Janet Fraser
Chief Regulatory Officer
Phone: 604-623-4046
Fax: 604-623-4407
bchydroregulatorygroup@bchydro.com

March 7, 2014

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

Dear Ms. Hamilton:

RE: British Columbia Utilities Commission (BCUC)
British Columbia Hydro and Power Authority (BC Hydro)
F2015 to F2016 Revenue Requirements Rate Application (F15-F16 RRRA)
F2014 to F2016 Expenditures on Demand-Side Measures (DSM)
Retail Access
Direction Nos. 6 and 7 to the BCUC
Amendments to Heritage Special Directive No. HC1
Repeal of Heritage Special Direction No. HC2

BC Hydro writes to apply for a final order confirming its rates in F2014, F2015 and F2016 further to the Province's November 26, 2013 announcement in regard to BC Hydro (**BC Hydro Plan**)[1] and subsequent changes to the regulatory framework regarding BC Hydro's revenue requirements and rates. Related corollary relief is also sought with respect to BC Hydro's regulatory accounts, among other matters. The specific order sought regarding BC Hydro's F2014, F2015 and F2016 rates is set out in **Appendix A** (**Draft Order A**).

BC Hydro is also applying for a final order cancelling BC Hydro's retail access program and accepting BC Hydro's withdrawal of any obligation to provide unbundled transmission services pursuant to BC Hydro's Open Access Transmission Tariff (**OATT**) to retail customers in British Columbia. The specific order sought regarding retail access is set out in **Appendix B** (**Draft Order B**).

1. Background

Introduction

BC Hydro's current F2014 rates have been set as final by BCUC Order No. G-77-12A, subject to acceptance by the BCUC of BC Hydro's F2014 DSM expenditures, and they will expire on March 31, 2014. In the normal course BC Hydro would have filed a full revenue requirements

[1] The BC Hydro Plan can be found at the following website: http://www.newsroom.gov.bc.ca/2013/11/10-year-plan-means-predictable-rates-as-bc-hydro-invests-in-system.html.

application (**RRA**), seeking average rate increases for F2015 (at least), and acceptance of DSM expenditures, on the basis of evidence regarding BC Hydro's cost structure and DSM plans.

The announcement by the Province of the BC Hydro Plan on November 26, 2013 and the subsequent issuance of various enactments regarding BC Hydro's revenue requirements and rates have resulted in quite a different application than would normally be the case. In particular, under the revised regulatory framework the BCUC must issue final orders to set BC Hydro's rates for F2015 and F2016 within 20 days of this application being filed, being March 27, 2014. This is a challenging deadline to meet in light of the complexity of BC Hydro's cost structure and the revised regulatory framework. Accordingly, this application is mostly given over to explaining what orders are required by reference to the new enactments and BC Hydro's F2015 and F2016 revenue requirements model (**F15-F16 RR Model**) attached as **Appendix C**. However, because the revised regulatory framework will have on-going effect aside from the settlement of F2015 and F2016 rates, some discussion is also given over to explaining the revised framework.

The revised regulatory framework regarding BC Hydro's revenue requirement rates has been effected through the following:

1. B.C. Reg. 29/2014 enacts new Direction No. 6 to the BCUC, which compels certain F2015 and F2016 revenue requirement and rate orders by March 27, 2014. Upon those required orders being issued, Direction No. 6 will no longer have any legal effect.
2. B.C. Reg. 28/2014 enacts new Direction No. 7 to the BCUC, which continues the essential elements of the Heritage Contract framework formerly enshrined in Heritage Special Direction No. HC2 (**HSD#2**) and establishes new on-going elements, some of which have effect in regard to F2014, F2015 and F2016. The same Regulation effects the repeal of HSD#2.
3. Order in Council No. 095/2014 enacts an amendment to Heritage Special Directive No. HC1 (**HSD#1**) to BC Hydro, which has the effect of reducing BC Hydro's annual dividend to the Province after 2017 until it reaches zero and keeping it at zero until BC Hydro's debt-equity ratio reaches 60:40

These enactments are attached as **Appendices D, E** and **F**, respectively.

As noted, Appendix A is Draft Order A regarding BC Hydro's F2014, F2015 and F2016 rates and is central to this application. Draft Order A sets out all the orders required from the BCUC by March 27, 2014 in consequence of Direction Nos. 6 and 7, with the exception of orders relating to retail access, which is addressed by Draft Order B in Appendix B. For convenience, each element of Draft Order A and Draft Order B is, where applicable, cross-referenced to the applicable provision in one or other of those enactments.

The F15-F16 RR Model attached as Appendix C shows, in a format substantially consistent with previous BC Hydro RRAs, each element of BC Hydro's cost structure in F2015 and F2016 consistent with Draft Order A and Direction Nos. 6 and 7.

The balance of this "Background" section provides further information on the new enactments and regulatory framework.

The subsequent section entitled "Explanation of Requested BCUC Orders" provides a provision-by-provision explanation of Draft Orders A and B, cross-referencing where applicable to the appropriate enactment or schedule in the F15-F16 RR Model.

Section 3 summarizes BC Hydro's F2015 and F2016 revenue requirements, and section 4 addresses previous BCUC directives and BC Hydro's commitments regarding BC Hydro's revenue requirement applications.

Direction No. 6 to the BCUC

Direction No. 6 is a direction to the BCUC pursuant to section 3 of the *Utilities Commission Act,* RSBC 1996, c. 473, as amended (**the Act**). Direction No. 6 came into force on March 6, 2014. It has the force of law and compels the BCUC to issue final orders set out in the direction, and as applied for by BC Hydro in this application, within 20 days of the filing of this application with the BCUC. Direction No. 6 concerns F2014, F2015 and F2016 only and, once the BCUC has issued the order requested in this application, will no longer have any legal effect.

Among other things, Direction No. 6 requires the BCUC to issue orders addressing the following:

- The DSM expenditure schedule for F2014, F2015 and F2016 (attached as Appendix A to Direction No. 6 and Schedule A to Draft Order A) is to be accepted by the BCUC
- The BCUC must confirm BC Hydro's rates for F2014 as final and no longer subject to refund
- The BCUC must set BC Hydro's Electric Tariff rates for F2015 and F2016 in accordance with Appendix B to Direction No. 6, and BC Hydro's OATT rates for F2015 and F2016 in accordance with Appendix C to that direction (Schedules B and C respectively, to Draft Order A). The F2015 rates are 9 per cent higher, on average than the F2014 rates, and the F2016 rates are 6 per cent higher on average than F2015 rates. All the rates in Appendices B and C of Direction No. 6 are consistent with the applicable rate increase (9 per cent or 6 per cent) and, with one exception, were calculated in accordance with previous BCUC-ordered pricing principles. The exception is the Transmission Service Rate (**TSR**) stepped rate (**RS1823**). Contrary to the pricing principle established in BCUC Order No. G-79-05, approval of the rates set out in Appendix B to Direction No. 6 (Schedule B to Draft Order A) will effectively result in the 9 per cent and 6 per cent rate increases being applied equally to the Tier 1 and Tier 2 energy rates (and to the Demand Charges, as is normally the case) of the TSR rate.
- Specific amounts to be amortized from BC Hydro's regulatory accounts in each of F2015 and F2016 are prescribed for a majority of BC Hydro's regulatory accounts

- BC Hydro's F2014 rate of Return on Equity (**ROE**) effectively remains at 11.84 per cent, rather than being reduced as it would otherwise have been to reflect the BCUC's Stage 1 Generic Cost of Capital decision (Order No. G-75-13)

Direction No. 7 to the BCUC

Direction No. 7 is also a direction to the BCUC pursuant to section 3 of the Act. Direction No. 7 also came into force on March 6, 2014 and has the force of law. Direction No. 7 primarily concerns the F2017 and future fiscal periods, although some of its provisions also have an impact in regard to F2014, F2015 and F2016 and therefore is relevant to the order being requested in this application. In addition, Direction No. 7 re-enacts the content of HSD#2, including the Heritage Contract. Accordingly, the Heritage Contract framework continues, although somewhat amended as described herein.

Notable elements of Direction No. 7 are as follows:

- As described in the BC Hydro Plan, rate caps will be in place for F2017, F2018 and F2019 at 4 per cent, 3.5 per cent and 3 per cent respectively. Any BCUC approved revenue requirements that would (absent the rate caps) result in rates greater than the capped amounts will be placed into the Rate Smoothing Regulatory Account that the BCUC is required to establish under Direction No. 7. By implication, BC Hydro will be filing a revenue requirements application in regard to F2017 and future fiscal years about two years from now (i.e., fourth quarter of F2016).
- BC Hydro's rate of ROE will continue at 11.84 per cent for F2015, F2016 and F2017. For F2018 and subsequent years, BC Hydro's ROE (i.e., expressed in dollars) will effectively be increased by the amount of any increase in the British Columbia Consumer Price Index for the applicable year, independent of the rate of ROE and deemed equity (even as BC Hydro's rate base continues to grow at a rate faster than inflation).
- The "floor" of $0.00 in the definition of Trade Income is removed for F2014. As a result, Powerex's anticipated net loss for F2014 will be placed into the Trade Income Deferral Account (**TIDA**). For F2015 and future years, the floor will be reinstated, and Powerex net losses will not be allowed into the TIDA.
- With regard to BC Hydro's regulatory accounts:
    - o As part of the BC Hydro Plan, the Province announced the permanent closure of the Burrard Thermal generating station other than those assets required for transmission support services. Costs incurred by BC Hydro in F2014 and later years to decommission the plant are to be deferred to the Non-Heritage Deferral Account (**NHDA**).
    - o Two new regulatory accounts are to be approved effective in F2015:
        1) the Rate Smoothing Regulatory Account, which will function in a fashion similar to the F2012-F2014 Rate Smoothing Account, namely to allow for the deferral

and more gradual recovery of one or more large, non-recurring revenue requirement increases, with the objective of smoothing rate increases so that there is less volatility from year to year

2) the Real Property Sales Regulatory Account, to defer the variances between forecast and actual net gains from real property sales

- The Deferral Account Rate Rider (**DARR**) will be set at 5 per cent for F2015 and future years, unless BC Hydro applies to have it changed. The revenue received from the DARR is to be apportioned between general revenue and the balances of the Heritage Deferral Account (**HDA**), the NHDA and the TIDA depending on the net balance of the three accounts. The allocation methodology uses the DARR allocation table initially approved by the BCUC in its decision on BC Hydro's F09/F10 RRA (**DARR Allocation Table**) and further confirmed through BCUC Order No. G-77-12A[2]. The DARR revenue in excess of what would otherwise be collected under the DARR Allocation Table will be accounted for as general revenue and thereby used to offset general rate increases. In accordance with this mechanism, all of the DARR revenue in F2015 and F2016 is forecasted to be allocated to paying down the balance of the deferral accounts.
- With regard to BC Hydro's Retail Access Program, by March 23, 2014, the BCUC must cancel the program. In addition and also by March 23, 2014, the BCUC must accept BC Hydro's withdrawal of any obligation it may have to offer unbundled transmission services directly or indirectly to retail customers under the OATT, or to those who would supply such customers. In anticipation of further development work on retail access issues,[3] BC Hydro hereby withdraws any such obligations. Since March 23, 2014 is a Sunday, Direction No. 7 effectively requires the BCUC to issue these orders by end of day Friday, March 21, 2014.

2. Explanation of Requested BCUC Orders

As noted, the requested orders are attached at Appendix A and Appendix B.

[2] This was the BCUC order issued in response to Direction No. 3 and BC Hydro's F12-F14 Amended Revenue Requirements Application.

