Total**		1,279.7	1,227.2	1,192.9	1,138.7	(54.2)	1,285.7	1,306.1	20.4	1,529.2	223.1

Total Costs - Customer Care & Conservation
($ million)

Line	Column	Reference	F2007 Actual	F2008 Actual	F2009 RRA	F2009 Actual	F2009 Difference	F2010 RRA	F2010 Actual	F2010 Difference	F2011 Update	F2011 Increase
			1	2	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10 = 9 - 7
1	Cost of Energy	4.0 L60	656.2	765.6	736.7	707.7	(29.0)	798.3	708.1	(90.2)	647.3	(60.7)
2	Current Operating Costs	5.0 L46	86.5	90.3	86.4	90.8	4.4	88.8	88.0	(0.8)	110.0	22.0
3	Taxes	6.0 L29	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.6	1.6
4	Current Amortization	7.0 L55	1.2	(8.8)	2.0	3.2	1.2	2.2	1.7	(0.5)	17.8	16.1
5	Current Finance Charges	8.0 L70	0.2	0.5	0.7	0.5	(0.2)	0.8	0.3	(0.5)	0.3	(0.0)
6	Return on Equity	9.0 L51	0.2	0.4	0.5	0.4	(0.1)	0.6	0.2	(0.4)	0.4	0.2
7	Corporate Allocation	3.1 L55	0.0	0.0	31.4	31.4	0.0	32.9	32.9	0.0	34.9	2.0
8	Non-Tariff Revenue	15.0 L13	(13.8)	(9.7)	(12.5)	(12.6)	(0.1)	(11.8)	(14.9)	(3.1)	(12.8)	2.1
9	Total		730.4	838.3	845.2	821.4	(23.8)	911.7	816.2	(95.5)	799.5	(16.8)

Total Costs - Transmission Owner
($ million)

Line	Column	Reference	F2007 Actual	F2008 Actual	F2009 RRA	F2009 Actual	F2009 Difference	F2010 RRA	F2010 Actual	F2010 Difference	F2011 Update	F2011 Increase
			1	2	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10 = 9 - 7
1	**Cost of Energy**	N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	**Current Operating Costs**	5.0 L47	93.4	94.7	94.4	97.6	3.2	95.9	112.6	16.8	104.0	(8.7)
3	**Taxes**	6.0 L30	88.5	94.4	100.0	100.0	0.0	104.1	104.1	0.0	106.5	2.4
4	**Current Amortization**	7.0 L56	92.3	99.1	103.9	97.4	(6.6)	114.9	111.5	(3.4)	125.9	14.4
5	**Current Finance Charges**	8.0 L71	121.6	121.8	125.0	123.9	(1.1)	135.9	126.7	(9.2)	87.0	(39.7)
6	**Return on Equity**	9.0 L52	107.5	97.8	96.5	97.3	0.8	109.5	100.9	(8.6)	149.7	48.8
7	**Corporate Allocation**	3.1 L56	11.2	10.8	19.2	19.2	0.0	20.8	20.8	0.0	11.1	(9.6)
8	**Non-Tariff Revenue**	15.0 L17	(11.8)	(12.0)	(11.9)	(11.6)	0.3	(11.7)	(11.4)	0.3	(12.0)	(0.6)
	Internal Allocations:											
9	GRTA Asset Charges		(37.9)	(37.9)	(35.0)	(35.0)	0.0	(35.1)	(35.1)	0.0	**(35.1)**	0.0
10	SDA Asset Charges		(25.3)	(24.9)	(29.7)	(29.5)	0.2	(32.8)	(31.6)	1.2	**(29.2)**	2.4
11	Total		(63.2)	(62.8)	(64.7)	(64.5)	0.2	(67.9)	(66.7)	1.2	(64.3)	2.4
	Inter-Segment Revenue											
12	Powerex PTP Charges		(33.8)	(33.0)	(28.3)	(34.6)	(6.3)	(29.5)	**(35.2)**	(5.7)	**(15.1)**	20.1
13	BC Hydro PTP Charges		(20.5)	(21.3)	(28.3)	(21.3)	7.0	(31.0)	**(24.8)**	6.2	**(32.8)**	(8.0)
14	Total		(54.3)	(54.4)	(56.6)	(55.9)	0.7	(60.5)	(60.0)	0.5	(47.9)	12.1
15	**Total**		385.3	389.3	406.0	403.5	(2.5)	440.9	438.4	(2.5)	459.9	21.5
	Owner's Revenue Requirement											
16	Total Costs	Line 15	385.3	389.3	406.0	403.5	(2.5)	440.9	438.4	(2.5)	459.9	21.5
17	Less Asset Management Fee	5.4 L3	(87.3)	(87.3)	(90.9)	(90.9)	0.0	(92.4)	(92.4)	0.0	(91.4)	1.0
18	Plus Short-term PTP/Ancillary	15.0 L14	8.5	8.5	8.4	8.2	(0.2)	8.3	8.1	(0.2)	8.4	0.3
19	Plus Inter-Segment Revenue	Line 14	54.3	54.4	56.6	55.9	(0.7)	60.5	60.0	(0.5)	47.9	(12.1)
20	Owner's Revenue Requirement		360.8	364.9	380.1	376.7	(3.4)	417.3	414.1	(3.2)	424.9	10.8
	BC Hydro Services to BCTC											
21	Engineering Services		53.5	62.7	58.0	65.9	7.9	61.1	**60.9**	(0.2)	**N/A**	**N/A**
22	Field Services		103.5	104.4	111.1	126.4	15.3	114.9	**142.3**	27.4	**N/A**	**N/A**
23	Interconnected Operations Services		4.2	4.0	4.0	4.5	0.5	4.0	**3.1**	(0.9)	**N/A**	**N/A**
24	Other Services		5.0	4.9	5.1	**4.0**	(1.1)	5.1	**3.6**	(1.5)	**N/A**	**N/A**
25	Total		166.2	176.0	178.2	200.8	22.6	185.1	209.9	24.8	**N/A**	**N/A**
	BCTC Services to BC Hydro											
26	Generation Real Time Dispatch		0.9	1.0	1.0	1.0	0.0	1.0	1.0	0.0	**N/A**	**N/A**
27	Distribution Real Time Dispatch		6.7	6.8	6.9	7.0	0.1	7.1	**7.4**	0.3	**N/A**	**N/A**
28	GRTA Asset Management Fee		5.4	5.4	8.3	8.3	0.0	8.2	8.2	0.0	**N/A**	**N/A**
29	SDA Asset Management Fee		12.7	16.2	15.0	15.6	0.6	14.7	**16.8**	2.1	**N/A**	**N/A**
30	Total		25.7	29.4	31.2	31.9	0.7	31.0	33.4	2.4	**N/A**	**N/A**

Total Costs - Field Operations
($ million)

Line	Column	Reference	F2007 Actual	F2008 Actual	F2009 RRA	F2009 Actual	F2009 Difference	F2010 RRA	F2010 Actual	F2010 Difference	F2011 Update	F2011 Increase
			1	2	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10 = 9 - 7
1	**Cost of Energy**	N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	**Current Operating Costs**	5.0 L48	111.8	128.9	139.2	141.5	2.3	160.3	140.1	(20.2)	148.5	8.3
3	**Taxes**	6.0 L31	20.9	22.2	23.9	23.9	0.0	27.8	27.8	0.0	25.8	(2.0)
4	**Current Amortization**	7.0 L57	86.8	93.3	103.1	103.7	0.6	114.3	107.0	(7.3)	131.5	24.6
5	**Current Finance Charges**	8.0 L72	133.5	128.1	134.3	135.2	0.9	144.5	142.1	(2.3)	103.6	(38.5)
6	**Return on Equity**	9.0 L53	118.0	102.9	103.6	106.1	2.5	116.4	113.2	(3.2)	178.4	65.2
7	**Corporate Allocation**	3.1 L57	77.6	74.6	73.0	73.0	0.0	77.9	77.9	0.0	96.3	18.5
8	**Non-Tariff Revenue**	15.0 L18	(1.9)	(2.0)	(2.0)	(4.3)	(2.3)	(2.0)	(4.6)	(2.6)	(6.7)	(2.1)
	Internal Allocations											
9	SDA Asset Charges	3.4 L10	25.3	24.9	29.7	29.5	(0.2)	32.8	31.6	(1.2)	29.2	(2.4)
10	**Total**		572.0	572.9	604.8	608.6	3.7	671.9	635.1	(36.8)	706.5	71.4

Cost of Energy (COE)

Line		Reference	F2007 Actual	F2008 Actual	F2009 RRA	F2009 Actual	F2009 Difference	F2010 RRA	F2010 Actual	F2010 Difference	F2011 Update	F2011 Increase
		Column	1	2	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10 = 9 - 7
	Cost of Energy ($ million)											
	Heritage Energy											
1	Hydroelectric (water rentals)		257.5	315.0	334.0	309.7	(24.3)	339.1	**311.1**	(28.1)	319.8	8.7
2	Impact of Proposed Rates		0.0	0.0	0.0	0.0	0.0	0.0	**0.0**	0.0	3.7	3.7
3	Market electricity purchases		249.7	153.3	32.6	272.6	240.0	59.6	**80.5**	20.9	148.3	67.8
4	Market Purchases to Non-Heritage		(135.3)	(143.5)	0.0	(22.8)	(22.8)	0.0	**0.0**	0.0	0.0	0.0
5	Natural gas for thermal generation		65.0	49.1	40.6	47.3	6.7	39.2	**38.9**	(0.3)	37.3	(1.6)
6	Domestic transmission		14.9	15.7	15.3	15.8	0.5	15.5	**15.9**	0.4	**15.7**	(0.2)
7	Surplus Sales		0.0	(31.9)	(1.5)	(9.7)	(8.2)	(6.8)	**0.0**	6.8	**0.0**	0.0
8	Other		6.2	6.0	1.8	2.4	0.6	0.0	**8.4**	8.4	**(5.9)**	(14.3)
9	Total		458.0	363.7	422.7	615.3	192.6	446.6	454.8	8.2	519.0	64.2
	Non-Heritage Energy											
10	Mkt Purchases From Heritage	Line 4	135.3	143.5	0.0	22.8	22.8	0.0	0.0	0.0	0.0	0.0
11	Waneta (water rentals)		0.0	0.0	0.0	0.0	0.0	0.0	**0.5**	0.5	6.9	6.4
12	Impact of Proposed Rates		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1
13	IPPs and Long-Term Commitments		364.4	480.0	583.1	543.0	(40.1)	627.6	**567.4**	(60.2)	710.4	143.0
14	Non-Integrated Area		20.4	21.7	25.7	24.0	(1.7)	26.5	**20.7**	(5.8)	23.6	2.9
15	Gas & Other Transportation		9.5	11.5	17.1	11.5	(5.6)	16.0	**11.4**	(4.6)	**13.3**	1.9
16	Domestic Transmission		36.8	75.7	91.9	92.0	0.1	88.9	**87.9**	(1.0)	**94.9**	7.0
17	Net Purchases (Sales) from Powerex		66.8	(125.6)	1.1	(25.8)	(26.9)	19.9	**67.2**	47.3	**46.8**	(20.4)
18	Total		633.2	606.7	718.9	667.5	(51.4)	778.9	755.1	(23.8)	896.1	140.9
19	**Total GAAP COE**	Lines 9+18	1,091.2	970.4	1,141.6	1,282.8	141.3	1,225.5	1,209.9	(15.6)	1,415.1	205.2
	Sources of Supply (GWh)											
	Heritage Energy											
20	Hydroelectric (water rentals)		44,476	52,140	48,274	43,812	-4,462	46,817	**43,137**	-3,680	**40,669**	-2,468
21	Net Purchases (Sales) from Powerex		656	-2,412	-161	-65	96	213	**1,525**	1,312	**847**	-678
22	Market electricity purchases		5,698	2,258	588	5,020	4,432	1,091	**2,161**	1,070	**3,553**	1,392
23	Market Purchases to Non-Heritage		-3,087	-2,113	0	-419	-419	0	0	0	0	0
24	Natural gas for thermal generation		847	423	272	312	40	260	**400**	141	**329**	-71
25	Surplus Sales		0	-811	-24	-196	-172	-99	**0**	99	**0**	0
26	Exchange net		410	-485	-12	536	548	224	**-1,092**	-1,316	**177**	1,269
27	Total		49,000	49,000	48,937	49,000	63	48,505	46,131	-2,375	45,575	-555
	Non-Heritage Energy											
28	Waneta (water rentals)		0	0	0	0	0	0	**71**	71	**1,008**	937
29	IPPs and Long-Term Commitments		6,041	7,765	8,950	8,374	-576	9,277	**8,893**	-384	**10,504**	1,611
30	Mkt Purchases From Heritage	Line 23	3,087	2,113	0	419	419	0	0	0	0	0
31	Non-Integrated Area		112	115	112	116	4	115	**113**	-2	**116**	3
32	Total		9,240	9,993	9,062	8,909	-153	9,392	9,077	-315	11,628	2,551
33	**Total Sources of Supply**	Lines 27+32	58,240	58,993	57,999	57,909	-90	57,898	55,208	-2,690	57,204	1,996
34	**Less Line Loss and System Use**		-5,329	-5,694	-5,297	-5,593	-296	-5,276	-4,975	301	-5,409	-434
35	**Total Domestic Sales**	14.0 L9	52,911	53,299	52,702	52,316	-386	52,622	50,233	-2,389	51,794	1,561

BC Hydro
F11 RRA
Cost of Energy (COE)

Line	Column	Reference	F2007 Actual	F2008 Actual	F2009 RRA	F2009 Actual	F2009 Difference	F2010 RRA	F2010 Actual	F2010 Difference	F2011 Update	F2011 Increase
			1	2	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10 = 9 - 7
36	**Line Loss as % of Sales**		10.07%	10.68%	10.05%	10.69%	0.64%	10.03%	**9.90%**	-0.12%	**10.44%**	0.54%
	Unit Costs ($/MWh)											
37	Hydroelectric (water rentals)		5.8	6.0	6.9	7.1	0.2	7.4	7.2	(0.2)	**7.9**	0.7
38	Impact of Proposed Rates		-	-	-	-	-	-	-	-	0.1	0.1
39	Waneta (water rentals)		-	-	-	-	-	-	7.0	-	**6.8**	-
40	Impact of Proposed Rates		-	-	-	-	-	-	-	-	0.1	-
41	IPPs and Long-Term Commitments		60.3	61.8	65.2	64.8	(0.3)	67.7	63.8	(3.8)	**67.6**	3.8
42	Market electricity purchases		43.8	67.9	55.4	54.3	(1.1)	54.7	37.3	(17.4)	**41.7**	4.5
43	Natural gas for thermal generation		76.7	116.1	149.5	151.6	2.1	151.1	97.3	(53.8)	**113.3**	16.0
44	Non-Integrated Area		181.9	187.7	228.7	206.9	(21.8)	229.8	183.1	(46.7)	**202.8**	19.7
45	Total Weighted Cost		20.6	18.2	21.7	24.5	2.9	23.3	24.1	0.8	27.3	3.2
	Current Cost of Energy											
46	GAAP Cost of Energy	Line 19	1,091.2	970.4	1,141.6	1,282.8	141.3	1,225.5	1,209.9	(15.6)	1,415.1	205.2
47	HDA Additions		23.4	54.3	0.0	(259.8)	(259.8)	0.0	(3.1)	(3.1)	0.0	3.1
48	NHDA Additions		(35.5)	107.1	0.0	12.9	12.9	0.0	(44.9)	(44.9)	(222.5)	(177.6)
49	BCTCDA Additions		14.4	(10.9)	0.0	6.2	6.2	0.0	(9.6)	(9.6)	(23.1)	(13.5)
50	Deferred GMS 3 COE		0.0	0.0	(22.0)	(21.2)	0.8	5.0	(8.3)	(13.3)	0.0	8.3
51	GMS 3 Insurance Proceeds		0.0	0.0	0.0	0.0	0.0	0.0	10.5	10.5	0.0	(10.5)
52	Deferred Operating Expenses		0.0	6.0	0.0	1.5	1.5	0.0	2.1	2.1	0.0	(2.1)
53	Deferred Waneta Costs		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(30.0)	(30.0)
54	HDA Recoveries		53.3	50.2	12.0	22.6	10.6	13.0	29.3	16.3	63.3	34.0
55	NHDA Recoveries		45.3	58.9	14.6	14.9	0.3	15.8	6.6	(9.2)	23.3	16.6
56	BCTCDA Recoveries		(1.2)	3.7	3.3	6.2	2.9	3.6	0.9	(2.7)	3.6	2.8
57	Total		1,190.8	1,239.8	1,149.4	1,066.2	(83.2)	1,262.9	1,193.3	(69.5)	1,229.6	36.3
	Total Current COE by Bus Group											
58	Corporate		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
59	EARG		534.7	474.2	412.7	358.5	(54.2)	464.6	485.2	20.7	582.3	97.0
60	Customer Care & Conservation		656.2	765.6	736.7	707.7	(29.0)	798.3	708.1	(90.2)	647.3	(60.7)
61	Transmission		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
62	Field Operations		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
63	Total		1,190.8	1,239.8	1,149.4	1,066.2	(83.2)	1,262.9	1,193.3	(69.5)	1,229.6	36.3
	Heritage Payment Obligation											
64	Heritage Energy	Line 9	458.0	363.7	422.7	615.3	192.6	446.6	454.8	8.2	519.0	64.2
65	Commodity Risk		1.3	1.9	0.0	91.4	91.4	0.0	**(10.7)**	(10.7)	0.0	10.7
66	Notional Water Rentals		2.5	(11.8)	(1.0)	(0.3)	0.7	1.5	**10.8**	9.3	**5.9**	(4.9)
67	Skagit and Ancillary Revenue		(22.6)	(19.7)	(21.2)	(26.6)	(5.4)	(22.6)	**(19.4)**	3.2	**(20.5)**	(1.1)
68	Load Curtailment		0.0	(5.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
69	Deferred Operating Expenses	5.0 L31	0.0	6.0	0.0	1.5	1.5	0.0	2.1	2.1	0.0	(2.1)
70	Transfer to GMS 3 Reg Account		0.0	0.0	0.0	(21.2)	(21.2)	0.0	(8.3)	(8.3)	**0.0**	8.3
71	Other		1.1	(1.3)	5.9	6.0	0.1	6.7	**6.1**	(0.6)	**6.5**	0.4
72	Total		440.3	333.8	406.4	666.1	259.8	432.2	435.3	3.1	510.9	75.6
73	**Total System Inflow (% of Normal)**		89%	109%	103%	96%	-7%	100%	**86%**	-14%	**90%**	4%

Cost of Energy (COE)

Line	Column	Reference	F2007 Actual	F2008 Actual	F2009 RRA	F2009 Actual	F2009 Difference	F2010 RRA	F2010 Actual	F2010 Difference	F2011 Update	F2011 Increase
			1	2	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10 = 9 - 7
	Non-Heritage COE Subject to NHDA											
74	Non-Heritage Cost of Energy	Line 18	633.2	606.7	718.9	667.5	(51.4)	778.9	755.1	(23.8)	896.1	140.9
75	Commodity Risk		19.8	(3.0)	0.0	9.3	9.3	0.0	**3.9**	3.9	0.0	(3.9)
76	F/X Gains on Powerex Trade		(0.2)	(18.6)	0.0	9.7	9.7	0.0	(8.8)	(8.8)	0.0	8.8
77	Less Domestic Transmission	Line 16	(36.8)	(75.7)	(91.9)	(92.0)	(0.1)	(88.9)	(87.9)	1.0	(94.9)	(7.0)
78	Notional Water Rental	Line 66	(2.5)	11.8	1.0	0.3	(0.7)	(1.5)	(10.8)	(9.3)	(5.9)	4.9
79	Load Variance		(3.5)	38.0	0.0	20.4	20.4	0.0	82.6	82.6	0.0	(82.6)
80	ROE Adjustment		0.0	(33.7)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
81	ABSU Founding Partner Benefits		(0.6)	(0.5)	0.0	(0.5)	(0.5)	0.0	(0.6)	(0.6)	**(0.4)**	0.2
82	Other		(3.9)	0.2	0.0	0.4	0.4	0.0	(0.1)	(0.1)	0.0	0.1
82.1	NHDA Baseline Adjustment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(222.5)	(222.5)
83	Total		605.5	525.2	628.0	615.1	(12.9)	688.5	733.4	44.9	572.3	(161.1)

BC Hydro
F11 RRA

Operating Costs - Summary
($ million)