[3] The BC Hydro Plan contemplates a future rate design process to examine ways to provide industrial customers with more options to reduce their electricity costs, as recommended by the Industrial Electricity Policy Review Task Force. This element of the BC Hydro Plan is a reference to the Government's response to the Task Force's recommendation Number 11 regarding the retail access program, summarized in the following Backgrounder on the Industrial Electricity Policy Review Report:
http://www.newsroom.gov.bc.ca/downloads/Backgrounder_Industrial_Electricity_Policy_Review_Report.pdf.

Order to be Issued within 20 Days (Draft Order A)

Section 3 of Direction No. 6 requires that the BCUC issue its final orders with regard to BC Hydro's F2014, F2015 and F2016 revenue requirements rates within 20 days of the date on which BC Hydro files its application. As BC Hydro filed its application on March 7, 2014, the BCUC is therefore required to issue its final order no later than March 27, 2014

DSM Expenditure Schedule and F2014 Rates

Paragraph 1 of Draft Order A relates to section 3(a) of Direction No. 6, which requires that the BCUC accept BC Hydro's DSM Expenditure Schedule for F2014, F2015 and F2016 attached as Appendix A to Direction No. 6 and as Schedule A to Draft Order A. A description of BC Hydro's F2014 to F2016 DSM initiatives, as well as the energy and capacity savings the DSM initiatives are expected to achieve, is set out in **Appendix G** to this application. Line 49/schedule 5 of the F15-F16 RR Model shows the DSM costs for F2014, F2015 and F2016.

Paragraph 2 of Draft Order A responds to section 3(b) of Direction No. 6, which requires the BCUC to confirm BC Hydro's F2014 rates as final and no longer subject to refund. BCUC Order No. G-77-12A set BC Hydro's F2014 rates as final subject to the BCUC's acceptance of BC Hydro's F2014 DSM expenditure schedule under section 44.2 of the Act. In consequence of the acceptance and by virtue of section 3(b) of Direction No. 6, the BCUC must order that BC Hydro's F2014 rates (including the OATT rates) are final and no longer subject to refund.

F2015 and F2016 BC Hydro Electric Tariff Rates

Paragraphs 3 and 4 of Draft Order A respond to section 3(c) of Direction No. 6 which requires the BCUC to approve the Electric Tariff rates as set out in Appendix B to Direction No. 6. The rates shown in Appendix B of Direction No. 6 and Schedule B to Draft Order A are the result of BC Hydro applying a 9 per cent average rate increase to the F2014 approved final rates to yield the new F2015 rates and a 6 per cent average rate increase to the F2015 rates to yield the F2016 rates, subject in all cases to BCUC-approved pricing principles except as noted previously.

Three other rate schedules are also affected as a consequence of the equal application of the 9 per cent and 6 per cent increases to the Tier 1 and Tier 2 energy prices of the TSR stepped rate.

1. Rate Schedule 1825 – Transmission Service – Time-of-Use (**RS 1825**) has differing pricing for Winter and Spring high load hour and low load hour periods that is derived from the Tier 2 price for RS 1823. Therefore, the pricing for F2015 and F2016 for RS 1825 will vary from what it otherwise would be as a result of the TSR stepped rate pricing. BC Hydro notes, however, that there are currently no transmission service customers using RS 1825.

2. Rate Schedule 1880 – Transmission Service – Standby and Maintenance Supply (**RS 1880**) is a rate available to transmission services customers who have their own generation and is used when all or part of a customer's generating plant has been curtailed. The energy charge for RS 1880 is the same as the Tier 2 price under RS 1823 and, therefore, will also vary from what it otherwise would be as a result of the TSR stepped rate pricing. In particular, the energy charge for RS 1880 will increase from 7.36 cents/kWh to 8.022 cents/kWh for F2015 and to 8.503 cents/kWh for F2016 (amounting to 9 per cent and 6 per cent rate increases respectively).
3. Finally, the rate charged under Tariff Supplement No. 76 – Shore Power is tied directly to the pricing of RS 1880, as it is calculated as the RS 1880 rate multiplied by a distribution loss factor, resulting in Shore Power rates of 8.298 cents/kWh and 8.795 cents/kWh in F2015 and F2016, respectively. Again, this varies from what it otherwise would be as a result of the TSR stepped rate pricing.

F2015 and F2016 OATT Rates

Paragraphs 5 and 6 of Draft Order A approve the OATT rates in accordance with section 3(d) of Direction No. 6. Section 3(d) of Direction No. 6 requires the BCUC to approve the OATT rates for F2015 and F2016 as shown in Appendix C to Direction No. 6.

Deferral Account Rate Rider (DARR)

Paragraph 7 of Draft Order A sets the DARR at 5 per cent, further to sections 10(1) and (2) of Direction No. 7.

Line 21/schedule 1 of the F15-F16 RR Model attached as Appendix C shows forecast DARR revenue in F2015 and F2016.

F2015 Rate Schedules

Paragraph 8 of Draft Order A requires BC Hydro to file updated OATT and Electric Tariff sheets to reflect the new rates approved for F2015 by March 31, 2014 (BC Hydro's proposed date).

Return on Deemed Equity

Paragraph 9 of Draft Order A responds to section 4(d)(i) of Direction No. 7 which requires the BCUC to ensure BC Hydro's rates are set so as to allow BC Hydro to earn a rate of ROE of 11.84 per cent on its deemed equity in both F2015 and F2016.

Line 46/schedule 9 of the F15-F16 RR Model shows the rate of return on equity, and line 47/schedule 9 shows the return on equity.

New Regulatory Accounts

Paragraph 10 of Draft Order A approves the establishment of a new regulatory account called the Rate Smoothing Regulatory Account, as required by section 7(h)(i) of Direction No. 7. By this application, BC Hydro seeks BCUC approval to establish the Rate Smoothing Regulatory Account to defer, for recovery in future years, those portions of BC Hydro's revenue requirement for each fiscal year, beginning in F2015, that are not (or were not) recovered in rates in that particular fiscal year. As its name suggests, the Rate Smoothing Regulatory Account allows rate increases to be spread out over the course of a period of years. The BC Hydro Plan contemplates that the Rate Smoothing Regulatory Account will be cleared over 10 years.

Line 173/schedule 2.2 of the F15-F16 RR Model attached in Appendix C shows the amounts to be deferred to the Rate Smoothing Regulatory Account in F2015 and F2016.

Similarly, paragraph 11 of Draft Order A approves the establishment of a new regulatory account called the Real Property Sales Regulatory Account, as required by section 7(h)(ii) of Direction No. 7. In this application, BC Hydro seeks the BCUC's approval to establish the Real Property Sales Regulatory Account to allow BC Hydro to defer the variances between BC Hydro's forecast and actual net gains from sales of its real property each fiscal year.

For each of F2015 and F2016, BC Hydro is forecasting net gains from the sale of real property of $10 million as shown in line 82/schedule 5 of the F15-F16 RR Model.

Existing Regulatory Accounts

- Paragraph 12 of Draft Order A complies with section 3 (h) of Direction No. 6 by allowing BC Hydro to defer its F2015 and F2016 operating costs associated with the development of the Site C project to the existing Site C Regulatory Account. The Site C operating costs are not forecast for F2015 and F2016 in the F15-F16 RR Model.
- Paragraph 13 of Draft Order A complies with section 3(l)(ii) of Direction No. 6. It orders BC Hydro to defer to the SMI Regulatory Account BC Hydro's net operating costs incurred in F2015 and F2016 arising from the smart metering and infrastructure program and net operating costs arising from the meter choices program (approved by BCUC Order No. G-166-13). The forecast net operating costs are found on Line 56/schedule 5 of the F15-F16 RR Model which shows forecast deferrals of $28.4 million in F2015 and $21.5 million in F2016. The definition of "smart metering and infrastructure program" in section 1 of Direction No. 6 includes both BC Hydro's smart meter program and its smart grid program (which it is required to pursue under section 17(4) of the *Clean Energy Act*).

- Paragraph 14 of Draft Order A concerns BC Hydro's F2014 ROE, as required by section 3(v) of Direction No. 6. This order effects an 11.84 per cent ROE for F2014 by reversing the credit to the NHDA arising from paragraph 1(xxvii) of BCUC Order No. G-77-12A which was issued in compliance with section 3(l) of Direction No. 3 to the BCUC.[4]
- Paragraph 15 of Draft Order A requires BC Hydro to continue to defer to the NHDA the difference between actual and forecast domestic customer load, as required by section 7(c)(i) of Direction No. 7. As BC Hydro does not forecast variances for variance regulatory accounts, no load variances have been forecasted for inclusion in the NHDA in F2015 and F2016.
- Paragraph 16 of Draft Order A requires BC Hydro to defer to the NHDA the "Burrard Costs" further to section 7(c)(ii) of Direction No. 7. Burrard Costs are defined as BC Hydro's costs, beginning in F2014, arising from the decommissioning of the parts of the Burrard Thermal Generating Station not required for transmission support. These include not only the costs associated with decommissioning parts of the generating station itself but also, without limitation: the costs associated with retaining employees at the Burrard Generating Station until the electricity generating units are no longer in operation; damages or contractual penalties that may arise as a result of the decommissioning; and the net increase in amortization expense in F2015 and F2016 that will result from a future BCUC order required under section 15 of Direction No. 7.[5] Burrard Costs will likely be incurred and included in the NHDA, but these are not yet known and therefore not forecast at this time.
- Paragraph 17 of Draft Order A addresses the requirement set out in section 7(d)(i) of Direction No. 7, by ordering BC Hydro to defer to the DSM Regulatory Account the costs arising from the development, implementation and administration of demand-side measures. Both Draft Order A and Direction No. 7 expressly address costs arising from BC Hydro's

[4] Section 3(l) of Direction No. 3 required the BCUC to order that BC Hydro defer to the NHDA the difference between (i) the forecast F2014 ROE calculated on the basis of a rate of ROE of 11.84 per cent, and (ii) the forecast F2014 ROE that was to be calculated at a later date as a result of a subsequent BCUC order arising from the BCUC's Generic Cost of Capital Proceeding. On May 10, 2013 the BCUC issued BCUC Order No. G-75-13 which resulted in a reduction in the Benchmark Utility Return on Equity from 9.5 per cent to 8.75 per cent, effective January 1, 2013. This resulted in a nominal reduction to BC Hydro's allowed ROE for F2014 from 11.84 per cent to 10.62 per cent. Paragraph 1(xxvii) of BCUC Order No. G-77-12A, consistent with section 3(l) of Direction No. 3, required that BC Hydro account for that reduction as a credit to the NHDA. Paragraph 14 of Draft Order A does the opposite, requiring BC Hydro to record a debit into the NHDA equal to the amount credited to that account under BCUC Order No. G-77-12A.

[5] Section 15 of Direction No. 7 contemplates a BC Hydro application to the BCUC for permission to cease operating the parts of Burrard Generating Station not required for transmission support. If and when BC Hydro proceeds with the decommissioning of the Burrard Generating Station, it will bring an application to set depreciation rates for the Burrard assets as set out in Appendix B to Direction No. 7

"specified demand-side measures", which are also to be deferred to the DSM Regulatory Account. These are defined in Direction No. 7 by reference to the Demand-Side Measures Regulation under the Act and include BC Hydro's community engagement, education and technology innovation programs.

Appendix G to this application describes BC Hydro's expenditures on demand-side measures as well as BC Hydro's accounting practices with respect to those expenditures. Section 7(d)(ii) of Direction No. 7 requires the BCUC to allow BC Hydro to amortize DSM costs in the DSM Regulatory Account over a 15-year period, which is consistent with BC Hydro's previous practices and BCUC Order No. G-77-12A.

Line 49/schedule 5 of the F15-F16 RR Model shows the forecast deferrals to the DSM Regulatory Account.