Line		Reference	F2007 Actual	F2008 Actual	F2009 RRA	F2009 Actual	F2009 Difference	F2010 RRA	F2010 Actual	F2010 Difference	F2011 Update	F2011 Increase
Line	Column		1	2	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10 = 9 - 7
	Operating Costs by Business Unit											
1	Corporate (excl Non-Current PEB)		133.9	140.2	157.8	166.0	8.2	165.1	160.4	(4.7)	167.9	7.4
2	EARG		99.9	109.2	139.8	136.0	(3.8)	147.4	134.1	(13.3)	131.2	(2.9)
3	CC&C		86.5	90.3	86.4	90.8	4.4	88.8	88.0	(0.8)	99.7	11.7
4	Transmission		93.4	94.7	94.4	97.6	3.2	95.9	112.6	16.8	97.2	(15.5)
5	Field Operations		111.8	128.9	139.2	139.5	0.3	160.3	137.6	(22.7)	141.6	3.9
6	Non-Current PEB - Pension		(15.9)	(42.2)	(51.3)	(44.6)	6.7	(51.4)	34.2	85.6	21.2	(13.0)
7	Non-Current PEB - Other		42.1	26.8	41.6	27.1	(14.5)	42.0	26.8	(15.2)	30.0	3.2
8	F09/F10 RRA Adjustments		0.0	0.0	0.0	0.0	0.0	(19.4)	0.0	19.4	0.0	0.0
8.1	BCTC Integration Adjustment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Total Before Regulatory Accounts		551.8	547.8	607.9	612.4	4.5	628.7	693.8	65.1	688.7	(5.1)
	Operating Costs by Resource											
10	Labour (excl Non-Current PEB)		368.7	391.3	466.2	443.4	(22.8)	490.9	489.4	(1.5)	504.6	15.2
11	Services - ABSU		134.0	137.6	130.5	130.8	0.3	132.7	106.9	(25.7)	101.0	(6.0)
12	Services - BCTC		115.5	119.0	123.0	125.9	2.8	124.3	130.2	5.9	124.1	(6.0)
13	Services - Other		228.7	250.7	261.7	307.5	45.8	295.2	319.1	24.0	300.2	(18.9)
14	Materials		58.7	62.2	49.4	76.5	27.1	50.0	66.0	16.0	49.3	(16.7)
15	Buildings & Equipment		26.0	32.1	26.9	38.3	11.4	28.2	63.7	35.6	54.3	(9.5)
16	Capitalized Overhead		(162.2)	(171.3)	(216.9)	(196.1)	20.8	(225.6)	(236.0)	(10.4)	(239.3)	(3.4)
17	External Recoveries		(243.9)	(258.5)	(223.2)	(296.4)	(73.2)	(238.1)	(306.7)	(68.6)	(256.7)	49.9
18	Non-Current PEB - Pension		(15.9)	(42.2)	(51.3)	(44.6)	6.7	(51.4)	34.2	85.6	21.2	(13.0)
19	Non-Current PEB - Other		42.1	26.8	41.6	27.1	(14.5)	42.0	26.8	(15.2)	30.0	3.2
20	F09/F10 RRA Adjustments		0.0	0.0	0.0	0.0	0.0	(19.4)	0.0	19.4	0.0	0.0
21.1	BCTC Integration Adjustment	Line 8.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
21	Total Before Regulatory Accounts		551.8	547.8	607.9	612.4	4.5	628.7	693.8	65.1	688.7	(5.1)
	Regulatory Account Recoveries											
21.1	DSM - F11 Settlement Adj.		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.3	10.3
22	First Nation Costs		4.2	2.9	5.9	6.0	0.1	6.7	5.7	(1.0)	6.5	0.8
23	Site C		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
24	Storm Restoration		0.0	0.0	0.0	2.0	2.0	0.0	2.5	2.5	0.0	(2.5)
25	Procurement Enhancement		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
25.1	PEI - F11 Settlement Adj.		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.5	5.5
26	Capital Project Investigation		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
27	Net Employment Costs		0.0	0.0	0.0	28.2	28.2	0.0	29.5	29.5	(62.9)	(92.5)
28	Non-Current Pension Cost		0.0	0.0	0.0	0.0	0.0	0.0	(85.6)	(85.6)	17.1	102.7
	Environmental Provisions:											
28.1	EARG		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.9	0.9
28.2	Transmission		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.8	6.8
28.3	Field Operations		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.9	6.9
29	Total		4.2	2.9	5.9	36.2	30.3	6.7	(47.9)	(54.6)	(9.0)	38.9
30	**Total Current Operating**	Lines 9 + 29	556.0	550.7	613.8	648.6	34.8	635.4	645.9	10.5	679.7	33.8
	Deferral Account Additions											
31	Transfers to HDA		0.0	6.0	0.0	1.5	1.5	0.0	2.1	2.1	0.0	(2.1)

Operating Costs - Summary
($ million)

Line	Column	Reference	F2007 Actual	F2008 Actual	F2009 RRA	F2009 Actual	F2009 Difference	F2010 RRA	F2010 Actual	F2010 Difference	F2011 Update	F2011 Increase
			1	2	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10 = 9 - 7
	Regulatory Account Additions											
32	Demand-Side Management		46.4	63.3	112.1	94.9	(17.2)	138.2	130.4	(7.8)	184.4	54.0
33	First Nations Costs		4.4	5.7	7.7	5.5	(2.2)	1.9	4.1	2.2	3.6	(0.5)
34	First Nations Provisions		6.6	231.3	20.5	26.2	5.7	19.0	12.2	(6.8)	16.4	4.2
35	Site C		3.6	4.6	17.5	24.8	7.3	14.6	22.1	7.5	40.0	17.9
36	Storm Restoration		32.9	7.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
37	Procurement Enhancement		0.0	7.3	20.9	21.0	0.1	3.8	8.9	5.1	2.0	(6.9)
38	Capital Project Investigation		0.0	11.8	14.6	15.7	1.1	8.6	9.2	0.6	8.2	(1.0)
39	GM Shrum 3		0.0	0.0	0.0	19.9	19.9	0.0	(1.6)	(1.6)	0.0	1.6
40	Smart Metering & Infrastructure		0.0	0.0	0.0	8.6	8.6	0.0	8.8	8.8	19.7	10.9
41	Home Purchase Offer Plan		0.0	0.0	0.0	0.7	0.7	0.0	7.1	7.1	4.9	(2.2)
41.1	Environmental Provisions		0.0	0.0	0.0	0.0	0.0	0.0	289.5	289.5	13.2	(276.3)
42	Total		93.9	331.8	193.3	217.3	24.0	186.1	490.7	304.6	292.4	(198.3)
43	**Total GAAP Operating**	Lines 9+31+42	645.7	885.6	801.2	831.1	29.9	814.8	1,186.6	371.8	981.2	(205.4)
	Current Operating by Business Group											
44	Corporate		133.9	140.2	157.8	194.2	36.4	165.1	190.0	24.8	110.4	(79.5)
45	EARG		104.1	112.1	145.7	142.0	(3.7)	154.1	139.8	(14.3)	138.6	(1.2)
46	CC&C		86.5	90.3	86.4	90.8	4.4	88.8	88.0	(0.8)	110.0	22.0
47	Transmission		93.4	94.7	94.4	97.6	3.2	95.9	112.6	16.8	104.0	(8.7)
48	Field Operations		111.8	128.9	139.2	141.5	2.3	160.3	140.1	(20.2)	148.5	8.3
49	Non-Current PEB - Pension	Lines 6 + 28	(15.9)	(42.2)	(51.3)	(44.6)	6.7	(51.4)	(51.4)	0.0	38.3	89.7
50	Non-Current PEB - Other	Line 7	42.1	26.8	41.6	27.1	(14.5)	42.0	26.8	(15.2)	30.0	3.2
51	F09/F10 RRA Adjustments	Line 8	0.0	0.0	0.0	0.0	0.0	(19.4)	0.0	19.4	0.0	0.0
51.1	BCTC Integration Adjustment	Line 8.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
52	Total		556.0	550.7	613.8	648.6	34.8	635.4	645.9	10.5	679.7	33.8

Operating Costs Before Regulatory Accounts - Corporate
($ million)

		F2007	F2008	F2009			F2010			F2011	F2011
	Reference	Actual	Actual	RRA	Actual	Difference	RRA	Actual	Difference	Update	Increase
Line	Column	1	2	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10 = 9 - 7
	Executive										
1	Labour	1.5	1.6	1.6	1.5	(0.1)	1.7	1.7	(0.0)	1.2	(0.5)
2	Services - ABSU	0.0	0.0	0.1	0.1	0.0	0.1	0.1	0.0	0.0	(0.1)
3	Services - BCTC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	Services - Other	2.0	1.9	1.9	2.7	0.8	1.9	2.7	0.8	2.3	(0.3)
5	Materials	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)
6	Buildings & Equipment	0.0	0.0	0.0	0.1	0.0	0.0	0.0	(0.0)	0.0	(0.0)
7	Capitalized Overhead	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	External Recoveries	(0.1)	(0.3)	(0.1)	(0.0)	0.1	(0.1)	(0.2)	(0.1)	(0.1)	0.1
9	Total	3.4	3.3	3.5	4.4	0.9	3.6	4.3	0.8	3.5	(0.9)
	Sustainability										
10	Labour	0.9	1.1	0.9	0.5	(0.4)	0.9	0.0	(0.9)	0.0	0.0
11	Services - ABSU	0.1	0.1	0.0	0.0	(0.0)	0.0	0.0	(0.0)	0.0	0.0
12	Services - BCTC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	Services - Other	0.5	0.3	0.4	0.0	(0.4)	0.4	0.0	(0.4)	0.0	0.0
14	Materials	0.0	0.0	0.0	0.0	(0.0)	0.0	0.0	(0.0)	0.0	0.0
15	Buildings & Equipment	0.0	0.0	0.0	0.0	(0.0)	0.0	0.0	(0.0)	0.0	0.0
16	Capitalized Overhead	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
17	External Recoveries	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
18	Total	1.5	1.4	1.3	0.5	(0.8)	1.4	0.0	(1.4)	0.0	0.0
	Corporate Affairs										
19	Labour	6.4	6.1	7.2	6.1	(1.1)	7.6	8.4	0.8	7.3	(1.1)
20	Services - ABSU	0.1	0.2	0.2	0.2	0.1	0.2	0.3	0.1	0.1	(0.2)
21	Services - BCTC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22	Services - Other	5.3	4.8	5.2	4.8	(0.4)	4.9	6.0	1.2	4.8	(1.2)
23	Materials	0.4	0.6	0.6	1.1	0.5	0.6	0.7	0.1	0.5	(0.2)
24	Buildings & Equipment	0.2	0.2	0.2	0.1	(0.0)	0.2	0.1	(0.0)	0.1	(0.1)
25	Capitalized Overhead	0.0	0.0	(0.1)	(0.1)	0.0	(0.1)	(0.0)	0.1	0.0	0.0
26	External Recoveries	(0.1)	(0.1)	(0.1)	(0.1)	(0.0)	(0.1)	(0.2)	(0.0)	(0.1)	0.0
27	Total	12.3	11.8	13.0	12.1	(0.9)	13.2	15.5	2.3	12.8	(2.7)
	Corporate Human Resources										
28	Labour	6.4	6.7	6.8	7.4	0.5	7.3	8.7	1.4	7.5	(1.3)
29	Services - ABSU	5.9	6.9	8.1	8.1	(0.1)	8.3	6.7	(1.5)	7.7	1.0
30	Services - BCTC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
31	Services - Other	3.2	3.4	5.1	5.0	(0.2)	4.8	2.7	(2.2)	4.7	2.1
32	Materials	0.2	0.1	0.3	0.2	(0.0)	0.2	0.1	(0.1)	0.1	0.0
33	Buildings & Equipment	0.1	0.1	0.1	0.1	0.0	0.1	0.1	0.1	0.0	(0.1)
34	Capitalized Overhead	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
35	External Recoveries	(0.0)	(0.0)	0.0	(0.0)	(0.0)	0.0	(0.2)	(0.2)	(0.3)	(0.1)
36	Total	15.8	17.1	20.4	20.7	0.3	20.8	18.2	(2.5)	19.9	1.7

Operating Costs Before Regulatory Accounts - Corporate
($ million)

Line		Reference	F2007 Actual	F2008 Actual	F2009 RRA	F2009 Actual	F2009 Difference	F2010 RRA	F2010 Actual	F2010 Difference	F2011 Update	F2011 Increase
	Column		1	2	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10 = 9 - 7
	Finance & Corporate Resources											
37	Labour		26.0	31.4	36.1	37.0	0.9	37.6	40.7	3.2	43.9	3.2
38	Services - ABSU		63.9	63.0	56.5	57.9	1.4	57.0	41.6	(15.4)	37.2	(4.4)
39	Services - BCTC		0.6	0.6	0.6	0.5	(0.0)	0.6	0.6	0.0	0.6	0.0
40	Services - Other		21.8	20.7	21.2	36.5	15.3	24.2	33.5	9.3	31.2	(2.3)
41	Materials		1.1	1.1	1.3	1.4	0.1	1.3	1.4	0.1	1.3	(0.0)
42	Buildings & Equipment		6.0	9.7	9.9	11.7	1.7	10.2	28.9	18.7	34.5	5.6
43	Capitalized Overhead		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
44	External Recoveries		(12.1)	(12.8)	(10.9)	(13.8)	(2.8)	(11.0)	(15.4)	(4.4)	(13.8)	1.6
45	Total		107.4	113.6	114.7	131.3	16.6	119.7	131.3	11.6	135.0	3.7
	Safety, Health & Environment											
46	Labour		5.2	6.9	7.4	6.6	(0.9)	7.8	7.2	(0.6)	8.1	0.9
47	Services - ABSU		0.2	1.4	1.5	1.4	(0.1)	1.5	1.2	(0.3)	1.3	0.1
48	Services - BCTC		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
49	Services - Other		2.7	2.8	3.5	4.0	0.5	3.9	3.4	(0.5)	3.5	0.1
50	Materials		0.1	0.3	0.1	0.2	0.1	0.5	0.2	(0.3)	0.1	(0.0)
51	Buildings & Equipment		0.1	0.3	0.1	0.1	0.0	0.1	0.1	0.1	0.4	0.2
52	Capitalized Overhead		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
53	External Recoveries		(0.1)	(0.1)	0.0	(0.0)	(0.0)	0.0	(0.0)	(0.0)	0.0	0.0
54	Total		8.3	11.6	12.6	12.2	(0.4)	13.8	12.0	(1.7)	13.4	1.3
	Smart Metering and Infrastructure											
55	Labour		0.0	2.1	0.7	0.7	(0.0)	0.7	1.0	0.2	0.6	(0.3)
56	Services - ABSU		0.0	(0.1)	0.0	0.0	(0.0)	0.0	0.0	(0.0)	0.0	0.0
57	Services - BCTC		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
58	Services - Other		0.0	3.6	0.4	0.1	(0.3)	0.3	0.3	(0.0)	0.3	0.0
59	Materials		0.0	0.1	0.0	0.0	(0.0)	0.0	0.0	(0.0)	0.0	0.0
60	Buildings & Equipment		0.0	0.2	0.0	0.0	(0.0)	0.0	(0.0)	(0.0)	0.0	0.0
61	Capitalized Overhead		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
62	External Recoveries		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
63	Total		0.0	5.8	1.1	0.7	(0.3)	1.1	1.2	0.1	0.9	(0.3)
	Corporate Costs											
64	Labour		15.8	(49.7)	(10.3)	(42.7)	(32.4)	(10.1)	56.1	66.2	49.2	(6.9)
65	Services - ABSU		5.5	5.8	5.6	6.1	0.6	5.8	6.8	0.9	6.9	0.1
66	Services - BCTC		0.6	0.0	0.0	0.0	0.0	0.0	(0.0)	(0.0)	0.0	0.0
67	Services - Other		24.1	25.9	24.7	20.1	(4.6)	25.2	20.4	(4.9)	26.4	6.0
68	Materials		0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)
69	Buildings & Equipment		0.4	0.0	0.0	0.0	0.0	0.0	(0.0)	(0.0)	0.0	0.0
70	Capitalized Overhead		(31.6)	(19.2)	(38.6)	(15.8)	22.8	(38.7)	(42.4)	(3.8)	(47.4)	(5.0)
71	External Recoveries		(3.2)	(2.7)	0.0	(1.4)	(1.4)	0.0	(1.8)	(1.8)	(1.3)	0.5
72	Total		11.5	(39.8)	(18.6)	(33.5)	(14.9)	(17.7)	38.9	56.6	33.7	(5.2)

Operating Costs Before Regulatory Accounts - Corporate
($ million)

Line		Reference	F2007 Actual	F2008 Actual	F2009 RRA	F2009 Actual	F2009 Difference	F2010 RRA	F2010 Actual	F2010 Difference	F2011 Update	F2011 Increase
	Column		1	2	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10 = 9 - 7
	Total Corporate											
73	Labour		62.1	6.2	50.5	17.0	(33.5)	53.6	123.9	70.3	117.9	(6.0)
74	Services - ABSU		75.7	77.2	72.0	73.9	1.9	72.9	56.7	(16.2)	53.3	(3.4)
75	Services - BCTC		1.1	0.6	0.6	0.5	(0.0)	0.6	0.5	(0.0)	0.6	0.0
76	Services - Other		59.5	63.4	62.4	73.2	10.8	65.5	68.8	3.3	73.2	4.3
77	Materials		1.9	2.2	2.3	3.0	0.7	2.7	2.5	(0.2)	2.2	(0.3)
78	Buildings & Equipment		6.9	10.5	10.3	12.1	1.8	10.5	29.3	18.8	35.0	5.7
79	Capitalized Overhead		(31.6)	(19.2)	(38.7)	(15.9)	22.8	(38.8)	(42.5)	(3.7)	(47.4)	(4.9)
80	External Recoveries		(15.5)	(16.0)	(11.2)	(15.3)	(4.1)	(11.3)	(17.8)	(6.5)	(15.6)	2.2
81	Total		160.1	124.8	148.1	148.5	0.4	155.7	221.4	65.7	219.1	(2.4)

Operating Costs Before Regulatory Accounts - EARG
($ million)

Line	Column	Reference	F2007 Actual	F2008 Actual	F2009 RRA	F2009 Actual	F2009 Difference	F2010 RRA	F2010 Actual	F2010 Difference	F2011 Update	F2011 Increase
			1	2	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10 = 9 - 7
	Engineering											
1	Labour		38.4	44.9	50.1	49.2	(0.9)	53.3	47.7	(5.6)	51.4	3.7
2	Services - ABSU		0.3	0.5	0.2	0.8	0.6	0.2	1.1	0.9	0.4	(0.8)
3	Services - BCTC		0.0	0.3	0.0	0.4	0.4	0.0	0.5	0.5	0.0	(0.5)
4	Services - Other		18.5	18.7	10.5	25.8	15.3	11.5	27.8	16.3	13.9	(14.0)
5	Materials		12.3	12.2	5.3	17.9	12.6	5.3	11.9	6.6	5.4	(6.5)
6	Buildings & Equipment		1.8	4.2	1.2	4.9	3.7	1.3	4.2	2.8	0.8	(3.4)
7	Capitalized Overhead		(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	External Recoveries		(81.9)	(89.0)	(64.3)	(100.3)	(35.9)	(67.5)	(97.7)	(30.1)	(68.2)	29.4
9	Total		(10.5)	(8.1)	3.0	(1.2)	(4.2)	4.2	(4.4)	(8.6)	3.6	8.0
	Generation Project Delivery											
10	Labour		2.1	3.1	4.1	4.0	(0.1)	4.4	4.3	(0.1)	4.8	0.5
11	Services - ABSU		0.0	0.0	0.0	0.1	0.1	0.0	0.5	0.4	0.1	(0.4)
12	Services - BCTC		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	Services - Other		0.5	1.0	0.7	1.5	0.8	0.7	1.4	0.7	1.0	(0.4)
14	Materials		0.0	0.1	0.0	0.1	0.1	0.0	0.2	0.1	0.1	(0.1)
15	Buildings & Equipment		0.1	0.2	0.2	0.1	(0.1)	0.2	0.0	(0.2)	0.0	(0.0)
16	Capitalized Overhead		(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
17	External Recoveries		0.0	(0.0)	0.0	(0.0)	(0.0)	0.0	0.0	0.0	0.0	0.0
18	Total		2.7	4.5	5.0	5.8	0.8	5.3	6.4	1.0	5.9	(0.5)
	Generation Operations											
19	Labour		65.3	63.4	72.9	69.4	(3.4)	73.9	75.1	1.2	74.5	(0.6)
20	Services - ABSU		0.4	0.1	0.0	0.3	0.2	0.0	0.3	0.3	0.1	(0.3)
21	Services - BCTC		0.9	1.0	1.0	1.0	0.0	1.0	1.1	0.1	1.1	0.1
22	Services - Other		26.4	29.9	39.8	40.7	0.9	49.4	42.9	(6.6)	38.1	(4.8)
23	Materials		8.4	9.3	6.9	11.5	4.6	6.7	9.9	3.2	7.3	(2.6)
24	Buildings & Equipment		3.1	2.9	2.6	3.3	0.7	2.7	4.0	1.2	1.7	(2.2)
25	Capitalized Overhead		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
26	External Recoveries		(1.4)	(1.7)	(0.5)	(1.4)	(0.9)	(0.5)	(0.9)	(0.4)	(0.6)	0.3
27	Total		103.1	105.0	122.7	124.8	2.1	133.3	132.3	(1.0)	122.2	(10.1)
	Safety & Technical Training											
28	Labour		1.4	3.6	4.2	3.5	(0.7)	4.3	3.8	(0.5)	4.1	0.3
29	Services - ABSU		0.1	0.1	0.0	0.1	0.1	0.0	0.0	0.0	0.0	(0.0)
30	Services - BCTC		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
31	Services - Other		0.7	0.9	1.2	1.5	0.3	1.8	0.6	(1.2)	0.8	0.2
32	Materials		0.1	0.1	0.2	0.1	(0.1)	0.3	0.1	(0.2)	0.1	(0.0)
33	Buildings & Equipment		0.0	0.1	0.1	0.1	(0.0)	0.1	0.0	(0.1)	0.1	0.1
34	Capitalized Overhead		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
35	External Recoveries		(0.0)	0.0	0.0	(0.0)	(0.0)	0.0	0.0	0.0	0.0	0.0
36	Total		2.2	4.7	5.7	5.4	(0.4)	6.5	4.5	(2.0)	5.0	0.5