- Paragraph 18 of Draft Order A responds to section 7(e) of Direction No. 7 by requiring BC Hydro to continue to defer to the Rock Bay Remediation Regulatory Account the costs made subject to that account by BCUC Order No. G-75-11, including F2014 costs. As a result of the BCUC order required by section 7(e) of Direction No. 7, it will no longer be necessary for BC Hydro to file an annual application with the BCUC requesting the inclusion in the Rock Bay Regulatory Account of the Rock Bay costs for any particular fiscal year.

  Line 134/schedule 2.2 of the F15-F16 RR Model sets out the forecast amounts to be deferred to the Rock Bay Remediation Regulatory Account in F2015 and F2016.

- Paragraphs 19 and 20 of Draft Order A comply with sections 7(f) and (g) of Direction No. 7 respectively. They require BC Hydro to continue to record the variances between forecast and actual asbestos remediation costs and forecast and actual non-current pension costs to the regulatory accounts established for those purposes. As BC Hydro does not forecast variances for variance deferral accounts, no variances have been forecasted for inclusion in these accounts in F2015 and F2016.

- Paragraphs 21 and 22 of Draft Order A address the requirements set out in sections 7(i)(i) and (ii) of Direction No. 7. They require both the First Nations Costs Regulatory Account and the Real Property Sales Regulatory Account to accrue interest in each fiscal year at BC Hydro's weighted average cost of debt[6].

  Line 12/schedule 2.2 of the F15-F16 RR Model shows the forecast interest accrued on the First Nations Costs Regulatory Account

- Paragraph 23 of Draft Order A directs how revenue from the DARR is to be allocated, with express reference to section 10(3) of Direction No. 7. The provision requires that revenue from the DARR be apportioned between the three deferral accounts (the HDA, NHDA and TIDA) and general revenue. DARR revenue will be applied to the three deferral accounts based on the table in Section 14 of Direction No. 7. The table is substantively identical to the DARR Allocation Table that has been used to set the DARR in previous fiscal years.

6 No interest is forecast on variance accounts.

Equation 1 in section 10(3) of Direction No. 7 calculates the amount of DARR revenue that will be apportioned to general revenue, with the balance being used to draw down the three deferral accounts proportionally in accordance with paragraph 10(3)(iii).

Lines 5, 12, 20/schedule 2.1 of the F15-F16 RR Model show the forecast amounts that will be allocated to the HDA, the NHDA and the TIDA in F2015 and F2016, respectively. There are no amounts that will be apportioned to general revenue in F2015 and F2016.

F2015 and F2016 Regulatory Account Baseline Forecasts

Paragraph 24 of Draft Order A fulfills the requirements in sections 3(e) and (f) of Direction No. 6. It expressly approves certain baseline forecasts for the regulatory accounts that record variances between forecast and actual costs or expenditures. To allow easy reference to the F15-F16 RR Model, the table in Draft Order A is reproduced below with cross-references to the applicable schedule.

Table 1 Regulatory Baseline Amounts

Forecast (Applicable Account)	F15-F16 RR Model Reference	F2015 ($ million)	F2016 ($ million)
Heritage Payment Obligation (HDA)	Line 75 (schedule 4.0)	353.2	399.2
Non-Heritage Cost of Energy Subject to Deferral (NHDA)	Line 88 (schedule 4.0)	1,074.3	1,032.2
Total Rate Revenue (NHDA)	Line 22 (schedule 1.0)	4,168.3	4,459.7
Trade Income (TIDA)	Line 17 (schedule 1.0)	110.0	110.0
Non-Current Pension Costs	Line 61 (schedule 8.0)	2.9	0.1
Storm Restoration Costs	N/A[7]	3.9	3.9
Total Finance Charges	Lines 71 – Line 60 – Line 61 (schedule 8.0)	602.6	725.2
Amortization of Capital Additions	Line 73 – Line 72 (schedule 13.0)	34.7	106.7
Real Property Sales	Line 82 (schedule 5.0)	10.0	10.0
Asbestos Remediation Costs	Line 166 (schedule 2.2)	1.8	0.9

Specific Amortization Orders

Paragraphs 25 through 37 of Draft Order A direct the amortization of specific amounts from BC Hydro's regulatory accounts, in compliance with Direction No. 6. Table 2 below shows the amounts required to be amortized from each regulatory account in F2015 and F2016, with reference to the applicable paragraph of Draft Order A, the corresponding section of

[7] The baseline amount for this item is included within the operating costs total shown on line 5/schedule 5.4.

Direction No. 6, and the corresponding entry in the F15-F16 RR Model. The amortization amounts have been determined consistently with the Regulatory Accounts Report at **Appendix H**.

Table 2 Regulatory Account Amortization Amounts

Regulatory Account	Draft Order A Paragraph Reference	Direction No. 6 Section Reference	F15-F16 RR Model Reference	F2015 ($ million)	F2016 ($ million)
First Nations Costs	25	3(g)	Line 28 (schedule 5.0)	43.5	43.3
Storm Restoration	26	3(i)	Line 30 (schedule 5.0)	1.4	1.4
Capital Additions	27	3(j)	Line 57 (schedule 7.0)	9.8	9.4
Total Finance Charges	28	3(k)	Line 69 (schedule 8.0)	25.5	25.5
SMI	29	3(l)(i)	Line 35 (schedule 5.0)	30.5	31.3
Home Purchase Option Plan	30	3(m)	Line 36 (schedule 5.0)	11.8	11.3
Non-current Pension Costs	31	3(n)	Line 37 (schedule 5.0)	32.6	15.5
Rock Bay	32	3(o)	Line 99 (schedule 5.0)	51.5	50.5
IFRS PP&E	33	3(p)(i)	Line 38 (schedule 5.0)	15.9	19.8
IFRS Pension	34	3(q)	Line 39 (schedule 5.0)	38.2	38.2
Arrow Water Divestiture Costs	35	3(r)	Line 100 (schedule 5.0)	4.7	4.5
Arrow Water Provision	36	3(s)	Line 101 (schedule 5.0)	0.3	0.3
Asbestos Remediation	37	3(t)	Sum of Lines 95 through 98 (schedule 5.0)	12.1	10.7

Specific Deferral Orders

Paragraph 38 of Draft Order A requires BC Hydro to defer to the IFRS PP&E Regulatory Account $156.8 million in F2015 and $134.4 million in F2016. These amounts can be found in line 58/schedule 5 of the F15-F16 RR Model. Paragraph 38 of Draft Order A implements the requirement set out in section 3(p)(ii) of Direction No. 6.

Paragraph 39 of Draft Order A requires BC Hydro to defer to the Rate Smoothing Regulatory Account $166.2 million in F2015 and $121.2 million in F2016. These amounts can be found in line 103/schedule 5 of the F15-F16 RR Model. Paragraph 39 implements the requirement set out in section 3(u) of Direction No. 6.

Order to be Issued by March 23, 2014 (Draft Order B)

Unlike the orders set out in Draft Order A, which must be issued within 20 days of BC Hydro filing this application, the orders in Draft Order B must be issued on or before March 23, 2014. As March 23, 2014 falls on a Sunday, in effect the orders in Draft Order B are required no later than end of day on March 21, 2014. Draft Order B responds to the requirements in section 14(1)(a) and (b) of Direction No. 7 regarding retail access. Paragraph 1 approves BC Hydro's withdrawal of any obligation to offer unbundled transmission services pursuant to BC Hydro's OATT to retail customers in British Columbia and to those who supply such customers, as effected above. Paragraph 2 cancels the Retail Access Program as defined in BCUC Order No. G-39-12.

3. F2015 and F2016 Revenue Requirements

Table 3 summarizes the components of BC Hydro's revenue requirements for F2015 and F2016 and shows the revenue shortfalls that would result from existing rates.

Table 3 Revenue Requirements Summary

	F15-F16 RR Model Schedule 1 Reference (Appendix C)	F2015 ($ million)	F2016 ($ million)
Cost of Energy	Line 1	1,384.5	1,391.7
Operating Costs	Line 2	1,170.8	1,146.6
Taxes	Line 3	213.8	224.1
Amortization	Line 4	698.7	758.0
Finance Charges	Line 5	725.0	838.3
Return on Equity	Line 6	581.5	651.9
Non-Tariff and Other Utility Revenue	Line 7 + Line 20	(137.5)	(143.1)
Inter-segment Revenue	Line 8	(52.6)	(53.5)
Net Deferral/Regulatory Accounts	Line 12 + Line 16	(93.4)	(16.2)
Subsidiary Net Income	Line 19	(114.2)	(115.1)
DARR Revenue	Line 11	(208.4)	(223.0)
Total Revenue Requirement	Line 22	4,168.2	4,459.7
Rate Revenue at Current Rates	Line 26	3,824.2	3,860.0
Revenue Shortfall	Line 27	344.0	599.7
Rate Increase (%)	Line 28	9.0	6.0

4. BC Hydro Commitments and Previous BCUC Directives

BC Hydro's F12-F14 Amended Revenue Requirements Application was resolved through the enactment of Direction No. 3 on May 22, 2012 and the subsequent issuance of BCUC Order No. G-77-12A. In its filing of May 23, 2012 to the BCUC in response to Direction No. 3, BC Hydro made several commitments with regard to information that would be provided no later than the filing of its next RRA. In addition, BCUC Order No. G-77-12A also contained directions to which BC Hydro was to respond in its next application. In this section, BC Hydro discusses these commitments and BCUC directives, as well as applicable revenue requirement directives from previous proceedings.

BC Hydro Commitments

Regulatory Accounts Report

One of BC Hydro's May 2012 commitments was to provide a more detailed regulatory accounts plan. Attached as Appendix H is BC Hydro's Regulatory Accounts Report dated February 28, 2014. The report describes BC Hydro's regulatory accounts, its plan to reduce the total balance and number of accounts and its principles regarding potential new accounts and the application of interest to the accounts. Direction Nos. 6 and 7 and this application are entirely consistent with the report.

10-Year Capital Plan

BC Hydro also committed in May 2012 to filing a long-term capital plan no later than its next RRA. Direction Nos. 6 and 7, however, have precluded the full evidentiary hearing of a revenue requirements application until the filing of its next RRA in 2016. BC Hydro reiterates its commitment to file a long-term capital plan with that application at that time. In addition, BC Hydro will continue to keep stakeholders apprised of its capital plans through the annual capital project information included in its Annual Financial Report to the BCUC that is filed by the end of July in each year.

Long-term Workforce Plan

BC Hydro also committed in May 2012 to filing a long-term workforce plan no later than its next RRA. As with the 10-Year Capital Plan, BC Hydro remains committed to providing this plan with the filing of its next RRA in 2016.

Previous BCUC Directives

BCUC Order No. G-77-12A

BCUC Order No. G-77-12A contained several directions to be addressed by BC Hydro in its next revenue requirements application.

1) Directive 4 (a): BC Hydro is directed to include in its next RRA an analysis of, and proposal for, a formulaic method for clearing the net balance in the Deferral Accounts that considers

the forecast changes to the balance and does not contain a maximum/minimum limit in a range which has already been surpassed.

BC Hydro Response

Direction No. 7 requires BC Hydro to maintain the DARR at 5 per cent and to allocate the revenue received between the deferral accounts and general revenue based upon a formula contained in Direction No. 7. Therefore, BC Hydro considers that directive 4(a) has been superseded by Direction No. 7. BC Hydro also notes that directive 4 (a) is addressed in section 1 of Appendix A of its Regulatory Accounts Report (Appendix H) which describes the use of the DARR Allocation Table.

2) Directive 4 (b): BC Hydro is directed to include in its next RRA its accounting practices and policies concerning DSM expenditures.