Operating Costs Before Regulatory Accounts - EARG
($ million)

		F2007	F2008	F2009			F2010			F2011	F2011
	Reference	Actual	Actual	RRA	Actual	Difference	RRA	Actual	Difference	Update	Increase
Line	Column	1	2	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10 = 9 - 7
	Aboriginal Relations										
37	Labour	1.2	1.4	2.5	2.0	(0.5)	2.7	2.5	(0.2)	2.5	0.0
38	Services - ABSU	0.1	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.0	(0.1)
39	Services - BCTC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
40	Services - Other	0.7	0.7	2.1	0.8	(1.3)	1.6	1.6	0.0	1.0	(0.6)
41	Materials	0.0	0.0	0.1	0.1	(0.1)	0.1	0.0	(0.1)	0.1	0.1
42	Buildings & Equipment	0.0	0.1	0.0	0.1	0.0	0.0	0.0	(0.0)	0.0	0.0
43	Capitalized Overhead	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
44	External Recoveries	(0.0)	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
45	Total	2.0	2.2	4.7	2.9	(1.8)	4.5	4.2	(0.3)	3.6	(0.6)
	EARG Business Unit Support										
46	Labour	15.2	16.3	17.1	17.2	0.1	17.6	17.9	0.3	16.9	(1.1)
47	Services - ABSU	0.2	0.5	0.0	0.5	0.5	0.0	0.3	0.3	0.0	(0.3)
48	Services - BCTC	5.4	5.4	8.3	8.3	0.0	8.2	8.2	0.0	8.2	0.0
49	Services - Other	2.1	3.4	4.4	3.6	(0.8)	3.8	2.8	(1.0)	2.2	(0.6)
50	Materials	0.2	0.4	0.4	0.2	(0.2)	0.2	0.2	(0.0)	0.1	(0.1)
51	Buildings & Equipment	0.9	0.6	0.6	0.9	0.2	0.6	0.6	(0.1)	0.7	0.1
52	Capitalized Overhead	(23.3)	(24.9)	(32.1)	(32.1)	0.0	(36.9)	(38.7)	(1.8)	(37.2)	1.5
53	External Recoveries	(0.2)	(0.7)	0.0	(0.2)	(0.2)	0.0	(0.3)	(0.3)	0.0	0.3
54	Total	0.4	0.8	(1.3)	(1.7)	(0.3)	(6.4)	(8.8)	(2.5)	(9.0)	(0.2)
	Total EARG										
55	Labour	123.6	132.7	150.8	145.3	(5.5)	156.3	151.3	(5.0)	154.1	2.8
56	Services - ABSU	1.0	1.2	0.3	1.9	1.7	0.3	2.3	2.1	0.5	(1.8)
57	Services - BCTC	6.3	6.7	9.3	9.7	0.4	9.2	9.8	0.6	9.3	(0.4)
58	Services - Other	48.9	54.7	58.7	73.8	15.2	68.8	77.1	8.3	56.9	(20.2)
59	Materials	21.0	22.2	13.0	29.9	16.9	12.7	22.3	9.5	13.0	(9.3)
60	Buildings & Equipment	5.9	8.1	4.8	9.3	4.6	5.0	8.8	3.8	3.4	(5.4)
61	Capitalized Overhead	(23.3)	(24.9)	(32.1)	(32.1)	0.0	(36.9)	(38.7)	(1.8)	(37.2)	1.5
62	External Recoveries	(83.4)	(91.5)	(64.8)	(101.8)	(37.0)	(68.0)	(98.8)	(30.8)	(68.9)	30.0
63	Total	99.9	109.2	139.8	136.0	(3.8)	147.4	134.1	(13.3)	131.2	(2.9)

Operating Costs Before Regulatory Accounts - CC&C
($ million)

Line	Reference / Column	F2007 Actual	F2008 Actual	F2009 RRA	F2009 Actual	F2009 Difference	F2010 RRA	F2010 Actual	F2010 Difference	F2011 Update	F2011 Increase
		1	2	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10 = 9 - 7
	Customer Care										
1	Labour	5.9	8.4	8.7	9.8	1.1	9.4	9.8	0.4	9.7	(0.1)
2	Services - ABSU	55.5	56.7	56.7	52.8	(3.8)	57.8	45.4	(12.4)	45.2	(0.2)
3	Services - BCTC	1.4	0.9	0.0	1.3	1.3	0.0	2.5	2.5	0.0	(2.5)
4	Services - Other	8.4	10.2	8.9	15.7	6.8	9.4	19.6	10.1	19.7	0.1
5	Materials	0.1	0.3	0.1	0.1	0.1	0.1	0.0	(0.0)	0.0	0.0
6	Buildings & Equipment	0.3	0.3	0.3	0.9	0.6	0.3	1.1	0.7	0.7	(0.3)
7	Capitalized Overhead	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	External Recoveries	(5.9)	(5.2)	(6.2)	(6.5)	(0.3)	(6.2)	(8.0)	(1.8)	(6.2)	1.8
9	Total	65.9	71.5	68.4	74.3	5.9	70.9	70.4	(0.5)	69.1	(1.3)
	Power Smart										
10	Labour	1.2	1.7	1.0	0.8	(0.2)	1.0	1.1	0.0	0.8	(0.3)
11	Services - ABSU	0.0	0.0	0.2	0.0	(0.2)	0.2	0.0	(0.2)	0.0	0.0
12	Services - BCTC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	Services - Other	2.0	0.8	0.4	(0.1)	(0.5)	0.4	0.2	(0.2)	0.1	(0.0)
14	Materials	0.1	0.0	0.1	0.0	(0.0)	0.1	0.0	(0.0)	0.0	(0.0)
15	Buildings & Equipment	0.1	0.2	0.1	0.0	(0.0)	0.0	0.0	0.0	0.0	(0.0)
16	Capitalized Overhead	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
17	External Recoveries	(0.0)	(0.0)	0.0	(0.0)	(0.0)	0.0	(0.0)	(0.0)	0.0	0.0
18	Total	3.4	2.8	1.7	0.7	(1.0)	1.7	1.3	(0.4)	1.0	(0.3)
	Energy Planning Group										
19	Labour	3.8	4.0	4.5	4.3	(0.2)	4.8	4.2	(0.5)	4.2	(0.1)
20	Services - ABSU	0.0	0.0	0.1	0.0	(0.1)	0.1	0.0	(0.1)	0.0	0.0
21	Services - BCTC	0.0	0.0	0.3	0.2	(0.1)	0.3	0.3	(0.0)	0.3	0.0
22	Services - Other	1.7	1.3	1.5	1.2	(0.3)	1.5	0.8	(0.6)	1.3	0.4
23	Materials	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)
24	Buildings & Equipment	0.0	0.1	0.2	0.0	(0.1)	0.2	0.1	(0.0)	0.2	0.0
25	Capitalized Overhead	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
26	External Recoveries	(0.0)	(0.0)	0.0	(0.0)	(0.0)	(0.0)	(0.1)	(0.1)	0.0	0.1
27	Total	5.7	5.4	6.5	5.8	(0.8)	6.8	5.4	(1.4)	5.9	0.5
	Power Acquisition Group										
28	Labour	2.2	3.1	3.4	3.6	0.3	3.5	3.8	0.3	3.7	(0.1)
29	Services - ABSU	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)
30	Services - BCTC	0.0	0.0	0.0	0.2	0.2	0.0	0.2	0.2	0.0	(0.2)
31	Services - Other	0.7	1.0	0.8	2.0	1.2	0.9	1.1	0.3	15.1	13.9
32	Materials	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	0.0	0.0
33	Buildings & Equipment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	0.0	0.0
34	Capitalized Overhead	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
35	External Recoveries	(0.0)	(0.4)	0.0	(1.7)	(1.7)	0.0	0.0	0.0	(0.3)	(0.3)
36	Total	2.9	3.8	4.3	4.3	0.0	4.5	5.3	0.8	18.5	13.3

Operating Costs Before Regulatory Accounts - CC&C
($ million)

		F2007	F2008	F2009			F2010			F2011	F2011
	Reference	Actual	Actual	RRA	Actual	Difference	RRA	Actual	Difference	Update	Increase
Line	Column	1	2	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10 = 9 - 7
	Chief Technology Office										
37	Labour	0.3	0.5	1.4	1.3	(0.1)	1.8	1.9	0.2	1.6	(0.3)
38	Services - ABSU	0.0	0.0	0.0	0.0	(0.0)	0.0	0.0	(0.0)	0.0	(0.0)
39	Services - BCTC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
40	Services - Other	1.4	2.4	2.0	1.5	(0.5)	1.7	1.9	0.2	1.9	(0.0)
41	Materials	0.0	0.0	0.0	0.0	(0.0)	0.0	0.1	0.1	0.0	(0.1)
42	Buildings & Equipment	0.0	0.0	0.0	0.2	0.2	0.0	0.1	0.1	0.0	(0.1)
43	Capitalized Overhead	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
44	External Recoveries	(0.1)	0.0	0.0	(0.1)	(0.1)	0.0	(0.7)	(0.7)	0.0	0.7
45	Total	1.7	2.9	3.4	2.9	(0.5)	3.5	3.3	(0.1)	3.5	0.2
	CC&C Business Unit Support										
46	Labour	4.9	5.0	5.2	5.4	0.2	5.4	5.5	0.1	5.5	(0.0)
47	Services - ABSU	0.0	0.2	0.0	0.1	0.0	0.0	0.4	0.3	0.0	(0.4)
48	Services - BCTC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
49	Services - Other	4.1	0.8	1.0	1.4	0.4	1.1	0.6	(0.5)	0.4	(0.3)
50	Materials	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	(0.0)
51	Buildings & Equipment	0.3	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	0.0	(0.0)
52	Capitalized Overhead	(1.6)	(1.7)	(3.7)	(3.7)	(0.0)	(4.4)	(3.6)	0.8	(3.7)	(0.1)
53	External Recoveries	(0.8)	(0.6)	(0.6)	(0.6)	0.0	(0.6)	(0.6)	(0.0)	(0.6)	0.0
54	Total	7.0	3.8	2.0	2.7	0.7	1.6	2.4	0.8	1.6	(0.8)
	Total CC&C										
55	Labour	18.4	22.7	24.1	25.3	1.1	26.0	26.4	0.4	25.5	(0.9)
56	Services - ABSU	55.7	57.0	56.9	52.9	(4.0)	58.1	45.8	(12.3)	45.3	(0.5)
57	Services - BCTC	1.4	0.9	0.3	1.8	1.5	0.3	3.0	2.7	0.3	(2.7)
58	Services - Other	18.3	16.5	14.7	21.8	7.1	14.9	24.2	9.3	38.3	14.1
59	Materials	0.3	0.4	0.2	0.3	0.1	0.2	0.3	0.0	0.1	(0.1)
60	Buildings & Equipment	0.8	0.7	0.6	1.2	0.7	0.5	1.4	0.8	0.9	(0.4)
61	Capitalized Overhead	(1.6)	(1.7)	(3.7)	(3.7)	(0.0)	(4.4)	(3.6)	0.8	(3.7)	(0.1)
62	External Recoveries	(6.9)	(6.3)	(6.8)	(8.8)	(2.0)	(6.8)	(9.5)	(2.7)	(7.1)	2.4
63	Total	86.5	90.3	86.4	90.8	4.4	88.8	88.0	(0.8)	99.7	11.7

Operating Costs Before Regulatory Accounts - Transmission
($ million)

			F2007	F2008	F2009			F2010			F2011	F2011
		Reference	Actual	Actual	RRA	Actual	Difference	RRA	Actual	Difference	Update	Increase
Line		Column	1	2	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10 = 9 - 7
	Total Transmission											
1	Labour		1.1	0.7	0.9	0.9	(0.0)	0.9	0.8	(0.1)	0.7	(0.1)
2	Services - ABSU		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)
3	Services - BCTC		87.3	87.3	90.9	90.9	0.0	92.4	92.4	0.0	91.4	(1.0)
4	Services - Other		4.9	6.3	2.2	4.8	2.6	2.1	18.3	16.2	4.3	(14.0)
5	Materials		0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.3	0.0	(0.3)
6	Buildings & Equipment		0.4	0.3	0.5	1.0	0.5	0.5	0.8	0.3	0.8	(0.1)
7	Capitalized Overhead		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	External Recoveries		(0.2)	0.0	0.0	(0.0)	(0.0)	0.0	0.0	0.0	0.0	0.0
9	Total		93.4	94.7	94.4	97.6	3.2	95.9	112.6	16.8	97.2	(15.5)

Operating Costs Before Regulatory Accounts - Field Operations
($ million)

Line	Reference / Column	F2007 Actual	F2008 Actual	F2009 RRA	F2009 Actual	F2009 Difference	F2010 RRA	F2010 Actual	F2010 Difference	F2011 Update	F2011 Increase
		1	2	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10 = 9 - 7
	Distribution Operations										
1	Labour	88.8	100.9	104.8	115.9	11.1	111.6	111.8	0.2	113.2	1.4
2	Services - ABSU	0.4	0.9	0.1	0.9	0.8	0.1	0.8	0.6	0.1	(0.6)
3	Services - BCTC	19.4	23.3	21.9	23.0	1.0	21.8	24.5	2.7	22.6	(1.9)
4	Services - Other	55.7	64.5	76.7	80.6	3.9	91.5	74.9	(16.6)	72.1	(2.9)
5	Materials	6.5	7.9	7.9	8.7	0.8	8.1	9.5	1.4	6.2	(3.4)
6	Buildings & Equipment	4.4	4.7	4.1	5.3	1.2	4.1	4.2	0.1	3.8	(0.4)
7	Capitalized Overhead	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	External Recoveries	(22.2)	(19.9)	(17.5)	(23.4)	(5.9)	(20.8)	(22.4)	(1.7)	(15.8)	6.6
9	Total	152.9	182.5	198.0	211.0	12.9	216.5	203.3	(13.2)	202.1	(1.1)
	Transmission & Construction Services										
10	Labour	54.7	62.2	68.2	72.7	4.5	70.4	77.2	6.8	84.3	7.2
11	Services - ABSU	0.4	0.3	0.3	0.3	(0.0)	0.2	0.1	(0.1)	0.3	0.2
12	Services - BCTC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)
13	Services - Other	19.7	24.7	21.6	25.5	3.9	22.5	21.5	(1.0)	23.9	2.4
14	Materials	10.3	10.3	9.4	11.8	2.4	9.8	13.1	3.3	11.6	(1.4)
15	Buildings & Equipment	3.2	3.3	2.3	3.1	0.8	2.4	13.9	11.5	5.8	(8.1)
16	Capitalized Overhead	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
17	External Recoveries	(101.0)	(114.6)	(112.0)	(132.3)	(20.2)	(116.1)	(132.9)	(129.9)	(126.3)	6.6
18	Total	(12.7)	(13.8)	(10.2)	(18.9)	(8.6)	(10.8)	(7.1)	3.7	(0.3)	6.8
	Operational Support Services										
19	Labour	18.5	21.4	23.2	23.3	0.1	24.2	24.7	0.5	24.4	(0.3)
20	Services - ABSU	0.3	0.1	0.2	0.2	0.0	0.2	0.4	0.2	0.2	(0.2)
21	Services - BCTC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22	Services - Other	13.5	15.5	14.7	19.1	4.3	14.8	18.7	4.0	19.5	0.7
23	Materials	18.7	19.1	16.6	22.0	5.3	16.1	16.3	0.2	15.8	(0.6)
24	Buildings & Equipment	3.6	3.3	3.1	4.6	1.5	3.1	4.0	0.9	3.7	(0.2)
25	Capitalized Overhead	(0.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
26	External Recoveries	(8.7)	(7.6)	(8.3)	(11.4)	(3.1)	(8.1)	(10.5)	(2.4)	(9.7)	0.8
27	Total	45.9	51.9	49.6	57.7	8.1	50.3	53.6	3.3	53.9	0.2
	FO Business Unit Support										
28	Labour	27.7	29.0	33.9	25.5	(8.3)	38.5	34.2	(4.3)	35.6	1.3
29	Services - ABSU	0.5	0.8	0.7	0.8	0.0	0.8	0.7	(0.0)	1.3	0.5
30	Services - BCTC	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
31	Services - Other	8.3	5.2	10.8	8.6	(2.2)	15.1	15.6	0.5	12.1	(3.6)
32	Materials	(0.1)	0.1	0.0	0.8	0.7	0.4	1.8	1.4	0.4	(1.4)
33	Buildings & Equipment	1.0	1.2	1.3	1.7	0.4	2.0	1.4	(0.6)	0.9	(0.5)
34	Capitalized Overhead	(105.6)	(125.5)	(142.3)	(144.3)	(2.0)	(145.5)	(151.2)	(5.8)	(151.0)	0.2
35	External Recoveries	(5.9)	(2.8)	(2.6)	(3.4)	(0.8)	(7.0)	(14.7)	(7.7)	(13.3)	1.4
36	Total	(74.2)	(91.8)	(98.2)	(110.3)	(12.2)	(95.6)	(112.2)	(16.5)	(114.1)	(1.9)

Operating Costs Before Regulatory Accounts - Field Operations
($ million)

		Reference	F2007	F2008	F2009			F2010			F2011	F2011
			Actual	Actual	RRA	Actual	Difference	RRA	Actual	Difference	Update	Increase
Line		Column	1	2	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10 = 9 - 7
	Total Field Operations											
37	Labour		189.7	213.6	230.1	237.5	7.4	244.8	247.9	3.2	257.6	9.7
38	Services - ABSU		1.7	2.2	1.3	2.2	0.8	1.4	2.1	0.7	1.9	(0.2)
39	Services - BCTC		19.4	23.6	21.9	23.0	1.0	21.8	24.5	2.7	22.6	(1.9)
40	Services - Other		97.1	109.9	123.8	133.8	10.0	143.9	130.8	(13.1)	127.5	(3.3)
41	Materials		35.4	37.4	33.9	43.2	9.3	34.4	40.7	6.3	34.0	(6.7)
42	Buildings & Equipment		12.1	12.5	10.8	14.6	3.8	11.6	23.5	11.9	14.2	(9.3)
43	Capitalized Overhead		(105.7)	(125.5)	(142.3)	(144.3)	(2.0)	(145.5)	(151.2)	(5.8)	(151.0)	0.2
44	External Recoveries		(137.8)	(144.8)	(140.4)	(170.5)	(30.1)	(152.0)	(180.6)	(28.6)	(165.2)	15.4
45	Total		111.8	128.9	139.2	139.5	0.3	160.3	137.6	(22.7)	141.6	3.9

BC Hydro
F11 RRA

Taxes
($ million)

Line	Column	Reference	F2007 Actual	F2008 Actual	F2009 RRA	F2009 Actual	F2009 Difference	F2010 RRA	F2010 Actual	F2010 Difference	F2011 Update	F2011 Increase
			1	2	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10 = 9 - 7
	Corporate											
1	Grants in Lieu		4.7	5.0	5.3	5.3	0.0	5.6	**5.7**	0.1	**6.0**	0.4
2	School Taxes		3.1	3.1	3.7	3.6	(0.2)	3.9	**3.8**	(0.1)	**3.9**	0.2
3	Total		7.8	8.1	9.0	8.9	(0.2)	9.5	9.5	0.0	10.0	0.5
	EARG											
4	Grants in Lieu		12.7	16.0	16.9	16.9	0.0	17.6	**17.9**	0.2	**18.8**	0.9
5	School Taxes		17.2	17.9	18.5	18.3	(0.2)	19.1	**18.8**	(0.3)	**19.6**	0.8
6	Total		29.9	33.9	35.5	35.2	(0.2)	36.7	36.7	(0.1)	38.4	1.8
	CC&C											
7	Grants in Lieu		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**	0.0
8	School Taxes		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**	0.0
8.1	**IPP Capital Leases**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**1.6**	1.6
9	Total		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.6	1.6
	Transmission											
10	Grants in Lieu		26.1	28.1	30.6	30.8	0.2	32.1	**32.3**	0.2	**33.6**	1.3
11	School Taxes		62.4	66.3	69.4	68.3	(1.1)	72.0	**69.8**	(2.2)	**72.9**	3.2
12	Total		88.5	94.4	100.0	99.1	(0.9)	104.1	102.1	(2.0)	106.5	4.4
	Field Operations											
13	Grants in Lieu		5.2	5.5	5.9	5.9	(0.0)	6.2	**6.2**	0.0	**6.2**	0.0
14	School Taxes		15.6	16.7	18.0	17.7	(0.3)	21.7	**18.2**	(3.4)	**19.5**	1.3
15	Total		20.9	22.2	23.9	23.5	(0.3)	27.8	24.4	(3.4)	25.8	1.4
	Total Before Regulatory Accounts											
16	Grants in Lieu		48.7	54.5	58.8	58.9	0.2	61.4	62.0	0.6	64.6	2.6
17	School Taxes		98.3	104.0	109.6	107.8	(1.8)	116.6	110.6	(6.1)	116.1	5.5
17.1	**IPP Capital Leases**	Line 8.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.6	1.6
18	Total		147.1	158.6	168.4	166.7	(1.7)	178.1	172.6	(5.5)	182.3	9.7
	Regulatory Account Recoveries											
19	Corporate		0.0	0.0	0.0	0.2	0.2	0.0	(0.0)	(0.0)	0.0	0.0
20	EARG		0.0	0.0	0.0	0.2	0.2	0.0	0.1	0.1	0.0	(0.1)
21	CC&C		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22	Transmission		0.0	0.0	0.0	0.9	0.9	0.0	2.0	2.0	0.0	(2.0)
23	Field Operations		0.0	0.0	0.0	0.3	0.3	0.0	3.4	3.4	0.0	(3.4)
24	Total		0.0	0.0	0.0	1.7	1.7	0.0	5.5	5.5	0.0	(5.5)
25	**Total Current Taxes**	Lines 18+24	147.1	158.6	168.4	168.4	0.0	178.1	178.1	0.0	182.3	4.2
26	**Total GAAP Taxes**	Line 18	147.1	158.6	168.4	166.7	(1.7)	178.1	172.6	(5.5)	182.3	9.7
	Total Current Taxes by Business Group											
27	Corporate		7.8	8.1	9.0	9.0	0.0	9.5	9.5	0.0	10.0	0.5
28	EARG		29.9	33.9	35.5	35.5	0.0	36.7	36.7	0.0	38.4	1.7
29	CC&C		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.6	1.6
30	Transmission		88.5	94.4	100.0	100.0	0.0	104.1	104.1	0.0	106.5	2.4
31	Field Operations		20.9	22.2	23.9	23.9	0.0	27.8	27.8	0.0	25.8	(2.0)
32	Total		147.1	158.6	168.4	168.4	0.0	178.1	178.1	0.0	182.3	4.2