BC Hydro Response

Direction No. 7 defines precisely the costs that are subject to the DSM Regulatory Account as well as the amortization period. Therefore, BC Hydro considers that directive 4(b) has been superseded by Direction No. 7. Nevertheless, Appendix G to this application responds to directive 4(b) by providing a discussion of BC Hydro's accounting practices and policies concerning DSM expenditures (section 1.4 of Appendix G).

3) Directive 4(c): BC Hydro is directed to include in its next RRA a range of reasonable amortization periods, and the associated amortization amounts, to be applied to the following regulatory accounts: First Nations Costs, Home Purchase Option Plan (**HPOP**) and Rock Bay Remediation Costs.

BC Hydro Response

Direction No. 6 requires specific amortization in F2015 and F2016 from these three accounts as noted above. BC Hydro also discusses the amortization periods of these three accounts in section 3 of its Regulatory Accounts Report (Appendix H), as follows:

a) \$43.5 million and \$43.3 million are to be amortized in F2015 and F2016, respectively, from the First Nations Costs Regulatory account (section 3(g) of Direction No. 6), consistent with the 10-year amortization period with respect to lump sum settlement costs, as described in Table 4, note 1 of the Regulatory Accounts Report

b) The Home Purchase Option Plan Regulatory Account is to be fully amortized over two years in the amounts of \$11.8 million and \$11.3 million in F2015 and F2016 respectively (section 3(m) of Direction No. 6)

c) \$51.5 million and \$50.5 million are to be amortized in F2015 and F2016, respectively, from the Rock Bay Remediation Regulatory Account (section 3(o) of Direction No. 6), consistent with the 2-year amortization period of Rock Bay costs described in Table 4 of the Regulatory Accounts Report

4) Directive 4(d): BC Hydro is directed to include in its next RRA the appropriate amortization period of its SMI Program assets in light of evidence regarding their anticipated useful lives.

BC Hydro Response

As discussed in section 3 and Table 4 of its Regulatory Accounts Report (Appendix H), BC Hydro believes that the appropriate amortization period for its deferred SMI Program costs is 15 years. Direction No. 6 requires that amortization expense of $30.5 million and $31.3 million in F2015 and F2016 respectively be allowed, consistent with this position.

5) Directive 4 (e): BC Hydro is directed to include in its next RRA an analysis as to whether the TIDA should be treated as one of the Deferral Accounts. BC Hydro must also show what the rate relief would be in the absence of the TIDA being treated as one of the deferral accounts.

BC Hydro Response

Section 10(3) of Direction No. 7 sets the DARR and prescribes the allocation of revenues collected through the DARR. Direction No. 7 effectively maintains the TIDA as one of the deferral accounts. In addition, Table A-1 in Appendix A to the Regulatory Accounts Report, (Appendix H) provides the rate impact analysis of removing the TIDA as a deferral account and no longer amortizing it using the DARR Allocation Table and instead amortizing the account over five years. In section 1 of Appendix A of the Regulatory Accounts Report, BC Hydro also discusses the reasons why the TIDA should remain as a Deferral Account.

BCUC Order No. G-7-13

BCUC Order No. G-7-13 was issued in response to BC Hydro's application for approval of the Asbestos Remediation Costs Regulatory Account.

Directive 5 of that order requires BC Hydro to file for the recovery of the asbestos remediation costs as part of its next RRA. Section 3(t) of Direction No. 6 requires that $12.1 million and $10.7 million be amortized in F2015 and F2016, respectively.

Directive 6 of BCUC Order No. G-7-13 directed that for F2015 and future years, BC Hydro is to apply to the BCUC for approval to record in the Asbestos Remediation Regulatory Account any variance from the amount of asbestos remediation costs included in revenue requirements for the respective test year and the actual asbestos remediation costs incurred, plus interest at BC Hydro's weighted average cost of debt for its current fiscal year. Section 7(f) of Direction No. 7 requires the BCUC to allow the variance between actual and forecast costs to be deferred to the Asbestos Remediation Regulatory Account.

BCUC Order No. G-57-13

BCUC Order No. G-57-13 was issued in response to BC Hydro's application for approval to record its F2013 Rock Bay remediation costs in the Rock Bay Remediation Regulatory Account. In summary, the order directs that:

- BC Hydro is to apply for recovery in rates of the costs in the account related to the Transport Canada litigation and settlement, including a proposed amortization period for cost recovery, as part of BC Hydro's next RRA; and
- BC Hydro is to include the following information as part of its RRA:
    - o BC Hydro's best estimate of when it expects to apply for recovery in rates of the Account
    - o BC Hydro's best estimate of the expected final balance of the account once all Rock Bay remediation costs have been incurred and all remediation activities have been completed
    - o The status of Rock Bay remediation activities

BC Hydro Response

As noted above, amortization from the Rock Bay Remediation Regulatory Account is to be allowed in the amounts of $51.5 million and $50.5 million in F2015 and F2016 respectively (section 3(o) of Direction No. 6). BC Hydro notes that section 7(e) of Direction No. 7 requires that BC Hydro continue to record in the Rock Bay Remediation Regulatory Account the costs that it incurs for remediation of Rock Bay. BC Hydro will propose an amortization schedule for any remaining balance in its next RRA. **Appendix I** briefly describes the status of the Rock Bay remediation activities.

<u>BCUC Order No. G-16-09</u>

BCUC Order No. G-16-09 was issued in connection with BC Hydro’s F09/F10 RRA. Several directives contained in the order are still applicable to F2015 and F2016.

1) Directive No. 57: Uniform System of Accounts (**USoA**). BC Hydro was directed to file USoA financial information in its revenue requirement applications after January 1, 2011.

   BC Hydro Response

   BC Hydro has been providing financial information in a USoA format as part of its Annual Report to the BCUC, beginning with the F2012 Annual Report, and will continue to do so for F2015 and F2016.

2) Directive No. 51: Capital expenditures. The BCUC recommended that BC Hydro include in its next RRA the implications arising from planned capital expenditures, set out for each capital item.

   BC Hydro Response

   BC Hydro has filed schedules I and J in its recent RRAs in compliance with this Directive. BC Hydro will be filing schedules I and J with its F2014 Annual Report to the BCUC due by the end of July 2014.

BCUC Order No. G-143-06

BCUC Order No. G-143-06 was issued in connection with BC Hydro's F07/F08 RRA. Directives No. 19 to 21 concerned BC Hydro's capital plan and required that BC Hydro file bi-annually its capital plan identifying all capital expenditures for the current and following fiscal period, as well as total expenditure and in-service date forecasts for project already underway in those periods.

BC Hydro Response

BC Hydro has filed the capital plan information as schedules I and J in its recent RRAs. As noted above, BC Hydro will be filing schedules I and J with its F2014 Annual Report to the BCUC due by the end of July 2014.

5. Conclusion

BC Hydro respectfully submits that the draft orders in Appendices A and B comply with the revised regulatory framework governing BC Hydro and meet the specific legal requirements established in Direction Nos. 6 and 7, as explained in this application. Accordingly, BC Hydro requests that the BCUC issue:

1. a final order that is substantially consistent with Draft Order A within 20 days of the date on which this application is filed (i.e., by March 27, 2014)
2. a final order that is substantially consistent with Draft Order B on or before March 23, 2014 (since March 23, 2014 is a Sunday, this order must be issued by end of day on March 21, 2014)

For further information, please contact Fred James at 604-623-4317 or by email at bchydroregulatorygroup@bchydro.com.

Yours sincerely,

Janet Fraser
Chief Regulatory Officer

fj/af

Enclosure (1)

Copy to: BCUC Project No. 3698622 (F12-F14 RRA) Registered Intervener Distribution List.

F2015 to F2016 Revenue Requirements
Rate Application

Appendix A

Draft Order A

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER G-

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, BC V6Z 2N3 CANADA
web site: http://www.bcuc.com

TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

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

and

Application by British Columbia Hydro and Power Authority (BC Hydro)
Regarding its Rates for F2014, F2015 and F2016,
Expenditures on Demand Side Measures in F2014, F2015 and F2016 and
Retail Access

BEFORE:

, 2014

ORDER

WHEREAS:

A. On November 26, 2013, the Province of British Columbia announced a 10-year plan regarding BC Hydro's rates and revenue requirements including, among other things, average rate increases of 9% and 6% in F2015 and F2016, respectively;

B. On March 6, 2014 B.C. Reg. 29/2014 enacted Direction No. 6 to the British Columbia Utilities Commission (Direction No. 6);

C. On March 6, 2014 B.C Reg. 28 /2014 enacted Direction No. 7 to the British Columbia Utilities Commission (Direction No. 7), and repealed Heritage Special No. HC2 to the British Columbia Utilities Commission (HSD#2);

D. On March 6, 2014 Order in Council No. 0952014 effected certain amendments to Heritage Special Directive No. HC1to the British Columbia Hydro and Power Authority (HSD#1);

E. On March 7, 2014 BC Hydro filed an application pursuant to the Utilities Commission Act (the Act), and Direction Nos. 6 and 7, seeking Commission orders that, among other things, would confirm as final and no longer subject to refund BC Hydro's 2014 rates; set its F2015 and F2016 Electric Tariff rates; and set its F2015 and F2016 Open Access Transmission Tariff (OATT) rates (the F15-F16 RRRA);

F. The F2015 and F2016 rates for which approval is sought are prescribed by Direction No. 6, and effect average rate increases of 9% and 6% per year, respectively.

British Columbia
Utilities Commission

Order
Number G-

NOW THEREFORE the Commission orders as follows:

1. BC Hydro's F2014, F2015 and F2016 schedule of expenditures on demand-side measures is accepted as shown in Schedule A. [NTD: D6, 3(a)]

2. BC Hydro's F2014 rates, as set by BCUC Order No. G-77-12A, are confirmed as final and no longer subject to refund. [NTD: D6, 3(b)]

3. BC Hydro's F2015 Electric Tariff rates are set as shown in Schedule B, effective April 1, 2014 on a final, non-refundable basis. [NTD: D6, 3(c)]

4. BC Hydro's F2016 Electric Tariff rates are set as shown in Schedule B, effective April 1, 2015 on a final, non-refundable basis. [NTD: D6, 3(c)]

5. BC Hydro's F2015 OATT rates are set as shown in Schedule C, effective April 1, 2014 on a final, non-refundable basis. [NTD: D6, 3(d)]

6. BC Hydro's F2016 OATT rates are set as shown in Schedule C, effective April 1, 2015 on a final, non-refundable basis. [NTD: D6, 3(d)]

7. The Deferral Account Rate Rider is set at 5% on a final, non-refundable basis. [NTD: D7, 10(1)]

8. By March 31, 2014 BC Hydro must file rate schedules with the Commission reflecting the F2015 OATT rate and Electric Tariff rate orders above.