Depreciation and Amortization
($ million)

Line		Reference	F2007 Actual	F2008 Actual	F2009 RRA	F2009 Actual	F2009 Difference	F2010 RRA	F2010 Actual	F2010 Difference	F2011 Update	F2011 Increase
	Column		1	2	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10 = 9 - 7
	Amortization of Capital Assets											
1	Corporate	12.1 L8+9	40.3	44.1	47.5	47.9	0.4	51.1	51.8	0.7	53.8	2.0
2	EARG	12.2 L8+9	115.8	114.3	114.1	115.9	1.7	117.9	123.2	5.3	142.2	19.0
3	Customer Care & Conservation	12.3 L8+9	1.2	1.7	2.0	1.8	(0.2)	2.2	1.7	(0.5)	2.4	0.7
4	Transmission	12.4 L8+9+10	91.8	94.7	100.6	98.3	(2.3)	111.8	105.7	(6.1)	118.6	12.9
5	Field Operations	12.5 L8+9	111.6	120.1	133.5	128.4	(5.1)	145.8	138.5	(7.3)	159.9	21.4
6	Total		360.7	374.8	397.7	392.3	(5.4)	428.9	420.9	(8.0)	476.8	56.0
	Amortization of Contributions											
7	EARG	11.0 L3+11	(9.6)	(9.6)	(9.6)	(9.6)	0.0	(9.6)	(9.1)	0.5	(2.1)	7.0
8	Transmission	11.0 L20	(3.7)	(3.8)	(4.3)	(4.0)	0.3	(5.1)	(3.6)	1.5	(4.9)	(1.3)
9	Field Operations	11.0 L29	(15.5)	(18.2)	(18.8)	(19.3)	(0.5)	(20.8)	(24.7)	(4.0)	(22.7)	2.0
10	Total		(28.8)	(31.5)	(32.7)	(32.9)	(0.2)	(35.5)	(37.4)	(2.0)	(29.7)	7.7
	Dismantling Costs											
11	Corporate		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	EARG		2.2	2.6	4.2	3.0	(1.2)	7.7	4.7	(3.0)	19.5	14.8
13	CC&C		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	Transmission		3.4	4.4	4.3	3.7	(0.6)	4.7	5.6	0.9	5.6	0.0
15	Field Operations		10.4	11.2	8.5	13.0	4.5	8.7	2.5	(6.2)	8.8	6.3
16	Total		16.0	18.1	17.0	19.7	2.7	21.0	12.8	(8.3)	33.9	21.2
	Capital Asset Write-Offs											
17	Corporate		0.4	0.1	2.3	0.5	(1.8)	2.1	0.7	(1.4)	11.0	10.3
18	EARG		4.1	3.5	3.0	2.0	(1.0)	3.0	1.4	(1.6)	2.0	0.6
19	CC&C		(0.0)	(10.4)	0.0	1.4	1.4	0.0	0.0	0.0	0.0	0.0
20	Transmission		(2.5)	4.6	3.5	(1.1)	(4.6)	2.9	4.2	1.3	3.4	(0.8)
21	Field Operations		4.7	4.2	(0.0)	6.1	6.1	0.0	3.9	3.9	0.0	(3.9)
22	Total		6.6	2.0	8.7	9.0	0.2	8.0	10.2	2.1	16.4	6.2
	IPP Capital Leases											
22.1	CC&C		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	15.4	15.4
	Amortization of PBC ARO											
22.2	Transmission		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.5	2.5
22.3	Field Operations		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.1	4.1
22.4	Total		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.5	6.5
	Regulatory Account Additions											
23	F07/F08 RRA Depn Study		24.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23.1	Deferred Environmental Liability		0.0	0.0	0.0	0.0	0.0	0.0	31.0	31.0	0.0	(31.0)
23.2	Total		24.0	0.0	0.0	0.0	0.0	0.0	31.0	31.0	0.0	(31.0)
24	**Total GAAP Amortization**		378.5	363.4	390.7	388.0	(2.7)	422.5	437.4	14.9	519.4	82.0
	Other Regulatory Account Additions											
25	Deferred PEI Amortization		0.0	0.0	0.6	0.0	(0.6)	1.1	0.0	(1.1)	0.0	0.0
26	Deferred SMI Amortization		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.9	8.9
27	Total		0.0	0.0	0.6	0.0	(0.6)	1.1	0.0	(1.1)	8.9	8.9

Depreciation and Amortization
($ million)

Line		Reference	F2007 Actual	F2008 Actual	F2009 RRA	F2009 Actual	F2009 Difference	F2010 RRA	F2010 Actual	F2010 Difference	F2011 Update	F2011 Increase
	Column		1	2	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10 = 9 - 7
	Regulatory Account Recoveries											
	DSM Amortization											
28	EARG - 90%	2.2 L4+5	30.2	32.5	37.4	37.6	0.1	47.3	46.7	(0.5)	56.8	10.1
29	Transmission - 10%	2.2 L4+5	3.4	3.6	4.2	4.2	0.0	5.3	5.2	(0.1)	6.3	1.1
30	Total		33.6	36.1	41.6	41.8	0.2	52.5	51.9	(0.6)	63.1	11.2
	Depn Study Amortization											
31	Corporate		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
32	EARG		1.4	4.8	4.8	4.8	0.0	4.8	4.8	0.0	4.8	0.0
33	CC&C		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
34	Transmission		3.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
35	Field Operations		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
36	Total		4.8	4.8	4.8	4.8	0.0	4.8	4.8	0.0	4.8	0.0
	FRSR Amortization											
37	Corporate	Line 11	(0.0)	0.0	0.0	0.0	0.0	0.0	0.000	0.0	0.0	0.0
38	EARG	Line 12	(2.2)	(2.6)	(4.2)	(3.0)	1.2	(7.7)	(4.662)	3.0	(19.5)	(14.8)
39	CC&C	Line 13	0.0	0.0	0.0	0.0	0.0	0.0	0.000	0.0	0.0	0.0
40	Transmission	Line 14	(3.4)	(4.4)	(4.3)	(3.7)	0.6	(4.7)	(5.600)	(0.9)	(5.6)	(0.0)
41	Field Operations	Line 15	(10.4)	(11.2)	(8.5)	(13.0)	(4.5)	(8.7)	(2.500)	6.2	(8.8)	(6.3)
42	Adjustment		0.0	0.0	0.0	(0.3)	(0.3)	0.0	0.000	0.0	0.0	0.0
43	Total		(16.0)	(18.1)	(17.0)	(20.0)	(3.0)	(21.0)	(12.762)	8.3	(33.9)	(21.2)
44	**Pre-1996 CIAC Amortization**		(14.0)	(12.7)	(11.6)	(11.6)	0.0	(10.8)	(10.7)	0.1	(9.7)	1.0
	Capital Additions Regulatory Account											
45	Corporate		0.0	0.0	0.0	2.8	2.8	0.0	2.4	2.4	(5.8)	(8.2)
46	EARG		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
47	CC&C		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
48	Transmission		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
49	Field Operations		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
50	Total		0.0	0.0	0.0	2.8	2.8	0.0	2.4	2.4	(5.8)	(8.2)
51	**Total Recoveries**		8.4	10.1	17.8	17.8	(0.0)	25.5	35.7	10.2	18.5	(17.1)
52	**Total Current Amortization**		362.9	373.4	407.9	405.9	(2.1)	446.8	442.1	(4.8)	529.0	86.9
	Current Amortization by Business Group											
53	Corporate		40.7	44.2	49.2	50.9	1.7	52.1	54.9	2.8	50.1	(4.8)
54	EARG		141.9	145.6	149.7	150.7	0.9	163.4	167.0	3.6	203.7	36.7
55	CC&C		1.2	(8.8)	2.0	3.2	1.2	2.2	1.7	(0.5)	17.8	16.1
56	Transmission		92.3	99.1	103.9	97.4	(6.6)	114.9	111.5	(3.4)	125.9	14.4
57	Field Operations		86.8	93.3	103.1	103.7	0.6	114.3	107.0	(7.3)	131.5	24.6
58	Total		362.9	373.4	407.9	405.9	(2.1)	446.8	442.1	(4.8)	529.0	86.9

Finance Charges
($ million)

Line	Column	Reference	F2007 Actual	F2008 Actual	F2009 RRA	F2009 Actual	F2009 Difference	F2010 RRA	F2010 Actual	F2010 Difference	F2011 Update	F2011 Increase
			1	2	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10 = 9 - 7
	Increase in Cash											
1	Net Income	9.0 L44	407.0	369.0	359.4	365.6	6.2	451.5	447.0	(4.5)	602.3	155.3
2	Dividend (One Year Lag)	9.0 L4	(223.3)	(330.9)	(288.3)	(288.3)	0.0	(100.7)	0.0	100.7	(46.9)	(46.9)
3	Amortization	7.0 L24	378.5	363.4	390.7	388.0	(2.7)	422.5	437.4	14.9	519.4	82.0
4	Deferral Account Additions	2.1 L28	22.4	96.3	0.0	(239.6)	(239.6)	0.0	(249.1)	(249.1)	(245.6)	3.5
5	Deferral Account Recoveries	2.1 L30	50.2	55.9	14.1	14.0	(0.0)	15.3	29.7	14.5	113.9	84.1
6	Regulatory Account Additions	2.2 L133	(115.6)	(314.2)	(213.1)	(271.3)	(58.2)	(244.6)	(542.1)	(297.5)	(331.7)	210.4
7	Regulatory Account Recoveries	2.2 L135	28.6	28.3	47.7	79.0	31.3	40.5	107.9	67.5	(83.2)	(191.1)
8	First Nations Provisions	2.2 L14	6.6	231.3	20.5	26.2	5.7	19.0	12.2	(6.8)	16.4	4.2
8.1	Environmental Provisions	2.0 L110.2	0.0	0.0	0.0	0.0	0.0	0.0	289.5	289.5	13.2	(276.3)
9	Capital Expenditures	13.0 L17-11	(801.7)	(1,062.7)	(1,585.9)	(1,391.3)	194.6	(1,589.5)	(2,400.0)	(810.5)	(1,636.3)	763.7
10	Contributions in Aid	11.0 L35	85.4	100.4	112.2	95.4	(16.8)	99.5	101.4	1.9	100.6	(0.8)
11	Decrease in Sinking Funds	Line 15	152.3	162.3	512.9	488.8	(24.1)	(2.8)	24.1	26.9	(0.4)	(24.5)
12	Change in Working Cap & Other		(150.8)	(178.7)	(55.7)	(570.6)	(514.9)	(130.1)	**381.7**	511.8	**11.3**	(370.4)
13	Total		(160.3)	(479.6)	(685.5)	(1,304.1)	(618.7)	(1,019.4)	(1,360.3)	(340.8)	(967.0)	393.2
	Sinking Funds											
14	Beginning of Year		845.9	732.7	595.2	595.2	0.0	91.7	114.8	23.1	95.9	(18.9)
15	Decrease in Sinking Funds		(152.3)	(162.3)	(512.9)	(488.8)	24.1	2.8	**(24.1)**	(26.9)	**0.4**	24.5
16	Sinking Fund Income		39.1	24.8	9.4	8.4	(1.0)	4.6	**5.2**	0.6	**4.5**	(0.7)
17	End of Year		732.7	595.2	91.7	114.8	23.1	99.1	95.9	(3.2)	100.8	4.9
18	Mid-Year Balance		789.3	664.0	343.5	355.0	11.6	95.4	105.4	9.9	98.3	(7.0)
	Long-Term Debt											
19	Beginning of Year		7,066.5	6,820.2	7,140.5	7,140.5	0.0	7,623.7	7,749.7	126.0	8,877.2	1,127.5
20	Adjustment to F2008 Opening		0.0	146.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
21	Bonds Retired		(526.0)	(541.6)	(93.8)	(93.8)	0.0	(626.5)	(631.5)	(5.0)	(150.0)	481.5
22	Bonds Issued		300.0	830.0	601.7	351.6	(250.1)	1,650.3	**2,070.0**	419.7	0.0	(2,070.0)
23	Bonds Planned Issues		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**500.0**	500.0
24	Revaluation of US $ Debt		(20.3)	(176.7)	(20.4)	296.6	317.0	53.8	**(301.3)**	(355.1)	**3.5**	304.8
25	Revaluation to Fair Value		0.0	60.4	0.0	61.8	61.8	0.0	**(41.4)**	(41.4)	0.0	41.4
26	Other Additions		0.0	5.4	(0.6)	(2.0)	(1.4)	0.0	**46.1**	46.1	0.0	(46.1)
27	Amortization of Issue Costs		0.0	(3.6)	(3.7)	(5.0)	(1.3)	(4.7)	(14.4)	(9.7)	**(17.0)**	(2.6)
28	End of Year		6,820.2	7,140.5	7,623.7	7,749.7	126.0	8,696.6	8,877.2	180.6	9,213.7	336.5
29	Mid-Year Balance		6,943.4	6,980.4	7,382.1	7,445.1	63.0	8,160.2	8,313.5	153.3	9,045.5	732.0
30	Interest Rate - Planned Issues										**4.55%**	
31	Debt Costs - Excluding Planned		491.3	474.8	488.4	478.4	(10.0)	515.0	**494.1**	(20.9)	**533.0**	38.9
32	Debt Costs - Planned Issues		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11.4	11.4
33	Total Long-Term Debt Costs		491.3	474.8	488.4	478.4	(10.0)	515.0	494.1	(20.9)	544.4	50.3

Finance Charges
($ million)

Line		Reference	F2007 Actual	F2008 Actual	F2009 RRA	F2009 Actual	F2009 Difference	F2010 RRA	F2010 Actual	F2010 Difference	F2011 Update	F2011 Increase
	Column		1	2	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10 = 9 - 7
	Short-Term Debt											
34	Beginning of Year		429.9	836.5	995.9	995.9	0.0	1,198.1	1,690.8	492.7	1,923.6	232.8
35	Increase in Cash Requirement	Line 13	160.3	479.6	685.5	1,304.1	618.7	1,019.4	1,360.3	340.8	967.0	(393.2)
36	Change in Long-Term Debt	Line 19-28	246.3	(320.3)	(483.2)	(609.2)	(126.0)	(1,072.9)	(1,127.5)	(54.6)	(336.5)	791.0
37	End of Year		836.5	995.9	1,198.1	1,690.8	492.7	1,144.7	1,923.6	778.9	2,554.1	630.5
38	Mid-Year Balance		633.2	916.2	1,097.0	1,343.3	246.3	1,171.4	1,807.2	635.8	2,238.9	431.7
39	Interest Rate										**0.81%**	
40	Debt Costs - Interest										18.1	
41	Debt Costs - Other										**0.3**	
42	Total Short-Term Debt Costs		24.3	37.4	31.0	25.4	(5.6)	36.3	7.7	(28.6)	18.4	10.7
	Interest Capitalized											
43	Unfinished Construction	13.0 L51	516.1	679.2	877.8	900.4	22.5	1,075.5	1,190.9	115.3	1,394.9	204.0
44	Less Not Subject to IDC		(153.6)	(152.2)	(33.1)	(132.0)	(98.9)	(125.9)	**(292.9)**	(166.9)	**(293.6)**	(0.8)
45	Unfinished Subject to IDC		362.5	527.0	844.7	768.4	(76.3)	949.6	898.0	(51.6)	1,101.2	203.2
46	Interest Rate (One Year Lag)	Line 80	6.62%	6.88%	6.52%	6.52%	0.00%	6.20%	6.55%	0.35%	4.47%	-2.08%
47	Interest Capitalized		24.0	36.3	55.1	50.1	(5.0)	58.8	58.8	(0.1)	49.2	(9.6)
	Total Before Regulatory Accounts											
48	Sinking Fund Income	Line 16	(39.1)	(24.8)	(9.4)	(8.4)	1.0	(4.6)	(5.2)	(0.6)	(4.5)	0.7
49	Long-Term Debt Costs	Line 33	491.3	474.8	488.4	478.4	(10.0)	515.0	494.1	(20.9)	544.4	50.3
50	Short-Term Debt Costs	Line 42	24.3	37.4	31.0	25.4	(5.6)	36.3	7.7	(28.6)	18.4	10.7
51	Interest Capitalized	Line 47	(24.0)	(36.3)	(55.1)	(50.1)	5.0	(58.8)	(58.8)	0.1	(49.2)	9.6
52	Swaps		2.7	6.8	(2.2)	(22.6)	(20.4)	5.8	**(29.9)**	(35.7)	**(23.0)**	6.9
53	Other Income		3.2	(5.8)	(1.8)	39.5	41.3	(1.1)	**9.9**	11.0	**14.4**	4.5
54	Total		458.4	452.1	450.9	462.2	11.3	492.5	417.8	(74.7)	500.5	82.7
	Interest on Regulatory Accounts											
55	Interest on Deferral Accounts	2.1 L29	(13.8)	(4.7)	(5.5)	(16.0)	(10.5)	(4.7)	(32.2)	(27.5)	(29.1)	3.1
56	Interest on Other Reg Accounts	2.2 L134	0.0	(3.3)	(3.6)	(3.9)	(0.2)	(5.7)	(9.9)	(4.2)	(11.2)	(1.3)
57	Total		(13.8)	(8.0)	(9.2)	(19.9)	(10.7)	(10.4)	(42.1)	(31.7)	(40.2)	1.9
	Regulatory Account Recoveries											
58	Amort. of FX Gains/Losses		16.0	15.3	24.0	23.9	(0.1)	8.3	10.0	1.7	**0.2**	(9.8)
59	Total Finance Charges	2.2 L87	0.0	0.0	0.0	(0.6)	(0.6)	0.0	104.7	104.7	(104.1)	(208.9)
60	Total		16.0	15.3	24.0	23.3	(0.7)	8.3	114.7	106.4	(103.9)	(218.7)
61	**Total Current Finance Chrgs**	Lines 54+57+60	460.6	459.4	465.7	465.7	(0.1)	490.4	490.4	0.0	356.3	(134.1)
	Regulatory Account Additions											
62	FX Gains/Losses		(2.4)	(17.6)	(2.8)	32.9	35.7	6.0	**(33.8)**	(39.8)	**0.4**	34.2
63	**Total GAAP Finance Charges**	Lines 54+62	456.0	434.5	448.1	495.1	47.0	498.5	384.0	(114.5)	500.9	116.9

Finance Charges
($ million)

Line		Reference	F2007 Actual	F2008 Actual	F2009 RRA	F2009 Actual	F2009 Difference	F2010 RRA	F2010 Actual	F2010 Difference	F2011 Update	F2011 Increase
	Column		1	2	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10 = 9 - 7
	Portion of Rate Base											
64	EARG	10.0 L19	44.6%	45.5%	44.2%	44.2%	0.1%	42.7%	45.1%	2.4%	46.5%	1.3%
65	CC&C	10.0 L20	0.0%	0.1%	0.1%	0.1%	0.0%	0.2%	0.1%	-0.1%	0.1%	0.0%
66	Transmission	10.0 L21	26.4%	26.5%	26.8%	26.6%	-0.2%	27.7%	25.8%	-1.9%	24.4%	-1.4%
67	Field Operations	10.0 L22	29.0%	27.9%	28.8%	29.0%	0.2%	29.5%	29.0%	-0.5%	29.1%	0.1%
68	Total		100.0%	100.0%	100.0%	100.0%	0%	100.0%	100.0%	0%	100.0%	0.0%
	Allocation of Current Finance Charges											
69	EARG		205.3	209.1	205.7	206.0	0.3	209.3	221.3	12.0	165.5	(55.8)
70	CC&C		0.2	0.5	0.7	0.5	(0.2)	0.8	0.3	(0.5)	0.3	(0.0)
71	Transmission		121.6	121.8	125.0	123.9	(1.1)	135.9	126.7	(9.2)	87.0	(39.7)
72	Field Operations		133.5	128.1	134.3	135.2	0.9	144.5	142.1	(2.3)	103.6	(38.5)
73	Total		460.6	459.4	465.7	465.7	(0.1)	490.4	490.4	0.0	356.3	(134.1)
	Net Debt											
74	Sinking Funds	Line 17	(732.7)	(595.2)	(91.7)	(114.8)	(23.1)	(99.1)	(95.9)	3.2	(100.8)	(4.9)
75	Temporary Investments		(7.6)	(22.2)	(10.0)	(190.4)	(180.4)	(10.0)	**(8.6)**	1.4	(10.0)	(1.4)
76	Long-Term Debt	Line 28	6,820.2	7,140.5	7,623.7	7,749.7	126.0	8,696.6	8,877.2	180.6	9,213.7	336.5
77	Short-Term Debt	Line 37	836.5	995.9	1,198.1	1,690.8	492.7	1,144.7	1,923.6	778.9	2,554.1	630.5
78	End of Year		6,916.4	7,519.0	8,720.1	9,135.3	415.2	9,732.2	10,696.3	964.1	11,657.0	960.7
79	Mid-Year Balance			7,217.7	8,119.6	8,327.1	207.6	9,226.2	9,915.8	689.6	11,176.7	1,260.9
80	**Weighted Average Cost of Debt**			6.52%	6.20%	6.55%		6.04%	4.47%		4.92%	

BC Hydro
F11 RRA
Return on Equity
($ million)

Line		Reference	F2007 Actual	F2008 Actual	F2009 RRA	F2009 Actual	F2009 Difference	F2010 RRA	F2010 Actual	F2010 Difference	F2011 Update	F2011 Increase
Line	Column		1	2	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10 = 9 - 7
	Shareholder's Equity											
1	Retained Earnings - Begining of Year		1,706.9	1,783.0	1,864.5	1,864.5	0.0	2,123.2	2,230.1	106.9	2,621.1	391.1
2	Adjustment to Opening Balance	CICA 3064	0.0	0.8	0.0	0.0	0.0	0.0	(9.0)	(9.0)	0.0	9.0
3	GAAP Return on Equity	Line 40	407.0	369.0	359.4	365.6	6.2	451.5	447.0	(4.5)	602.3	155.3
4	Dividend to Province	Line 15	(330.9)	(288.3)	(100.7)	0.0	100.7	(141.7)	(46.9)	94.8	(362.2)	(315.3)
5	Distribution to Province		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	Retained Earnings - End of Year		1,783.0	1,864.5	2,123.2	2,230.1	106.9	2,433.0	2,621.1	188.1	2,861.2	240.1
7	Accum Other Comp Income		0.0	56.8	56.8	(41.5)	(98.3)	0.0	53.1	53.1	53.1	0.0
8	Total Shareholder's Equity		1,783.0	1,921.3	2,180.0	2,188.5	106.9	2,433.0	2,674.2	188.1	2,914.3	240.1
	Dividend to Province											
9	Net Income	Line 40									602.3	
10	IDC (net of amortization)										(40.2)	
11	Distributable Surplus										562.1	
12	Maximum Dividend Percentage										85.0%	
13	Maximum Dividend Amount										477.8	
14	Minimum Equity Percentage										20.0%	
15	Dividend to Province										362.2	
	Deferred Revenue											
16	Skagit - Beginning of Year		307.0	327.6	348.3	348.3	0.0	368.9	361.8	(7.1)	370.6	
17	Payments Received		25.7	21.7	22.0	26.9	4.9	23.0	23.2	0.2	22.2	
18	Interest		13.3	14.2	15.4	8.6	(6.8)	18.0	1.9	(16.1)	3.1	
19	Revenues Earned		(18.4)	(15.2)	(16.8)	(22.0)	(5.2)	(18.4)	(16.3)	2.1	(17.5)	
20	Skagit - End of Year		327.6	348.3	368.9	361.8	(7.1)	391.5	370.6	(20.9)	378.4	
	Return on Equity											
21	Shareholder's Equity	Line 8	1,783.0	1,921.3								
22	Deferred Revenue	Line 20	327.6	348.3								
23	Contributions - Columbia River		165.8	156.6								
24	Contributions - EARG		7.5	7.2								
25	Contributions - Field Operations		646.5	696.0								
26	Contributions - Transmission		93.1	109.0								
27	Pre-1996 CIAC Adjustment		(14.0)	(26.6)								
28	Total Equity		3,009.5	3,211.8								
	Capitalization											
29	Net Debt	8.0 L78		7,519.0	8,720.1	9,135.3		9,732.2	10,696.3		11,657.0	
30	Shareholder's Equity	Line 8		1,921.3	2,180.0	2,188.5		2,433.0	2,674.2		2,914.3	
31	Total			9,440.3	10,900.1	11,323.9		12,165.2	13,370.5		14,571.3	
	Capital Structure											
32	Net Debt			79.6%	80.0%	80.7%		80.0%	80.0%		80.0%	
33	Equity			20.4%	20.0%	19.3%		20.0%	20.0%		20.0%	
34	Total			100.0%	100.0%	100.0%		100.0%	100.0%		100.0%	

Return on Equity
($ million)

Line		Reference	F2007 Actual	F2008 Actual	F2009 RRA	F2009 Actual	F2009 Difference	F2010 RRA	F2010 Actual	F2010 Difference	F2011 Update	F2011 Increase
	Column		1	2	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10 = 9 - 7
	Deemed Equity											
35	Percentage			30.0%	30.0%	30.0%		30.0%	30.0%		30.0%	
36	Year-End Deemed Equity			2,832.1	3,270.0	3,397.2		3,649.6	4,011.1		4,371.4	
37	Mid-Year Deemed Equity				3,051.1	3,114.6		3,459.8	3,704.1		4,191.3	
38	Achieved ROE		13.52%	11.49%		11.74%			12.07%			
39	Allowed ROE				11.78%			13.05%			14.37%	
40	GAAP Return on Equity		407.0	369.0	359.4	365.6	6.2	451.5	447.0	(4.5)	602.3	155.3
	ROE Regulatory Account Transfers											
41	Additions		0.0	0.0	0.0	0.0	0.0	56.4	56.4	0.0	0.0	(56.4)
42	Recoveries		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(11.3)	(11.3)
43	Total		0.0	0.0	0.0	0.0	0.0	56.4	56.4	0.0	(11.3)	(67.7)
44	**Current Return on Equity**		407.0	369.0	359.4	365.6	6.2	395.1	390.6	(4.5)	613.6	223.0
	Portion of Rate Base											
45	EARG	10.0 L19	44.6%	45.5%	44.2%	44.2%	0.1%	42.7%	45.1%	2.4%	46.5%	1.3%
46	CC&C	10.0 L20	0.0%	0.1%	0.1%	0.1%	0.0%	0.2%	0.1%	-0.1%	0.1%	0.0%
47	Transmission	10.0 L21	26.4%	26.5%	26.8%	26.6%	-0.2%	27.7%	25.8%	-1.9%	24.4%	-1.4%
48	Field Operations	10.0 L22	29.0%	27.9%	28.8%	29.0%	0.2%	29.5%	29.0%	-0.5%	29.1%	0.1%
49	Total		100.0%	100.0%	100.0%	100.0%	0.0%	100.0%	100.0%	0.0%	100.0%	0.0%
	Allocation of ROE											
50	EARG		181.4	167.9	158.8	161.7	3.0	168.6	176.3	7.6	285.0	108.8
51	CC&C		0.2	0.4	0.5	0.4	(0.1)	0.6	0.2	(0.4)	0.4	0.2
52	Transmission		107.5	97.8	96.5	97.3	0.8	109.5	100.9	(8.6)	149.7	48.8
53	Field Operations		118.0	102.9	103.6	106.1	2.5	116.4	113.2	(3.2)	178.4	65.2
54	Total		407.0	369.0	359.4	365.6	6.2	395.1	390.6	(4.5)	613.6	223.0

Rate Base
($ million)

Line		Column Reference	F2007 Actual	F2008 Actual	F2009 RRA	F2009 Actual	F2009 Difference	F2010 RRA	F2010 Actual	F2010 Difference	F2011 Update	F2011 Increase
			1	2	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10 = 9 - 7
	EARG											
1	Net Assets in Service	12.2 L14	3,914.1	3,981.6	4,188.2	4,145.4	(42.8)	4,323.8	5,083.6	759.8	5,452.1	368.5
2	Net Contributions	11.0 L14	(7.5)	(7.2)	(6.7)	(6.6)	0.1	(6.3)	(4.8)	1.5	(4.4)	0.4
3	90% of Net DSM	2.2 L6	253.9	278.4	341.8	326.1	(15.7)	418.9	398.6	(20.3)	498.5	99.9
4	Total		4,160.5	4,252.8	4,523.3	4,464.9	(58.4)	4,736.5	5,477.5	741.0	5,946.3	468.8
5	Mid-Year		4,060.1	4,206.7	4,388.0	4,358.9	(29.2)	4,629.9	4,971.2	341.3	5,711.9	740.7
	CC&C											
6	Net Assets in Service	12.3 L14	7.9	12.7	15.7	8.3	(7.4)	17.7	5.3	(12.4)	12.3	7.0
7	Net Contributions	N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	Total		7.9	12.7	15.7	8.3	(7.4)	17.7	5.3	(12.4)	12.3	7.0
9	Mid-Year		4.0	10.3	14.2	10.5	(3.7)	16.7	6.8	(9.9)	8.8	2.0
	Transmission											
10	Net Assets in Service	12.4 L15	2,493.9	2,548.4	2,959.4	2,862.8	(96.6)	3,244.9	3,029.9	(215.0)	3,230.4	200.5
11	Net Contributions	11.0 L23	(93.1)	(109.0)	(133.0)	(124.6)	8.4	(144.3)	(157.5)	(13.3)	(201.8)	(44.3)
12	10% of Net DSM	2.2 L6	28.2	30.9	38.0	36.2	(1.7)	46.5	44.3	(2.3)	55.4	11.1
13	Total		2,429.0	2,470.3	2,864.3	2,774.4	(89.9)	3,147.2	2,916.7	(230.5)	3,083.9	167.3
14	Mid-Year		2,406.3	2,449.6	2,667.3	2,622.3	(45.0)	3,005.8	2,845.6	(160.2)	3,000.3	154.8
	Field Operations											
15	Net Assets in Service	12.5 L14	3,093.2	3,404.0	3,771.4	3,756.1	(15.3)	4,169.3	4,144.2	(25.1)	4,567.7	423.5
16	Net Contributions	11.0 L33	(646.5)	(696.0)	(749.5)	(742.8)	6.7	(801.2)	(772.6)	28.5	(791.6)	(19.0)
17	Total		2,446.7	2,708.0	3,021.9	3,013.3	(8.6)	3,368.1	3,371.6	3.4	3,776.1	404.5
18	Mid-Year		2,640.9	2,577.4	2,865.0	2,860.6	(4.3)	3,195.0	3,192.4	(2.6)	3,573.9	381.4
	Portion of Rate Base											
19	EARG		44.6%	45.5%	44.2%	44.2%	0.1%	42.7%	45.1%	2.4%	46.5%	1.3%
20	CC&C		0.0%	0.1%	0.1%	0.1%	0.0%	0.2%	0.1%	-0.1%	0.1%	0.0%
21	Transmission		26.4%	26.5%	26.8%	26.6%	-0.2%	27.7%	25.8%	-1.9%	24.4%	-1.4%
22	Field Operations		29.0%	27.9%	28.8%	29.0%	0.2%	29.5%	29.0%	-0.5%	29.1%	0.1%
23	Total		100.0%	100.0%	100.0%	100.0%	0.0%	100.0%	100.0%	0.0%	100.0%	0.0%

Contributions
($ million)

Line	Column	Reference	F2007 Actual	F2008 Actual	F2009 RRA	F2009 Actual	F2009 Difference	F2010 RRA	F2010 Actual	F2010 Difference	F2011 Update	F2011 Increase
			1	2	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10 = 9 - 7
	Contributions - Columbia River Treaty											
1	Gross Contns - Beginning of Year		479.1	479.1	479.1	479.1	0.0	479.1	479.1	0.0	377.1	(102.0)
1.1	Retirements		0.0	0.0	0.0	0.0	0.0	0.0	**(102.0)**	(102.0)	0.0	102.0
1.2	Gross Contns - End of Year		479.1	479.1	479.1	479.1	0.0	479.1	377.1	(102.0)	377.1	0.0
2	Accum Amort - Beginning of Year		304.0	313.3	322.5	322.5	0.0	331.7	331.7	0.0	267.9	(63.8)
3	Amortization		9.3	9.2	9.2	9.2	0.0	9.2	**8.7**	(0.5)	**1.7**	(7.0)
3.1	Retirements		0.0	0.0	0.0	0.0	0.0	0.0	**(72.5)**	(72.5)	0.0	72.5
4	Accum Amort - End of Year		313.3	322.5	331.7	331.7	0.0	340.9	267.9	(73.0)	269.6	1.7
5	Net Contribution - End of Year		165.8	156.6	147.4	147.4	0.0	138.2	109.2	(29.0)	107.5	(1.7)
	Contributions in Aid - EARG											
6	Gross Contns - Beginning of Year		6.4	10.3	10.3	10.3	0.0	10.3	10.3	0.0	8.9	(1.4)
7	Additions		0.0	0.0	0.0	0.0	0.0	0.0	**0.0**	0.0	**0.0**	0.0
8	Retirements & Transfers		3.9	0.0	0.0	0.0	0.0	0.0	**(1.4)**	(1.4)	0.0	1.4
9	Gross Contns - End of Year		10.3	10.3	10.3	10.3	0.0	10.3	8.9	(1.4)	8.9	0.0
10	Accum Amort - Beginning of Year		2.4	2.8	3.2	3.2	0.0	3.6	3.7	0.1	4.1	
11	Amortization		0.3	0.4	0.4	0.4	(0.0)	0.4	0.4	0.0	**0.4**	0.0
12	Retirements & Transfers		0.1	0.0	0.0	0.2	0.2	0.0	0.0	0.0	0.0	0.0
13	Accum Amort - End of Year		2.8	3.2	3.6	3.7	0.1	4.0	4.1	0.1	4.5	0.4
14	Net Contributions - End of Year		7.5	7.2	6.7	6.6	(0.1)	6.3	4.8	(1.5)	4.4	(0.4)
	Contributions in Aid - Transmission											
15	Gross Contns - Beginning of Year		141.7	145.4	164.6	164.6	0.0	192.9	183.6	(9.3)	220.9	37.3
16	Additions		8.9	20.5	28.3	18.4	(9.9)	16.3	**36.5**	20.2	**49.2**	12.7
17	Retirements & Transfers		(5.2)	(1.3)	0.0	0.6	0.6	0.0	**0.8**	0.8	**(0.7)**	(1.5)
18	Gross Contns - End of Year		145.4	164.6	192.9	183.6	(9.3)	209.2	220.9	11.7	269.5	48.5
19	Accum Amort - Beginning of Year		51.0	52.3	55.6	55.6	0.0	59.9	59.0	(0.9)	63.4	4.4
20	Amortization		3.7	3.8	4.3	4.0	(0.3)	5.1	**3.6**	(1.5)	**4.9**	1.3
21	Retirements & Transfers		(2.4)	(0.5)	0.0	(0.6)	(0.6)	0.0	**0.8**	0.8	**(0.7)**	(1.5)
22	Accum Amort - End of Year		52.3	55.6	59.9	59.0	(0.9)	65.0	63.4	(1.6)	67.6	4.2
							0.0			0.0		
23	Net Contributions - End of Year		93.1	109.0	133.0	124.6	(8.4)	144.3	157.5	13.3	201.8	44.3
	Contributions in Aid - Field Operations											
24	Gross Contns - Beginning of Year		959.1	1,004.3	1,083.3	1,083.3	0.0	1,167.2	1,160.3	(6.9)	1,221.5	61.2
25	Additions		76.5	79.9	83.9	77.0	(6.9)	83.2	**64.9**	(18.3)	**51.4**	(13.5)
26	Retirements & Transfers		(31.3)	(0.9)	0.0	0.0	0.0	0.0	**(3.7)**	(3.7)	0.0	3.7
27	Gross Contns - End of Year		1,004.3	1,083.3	1,167.2	1,160.3	(6.9)	1,250.4	1,221.5	(28.9)	1,272.9	51.4
28	Accum Amort - Beginning of Year		373.0	357.8	387.3	387.3	0.0	417.7	417.5	(0.2)	448.9	31.4
29	Amortization		15.5	18.2	18.8	19.3	0.5	20.8	**24.7**	4.0	**22.7**	(2.0)
30	Amortization of Pre-1996 CIAC	2.2 L38	0.0	12.7	11.6	11.6	(0.0)	10.8	10.7	(0.1)	9.7	(1.0)
31	Retirements & Transfers		(30.7)	(1.4)	0.0	(0.7)	(0.7)	0.0	**(4.0)**	(4.0)	0.0	4.0
32	Accum Amort - End of Year		357.8	387.3	417.7	417.5	(0.2)	449.3	448.9	(0.4)	481.3	32.4
33	Net Contributions - End of Year		646.5	696.0	749.5	742.8	(6.7)	801.2	772.6	(28.5)	791.6	19.0

Contributions
($ million)

Line		Reference	F2007 Actual	F2008 Actual	F2009 RRA	F2009 Actual	F2009 Difference	F2010 RRA	F2010 Actual	F2010 Difference	F2011 Update	F2011 Increase
	Column		1	2	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10 = 9 - 7
	Contributions in Aid - Total											
34	Gross Contns - Beginning of Year		1,107.2	1,160.0	1,258.2	1,258.2	0.0	1,370.4	1,354.2	(16.2)	1,451.3	97.1
35	Additions		85.4	100.4	112.2	95.4	(16.8)	99.5	101.4	1.9	100.6	(0.8)
36	Retirements & Transfers		(32.6)	(2.2)	0.0	0.6	0.6	0.0	(4.3)	(4.3)	(0.7)	3.6
37	Gross Contns - End of Year		1,160.0	1,258.2	1,370.4	1,354.2	(16.2)	1,469.9	1,451.3	(18.6)	1,551.3	99.9
38	Accum Amort - Beginning of Year		426.4	412.9	446.0	446.0	0.0	481.2	480.1	(1.0)	516.4	36.3
39	Amortization		19.5	22.3	23.5	23.7	0.2	26.3	28.7	2.5	28.0	(0.7)
40	Amortization of Pre-96 CIAC		0.0	12.7	11.6	11.6	(0.0)	10.8	10.7	(0.1)	9.7	(1.0)
41	Retirements & Transfers		(33.0)	(1.9)	0.0	(1.2)	(1.2)	0.0	(3.2)	(3.2)	(0.7)	2.5
42	Accum Amort - End of Year		412.9	446.0	481.2	480.1	(1.0)	518.2	516.4	(1.8)	553.5	37.1
												0.0
43	Net Contributions - End of Year		747.1	812.2	889.2	874.1	(15.2)	951.7	934.9	(16.8)	997.8	62.9

Assets - Total (Excluding DSM)
($ million)

Line	Column	Reference	F2007 Actual	F2008 Actual	F2009 RRA	F2009 Actual	F2009 Difference	F2010 RRA	F2010 Actual	F2010 Difference	F2011 Update	F2011 Increase
			1	2	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10 = 9 - 7
	Gross Assets in Service											
1	Opening Balance		16,172.1	16,651.0	17,358.7	17,358.7	0.0	18,750.4	18,502.0	(248.4)	20,246.9	1,744.9
2	Adjustment to Opening Balance	CICA 3064	0.0	0.0	0.0	0.0	0.0	0.0	(11.5)	(11.5)	0.0	11.5
3	Capital Additions		736.2	802.0	1,449.4	1,265.3	(184.1)	1,330.6	1,995.0	664.4	1,627.8	(367.2)
4	Retirements & Transfers		(257.3)	(94.3)	(57.7)	(122.0)	(64.3)	(62.2)	(238.6)	(176.5)	(60.9)	177.7
5	Closing Balance		16,651.0	17,358.7	18,750.4	18,502.0	(248.4)	20,018.9	20,246.9	228.1	21,813.8	1,566.9
	Accumulated Amortization											
6	Opening Balance		6,645.8	6,791.9	7,088.4	7,088.4	0.0	7,433.5	7,375.2	(58.3)	7,553.8	178.6
7	Adjustment to Opening Balance	CICA 3064	0.0	0.0	0.0	0.0	0.0	0.0	(6.4)	(6.4)	0.0	6.4
8	Amort on March 2010 Assets		360.7	374.8	397.7	392.3	(5.4)	407.3	420.9	13.6	448.5	27.6
9	Amortization on Additions		0.0	0.0	0.0	0.0	0.0	21.6	0.0	(21.6)	28.4	28.4
10	Capital Asset Write-Offs		6.6	2.0	8.7	9.0	0.2	8.0	10.2	2.1	16.4	6.2
11	Depn Study Adjustment		24.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	Retirements & Transfers		(245.3)	(80.2)	(61.3)	(114.4)	(53.1)	(65.0)	(246.1)	(181.1)	(64.3)	181.8
13	Closing Balance		6,791.9	7,088.4	7,433.5	7,375.2	(58.3)	7,805.4	7,553.8	(251.6)	7,982.7	429.0
14	**Net Assets in Service (Year-End)**		9,859.1	10,270.3	11,316.9	11,126.8	(190.1)	12,213.5	12,693.2	479.7	13,831.1	1,137.9