<u>Return on Deemed Equity</u>

9. BC Hydro's allowed rate of return on deemed equity is set at 11.84% for each of F2015 and F2016. [NTD: D7, 4(d)(i)]

<u>New Regulatory Accounts</u>

10. The Rate Smoothing Regulatory Account is approved as applied for. [NTD: D7, 7(h)(i)]

11. The Real Property Sales Regulatory Account is approved as applied for. [NTD: D7, 7(h)(ii)]

<u>Existing Regulatory Accounts</u>

12. BC Hydro is to defer to the Site C Regulatory Account its F2015 and F2016 operating costs incurred in regard to the development of the Site C project. [NTD: D6, 3(h)]

13. BC Hydro is to defer to the SMI Regulatory Account its F2015 and F2016 net operating costs arising from the smart metering and infrastructure program and the net operating costs arising from BCUC Order No. G-166-13. [NTD: D6, 3(l)(ii)]

14. BC Hydro is to defer to the Non-Heritage Deferral Account the amount that is determined by subtracting the amount in subparagraph (ii) from the amount in subparagraph (i):

    (i) the forecast return on deemed equity in F2014 calculated on the basis of an annual rate of return on deemed equity in that year of 11.84%, and

    (ii) the forecast return on deemed equity in F2014 calculated on the basis of an annual rate of return on deemed equity in that year that is greater than or less than 11.84% as a result of the Commission's order arising from the generic cost of capital proceeding initiated by Commission Order No. G-20-12. [NTD: D6, 3(v)]

15. BC Hydro is to continue to defer to the Non-Heritage Deferral Account the variances between the actual and forecast cost of energy arising from differences between forecast and actual customer load. [NTD: D7, 7(c)(i)]

16. BC Hydro is to defer to the Non-Heritage Deferral Account its Burrard Costs. [NTD: D7, 7(c)(ii)]

17. BC Hydro is to defer to the DSM Regulatory Account its costs arising from the development, implementation and administration of demand-side measures, including costs arising from specified demand-side measures and public awareness programs. [NTD: D7, 7(d)(i)]

18. BC Hydro is to continue to defer to the Rock Bay Remediation Regulatory Account its Rock Bay costs. [NTD: D7, 7(e)]

19. BC Hydro is to continue to defer to the Asbestos Remediation Regulatory Account the variances between its actual and forecast asbestos remediation costs. [NTD: D7, 7(f)]

20. BC Hydro is to continue to defer to the Non-Current Pension Costs Regulatory Account the variances between its actual and forecast non-current pension costs. [NTD: D7, 7(g)]

21. The First Nations Costs Regulatory Account shall accrue interest in a fiscal year at BC Hydro's weighted average cost of debt in that year. [NTD: D7, 7(i)(i)],

22. The Real Property Sales Regulatory Account shall accrue interest in a fiscal year at BC Hydro's weighted average cost of debt in that year. [NTD: D7, 7(i)(ii)]

23. Forecast revenue from the Deferral Account Rate Rider is to be accounted for by BC Hydro in accordance with paragraph 10(3) of Direction No. 7. [NTD: D7, 10(3)]

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER G-

F2015 and F2016 Regulatory Account Baseline Forecasts

24. The following forecasts of costs and revenues are approved for the purposes of the applicable regulatory accounts: [NTD: D6, 3(e) and 3(f)]

Forecast (Regulatory Account)	**F2015 ($ million)**	**F2016 ($ million)**
Heritage Payment Obligation (HDA)	353.2	399.2
Non-Heritage cost of Energy Subject to Deferral (NHDA)	1,074.3	1,032.2
Total Rate Revenue (NHDA)	4,168.3	4,459.7
Trade Income (TIDA)	110.0	110.0
Non-Current Pension Costs	2.9	0.1
Storm Restoration Costs	3.9	3.9
Total Finance Charges	602.6	725.2
Amortization of Capital Additions	34.7	106.7
Real Property Gain/Loss	10.0	10.0
Asbestos Remediation Costs	1.8	0.9

Specific Amortization Orders

25. BC Hydro shall amortize from the First Nations Costs Regulatory Account the amounts of $43.5 million and $43.3 million in F2015 and F2016 respectively. [NTD: D6, 3(g)]

26. BC Hydro shall amortize from the Storm Restoration Regulatory Account the amounts of $1.4 million in each of F2015 and F2016. [NTD: D6, 3(i)]

27. BC Hydro shall amortize from the Capital Additions Regulatory Account the amounts of $9.8 million and $9.4 million in each of F2015 and F2016 respectively. [NTD: D6, 3(j)]

28. BC Hydro shall amortize from the Total Finance Charges Regulatory Account the amount of $25.5 million in each of F2015 and F2016. [NTD: D6, 3(k)]

29. BC Hydro shall amortize from the SMI Regulatory Account the amounts of $30.5 million and $31.3 million in F2015 and F2016 respectively. [NTD: D6, 3(l)(i)]

30. BC Hydro shall amortize from the Home Purchase Option Plan Regulatory Account the amounts of $11.8 million and $11.3 million in F2015 and F2016 respectively. [NTD: D6, 3(m)]

31. BC Hydro shall amortize from the Non-Current Pension Costs Regulatory Account he amounts of $32.6 million and $15.5 million in F2015 and F2016 respectively. [NTD: D6, 3(n)]

32. BC Hydro shall amortize from the Rock Bay Remediation Regulatory Account the amounts of $51.5 million and $50.5 million in F2015 and F2016 respectively. [NTD: D6, 3(o)]

33. BC Hydro shall amortize from the IFRS PP&E Regulatory Account the amounts of $15.9 million and $19.8 million in F2015 and F2016 respectively. [NTD: D6, 3(p)(i)]

34. BC Hydro shall amortize from the IFRS Pension Regulatory Account the amount of $38.2 million in each of F2015 and F2016. [NTD: D6, 3(q)]

35. BC Hydro shall amortize from the Arrow Water Divestiture Costs Regulatory Account the amounts of $4.7 million and $4.5 million in F2015 and F2016 respectively. [NTD: D6, 3(r)]

36. BC Hydro shall amortize from the Arrow Water Provision Regulatory Account the amount of $0.3 million in each of F2015 and F2016. [NTD: D6, 3(s)]

37. BC Hydro shall amortize from the Asbestos Remediation Regulatory Account the amounts of $12.1 million and $10.7 million in F2015 and F2016 respectively. [NTD: D6, 3(t)]

Specific Deferral Orders

38. BC Hydro is to defer to the IFRS PP&E Regulatory Account $156.8 million and $134.4 million in F2015 and F2016 respectively. [NTD: D6, 3(p)(ii)]

39. BC Hydro is to defer to the Rate Smoothing Regulatory Account $166.2 million and $121.2 million in F2015 and F2016 respectively. [NTD: D6, 3(u)]

DATED at the City of Vancouver, in the Province of British Columbia, this day of , 2014.

BY ORDER

Schedules:

Schedule A – DSM Expenditure Schedule from Direction No. 6

Schedule B – Electric Tariff Rates from Direction No 6

Schedule C – OATT Rates from Direction No. 6

SCHEDULE A
to Order G-xx-xx
Page 1 of 1

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, BC V6Z 2N3 CANADA
web site: http://www.bcuc.com

TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

Application by British Columbia Hydro and Power Authority (BC Hydro)
Regarding its Rates for F2014, F2015 and F2016,
Expenditures on Demand Side Measures in F2014, F2015 and F2016 and
Retail Access

APPENDIX A

F2014 – F2016 DSM Expenditure Schedule

$ MILLION	F2014	F2015	F2016
Codes and Standards	2.4	4.0	4.2
Rate Structures	6.5	2.0	1.7
Programs			
Residential	30.4	17.7	18.9
Commercial	66.4	39.5	40.0
Industrial	101.9	64.3	42.9
Total Programs	198.7	121.5	101.8
Supporting Initiatives	28.7	20.6	20.3
Total Energy Efficiency Portfolio	236.3	148.0	128.0
Capacity Focused DSM	0.0	2.4	3.1
Total	236.3	150.5	131.1

SCHEDULE B
to Order G-xx-xx
Page 1 of 5

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, BC V6Z 2N3 CANADA
web site: http://www.bcuc.com

TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

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ELECTRIC TARIFF RATES – F2015 and F2016

Rate Class	Rate Schedule	Rate	F2015	F2016
Residential	1101/1121	Basic Charge($/day)	0.1664	0.1764
		Step 1 energy rate ($/kWh)	0.0752	0.0797
		Step 2 energy rate ($/kWh)	0.1127	0.1195
Residential	1105 (closed)	Energy rate ($/kWh)	0.0492	0.0522
		Energy rate during period of interruption ($/kWh)	0.2865	0.3037
Residential Zone II	1107/1127	Basic Charge ($/day)	0.1775	0.1882
		Step 1 energy rate ($/kWh)	0.0901	0.0955
		Step 2 energy rate ($/kWh)	0.1548	0.1641
Residential	1148 (closed)	Basic Charge($/day)	0.1775	0.1882
		Energy rate ($/kWh)	0.0901	0.0955
Residential	1151/1161	Basic Charge ($/day)	0.1775	0.1882
		Energy rate ($/kWh)	0.0901	0.0955
Exempt General Service	1200/1201/ 1210/1211	Basic Charge($/day)	0.2129	0.2257
		Demand rate – Step 1 ($/kW)	0	0
		Demand rate – Step 2 ($/kW)	5.19	5.50
		Demand rate – Step 3 ($/kW)	9.95	10.55
		Energy Rate – Tier 1 ($/kWh)	0.1012	0.1073
		Energy Rate – Tier 2 ($/kWh)	0.0486	0.0515

Rate Class	Rate Schedule	Rate	F2015	F2016
General Service	1205/1206/ 1207	Energy rate – Tier 1 ($/kWh)	0.0492	0.0522
		Energy rate – Tier 2 ($/kWh)	0.0323	0.0342
		Energy rate during period of interruption ($/kWh)	0.2865	0.3037
Small General Service Zone II	1234	Basic Charge ($/day)	0.2129	0.2257
		Energy rate – Tier 1 ($/kWh)	0.1012	0.1073
		Energy rate – Tier 2 ($/kWh)	0.1686	0.1787
Distribution Service	1253	Monthly Minimum energy charge ($/month)	39.03	41.37
Distribution Service	1268	Energy charge ($/kWh)	0.00157	0.00166
Power Service	1278 (Closed)	$/kVA	2.526	2.678
		Energy charge ($/kWh)	0.06604	0.07
		Monthly minimum greater of $/kVA or ($)	4.93 9868.64	5.23 10460.76
Large General Service Zone II	1255/1256/ 1265/1266	Basic Charge ($/day)	0.2129	0.2257
		Energy charge – Tier 1 ($/kWh)	0.1012	0.1073
		Energy charge – Tier 2 ($/kWh)	0.1686	0.1787
Net Metering Service	1289	Energy rate ($/kWh)	0.0999	0.0999
Small General Service	1300/1301/ 1310/1311	Basic Charge ($/day)	0.2129	0.2257
		Energy Charge ($/kWh)	0.1012	0.1073
Irrigation	1401/1402	Irrigation season energy rate ($/kWh)	0.0487	0.0516
		Non-irrigation season energy charge – Tier 1 ($/kWh)	0.0487	0.0516
		Non-irrigation season energy rate - Tier 2 ($/kWh)	0.3864	0.4096
		Minimum charge irrigation season ($/kW)	4.87	5.16
		Non-irrigation season if consumption >500 kWh ($ per kW)	38.98	41.32
Medium General Service	1500/1501/ 1510/1511	Basic Charge ($/day)	0.2129	0.2257
		Demand rate – Step 1 ($/kW)	0.00	0.00
		Demand rate – Step 2 ($/kW)	5.19	5.50
		Demand rate – Step 3 ($/kW)	9.95	10.55
		Part 1 Energy Rate – Tier 1 ($/kWh)	0.0934	0.0989

Rate Class	Rate Schedule	Rate	F2015	F2016
		Part 1 Energy Rate – Tier 2 ($/kWh)	0.0651	0.0690
		Part 2 Energy Rate ($/kWh)	0.0971	0.0990
		Minimum Energy Rate ($/kWh)	0.0311	0.0330
Large General Service	1600/1601/ 1610/1611	Basic Charge ($/day)	0.2129	0.2257
		Demand rate – Step 1 ($/kW)	0.00	0.00
		Demand rate – Step 2 ($/kW)	5.19	5.50
		Demand rate – Step 3 ($/kW)	9.95	10.55
		Part 1 Energy Rate - Tier 1 ($/kWh)	0.1010	0.1066
		Part 1 Energy Rate– Tier 2 ($/kWh)	0.0486	0.0513
		Part 2 Energy Rate ($/kWh)	0.0971	0.0990
		Minimum Energy Charge ($/kWh)	0.0311	0.0330
Large General Service (150 kW and over) for Distribution Utilities	2600/2601/ 2610/2611	Basic Charge ($/day)	0.2129	0.2257
		Demand rate – Step 1 ($/kW)	0.00	0.00
		Demand rate – Step 2 ($/kW)	5.19	5.50
		Demand rate – Step 3 ($/kW)	9.95	10.55
		Part 2 Energy Rate $/kWh (RS1600)	0.0971	0.0990
		Embedded Cost Rate $/kWh	0.0501	0.0531
		Discount ($/kWh)	-0.0037	-0.0039
Street Lighting	1701	100 SV fixture rate ($/month)	15.61	16.55
		150 SV fixture rate ($/ month)	18.61	19.73
		200 SV fixture rate ($ month)	21.49	22.78
		175 MV fixture rate ($/ month)	17.15	18.18
		250 MV fixture rate ($/ month)	19.76	20.95
		400 MV fixture rate ($/ month)	25.48	27.01
Street Lighting	1702	Each Unmetered Fixture ($/watt per month)	0.03	0.0318
		Each Metered Fixture ($/kWh)	0.0901	0.0955
Street Lighting	1703	Energy rate ($/watt per month)	0.03	0.0318
		Contact rate ($/contact per month)	0.9057	0.96
Street Lighting	1704	Energy rate ($/kWh)	0.0901	0.0955

Rate Class	Rate Schedule	Rate	F2015	F2016
Street Lighting	1755 (closed)	1. Pole owned by Customer		
		175 MV or 100SV fixture charge ($ per month)	14.63	15.51
		400 MV or 150SV fixture charge ($ per month)	25.22	26.73
		2. Pole on public property		
		175 MV or 100SV fixture charge ($ per month)	15.54	16.47
		400 MV or 150SV fixture charge ($ per month)	26.13	27.70
		3. Pole paid by BC Hydro		
		175 MV or 100SV fixture charge ($ per month)	19.13	20.28
		400 MV or 150SV fixture charge ($ per month)	30.11	31.92
Transmission Service	1823	Demand rate ($/kVA)	6.925	7.341
		Energy rate A ($/kWh)	0.04059	0.04303
		Energy rate B - Tier 1 ($/kWh)	0.03619	0.03836
		Energy rate B - Tier 2 ($/kWh)	0.08022	0.08503
		Minimum demand ($/kVA)	6.925	7.341
Transmission Service	1825	Demand rate ($/kVA)	6.925	7.341
		Winter HLH energy rate (below 90%) ($/kWh)	0.03619	0.03836
		Winter HLH energy rate (above 90%) ($/kWh)	0.08952	0.09489
		Winter LLH energy rate (below 90%) ($/kWh)	0.03619	0.03836
		Winter LLH energy rate (above 90%) ($/kWh)	0.08113	0.08600
		Spring energy rate (below 90%) ($/kWh)	0.03619	0.03836
		Spring energy rate (above 90%) ($/kWh)	0.07226	0.07660
		Remaining energy rate (below 90%) ($/kWh)	0.03619	0.03836
		Remaining energy rate (above 90%) ($/kWh)	0.07923	0.08398
Transmission Service	1827	Demand rate ($/kVA)	6.925	7.341
		Energy rate ($/kWh)	0.04059	0.04303
		Minimum demand ($/kVA)	6.925	7.341

Rate Class	Rate Schedule	Rate	F2015	F2016
Transmission Service	1852	Excess demand rate ($/kVA)	6.925	7.341
Transmission Service	1853	Minimum Monthly Charge ($/month)	39.03	41.37
Transmission Service	1880	Administrative Charge per Period of Use ($)	150.00	150.00
		Energy charge ($/kWh)	0.08022	0.08503
Transmission Service FortisBC	3808	Demand Charge ($/kW)	6.925	7.341
		Energy rate ($/kWh)	4.059	4.303

SCHEDULE C
to Order G-xx-xx
Page 1 of 1

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, BC V6Z 2N3 CANADA
web site: http://www.bcuc.com

TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

Application by British Columbia Hydro and Power Authority (BC Hydro)
Regarding its Rates for F2014, F2015 and F2016,
Expenditures on Demand Side Measures in F2014, F2015 and F2016 and
Retail Access

BC HYDRO OATT RATES – F2015 and F2016

Service	Rate Schedule in Authority's Open Access Transmission Tariff	F2015 Rate	F2016 Rate
Network Integration Transmission Service	00	$52.1 million/month	$62.1 million/month
Long-Term Firm Point to Point Transmission Service	01	$53,698/MW/Year	$64,968/MW/Year
Monthly Short-term Firm and Non-Firm Point to Point Transmission Service	01	$4,474.87/MW/month	$5,413.99/MW/month
Weekly Short-term Firm and Non-Firm Point to Point Transmission Service	01	$1,032.66/MW/week	1,249.38/MW/week
Daily Short-term Firm and Non-Firm Point to Point Transmission Service	01	$147.12/MW/day	$177.99/MW/day
Hourly Short-term Firm and Non-Firm Point to Point Transmission Service	01	$6.13/MW/hour	$7.42/MW/hour
Scheduling, System Control, and Dispatch Service Fee	03	$0.102/MWh	$0.099/MWh

F2015 to F2016 Revenue Requirements Rate Application

Appendix B

Draft Order B

BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, BC V6Z 2N3 CANADA
web site: http://www.bcuc.com

TELEPHONE: (604) 6604700
BC TOLL FREE: 18006631385
FACSIMILE: (604) 6601102

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

and

Application by British Columbia Hydro and Power Authority (BC Hydro)
Regarding its Rates for F2014, F2015 and F2016,
Expenditures on Demand Side Measures in F2014, F2015 and F2016 and
Retail Access

BEFORE:

, 2014

ORDER

WHEREAS:

A. On November 26, 2013, the Province of British Columbia announced a 10-year plan regarding BC Hydro's rates and revenue requirements including, among other things, average rate increases of 9% and 6% in F2015 and F2016, respectively;

B. On March 6, 2014 B.C. Reg. 29/2014 enacted Direction No. 6 to the British Columbia Utilities Commission (Direction No. 6);

C. On March 6, 2014 B.C. Reg. 28/2014 enacted Direction No. 7 to the British Columbia Utilities Commission (Direction No. 7), and repealed Heritage Special No. HC2 to the British Columbia Utilities Commission (HSD#2);

D. On March 6, 2014 Order in Council No. 095/2014 effected certain amendments to Heritage Special Directive No. HC1to the British Columbia Hydro and Power Authority (HSD#1);

E. On March 7, 2014 BC Hydro filed an application pursuant to the Utilities Commission Act (the Act), and Direction Nos. 6 and 7, seeking Commission orders that, among other things, would confirm as final and no longer subject to refund BC Hydro's 2014 rates; set its F2015 and F2016 Electric Tariff rates; and set its F2015 and F2016 Open Access Transmission Tariff (OATT) rates (the F15-F16 RRRA);

F. The F15-F16 RRRA also seeks Commission orders, by March 23, 2014, that would cancel BC Hydro's Retail Access Program and accept BC Hydro's withdrawal of any obligation to offer unbundled transmission services pursuant to the OATT to retail customers in British Columbia and the withdrawal of such services to those who supply such customers.

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER G

NOW THEREFORE the Commission orders as follows:

Retail Access

1. The withdrawal by BC Hydro of any obligation to offer unbundled transmission services pursuant to BC Hydro's OATT to retail customers in British Columbia, and the withdrawal of such services to those who supply such customers, is accepted. [NTD: D7, 14(1)(a)]

2. BC Hydro's Retail Access Program, as defined in BCUC Order No. G-39-12, is cancelled. [NTD: D7, 14(1)(b)]

DATED at the City of Vancouver, in the Province of British Columbia, this day of , 2014.

BY ORDER

F2015 to F2016 Revenue Requirements
Rate Application

Appendix C

F2015 and F2016 Revenue Requirements Model

Revenue Requirements Model
Version: 2014-02-26

BC Hydro
F15-F16 RRA

Schedule 1.0
Page 2

Revenue Requirements Summary
($ million)

Line	Column	Reference	F2012 RRA	F2012 Actual	F2012 Diff	F2013 RRA	F2013 Actual	F2013 Diff	F2014 RRA	F2014 Forecast	F2014 Diff	F2015 Plan	F2016 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9 = 8 - 7	10	11
1	**Cost of Energy**	3.0 L14	1,203.2	1,043.0	(160.2)	1,348.3	1,057.3	(291.0)	1,469.5	1,292.1	(177.4)	1,384.5	1,391.7
2	**Operating Costs**	3.0 L20	1,354.7	1,452.0	97.3	1,348.1	1,307.8	(40.3)	1,267.6	1,267.0	(0.6)	1,170.8	1,146.6
3	**Taxes**	3.0 L24	183.9	184.2	0.3	193.1	194.1	1.0	202.7	202.1	(0.6)	213.8	224.1
4	**Amortization**	3.0 L28	615.5	586.2	(29.3)	663.5	635.0	(28.6)	655.8	646.2	(9.6)	698.7	758.0
5	**Finance Charges**	3.0 L33	570.0	558.6	(11.5)	649.3	576.3	(73.0)	700.0	674.0	(26.0)	725.0	838.3
6	**Return on Equity**	3.0 L37	558.9	558.4	(0.5)	520.2	509.3	(10.9)	555.7	544.7	(10.9)	581.5	651.9
7	**Non-Tariff Revenue**	3.0 L41	(82.9)	(80.8)	2.1	(110.6)	(119.1)	(8.5)	(113.5)	(120.7)	(7.3)	(121.3)	(126.6)
8	**Inter-Segment Revenue**	3.0 L47	(38.6)	(30.1)	8.5	(39.5)	(63.1)	(23.6)	(40.0)	(39.0)	1.0	(52.6)	(53.5)
	Deferral Accounts												
9	Deferral Account Additions	2.1 L33	(65.9)	4.0	69.9	(103.2)	6.9	110.1	(49.8)	(248.1)	(198.3)	0.0	0.0
10	Interest on Deferral Accounts	2.1 L34	(39.5)	(36.8)	2.6	(37.4)	(36.3)	1.1	(34.0)	(32.9)	1.1	(30.2)	(23.8)
11	Deferral Account Recoveries	2.1 L35	89.2	87.7	(1.5)	188.5	179.7	(8.8)	194.1	186.8	(7.3)	208.4	223.0
12	Total		(16.1)	54.9	71.0	47.9	150.3	102.4	110.3	(94.3)	(204.6)	178.2	199.2
	Other Regulatory Accounts												
13	Regulatory Account Additions	2.2 L212	(653.2)	(701.6)	(48.4)	(685.4)	(573.0)	112.4	(596.4)	(554.7)	41.7	(359.0)	(310.3)
14	Interest on Regulatory Accounts	2.2 L213	(14.6)	(11.2)	3.4	(26.0)	(18.4)	7.6	(38.7)	(25.6)	13.1	(37.1)	(37.9)
15	Regulatory Account Recoveries	2.2 L214	134.5	138.8	4.4	180.4	233.8	53.4	36.9	45.7	8.8	124.5	132.9
16	Total		(533.4)	(574.0)	(40.6)	(531.0)	(357.6)	173.4	(598.2)	(534.7)	63.5	(271.6)	(215.4)
	Subsidiary Net Income												
17	Powerex Net Income		(142.0)	(142.0)	(0.0)	(113.0)	(98.2)	14.8	(113.0)	**103.9**	216.9	**(110.0)**	**(110.0)**
18	Powertech Net Income		(1.5)	(2.6)	(1.1)	(2.3)	(2.9)	(0.6)	(5.9)	**(3.8)**	2.1	**(4.2)**	**(5.1)**
19	Total		(143.5)	(144.6)	(1.1)	(115.3)	(101.1)	14.2	(118.9)	100.1	218.9	(114.2)	(115.1)
20	**Less Other Utilities Revenue**	14.0 L17	(14.6)	(14.9)	(0.3)	(14.8)	(14.8)	(0.0)	(15.5)	(15.3)	0.2	(16.2)	(16.5)
21	**Less Deferral Rider**	14.0 L21	(89.2)	(87.7)	1.5	(188.5)	(179.7)	8.8	(194.1)	(186.8)	7.3	(208.4)	(223.0)
22	**Total Rate Revenue Requirement**		3,568.0	3,505.2	(62.8)	3,770.7	3,594.7	(176.0)	3,881.4	3,735.3	(146.1)	4,168.3	4,459.7
	Rate Revenue at Current Rates												
23	Total Domestic Revenue	14.0 L22	3,671.8	3,607.7	(64.1)	3,974.1	3,789.2	(184.9)	4,091.2	3,937.4	(153.8)	4,048.8	4,099.5
24	Less Other Utilities	Line 20	(14.6)	(14.9)	(0.3)	(14.8)	(14.8)	(0.0)	(15.5)	(15.3)	0.2	(16.2)	(16.5)
25	Less Deferral Rider	Line 21	(89.2)	(87.7)	1.5	(188.5)	(179.7)	8.8	(194.1)	(186.8)	7.3	(208.4)	(223.0)
26	Revenue Subject to Rate Increase		3,568.0	3,505.2	(62.8)	3,770.8	3,594.7	(176.1)	3,881.6	3,735.3	(146.3)	3,824.2	3,860.0
27	**Revenue Shortfall**	Line 22 - 26										344.0	599.7
28	**Rate Increases (May 1 for F2012)**		8.00%	8.00%		3.91%	3.91%		1.44%	1.44%		9.00%	6.00%
29	**Deferral Account Rate Rider**		2.50%	2.50%		5.00%	5.00%		5.00%	5.00%		5.00%	5.00%
30	**Net Bill Impact**		7.77%	7.75%		7.07%	7.06%		1.44%	1.44%		9.00%	6.00%