Assets - Corporate
($ million)

			F2007	F2008	F2009			F2010			F2011	F2011
		Reference	Actual	Actual	RRA	Actual	Difference	RRA	Actual	Difference	Update	Increase
Line	Column		1	2	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10 = 9 - 7
	Gross Assets in Service											
1	Opening Balance		736.7	727.9	711.3	711.3	0.0	805.4	756.2	(49.2)	870.5	114.3
2	Adjustment to Opening Balance	CICA 3064	0.0	0.0	0.0	0.0	0.0	0.0	(8.8)	(8.8)	0.0	8.8
3	Capital Additions	13.0 L40	51.0	19.0	108.4	68.9	(39.5)	128.7	143.2	14.5	203.2	60.0
4	Retirements & Transfers		(59.8)	(35.6)	(14.3)	(24.0)	(9.7)	(19.1)	**(20.1)**	(1.0)	(23.0)	(3.0)
5	Closing Balance		727.9	711.3	805.4	756.2	(49.2)	915.0	870.5	(44.5)	1,050.6	180.1
	Accumulated Amortization											
6	Opening Balance		392.9	377.9	387.7	387.7	0.0	423.1	402.0	(21.2)	440.4	38.4
7	Adjustment to Opening Balance	CICA 3064	0.0	0.0	0.0	0.0	0.0	0.0	(5.1)	(5.1)	0.0	5.1
8	Amort on March 2010 Assets		40.3	44.1	47.5	47.9	0.4	45.9	**51.8**	5.9	**45.0**	(6.8)
9	Amortization on Additions	13.0 L74	0.0	0.0	0.0	0.0	0.0	5.2	**0.0**	(5.2)	8.7	8.7
10	Capital Asset Write-Offs	7.0 L17	0.4	0.1	2.3	0.5	(1.8)	2.1	0.7	(1.4)	11.0	10.3
11	Depn Study Adjustment		6.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	Retirements & Transfers		(62.0)	(34.4)	(14.4)	(34.1)	(19.7)	(19.1)	**(9.0)**	10.1	(23.0)	(14.1)
13	Closing Balance		377.9	387.7	423.1	402.0	(21.2)	457.3	440.4	(16.9)	482.1	41.7
14	**Net Assets in Service (Year-End)**		350.0	323.6	382.3	354.2	(28.0)	457.7	430.1	(27.6)	568.5	138.4

Assets - Engineering, Aboriginal Relations & Generation
($ million)

Line	Column	Reference	F2007 Actual	F2008 Actual	F2009 RRA	F2009 Actual	F2009 Difference	F2010 RRA	F2010 Actual	F2010 Difference	F2011 Update	F2011 Increase
			1	2	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10 = 9 - 7
	Gross Assets in Service											
1	Opening Balance		6,146.1	6,203.7	6,380.6	6,380.6	0.0	6,695.9	6,654.8	(41.1)	7,616.8	962.0
2	Adjustment to Opening Balance	CICA 3064	0.0	0.0	0.0	0.0	0.0	0.0	(1.3)	(1.3)	0.0	1.3
3	Capital Additions	13.0 L41	85.6	189.8	323.7	292.7	(31.0)	256.6	1,110.7	854.1	512.6	(598.1)
4	Retirements & Transfers		(28.0)	(12.8)	(8.4)	(18.5)	(10.1)	(9.6)	**(147.3)**	(137.7)	(3.4)	143.9
5	Closing Balance		6,203.7	6,380.6	6,695.9	6,654.8	(41.1)	6,942.9	7,616.8	673.9	8,126.1	509.2
	Accumulated Amortization											
6	Opening Balance		2,186.3	2,289.6	2,399.0	2,399.0	0.0	2,507.8	2,509.5	1.7	2,533.2	23.7
7	Adjustment to Opening Balance	CICA 3064	0.0	0.0	0.0	0.0	0.0	0.0	(1.0)	(1.0)	0.0	1.0
8	Amort on March 2010 Assets		115.8	114.3	114.1	115.9	1.7	115.1	**123.2**	8.1	**136.3**	13.1
9	Amortization on Additions	13.0 L75	0.0	0.0	0.0	0.0	0.0	2.9	**0.0**	(2.9)	5.9	5.9
10	Capital Asset Write-Offs	7.0 L18	4.1	3.5	3.0	2.0	(1.0)	3.0	1.4	(1.6)	2.0	0.6
11	Depn Study Adjustment		8.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	Retirements & Transfers		(25.4)	(8.4)	(8.4)	(7.5)	0.9	(9.6)	**(99.8)**	(90.2)	(3.4)	96.4
13	Closing Balance		2,289.6	2,399.0	2,507.8	2,509.5	1.7	2,619.1	2,533.2	(85.9)	2,673.9	140.7
14	**Net Assets in Service (Year-End)**		3,914.1	3,981.6	4,188.2	4,145.4	(42.8)	4,323.8	5,083.6	759.8	5,452.1	368.5

Assets - Customer Care and Conservation
($ million)

Line	Column	Reference	F2007 Actual	F2008 Actual	F2009 RRA	F2009 Actual	F2009 Difference	F2010 RRA	F2010 Actual	F2010 Difference	F2011 Update	F2011 Increase
			1	2	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10 = 9 - 7
	Gross Assets in Service											
1	Opening Balance		38.0	42.5	48.9	48.9	0.0	53.8	44.7	(9.1)	10.2	(34.5)
2	Adjustment to Opening Balance	CICA 3064	0.0	0.0	0.0	0.0	0.0	0.0	(1.3)	(1.3)	0.0	1.3
3	Capital Additions	13.0 L42	7.5	6.8	5.0	8.6	3.6	4.2	5.3	1.1	9.5	4.2
4	Retirements & Transfers		(3.0)	(0.4)	(0.1)	(12.8)	(12.7)	(1.0)	**(38.5)**	(37.5)	(0.0)	38.5
5	Closing Balance		42.5	48.9	53.8	44.7	(9.1)	56.9	10.2	(46.7)	19.6	9.4
	Accumulated Amortization											
6	Opening Balance		33.9	34.6	36.2	36.2	0.0	38.1	36.4	(1.7)	4.9	(31.5)
7	Adjustment to Opening Balance	CICA 3064	0.0	0.0	0.0	0.0	0.0	0.0	(0.3)	(0.3)	0.0	0.3
8	Amort on March 2010 Assets		1.2	1.7	2.0	1.8	(0.2)	2.0	**1.7**	(0.3)	**1.9**	0.2
9	Amortization on Additions	13.0 L76	0.0	0.0	0.0	0.0	0.0	0.2	**0.0**	(0.2)	0.5	0.5
10	Capital Asset Write-Offs	7.0 L19	(0.0)	(10.4)	0.0	1.4	1.4	0.0	0.0	0.0	0.0	0.0
11	Depn Study Adjustment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	Retirements & Transfers		(0.5)	10.4	(0.1)	(3.0)	(2.9)	(1.0)	**(32.9)**	(31.9)	(0.0)	32.9
13	Closing Balance		34.6	36.2	38.1	36.4	(1.7)	39.2	4.9	(34.3)	7.3	2.4
14	**Net Assets in Service (Year-End)**		7.9	12.7	15.7	8.3	(7.4)	17.7	5.3	(12.4)	12.3	7.0

Assets - Transmission
($ million)

Line		Reference	F2007 Actual	F2008 Actual	F2009 RRA	F2009 Actual	F2009 Difference	F2010 RRA	F2010 Actual	F2010 Difference	F2011 Update	F2011 Increase
	Column		1	2	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10 = 9 - 7
	Gross Assets in Service											
1	Opening Balance		4,650.3	4,789.9	4,927.0	4,927.0	0.0	5,428.1	5,313.6	(114.5)	5,583.3	269.7
2	Adjustment to Opening Balance	CICA 3064	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	Capital Additions	13.0 L43	209.1	148.8	511.6	406.4	(105.2)	397.4	231.9	(165.5)	319.1	87.2
4	Retirements & Transfers		(69.6)	(11.7)	(10.5)	(19.8)	(9.3)	(9.4)	**37.8**	47.2	(9.9)	(47.7)
5	Closing Balance		4,789.9	4,927.0	5,428.1	5,313.6	(114.5)	5,816.1	5,583.3	(232.8)	5,892.5	309.2
	Accumulated Amortization											
6	Opening Balance		2,266.8	2,296.0	2,378.6	2,378.6	0.0	2,468.7	2,450.8	(17.9)	2,553.4	102.6
7	Adjustment to Opening Balance	CICA 3064	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	Amort on March 2010 Assets		91.8	94.7	100.6	98.3	(2.3)	105.9	**105.7**	(0.2)	**113.7**	8.0
9	Amortization on Additions	13.0 L77	0.0	0.0	0.0	0.0	0.0	5.6	**0.0**	(5.6)	4.5	4.5
10	Amortization Adjustment		0.0	0.0	0.0	0.0	0.0	0.3	**0.0**	(0.3)	**0.4**	0.4
11	Capital Asset Write-Offs	7.0 L20	(2.5)	4.6	3.5	(1.1)	(4.6)	2.9	4.2	1.3	3.4	(0.8)
12	Depn Study Adjustment		3.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	Retirements & Transfers		(63.5)	(16.6)	(14.0)	(25.0)	(11.1)	(12.3)	**(7.3)**	5.0	**(13.3)**	(6.0)
14	Closing Balance		2,296.0	2,378.6	2,468.7	2,450.8	(17.9)	2,571.2	2,553.4	(17.8)	2,662.2	108.8
15	**Net Assets in Service (Year-End)**		2,493.9	2,548.4	2,959.4	2,862.8	(96.6)	3,244.9	3,029.9	(215.0)	3,230.4	200.5

Assets - Field Operations
($ million)

Line	Column	Reference	F2007 Actual	F2008 Actual	F2009 RRA	F2009 Actual	F2009 Difference	F2010 RRA	F2010 Actual	F2010 Difference	F2011 Update	F2011 Increase
			1	2	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10 = 9 - 7
	Gross Assets in Service											
1	Opening Balance		4,601.0	4,887.0	5,290.9	5,290.9	0.0	5,767.2	5,732.7	(34.5)	6,166.1	433.4
2	Adjustment to Opening Balance	CICA 3064	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	Capital Additions	13.0 L44	383.0	437.6	500.7	488.6	(12.1)	543.7	503.9	(39.8)	583.4	79.5
4	Retirements & Transfers		(97.0)	(33.8)	(24.4)	(46.8)	(22.4)	(23.0)	**(70.5)**	(47.5)	**(24.5)**	46.0
5	Closing Balance		4,887.0	5,290.9	5,767.2	5,732.7	(34.5)	6,287.9	6,166.1	(121.8)	6,725.0	558.9
	Accumulated Amortization											
6	Opening Balance		1,766.0	1,793.8	1,886.9	1,886.9	0.0	1,995.8	1,976.6	(19.2)	2,021.9	45.3
7	Adjustment to Opening Balance	CICA 3064	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	Amort on March 2010 Assets		111.6	120.1	133.5	128.4	(5.1)	138.3	**138.5**	0.2	**151.6**	13.1
9	Amortization on Additions	13.0 L78	0.0	0.0	0.0	0.0	0.0	7.5	**0.0**	(7.5)	8.3	8.3
10	Capital Asset Write-Offs	7.0 L21	4.7	4.2	(0.0)	6.1	6.1	0.0	3.9	3.9	0.0	(3.9)
11	Depn Study Adjustment		5.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	Retirements & Transfers		(93.9)	(31.2)	(24.5)	(44.8)	(20.3)	(23.0)	**(97.1)**	(74.1)	(24.5)	72.6
13	Closing Balance		1,793.8	1,886.9	1,995.8	1,976.6	(19.2)	2,118.6	2,021.9	(96.7)	2,157.3	135.4
14	**Net Assets in Service (Year-End)**		3,093.2	3,404.0	3,771.4	3,756.1	(15.3)	4,169.3	4,144.2	(25.1)	4,567.7	423.5

Capital Expenditures and Additions
($ million)

Line		Reference	F2007 Actual	F2008 Actual	F2009 RRA	F2009 Actual	F2009 Difference	F2010 RRA	F2010 Actual	F2010 Difference	F2011 Update	F2011 Increase
	Column		1	2	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10 = 9 - 7
	Capital Expenditures											
1	Hydroelectric Generation		174.8	275.8	351.2	326.7	(24.5)	486.2	1,252.1	765.9	376.2	(875.9)
2	Diesel Generation		1.1	3.0	19.8	4.6	(15.2)	8.7	7.6	(1.1)	8.8	1.2
3	Thermal Generation		5.0	11.6	13.3	18.2	4.9	9.8	42.0	32.2	63.5	21.5
4	SDA Substations (sustaining)		5.5	7.2	25.1	23.0	(2.1)	31.6	30.6	(1.0)	30.1	(0.5)
5	Distribution		293.7	354.2	395.2	399.3	4.1	402.5	422.6	20.1	423.8	1.2
6	Information Technology		40.4	43.0	46.8	60.7	13.9	40.5	89.3	48.8	67.3	(22.0)
7	Vehicles		18.7	21.2	25.0	27.6	2.6	20.7	44.2	23.5	21.0	(23.2)
8	Properties and Other Capital		20.6	67.4	92.9	57.9	(35.0)	98.5	76.8	(21.7)	91.0	14.2
9	Smart Metering & Infrastructure		0.0	0.0	0.0	8.7	8.7	0.0	1.4	1.4	54.3	52.9
10	HPOP Properties for Resale		0.0	0.0	0.0	0.0	0.0	0.0	53.2	53.2	(20.9)	(74.1)
11	Demand Side Management	5.0 L32	46.4	63.3	112.1	94.9	(17.2)	138.2	130.4	(7.8)	184.4	54.0
12	Subtotal		606.2	846.7	1,081.4	1,021.6	(59.8)	1,236.7	2,150.2	913.5	1,299.5	(850.7)
13	Transmission Lines		69.9	124.4	246.8	223.9	(22.9)	136.2	129.4	(6.8)	159.6	30.2
14	Transmission Substations		122.9	92.3	273.0	156.2	(116.8)	281.8	192.9	(88.9)	242.2	49.3
15	Transmission Properties		0.0	6.9	9.1	14.2	5.1	10.5	18.7	8.2	20.4	1.7
16	SDA Substations (growth)		49.1	55.7	87.7	70.3	(17.4)	62.5	39.2	(23.3)	99.0	59.8
17	Total		848.1	1,126.0	1,698.0	1,486.2	(211.8)	1,727.7	2,530.4	802.7	1,820.7	(709.7)
	Total Capital Additions											
18	Hydroelectric Generation		81.0	181.4	308.2	274.8	(33.5)	245.4	1,086.1	840.7	497.6	(588.5)
19	Diesel Generation		2.6	0.3	13.3	0.5	(12.8)	14.3	10.3	(4.0)	10.5	0.2
20	Thermal Generation		2.1	4.1	12.6	16.6	4.0	10.3	19.4	9.1	10.1	(9.3)
21	Transmission Lines		101.1	34.6	291.7	266.8	(25.0)	113.5	72.6	(40.9)	77.7	5.1
	Substations											
22	Transmission Substations		108.0	111.2	210.4	134.1	(76.3)	273.5	148.9	(124.6)	228.3	79.4
23	SDA Substations		60.0	43.1	83.3	85.6	2.3	103.4	67.0	(36.4)	100.9	33.9
24	Distribution		298.0	368.4	372.9	368.7	(4.2)	398.9	388.9	(10.0)	436.6	47.7
	Information Technology											
25	Corporate		44.6	4.0	39.6	35.8	(3.8)	41.2	41.2	0.0	81.5	40.3
26	EARG		2.1	4.0	2.7	1.2	(1.5)	0.9	5.1	4.2	5.0	(0.1)
27	CC&C		7.3	6.8	1.6	4.4	2.8	0.0	4.4	4.4	3.0	(1.4)
28	Transmission		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
29	Field Operations		1.5	0.9	0.5	1.0	0.5	0.0	3.5	3.5	3.0	(0.5)
30	Vehicles		15.4	19.0	24.0	25.2	1.2	21.8	26.3	4.5	26.4	0.1
	Properties and Other Capital											
31	Corporate		6.4	15.0	68.8	33.1	(35.7)	87.5	48.8	(38.7)	88.3	39.5
32	EARG		0.4	0.3	0.2	0.1	(0.1)	0.0	0.1	0.1	0.0	(0.1)
33	CC&C		0.2	0.0	3.4	4.2	0.8	4.2	0.9	(3.3)	6.5	5.6
34	Transmission		0.0	3.0	9.5	5.5	(4.0)	10.5	10.4	(0.0)	13.1	2.7
35	Field Operations		5.5	6.0	6.7	7.6	0.9	5.4	7.9	2.5	6.1	(1.8)
36	Smart Metering & Infrastructure	Line 9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	54.3	54.3
37	HPOP Properties for Resale	Line 10	0.0	0.0	0.0	0.0	0.0	0.0	53.2	53.2	(20.9)	(74.1)
38	Demand Side Management	Line 11	46.4	63.3	112.1	94.9	(17.2)	138.2	130.4	(7.8)	184.4	54.0
39	Total		782.6	865.3	1,561.5	1,360.2	(201.3)	1,468.8	2,125.4	656.6	1,812.2	(313.2)

BC Hydro
F11 RRA
Capital Expenditures and Additions
($ million)

Line	Column	Reference	F2007 Actual	F2008 Actual	F2009 RRA	F2009 Actual	F2009 Difference	F2010 RRA	F2010 Actual	F2010 Difference	F2011 Update	F2011 Increase
			1	2	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10 = 9 - 7
	Summary of Additions											
40	Corporate		51.0	19.0	108.4	68.9	(39.5)	128.7	143.2	14.5	203.2	60.0
41	EARG		85.6	189.8	323.7	292.7	(31.0)	256.6	1,110.7	854.1	512.6	(598.1)
42	CC&C		7.5	6.8	5.0	8.6	3.6	4.2	5.3	1.1	9.5	4.2
43	Transmission		209.1	148.8	511.6	406.4	(105.2)	397.4	231.9	(165.5)	319.1	87.2
44	Field Operations		383.0	437.6	500.7	488.6	(12.1)	543.7	503.9	(39.8)	583.4	79.5
45	Demand Side Management		46.4	63.3	112.1	94.9	(17.2)	138.2	130.4	(7.8)	184.4	54.0
46	Total		782.6	865.3	1,561.5	1,360.2	(201.3)	1,468.8	2,125.4	656.6	1,812.2	(313.2)
	Unfinished Construction											
47	Beginning of Year		483.3	548.8	809.6	809.6	0.0	946.1	991.1	45.0	1,390.6	399.5
48	Adjustment to Opening Balance	CICA 3031, 3064	0.0	0.0	0.0	55.5	55.5	0.0	(5.5)	(5.5)	0.0	5.5
49	Change in Unfinished		65.5	260.8	136.5	126.0	(10.5)	258.9	405.0	146.1	8.5	(396.5)
50	End of Year		548.8	809.6	946.1	991.1	45.0	1,205.0	1,390.6	185.6	1,399.1	8.5
51	Mid-Year Balance		516.1	679.2	877.8	900.4	22.5	1,075.5	1,190.9	115.3	1,394.9	204.0
	Amortization on Additions											
52	Hydroelectric Generation	2.12%				3.4		2.6	4.6		5.3	
53	Diesel Generation	3.30%				0.0		0.2	0.2		0.2	
54	Thermal Generation	3.65%				1.1		0.2	0.4		0.2	
55	Transmission	1.90%				1.6		1.1	0.4		0.7	
	Substations											
56	Transmission Substations	3.30%				0.9		4.5	2.5		3.8	
57	SDA Substations	2.65%				0.7		1.4	1.0		1.3	
58	Distribution	2.41%				4.1		4.8	4.7		5.3	
	Information Technology											
59	Corporate	17.63%				3.8		3.6	5.1		7.2	
60	EARG	17.63%				0.1		0.1	2.3		0.4	
61	CC&C	17.63%				0.1		0.0	2.0		0.3	
62	Transmission	10.70%				0.0		0.0	0.0		0.0	
63	Field Operations	17.63%				0.2		0.0	1.6		0.3	
64	Vehicles	7.83%				0.7		0.9	1.0		1.0	
	Properties and Other Capital											
65	Corporate	3.54%				0.7		1.5	0.7		1.6	
66	EARG	7.87%				0.1		0.0	0.1		0.0	
67	CC&C	7.87%				0.0		0.2	0.2		0.3	
68	Transmission	0.00%				0.1		0.0	0.0		0.0	
69	Field Operations	7.87%				0.1		0.2	0.2		0.2	
70	Smart Metering & Infrastructure	5.00%				0.0		0.0	0.0		0.0	
71	HPOP Properties for Resale	0.00%				0.0		0.0	0.0		0.0	
72	Demand Side Management	10.00%				0.0		0.0	0.0		0.0	
73	Total					17.7		21.3	27.0		28.0	
	Summary of Amortization on Additions											
74	Corporate							5.2	5.8		8.7	
75	EARG							2.9	7.4		5.9	
76	CC&C							0.2	2.2		0.5	
77	Transmission							5.6	2.9		4.5	
78	Field Operations							7.5	8.7		8.3	
79	Demand Side Management							0.0	0.0		0.0	
80	Total							21.3	27.0		28.0	