BC Hydro
F15-F16 RRA

Schedule 2.1
Page 3

Deferral Accounts
($ million)

Line	Column	Reference	F2012 RRA	F2012 Actual	F2012 Diff	F2013 RRA	F2013 Actual	F2013 Diff	F2014 RRA	F2014 Forecast	F2014 Diff	F2015 Plan	F2016 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9 = 8 - 7	10	11
	Heritage Deferral Account												
1	Beginning of Year		247.7	247.7	0.0	276.3	243.8	(32.5)	226.8	69.9	(156.9)	65.4	51.2
2	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	Additions	Line 41	0.0	(31.9)	(31.9)	0.0	(123.7)	(123.7)	0.0	10.5	10.5	0.0	0.0
4	Interest		13.2	12.0	(1.2)	11.3	5.6	(5.8)	9.2	2.9	(6.3)	2.4	1.9
5	Recovery		(27.7)	(27.2)	0.5	(60.8)	(55.8)	5.1	(54.4)	(17.9)	36.5	(16.6)	(17.7)
6	Transfer of GM Shrum 3	2.2 L67	43.2	43.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	End of Year		276.3	243.8	(32.5)	226.8	69.9	(156.9)	181.6	65.4	(116.2)	51.2	35.4
	Non-Heritage Deferral Account												
8	Beginning of Year		362.1	362.1	0.0	405.3	367.0	(38.3)	438.2	467.5	29.3	386.3	302.6
9	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	62.2	62.2	0.0	0.0	0.0	0.0	0.0
10	Additions	Line 42	65.9	27.9	(38.0)	103.2	102.0	(1.2)	49.8	20.7	(29.1)	0.0	0.0
11	Interest		17.8	16.9	(1.0)	18.9	20.3	1.3	19.0	18.1	(0.8)	14.2	11.2
12	Recovery		(40.5)	(39.8)	0.7	(89.2)	(84.0)	5.2	(105.2)	(120.0)	(14.8)	(98.0)	(104.8)
13	Transfer of Storm Restoration	2.2 L47	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	Transfer from BCTCDA		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	End of Year		405.3	367.0	(38.3)	438.2	467.5	29.3	401.8	386.3	(15.4)	302.6	209.0
	Trade Income Deferral Account												
16	Beginning of Year		187.5	187.5	0.0	174.9	174.7	(0.2)	143.6	190.2	46.6	370.2	289.9
17	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	30.2	30.2	0.0	0.0	0.0	0.0	0.0
18	Additions	Line 43	0.0	(0.0)	(0.0)	0.0	14.8	14.8	0.0	216.9	216.9	0.0	0.0
19	Interest		8.4	7.9	(0.5)	7.2	10.5	3.3	5.8	11.9	6.1	13.6	10.7
20	Recovery		(21.0)	(20.6)	0.3	(38.5)	(40.0)	(1.5)	(34.5)	(48.8)	(14.4)	(93.9)	(100.4)
21	End of Year		174.9	174.7	(0.2)	143.6	190.2	46.6	114.9	370.2	255.2	289.9	200.2
	BCTC Deferral Account												
22	Beginning of Year		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23	Additions		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
24	Interest		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
25	Recovery		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
26	Transfer to NHDA		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
27	End of Year		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	End of Year Balances												
28	Heritage	Line 7	276.3	243.8	(32.5)	226.8	69.9	(156.9)	181.6	65.4	(116.2)	51.2	35.4
29	Non-Heritage	Line 15	405.3	367.0	(38.3)	438.2	467.5	29.3	401.8	386.3	(15.4)	302.6	209.0
30	Trade Income	Line 21	174.9	174.7	(0.2)	143.6	190.2	46.6	114.9	370.2	255.2	289.9	200.2
31	BCTC	Line 27	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
32	Total		856.6	785.6	(71.0)	808.6	727.6	(81.0)	698.3	821.9	123.6	643.7	444.5
	Summary												
33	Deferral Account Additions		65.9	(4.0)	(69.9)	103.2	(6.9)	(110.1)	49.8	248.1	198.3	0.0	0.0
34	Interest on Deferral Accounts		39.5	36.8	(2.6)	37.4	36.3	(1.1)	34.0	32.9	(1.1)	30.2	23.8
35	Deferral Account Recoveries		(89.2)	(87.7)	1.5	(188.5)	(179.7)	8.8	(194.1)	(186.8)	7.3	(208.4)	(223.0)
36	Transfer of GM Shrum 3	Line 6	43.2	43.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
37	Transfer of Storm Restoration	Line 13	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
38	Adjustment to Opening Balance	Line 2	0.0	0.0	0.0	0.0	92.4	92.4	0.0	0.0	0.0	0.0	0.0
39	Deferral Account Net Transfers		59.3	(11.7)	(71.0)	(47.9)	(57.9)	(10.0)	(110.3)	94.3	204.6	(178.2)	(199.2)
40	**Interest Rate**	8.0 L104	4.76%	4.82%	0.05%	4.60%	4.57%	-0.02%	4.62%	4.34%	-0.27%	4.21%	4.47%

Deferral Accounts
($ million)

Line	Column	Reference	F2012 RRA	F2012 Actual	F2012 Diff	F2013 RRA	F2013 Actual	F2013 Diff	F2014 RRA	F2014 Forecast	F2014 Diff	F2015 Plan	F2016 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9 = 8 - 7	10	11
	Summary of Items Subject to Deferral												
41	Heritage Payment Obligation	4.0 L75	408.7	376.8	(31.9)	404.5	280.8	(123.7)	373.7	384.2	10.5	353.2	399.2
42	Cost of Non-Heritage Energy	4.0 L88	743.9	771.7	27.9	852.3	954.3	102.0	1,053.6	1,074.3	20.7	1,074.3	1,032.2
43	Trade Income	1.0 L17	142.0	142.0	0.0	113.0	98.2	(14.8)	113.0	(103.9)	(216.9)	110.0	110.0

BC Hydro
F15-F16 RRA

Other Regulatory Accounts
($ million)

Line	Column	Reference	F2012 RRA	F2012 Actual	F2012 Diff	F2013 RRA	F2013 Actual	F2013 Diff	F2014 RRA	F2014 Forecast	F2014 Diff	F2015 Plan	F2016 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9 = 8 - 7	10	11
	Demand-Side Management												
1	Beginning of Year		506.4	506.4	0.0	649.0	638.0	(11.0)	794.5	732.4	(62.0)	820.6	897.8
2	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	Additions	5.0 L49	184.6	173.4	(11.2)	199.8	147.6	(52.2)	236.3	151.3	(85.0)	150.5	131.1
4	F11 RRA NSA Adjustment	5.0 L9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	Amortization on Existing		(42.0)	(41.8)	0.2	(42.0)	(53.2)	(11.2)	(42.0)	(41.8)	0.2	(73.3)	(73.3)
6	Amortization on Additions	13.0 L72	0.0	0.0	0.0	(12.3)	0.0	12.3	(25.6)	(21.4)	4.2	0.0	(10.0)
7	End of Year		649.0	638.0	(11.0)	794.5	732.4	(62.0)	963.2	820.6	(142.6)	897.8	945.6
	First Nations Costs												
8	Beginning of Year		98.6	98.6	0.0	159.0	152.6	(6.3)	167.4	167.9	0.5	174.9	174.2
9	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	Additions	5.0 L50	6.5	1.6	(4.9)	3.3	0.5	(2.8)	3.3	3.6	0.3	3.5	3.0
11	Transfer from Provision	Line 18	60.8	58.9	(1.9)	12.7	21.5	8.8	16.3	9.4	(6.9)	32.0	13.7
12	Interest		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.2	7.2
13	Recovery	5.0 L28	(7.0)	(6.5)	0.5	(7.6)	(6.8)	0.8	(6.9)	(5.9)	1.0	(43.5)	(43.2)
14	End of Year		159.0	152.6	(6.3)	167.4	167.9	0.5	180.1	174.9	(5.2)	174.2	154.8
	First Nations Settlement Provisions												
15	Beginning of Year		300.2	300.2	0.0	255.7	390.7	135.0	259.2	385.8	126.6	415.9	401.4
16	Additions - Operating	5.0 L84	16.3	149.4	133.1	0.0	0.0	0.0	0.0	18.4	18.4	0.0	0.0
17	Additions - Accretion	8.0 L76	0.0	0.0	0.0	16.2	16.7	0.5	16.2	21.1	4.9	17.5	17.7
18	Transfer to Negotiation Costs		(60.8)	(58.9)	1.9	(12.7)	(21.5)	(8.8)	(16.3)	(9.4)	6.9	(32.0)	(13.7)
19	End of Year		255.7	390.7	135.0	259.2	385.8	126.6	259.1	415.9	156.8	401.4	405.5
	F07/F08 RRA Depreciation Study												
20	Beginning of Year		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
21	Additions	7.0 L27	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22	Recovery	7.0 L43	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23	End of Year		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Site C												
24	Beginning of Year		103.3	103.3	0.0	230.1	181.1	(49.0)	392.1	258.4	(133.6)	361.6	376.9
25	Additions	5.0 L51	119.0	71.0	(48.0)	148.0	67.1	(80.9)	88.0	90.0	2.0	0.0	0.0
26	Interest		7.8	6.8	(1.0)	14.0	10.2	(3.8)	20.1	13.2	(7.0)	15.2	16.8
27	Recovery	5.0 L29	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
28	End of Year		230.1	181.1	(49.0)	392.1	258.4	(133.6)	500.2	361.6	(138.6)	376.9	393.7
	Future Removal and Site Restoration												
29	Beginning of Year		(140.3)	(140.3)	0.0	(106.1)	(120.4)	(14.4)	(85.2)	(87.4)	(2.2)	(65.7)	(41.1)
30	Adjustment to Opening Balance		0.0	(0.3)	(0.3)	0.0	16.6	16.6	0.0	0.0	0.0	0.0	0.0
31	Additions	N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
32	Recovery	7.0 L50	34.3	20.2	(14.1)	20.9	16.4	(4.5)	21.0	21.7	0.7	24.6	31.2
33	End of Year		(106.1)	(120.4)	(14.4)	(85.2)	(87.4)	(2.2)	(64.2)	(65.7)	(1.6)	(41.1)	(9.9)
	Foreign Exchange Gains/Losses												
34	Beginning of Year		(106.7)	(106.7)	0.0	(102.2)	(103.1)	(0.9)	(101.4)	(100.1)	1.3	(96.1)	(94.4)
35	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
36	Additions	8.0 L72	4.4	3.5	(0.9)	(0.2)	2.0	2.2	(1.0)	3.1	4.1	1.0	(0.1)
37	Recovery	8.0 L67	0.1	0.1	0.0	1.0	1.0	0.0	1.0	0.9	(0.1)	0.7	0.7
38	End of Year		(102.2)	(103.1)	(0.9)	(101.4)	(100.1)	1.3	(101.4)	(96.1)	5.3	(94.4)	(93.8)