Domestic Energy Sales and Revenue Forecast

Line	Reference / Column	F2007 Actual	F2008 Actual	F2009 RRA	F2009 Actual	F2009 Difference	F2010 RRA	F2010 Actual	F2010 Difference	F2011 Update	F2011 Increase
		1	2	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10 = 9 - 7
	Domestic Energy Sales (GWh)										
1	Residential	16,651	17,553	17,264	17,861	3.5%	16,967	17,593	3.7%	17,365	-1.3%
2	Light Industrial and Commercial	18,268	18,406	18,445	18,265	-1.0%	18,586	17,811	-4.2%	18,247	2.5%
3	Large Industrial	15,989	15,380	15,228	14,303	-6.1%	15,240	13,020	-14.6%	14,153	8.7%
4	Irrigation	82	75	61	75	23.7%	62	90	44.8%	79	-12.6%
5	Street Lighting	207	211	212	214	0.8%	214	216	1.1%	218	0.6%
6	City of New Westminster	429	442	390	440	12.8%	393	444	12.9%	441	-0.6%
7	Fortis	974	921	823	851	3.4%	881	753	-14.5%	981	30.2%
8	Other Utilities	311	311	279	308	10.3%	279	306	9.8%	311	1.6%
9	Total	52,911	53,299	52,702	52,316	-0.7%	52,622	50,233	-4.5%	51,794	3.1%
	Domestic Revenues ($million)										
10	Residential	1,066.3	1,147.9	1,155.8	1,191.5	3.1%	1,234.9	1,287.1	4.2%	1,338.0	4.0%
11	Light Industrial and Commercial	1,021.1	1,033.6	1,058.5	1,048.7	-0.9%	1,159.3	1,121.3	-3.3%	1,214.6	8.3%
12	Large Industrial	554.2	525.8	528.2	479.0	-9.3%	576.5	480.4	-16.7%	579.1	20.6%
13	Irrigation	3.4	3.4	2.9	3.4	14.4%	3.2	4.5	37.3%	4.0	-9.7%
14	Street Lighting	22.9	23.3	24.5	23.9	-2.2%	26.8	26.3	-2.2%	28.2	7.4%
15	City of New Westminster	15.7	16.3	14.7	16.5	12.6%	16.1	18.4	14.4%	19.1	4.0%
16	Fortis	37.0	35.2	32.6	33.9	3.9%	37.3	33.6	-9.9%	44.2	31.6%
17	Other Utilities	18.4	15.4	15.2	22.1	46.0%	16.6	16.4	-1.6%	17.6	7.5%
18	Subtotal	2,739.0	2,800.8	2,832.4	2,819.0	-0.5%	3,070.7	2,987.9	-2.7%	3,244.9	8.6%
19	Revenue from Deferral Rider	10.1	55.7	14.1	14.0	-0.4%	15.3	29.7	94.3%	113.9	283.7%
20	Total	2,749.1	2,856.5	2,846.4	2,833.0	-0.5%	3,086.0	3,017.6	-2.2%	3,358.8	11.3%
21	**Deferral Account Rate Rider**		2.0%	0.5%	0.5%		0.5%	1.0%		4.0%	
	Effective January 1, 2011									2.5%	28.8%
	Average Revenues ($/MWh)										
22	Residential	64.0	65.4	66.9	66.7	-0.4%	72.8	73.2	0.5%	77.1	5.3%
23	Light Industrial and Commercial	55.9	56.2	57.4	57.4	0.0%	62.4	63.0	0.9%	66.6	5.7%
24	Large Industrial	34.7	34.2	34.7	33.5	-3.5%	37.8	36.9	-2.5%	40.9	10.9%
25	Irrigation	41.5	45.1	48.2	44.5	-7.5%	52.4	49.7	-5.2%	51.3	3.3%
26	Street Lighting	110.6	110.6	115.4	112.0	-2.9%	125.4	121.4	-3.2%	129.7	6.8%
27	City of New Westminster	36.6	36.8	37.6	37.6	-0.2%	40.9	41.5	1.3%	43.4	4.6%
28	Fortis	38.0	38.2	39.6	39.8	0.5%	42.4	44.6	5.4%	45.1	1.1%
29	Other Utilities	59.2	49.4	54.3	71.9	32.4%	59.6	53.4	-10.4%	56.5	5.8%
30	Total (Excluding Misc Rev)	52.0	53.6	54.0	54.2	0.3%	58.6	60.1	2.4%	64.8	8.0%
	Peak Demand (MW)										
31	Distribution	7,402	7,586	7,728	7,642	-1.1%	7,806	7,650	-2.0%	7,815	2.2%
32	Transmission	1,873	1,766	1,825	1,510	-17.2%	1,789	1,492	-16.6%	1,698	13.8%
33	Other	345	404	423	371	-12.3%	429	413	-3.7%	415	0.5%
34	Losses	829	841	859	821	-4.5%	863	823	-4.7%	855	3.9%
35	Total	10,449	10,597	10,835	10,344	-4.5%	10,886	10,378	-4.7%	10,783	3.9%

Miscellaneous Revenue
($ million)

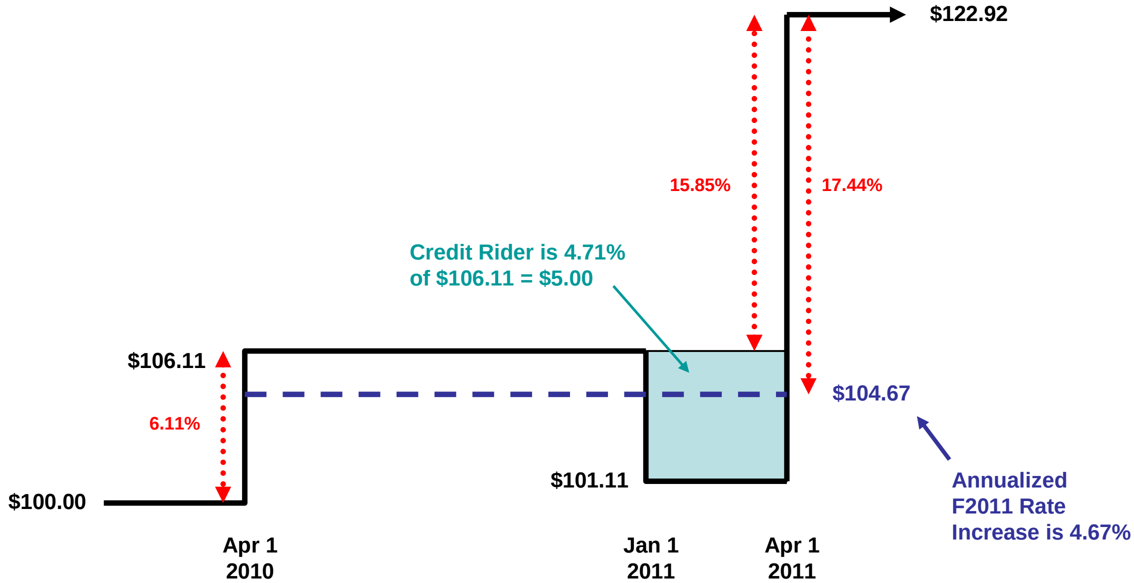
		F2007	F2008	F2009			F2010			F2011	F2011
	Reference	Actual	Actual	RRA	Actual	Difference	RRA	Actual	Difference	Update	Increase
Line	Column	1	2	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10 = 9 - 7
	Corporate										
1	Corporate General Rents	5.4	3.2	5.1	6.2	1.1	5.1	5.9	0.8	5.8	(0.1)
2	Diverson Net Recoveries	1.4	1.5	1.7	1.1	(0.6)	1.7	1.6	(0.1)	1.2	(0.4)
3	Net Gains on Property Sales	4.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	Total	10.9	4.7	6.8	7.3	0.5	6.8	7.5	0.7	7.0	(0.5)
	EARG										
5	Interconnected Operations Services	4.2	4.4	4.4	4.5	0.1	4.2	3.1	(1.1)	3.0	(0.1)
6	FX Loss - Cost of Energy	(2.2)	(2.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	Other	4.8	0.9	3.3	3.7	0.4	3.4	13.7	10.3	3.2	(10.5)
8	Total	6.8	3.0	7.7	8.2	0.5	7.6	16.8	9.2	6.2	(10.6)
	CC&C										
	Meter/Trans Rents & Power										
9	Factor Surcharges	8.0	7.7	8.7	8.1	(0.6)	8.7	8.9	0.2	9.3	0.4
10	Terasen Meter Reading	3.7	3.6	1.0	3.3	2.3	0.3	3.4	3.1	3.1	(0.4)
11	FX Loss - Cost of Energy	(1.3)	(6.9)	0.0	(0.1)	(0.1)	0.0	0.0	0.0	0.0	0.0
12	Other	3.4	5.3	2.8	1.3	(1.5)	2.8	2.6	(0.2)	0.5	(2.2)
13	Total	13.8	9.7	12.5	12.6	0.1	11.8	14.9	3.1	12.8	(2.1)
	Transmission										
14	Short-term PTP/Ancillary	8.5	8.5	8.4	8.2	(0.2)	8.3	8.1	(0.2)	8.4	0.3
15	Secondary Revenue	3.3	3.4	3.4	3.3	(0.1)	3.4	3.2	(0.2)	3.5	0.3
16	Lease Revenue from BCTC	0.0	0.1	0.1	0.1	0.0	0.0	0.2	0.2	0.1	(0.1)
17	Total	11.8	12.0	11.9	11.6	(0.3)	11.7	11.4	(0.3)	12.0	0.6
	Field Operations										
18	Secondary Use Revenue & Other	1.9	2.0	2.0	4.3	2.3	2.0	4.6	2.6	6.7	2.1
19	**Total**	45.2	31.4	40.9	44.0	3.1	39.9	55.2	15.3	44.6	(10.6)

Full-Time Equivalents (FTEs)

	Reference	F2007	F2008	F2009			F2010			F2011	F2011
		Actual	Actual	RRA	Actual	Difference	RRA	Actual	Difference	Update	Increase
Line	Column	1	2	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10 = 9 - 7
	Corporate										
1	Executive	11	11	12	9	-3	12	**9**	-3	8	-1
2	Sustainability	5	3	5	0	-5	5	**0**	-5	0	0
3	Corporate Affairs	96	109	131	145	14	126	**180**	54	154	-26
4	Corporate Human Resources	49	66	52	83	31	52	**104**	52	64	-41
5	Finance & Corporate Resources	244	294	359	380	21	358	**417**	59	429	12
6	Safety, Health & Environment	37	44	59	51	-8	57	**54**	-3	59	5
7	Smart Metering & Infrastructure	0	13	4	26	22	4	**34**	30	64	30
8	Total	441	539	621	694	73	614	798	184	777	-22
	EARG										
9	Aboriginal Relations	17	24	39	31	-7	41	**36**	-4	37	1
10	Generation Project Delivery	40	84	118	111	-7	119	**116**	-3	117	1
11	Generation Operations	615	652	715	697	-18	709	**691**	-18	688	-4
12	Safety & Technical Training	14	43	52	61	10	51	**65**	14	65	-1
13	Engineering	600	702	846	834	-12	893	**845**	-48	887	42
14	EARG Business Unit Support	170	200	221	208	-13	215	**210**	-4	191	-19
15	Total	1,455	1,706	1,990	1,943	-47	2,028	1,965	-64	1,985	21
	CC&C										
16	Customer Care	92	121	142	154	12	143	**150**	8	146	-4
17	Power Smart	108	159	173	195	22	187	**208**	20	216	8
18	Energy Planning Group	27	28	30	32	2	31	**30**	-0	28	-2
19	Power Acquisition Group	17	23	25	27	2	25	**28**	3	28	-0
20	Chief Technology Office	2	3	9	9	-1	12	**10**	-2	11	1
21	CC&C Business Unit Support	30	39	39	38	-1	39	**41**	2	41	0
22	Total	277	373	419	455	37	437	468	31	470	2
	Field Operations										
23	Distribution Operations	1,142	1,186	1,318	1,274	-44	1,327	**1,236**	-92	1,331	96
24	Trans & Construction Services	795	855	896	1,002	106	937	**1,116**	179	1,105	-11
25	Operational Support Services	215	248	270	275	5	273	**288**	15	275	-14
26	FO Business Unit Support	344	407	460	465	5	487	**482**	-5	481	-1
27	Total	2,497	2,697	2,944	3,016	72	3,024	3,122	98	3,192	70
28	**Total**	4,670	5,316	5,974	6,108	134	6,104	6,353	249	6,424	71

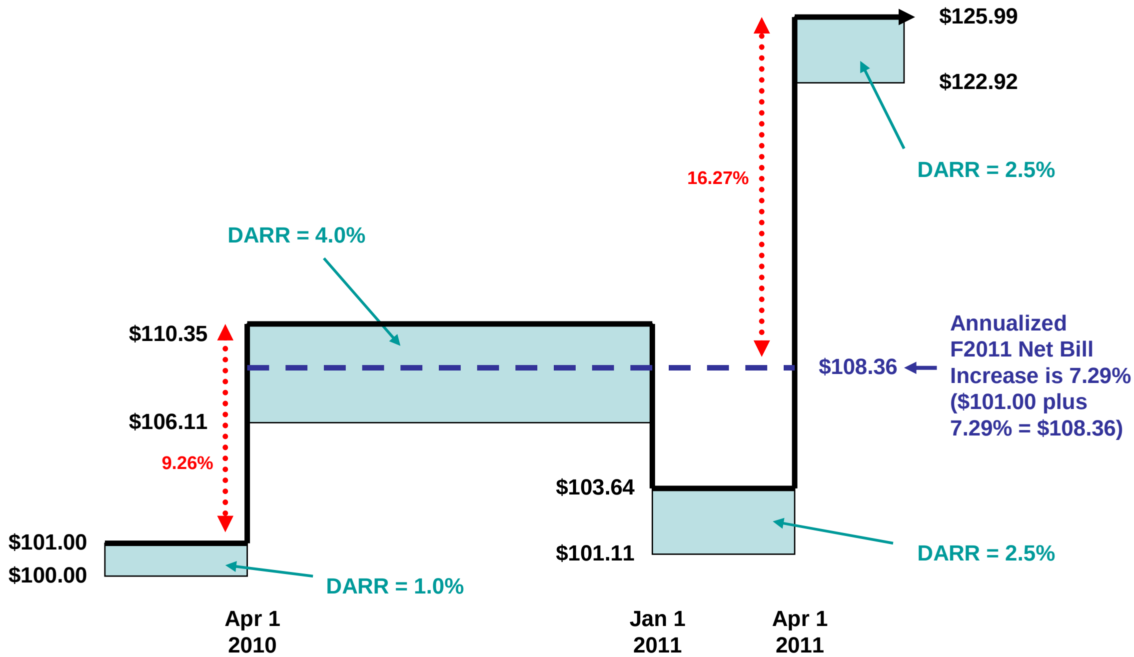
Appendix 2 – Illustration of Rate Changes

(for explanatory purposes only, before the Deferral Account Rate Rider)



Appendix 3 – Illustration of Net Bill Changes

(for explanatory purposes only, including the Deferral Account Rate Rider)



BC hydro

FOR GENERATIONS

Joanna Sofield
Chief Regulatory Officer
Phone: (604) 623-4046
Fax: (604) 623-4407
bchydroregulatorygroup@bchydro.com

November 18, 2010

Ms. Erica M. Hamilton
Commission Secretary
British Columbia Utilities Commission
Sixth Floor – 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Ms. Hamilton:

RE: Project No. 3698592
British Columbia Utilities Commission (BCUC)
British Columbia Hydro and Power Authority (BC Hydro)
Fiscal 2011 Revenue Requirement Application (F11 RRA)

BC Hydro writes to confirm its acceptance of the F11 RRA Settlement Agreement attached to Mr. Bill Grant's letter of November 18, 2010, and to provide the following comments.

At the start of the negotiated settlement process (NSP), BCUC staff tabled a written request from the BCUC Panel regarding two items of particular concern to the Panel, namely that recovery of BC Hydro's deferral account balances and preparation for its next revenue requirement application be addressed by participants in the NSP discussions. In response to the items identified by the BCUC Panel, and as set out in sections 9.i. and 9.ii. of the Settlement Agreement, BC Hydro has committed to:

- provide in its next revenue requirement application analyses of its current deferral account rate rider (DARR) adjustment mechanism and an alternative DARR adjustment mechanism, and, in that context, address the recent significant increase in its deferral account balances; and

- meet with interested parties and BCUC staff prior to November 30, 2010 to try to agree on an approach to BC Hydro's next revenue requirement application that best allows for a comprehensive review in a transparent, efficient and effective manner.

In BC Hydro's view, the Settlement Agreement represents a reasonable compromise of all issues arising from the F11 RRA, and BC Hydro respectfully submits that the BCUC ought to approve it.

BC hydro

BC Hydro thanks all participants for their efforts during these negotiations.

For further information, please contact the undersigned.

Yours sincerely,

JC Sofield

Joanna Sofield
Chief Regulatory Officer

js/af

Bull, Housser & Tupper LLP

3000 Royal Centre . PO Box 11130
1055 West Georgia Street
Vancouver . BC . Canada . V6E 3R3
Phone 604.687.6575 Fax 604.641.4949
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Reply Attention of:	R. Brian Wallace
Direct Phone:	604.641.4852
Direct Fax:	604.646.2506
E-mail:	RBW@bht.com
Our File:	10-2393
Date:	November 18, 2010

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Box 250
Vancouver, B.C.
V6Z 2N3

Attention: Bill Grant
Transition Advisor

Dear Sirs/Mesdames:

Re: British Columbia Hydro and Power Authority
Project No. 3698592/Order G-47-10
Fiscal 2011 Revenue Requirements Application
Negotiated Settlement

The Joint Industry Electricity Steering Committee (JIESC) writes to confirm its acceptance of the F2011 RRA Settlement Agreement attached to Mr. Bill Grant's letter of November 18, 2010.

The negotiations surrounding the settlement agreement were among the most difficult and long running that the JIESC has participated in. In the end a reasonable compromise agreement was reached.

This agreement allows all of the parties, most importantly BC Hydro, to close off F2011 without prejudice to some of the important discussions that must be held on a number of key issues during BC Hydro's next Revenue Requirements Application. JIESC believes that this is a better way of proceeding than dealing with these issues in a final manner during an oral F2011 RRA proceeding.

The JIESC respectfully submits that the BCUC should approve the F2011 RRA Negotiated Settlement Agreement as presented.

Bull, Houser & Tupper LLP

The JIESC joins with BC Hydro and other participants in thanking the Commission Staff without whose efforts and skill a settlement would not have been reached.

Yours truly,

Bull, Housser & Tupper LLP

R B Wallace

R. Brian Wallace

RBW/sg/2604110

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E-mail: cweafer@owenbird.com
Our File: 23841/0051

November 19, 2010

VIA ELECTRONIC MAIL

British Columbia Utilities Commission
Sixth Floor, 900 Howe Street
Vancouver, BC
V6Z 2N3

Attention: Erica M. Hamilton, Commission Secretary

Dear Sirs/Mesdames:

Re: British Columbia Hydro and Power Authority (BC Hydro) Fiscal 2011 Revenue Requirement Application (RRA), Project No. 3698592

We are counsel to the Commercial Energy Consumers Association of British Columbia (CEC) with respect to the above-noted matter. The CEC writes to confirm acceptance of the 2011 RRA Settlement Agreement attached to Mr. Bill Grant's letter of November 18, 2010. The CEC also provides the following comments.

At the start of the negotiated settlement process (NSP), BCUC staff tabled a written request from the BCUC Panel regarding two items of particular concern to the Panel one of which the CEC would comment on here, namely recovery of BC Hydro's deferral account balances. In response to this item identified by the BCUC Panel, and as set out in sections 9.1 of the Settlement Agreement, BC Hydro has committed to provide in its next revenue requirement application analyses of its current deferral account rate rider (DARR) adjustment mechanism and an alternative DARR adjustment mechanism, and, in that context, address the recent significant increase in its deferral account balances.

During this NSP process, the CEC prepared and circulated evidence on the DARR adjustment mechanism which the CEC believes provided value to the NSP process. While not appropriate to provide that evidence as part of these comments, the CEC wishes to indicate that it intends to prepare and file significant evidence on this issue and a set of other issues in the next revenue requirement proceeding to ensure the ratepayer interest in mitigating rate impacts is before the Commission.

That said, in the CEC's view, the Settlement Agreement represents a reasonable compromise for all issues arising from the 2011 RRA, and the CEC respectfully submits that the BCUC approve it.

OWEN · BIRD
LAW CORPORATION

The CEC thanks the Commission staff and all participants for their efforts during these negotiations, and would particularly acknowledge the value the facilitator, Mr. Bill Grant, brought to the process. Mr. Grant's fair and balanced treatment of all participants - combined with his historical and institutional knowledge, was invaluable to the success of this NSP.

If you have any questions regarding the foregoing, please do not hesitate to contact the undersigned.

Yours truly,

OWEN BIRD LAW CORPORATION

Christopher P. Weafer

CPW/jlb
cc: CEC
cc: BC Hydro
cc: Registered Intervenors

Catalyst

November 18, 2010

Catalyst Paper
65 Front Street
Suite 201
Nanaimo, British Columbia
Canada V9R 5H9

Tel: 250 734 8000
Fax: 250 734 8080

BC Utilities Commission
6th Floor - 900 Howe Street
Vancouver, BC V6Z 2N3

Attention: Bill Grant

VIA E-MAIL

Dear Mr. Grant:

Re: British Columbia Hydro and Power Authority
Project No. 3698592/Order G-47-10
Fiscal 2011 Revenue Requirements Application Negotiated Settlement

Catalyst Paper Corporation writes to confirm its acceptance of the F2011 RRA Settlement Agreement attached to Mr. Bill Grant's letter of November 18, 2010.

Catalyst Paper respectfully submits that the BCUC should approve the F2011 RRA Negotiated Settlement Agreement as presented.

Yours Truly,

Carlo Dal Monte

Carlo Dal Monte
Catalyst Paper Corporation

The
British Columbia
Public Interest
Advocacy Centre
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Coast Salish Territory
Tel: (604) 687-3063 Fax: (604) 682-7896
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Sarah Khan 687-4134
James L. Quail 687-3034
Ros Salvador 488-1315
Leigha Worth 687-3044
Barristers & Solicitors

Jodie Gauthier
Articled Student

November 16, 2010

Our file: 7453

BC Utilities Commission
6th Floor - 900 Howe Street
Vancouver, BC V6Z 2N3

Attention: Bill Grant

VIA E-MAIL

Dear Mr. Grant:

Re: British Columbia Hydro and Power Authority
F2011 Revenue Requirement Application

We continue to act for BCOAPO *et al.* in this matter. Our clients are community-based organizations active throughout British Columbia and they participate as the representatives of the interests of BC Hydro's residential ratepayers.

This is to advise that the Negotiated Settlement Agreement which was developed by the parties to the NSP in this proceeding is acceptable to our clients. We consent on their behalf to all of the terms of that Agreement being incorporated into an Order of the Commission, fully resolving this Application.

We wish to thank the Commission staff for their skill and diligence, and to acknowledge the strenuous efforts of all participants, in achieving a resolution.

Yours truly,

BC PUBLIC INTEREST ADVOCACY CENTRE

Original in file signed by:

Jim Quail
Executive Director

cc: parties of record

William J. Andrews

Barrister & Solicitor

1958 Parkside Lane, North Vancouver, BC, Canada, V7G 1X5
Phone: 604-924-0921, Fax: 604-924-0918, Email: wjandrews@shaw.ca

November 18, 2010

British Columbia Utilities Commission
Sixth Floor, 900 Howe Street, Box 250
Vancouver, BC, V6Z 2N3
Attn: Bill Grant, NSP Facilitator
By email: bill.grant@bcuc.com

Dear Sir:

Re: British Columbia Hydro and Power Authority
F2011 Revenue Requirements Application
BCUC Orders No. G47-10, G163-10
BCUC Project No. 3698592
Negotiated Settlement dated November 18, 2010

I am counsel for the intervenors B.C. Sustainable Energy Association and Sierra Club of British Columbia. BCSEA-SCBC (or "BCSEA") participated in the negotiated settlement process (NSP) and the reinstated NSP in this proceeding.

BCSEA and SCBC support the November 18, 2010 Negotiated Settlement Agreement.

By way of explanation of their position, BCSEA-SCBC add the following:

1. BCSEA-SCBC accept the negotiated agreement as a package reflecting the best outcome under the circumstances, bearing in mind the positions of other parties and Commission staff, and the fact that the agreement includes a commitment by BC Hydro to apply for at least a two year test period, and no more than a three-year test period, in its next revenue requirement application (NSA, item 9 (iv).
2. BCSEA-SCBC are directionally opposed to NSA item 9 (i), which reduces the deferral account rate rider (DARR) from 4% to 2.5% from January 1 to March 31, 2011, and item #23, reducing bills by 4.71% during the same 3-month period. BCSEA-SCBC believe the deferral account rate rider should stay at 4% for those last four months of F11, and that reductions in the F2011 revenue requirement should go toward reducing the enormous net balance in the deferral accounts. Their view is that a three-month reduction in bill impact:
   - is unwarranted in the face of a $766.8-million net balance in the deferral accounts (as of September 30, 2010, see item 9(i);
   - seriously confuses the important message to the ratepaying public that BC Hydro's electricity rates are increasing rapidly and will continue to increase rapidly for at least five years if not longer;
   - discourages conservation and efficiency efforts by sending a perverse price signal that electricity has suddenly become less valuable, when the reality is the exact opposite; and

- shifts the 'pain' of paying for current electricity consumption to future ratepayers at a time when current ratepayers are benefiting from very low embedded cost rates due to the heritage investments made by previous ratepayers.

3. BCSEA-SCBC have reservations about item 9 (i) regarding the mechanism for clearing the net balance in the deferral accounts (Trade Income Deferral Account, Heritage Deferral Account and Non-Heritage Deferral Account). The existing, Commission-approved DARR table has the advantage of being very simple, although BCSEA-SCBC acknowledge that some other parties consider it to be *too* simple. However, there is no evidence that a *ten*-year amortization of the HDA and NHDA minimizes the net cost to existing and future ratepayers. Moreover, BCSEA-SCBC believe that a revised mechanism to clear the deferral accounts should balance (a) minimization of the net cost to existing and future ratepayers, and (b) continuation of the heritage resources concept, in the sense that current ratepayers both receive the benefits of previous ratepayer-funded investments and pass on to future ratepayers the benefits of current investments.

Having noted these concerns, BCSEA-SCBC recommend that the Commission adopt, by order, the November 18, 2010 negotiated settlement agreement.

This was a lengthy and difficult negotiated settlement process. BCSEA-SCBC wish to endorse JIESC's November 18, 2010 expression of thanks on behalf of BC Hydro and other participants to the Commission staff and facilitator Bill Grant without whose efforts and skill a settlement would not have been reached.

Yours truly,

William J. Andrews

Barrister & Solicitor

cc. Distribution List by email

From: Dave Newlands [dnewlands@telus.net]
Sent: Friday, November 19, 2010 9:52 AM
To: Commission Secretary BCUC:EX
Cc: Bernadet Mark SPO; Wallace, Brian; Chris Weafer; David Austin; Bill Andrews; bcpiac@bcpiac.com; Sofield, Joanna
Subject: B C hydro

Dear Ms Hamilton

RE: British Columbia Hydro and Power Authority (B C Hydro) Fiscal 2011 Revenue Requirement,Project No. 3698592

Teck Coal participated in and has reviewed the Negotiated Settlement Document circulated by the British Columbia Utilities Commission by letter dated November 16th,2010.

The Settlement Agreement represents a reasonable compromise for all issues arising from the 2011 Revenue Requirements Application.

Teck Coal concurs with the Settlement Agreement and submits that the British Columbia Utilities Commission should approve the Negotiated Settlement Agreement as presented.

Yours truly

J. David Newlands

Cc Mark Bernadet ,General Manager,Business Improvement,Teck Coal

LCA
of BC
Line Contractors Association of BC

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www.lca.ca

18 November 2010

British Columbia utilities Commission
Sixth Floor, 900 Howe Street
Vancouver, BC V6Z 2N3

Attn: Erica Hamilton, Commission Secretary

Dear Ms Hamilton,

Re: BC Hydro F2011 RRA, Project #: 3698592 Settlement Agreement as contained in Bill Grant's 18 November Letter

The LCA's *sole* reservation concerning the 2011 RRA Settlement Agreement, so capably developed by all the participants in the Negotiated Settlement Process (NSP) under the superb leadership of Bill Grant, relates to the LCA Complaint, and to no other terms in the agreement.

BC Hydro and the LCA agreed upon a framework for resolving the LCA Complaint, which includes discussions between the LCA and BC Hydro. These discussions started before the formal Negotiated Settlement Process itself began and are continuing.

While these discussions have been positive and productive, the LCA is growing increasingly concerned about the amount of time being taken by BC Hydro to resolve the LCA Complaint, which was lodged with the BCUC on 8 June 2009. The LCA and BC Hydro agreed that BC Hydro would organize a meeting to occur in October 2010 between the LCA and BC Hydro senior management to review the progress on the issues that form the substance of the LCA Complaint. BC Hydro failed to organize this meeting, citing personnel and organizational changes as the reason.

Too often, in the LCA's judgment, BC Hydro finds itself in the position of citing personnel and organizational changes as the reason why a matter between in the LCA and BC Hydro cannot be handled in a timely manner. The LCA therefore wants to agree with BC Hydro upon a time line and an end-date for the resolution of the LCA Complaint, in the absence of which the LCA is unable to sign-off on any Negotiated Settlement Agreement. The LCA's underlying fear is that, in the absence of a defined end-date for its discussions with BC Hydro, these discussions will continue indefinitely without ever reaching a conclusion satisfactory to both parties.

In closing, the LCA notes that the obligations BC Hydro undertake *as an organization* remain obligations even in the face of personnel and organizational changes, including adherence to an agreed upon schedule for meetings.

Thank you.

Jeff Skosnik, PhD, CEO

IPPBC Independent Power Producers association of British Columbia

November 19, 2010

British Columbia Utilities Commission
Sixth Floor, 900 Howe Street
Vancouver, B.C.
V6Z 2N3

Attention: Bill Grant – Transition Advisor

Dear Sirs and Mesdames:

Re: BC Hydro F2011 Revenue Requirement Application ("F2011 RRA")
Negotiated Settlement Process

The IPPBC supports the Negotiated Settlement Agreement ("NSA") dated for Reference November 18, 2010 with the exception of section 9 (xiv) and in particular the date of July 31, 2011 which states as follows:

"not object to a review of the efficacy of its F2009-F2011 DSM expenditures in its F2012 section 44.2 DSM filing, which would be filed no later than July 31, 2011 and pursue a timely review process, and address, if timely, the BCUC decision on that filing in its Integrated Resource Plan to be submitted to government pursuant to the CEA. Nothing shall prevent parties from leading evidence with respect to additional cost-effective DSM available to mitigate future energy costs;"

In the F2011 RRA pre-hearing conferences[1] the IPPBC made it clear it wished to pursue the issue of the efficacy of BC Hydro's Demand Side Management ("DSM") or Power Smart programs through a prudency review if necessary.

Expenditures for DSM for the period F2009 to F2011 were previously approved by the British Columbia Utilities Commission ("BCUC") however the amortization of the costs with respect to prior expenditures, which include this period, are included as part of the F2011 RRA[2] and require BCUC approval. It is the requirement for this retrospective approval by the BCUC that provides the opportunity to review the efficacy of the prior expenditures by way of prudency review.

The evidence on the F2011 RRA record and in particular an analysis of BC Hydro's response to BCUC IR 1.38.1 (Exhibit B-6) and 2.356.1 (Exhibit B-11)

[1] TR Volume 1, pages 62-63 and TR Volume 2, pages 131-132
[2] Exhibit B-8, F11 RRA Evidentiary Update, Appendix 1, Schedule 7.0, page 35

IPPBC Independent Power Producers association of British Columbia

indicates that the initial requirement for a prudency review has been met and the efficacy of DSM should be fully reviewed as promptly as possible. Delaying the start of any review until July 31, 2011 is not in the best interests of BC Hydro's customers.

Prospective Power Smart expenditures will be part of BC Hydro's next Revenue Requirement application which, according to section 9 (iv) of the NSA:

"BC Hydro shall apply by March 2011 for at least a two year test period, and no more than a three year test period, in its next RRA, and Parties shall work towards a timely review of the RRA;"

The forecast Power Smart expenditures for the 2-3 test year period will be included in the next RRA. The assumption must be that these prospective expenditures will be based on detailed programs. It is difficult to understand how these expenditures can be in included in an application that is supposed to be ready by March 2011 but the details of which won't be available until July 31, 2011.

Under section 44.2 of the Utilities Commission Act BC Hydro is required to file for approval of its DSM expenditures. Practically, this filing should coincide with BC Hydro's March 2011 RRA filing because both have a prospective DSM component. However the NSA would allow BC Hydro to make its F2012 Section 44.2 filing by no later than July 31, 2011. The mismatch in the filing dates between March 2011 for the next BC Hydro RRA fling and July 31, 2011 Section 44.2 filing doesn't make any sense. The dates should match so the much needed review of Power Smart expenditures can take place as promptly as possible.

Put another way, BC Hydro will have approximately 4 months to finalize its DSM plans if the next RRA and section 44.2 application are filed coincidentally by March, 2011. If the July 31, 2011 date is allowed to stand, BC Hydro will have 8 months to file what is now referred to in section 9 (xiv) as its "F2012 section 44.2 filing". Four months should be more than adequate.

Looming in the background is the Clean Energy Act ("CEA") filing date for BC Hydro's next Integrated Resource Plan ("IRP"). According to the CEA, the latest date for this filing is December, 2011. It would be a benefit to all concerned if the efficacy of Power Smart is reviewed by the BCUC in an oral hearing before the IRP is submitted to the government for approval. With an estimated 6 month time frame for this review, the July 31, 2011 date does not allow for this review to be completed in enough time for BC Hydro to incorporate the results in its IRP.

Independent Power Producers Association of BC
1230 – 888 Dunsmuir Street, Vancouver, British Columbia V6C 3K4
Phone: 604.568.4778; Fax: 604.568.4724; www.ippbc.com Email: info@ippbc.com

IPPBC Independent Power Producers association of British Columbia

Given that there are only approximately four months left in BC Hydro's financial 2011 year, it would serve no useful purpose for the IPPBC to request the BCUC to reject the F2011 RRA in its entirety and hold a full public hearing.

The IPPBC respectfully requests that the BCUC either:

1. Accept the NSA except for a nominal amount of the DSM amortization amounts described in footnote 2 and conduct a prudency review of Power Smart on this basis.

2. Accept the NSA but amend the date in Section 9 (xiv) from July 31, 2011 to March, 2011.

The IPPBC continues to express its concerns about the "negative" outstanding balance in the Deferral Accounts which the IPPBC first raised and were noted in the BCUC's October 29, 2004 decision with respect to BC Hydro's 2004/05 to 2005/06 Revenue Requirements Application[3].

The IPPBC wishes to thank the BCUC staff for its perseverance and patience in what was a very difficult negotiated settlement process.

Yours truly,

"Original signed by David Austin"

David Austin

[3] At page 35

Independent Power Producers Association of BC
1230 – 888 Dunsmuir Street, Vancouver, British Columbia V6C 3K4
Phone: 604.568.4778; Fax: 604.568.4724; www.ippbc.com Email: info@ippbc.com

Hunter Litigation Chambers

HUNTER//BERARDINO//McEWAN//KAARDAL

November 26, 2010

File no: 1531.005

By Email

Erica M. Hamilton
Commission Secretary
British Columbia Utilities Commission
P.O. Box 250
6th Floor – 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Ms. Hamilton:

Re: British Columbia Hydro and Power Authority ("BC Hydro") Fiscal 2011 Revenue Requirements Application - Project No. 3698592

I write on behalf of the intervenor Canadian Office and Professional Employees Union, Local 378 ("COPE") and further to your letter of November 19, 2010 enclosing the proposed settlement package for BC Hydro's Fiscal 2011 Revenue Requirements Application.

COPE 378 has reviewed the proposed settlement agreement arising out of the recently concluded Negotiated Settlement Process ("NSP"). The proposed settlement package is acceptable to COPE and COPE supports the acceptance of the proposed settlement by the Commission. While COPE elected not to participate in the NSP, COPE believes, based on its review of the proposed settlement and the comments of other intervenors, that the proposed settlement represents a reasonable compromise of the issues arising out of the F2011 Revenue Requirements Application and the various information requests and other materials filed to date in this matter.

COPE wishes to note its particular support of paragraphs 9(ii), (viii), (xiii), (xv) and (xvi) of the proposed settlement. COPE believes these provisions, if carried through in a meaningful way, will provide positive and materials steps toward ensuring that:

(a) future revenue requirements applications have an increased level of transparency; and

(b) BC Hydro engages the Province in an effort to ensure that the BC Hydro's shareholder more fully understands the potential implications of future policy decisions made by the shareholder on ratepayers.

Finally, COPE thanks all participants in the NSP and the Commission Staff for all of their diligence, skill and effort in achieving this proposed settlement.

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PRACTICE CONDUCTED THROUGH A PERSONAL LAW CORPORATION

[redacted]

Please call if you have any questions.

Yours truly,

Hunter Litigation Chambers

Per:

Mark S. Oulton
MSO/bb

cc BC Hydro, Attention: Joanna Sofield, Chief Regulatory Officer
Lawson Lundell LLP, Attention: Jeff Christian and Ian Webb
Registered Intervenors
Client

FORTISBC

Dennis Swanson
Director, Regulatory Affairs

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November 26, 2010

Via Email

Ms. Erica M. Hamilton
Commission Secretary
BC Utilities Commission
Sixth Floor, 900 Howe Street, Box 250
Vancouver, BC V6Z 2N3

Dear Ms. Hamilton:

Re: British Columbia Power and Authority ("BC Hydro") Fiscal 2011 Revenue Requirements Application ("F2011 RRA") – Negotiated Settlement

On October 27, 2010, the Commission issued Order No. G-163-10 reinstating the Negotiated Settlement Process ("NSP") in the F2011 RRA proceeding. On November 2, 2010, BC Hydro advised the Commission that NSP participants achieved agreement on a settlement of all issues arising from the F2011 RRA. On November 19, 2010, the Commission requested Intervenors who did not participate in the settlement negotiations to provide their comments on the settlement package by Friday, November 26, 2010.

FortisBC thanks the Commission for the opportunity to provide input into the negotiated settlement and advises it has no comment. FortisBC advises that it intends to participate as an interested party in the meeting specified in paragraph 9 ii of the settlement agreement which has been set for November 30, 2010.

If you require further information or have any questions regarding this submission, please contact the undersigned.

Sincerely,

Dennis Swanson
Director, Regulatory Affairs

NEW WESTMINSTER
Electric Utility Commission
511 Royal Avenue, New Westminster, BC V3L 1H9

VIA EMAIL

November 26, 2010
British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, BC
V6Z 2N3

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: British Columbia Hydro and Power Authority ("BC Hydro") Fiscal 2011 Revenue Requirements Application ("F2011 RRA") – Negotiated Settlement

On October 27, 2010, the Commission issued Order No. G-163-10 reinstating the Negotiated Settlement Process ("NSP") in the F2011 RRA proceeding. On November 2, 2010, BC Hydro advised the Commission that NSP participants achieved agreement on a settlement of all issues arising from the F2011 RRA. On November 19, 2010, the Commission requested Intervenors who did not participate in the settlement negotiations to provide their comments on the settlement package by Friday, November 26, 2010.

The City of New Westminster, Electric Utility Commission thanks the Commission for the opportunity to provide input into the negotiated settlement and advises it has no comment. The City advise that it intends to participate as an interested party in the meeting specified in paragraph 9 ii of the settlement agreement which has been set for November 30, 2010.

If you require further information or have any questions regarding this submission, please contact the undersigned.

Yours truly,

Roderick Carle,
General Manager,
Electric Utility, City of New Westminster

cc (email only): Registered Parties

Terasen Gas

Diane Roy
Director, Regulatory Affairs

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November 26, 2010

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, BC
V6Z 2N3

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: British Columbia Hydro and Power Authority ("BC Hydro") Fiscal 2011 Revenue Requirements Application ("F2011 RRA") – Negotiated Settlement

Terasen Utilities Comment

On October 27, 2010, the Commission issued Order No. G-163-10 reinstating the Negotiated Settlement Process ("NSP") in the F2011 RRA proceeding. On November 2, 2010, BC Hydro advised the Commission that NSP participants achieved agreement on a settlement of all issues arising from the F2011 RRA. On November 19, 2010, the Commission requested Intervenors who did not participate in the settlement negotiations to provide their comments on the settlement package by Friday, November 26, 2010.

The group of Terasen gas distribution companies, including Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc. and Terasen Gas (Whistler) Inc. (collectively the "Terasen Utilities") thank the Commission for the opportunity to provide input into the negotiated settlement and advises it has no comment. The Terasen Utilities advise that it intends to participate as an interested party in the meeting specified in paragraph 9 ii of the settlement agreement which has been set for November 30, 2010.

If you require further information or have any questions regarding this submission, please contact the undersigned.

Yours very truly,

on behalf of the TERASEN UTILITIES

Original signed:

Diane Roy

cc (email only): Registered Parties