Other Regulatory Accounts
($ million)

Line	Column	Reference	F2012 RRA	F2012 Actual	F2012 Diff	F2013 RRA	F2013 Actual	F2013 Diff	F2014 RRA	F2014 Forecast	F2014 Diff	F2015 Plan	F2016 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9 = 8 - 7	10	11
	Pre-1996 Customer Contributions												
39	Beginning of Year		58.7	58.7	0.0	67.3	67.3	0.0	74.8	74.8	0.0	81.1	87.4
40	Additions	N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
41	Recovery	7.0 L51	8.6	8.6	0.0	7.5	7.5	0.0	6.3	6.3	0.0	6.3	4.7
42	End of Year		67.3	67.3	0.0	74.8	74.8	0.0	81.1	81.1	0.0	87.4	92.1
	Storm Restoration Costs												
43	Beginning of Year		(1.4)	(1.4)	0.0	(1.5)	0.6	2.1	(1.5)	(2.5)	(1.0)	(2.6)	(1.3)
44	Additions	5.0 L52	0.0	2.1	2.1	0.0	(3.1)	(3.1)	0.0	0.0	0.0	0.0	0.0
45	Interest		(0.1)	(0.1)	(0.0)	(0.1)	(0.0)	0.0	(0.1)	(0.1)	(0.0)	(0.1)	(0.0)
46	Recovery	5.0 L30	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.4	1.4
47	Transfer to NHDA		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
48	End of Year		(1.5)	0.6	2.1	(1.5)	(2.5)	(1.0)	(1.6)	(2.6)	(1.0)	(1.3)	0.0
	Procurement Enhancement												
49	Beginning of Year		38.0	38.0	0.0	(0.0)	0.0	0.0	(0.0)	0.0	0.0	0.0	0.0
50	Additions - Operating	5.0 L53	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
51	Additions - Amortization	7.0 L32	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
52	Interest		1.7	1.7	0.1	(0.0)	0.0	0.0	(0.0)	0.0	0.0	0.0	0.0
53	F11 RRA NSA Adjustment	5.0 L31	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
54	Recovery	5.0 L32	(39.7)	(39.7)	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
55	End of Year		(0.0)	0.0	0.0	(0.0)	0.0	0.0	(0.0)	0.0	0.0	0.0	0.0
	Capital Project Investigation												
56	Beginning of Year		49.0	49.0	0.0	44.1	44.3	0.2	39.2	39.5	0.3	34.7	29.9
57	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.2	0.2	0.0	0.0	0.0	0.0	0.0
58	Additions	5.0 L54	0.0	(0.1)	(0.1)	0.0	(0.6)	(0.6)	0.0	0.0	0.0	0.0	0.0
59	Interest		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
60	Recovery	5.0 L33	(4.9)	(4.6)	0.3	(4.9)	(4.4)	0.5	(4.9)	(4.8)	0.1	(4.8)	(4.8)
61	End of Year		44.1	44.3	0.2	39.2	39.5	0.3	34.3	34.7	0.4	29.9	25.0
	GM Shrum 3												
62	Beginning of Year		43.2	43.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
63	Additions - Deferred Operating	5.0 L55	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
64	Additions - COE	4.0 L49	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
65	Interest		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
66	Insurance Proceeds	4.0 L50	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
67	Transfer to HDA		(43.2)	(43.2)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
68	End of Year		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	F2010 ROE Adjustment												
69	Beginning of Year		45.1	45.1	0.0	33.8	33.8	0.0	22.6	22.6	0.0	11.3	0.0
70	Additions	9.0 L53	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
71	Interest	N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
72	Recovery	9.0 L54	(11.3)	(11.3)	0.0	(11.3)	(11.3)	0.0	(11.3)	(11.3)	0.0	(11.3)	0.0
73	End of Year		33.8	33.8	0.0	22.6	22.6	0.0	11.3	11.3	0.0	0.0	0.0

BC Hydro
F15-F16 RRA

Schedule 2.2
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Other Regulatory Accounts
($ million)

Line	Column	Reference	F2012 RRA	F2012 Actual	F2012 Diff	F2013 RRA	F2013 Actual	F2013 Diff	F2014 RRA	F2014 Forecast	F2014 Diff	F2015 Plan	F2016 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9 = 8 - 7	10	11
	Net Employment Costs												
74	Beginning of Year		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
75	Additions	N/A	0.0	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	0.0	0.0	0.0	0.0	0.0
77	Recovery	5.0 L34	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
78	End of Year		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Total Taxes												
79	Beginning of Year		(13.4)	(13.4)	0.0	0.0	(0.0)	(0.0)	0.0	(0.0)	(0.0)	(0.0)	(0.0)
80	Additions	N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
81	Interest		(0.3)	(0.6)	(0.3)	0.0	0.0	(0.0)	0.0	0.0	(0.0)	0.0	0.0
82	Recovery	6.0 L27	13.7	14.0	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
83	End of Year		0.0	(0.0)	(0.0)	0.0	(0.0)	(0.0)	0.0	(0.0)	(0.0)	(0.0)	(0.0)
	Amortization of Capital Additions												
84	Beginning of Year		(9.5)	(9.5)	0.0	0.0	(1.7)	(1.7)	0.0	(5.8)	(5.8)	(18.5)	(9.3)
85	Additions - Bad Debt	5.0 L60	0.0	0.5	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
86	Interest		(0.2)	(0.6)	(0.4)	0.0	(0.4)	(0.4)	0.0	(0.5)	(0.5)	(0.6)	(0.2)
87	Recovery	7.0 L57	9.7	7.9	(1.7)	0.0	(3.8)	(3.8)	0.0	(12.2)	(12.2)	9.8	9.4
88	End of Year		0.0	(1.7)	(1.7)	0.0	(5.8)	(5.8)	0.0	(18.5)	(18.5)	(9.3)	(0.1)
	Total Finance Charges												
89	Beginning of Year		(4.0)	(4.0)	0.0	0.0	5.5	5.5	0.0	1.2	1.2	(51.1)	(25.6)
90	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	43.2	43.2	0.0	0.0	0.0	0.0	0.0
91	Additions	N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
92	Interest	N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
93	Recovery	8.0 L69	4.0	9.5	5.5	0.0	(47.6)	(47.6)	0.0	(52.3)	(52.3)	25.5	25.5
94	End of Year		0.0	5.5	5.5	0.0	1.2	1.2	0.0	(51.1)	(51.1)	(25.6)	(0.1)
	Smart Metering & Infrastructure												
95	Beginning of Year		34.0	34.0	0.0	153.4	91.9	(61.4)	313.9	191.6	(122.3)	282.0	286.7
96	Adjustment to Opening Balance		0.0	(0.6)	(0.6)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
97	Additions - Deferred Operating	5.0 L56	46.4	14.6	(31.8)	50.4	37.4	(13.0)	15.2	25.5	10.3	28.4	21.5
98	Additions - Amortization	7.0 L28	52.4	38.8	(13.6)	59.7	36.4	(23.3)	38.3	26.0	(12.3)	0.0	0.0
99	Legacy Meter Contributions		0.0	0.0	0.0	0.0	(2.7)	(2.7)	0.0	0.0	0.0	0.0	0.0
100	Additions - Finance Charges	8.0 L73	9.1	0.1	(9.0)	22.8	12.0	(10.8)	29.2	16.1	(13.1)	0.0	0.0
101	Additions - ROE	9.0 L51	7.1	2.2	(4.9)	17.1	10.3	(6.8)	22.2	16.7	(5.5)	0.0	0.0
102	Additions - Non tariff revenues	15.0 L34	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(4.0)	(4.0)	(4.8)	(3.4)
103	Interest		4.4	2.8	(1.6)	10.5	6.4	(4.1)	16.9	10.1	(6.8)	11.7	12.5
104	Recovery	5.0 L35	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(30.5)	(31.3)
105	End of Year		153.4	91.9	(61.4)	313.9	191.6	(122.3)	435.7	282.0	(153.7)	286.7	286.0
	Home Purchase Option Plan												
106	Beginning of Year		18.4	18.4	0.0	23.9	20.1	(3.7)	26.7	21.3	(5.4)	22.2	11.1
107	Additions - Deferred Operating	5.0 L57	4.4	0.7	(3.7)	1.7	0.2	(1.5)	0.0	0.0	0.0	0.0	0.0
108	Additions - Interest	8.0 L74	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
109	Interest		1.0	0.9	(0.1)	1.1	1.0	(0.2)	1.2	0.9	(0.3)	0.7	0.2
110	Recovery	5.0 L36	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(11.8)	(11.3)
111	End of Year		23.9	20.1	(3.7)	26.7	21.3	(5.4)	28.0	22.2	(5.7)	11.1	0.0

Other Regulatory Accounts
($ million)

Line	Column	Reference	F2012 RRA	F2012 Actual	F2012 Diff	F2013 RRA	F2013 Actual	F2013 Diff	F2014 RRA	F2014 Forecast	F2014 Diff	F2015 Plan	F2016 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9 = 8 - 7	10	11
	Non-Current Pension Cost												
112	Beginning of Year		71.5	71.5	0.0	54.4	54.6	0.2	37.3	543.9	506.6	219.0	186.3
113	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	321.9	321.9	0.0	0.0	0.0	0.0	0.0
114	OCI Deferral	9.0 L8	0.0	0.0	0.0	0.0	191.7	191.7	0.0	(353.0)	(353.0)	0.0	0.0
115	Additions		0.0	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
116	Interest	N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
117	Recovery - Operating	5.0 L37	(17.1)	(17.1)	0.0	(17.1)	(17.1)	0.0	(17.1)	(17.1)	0.0	(32.6)	(15.5)
118	Recovery - Finance Charges	8.0 L68	0.0	0.0	0.0	0.0	(7.2)	(7.2)	0.0	45.2	45.2	0.0	0.0
119	End of Year		54.4	54.6	0.2	37.3	543.9	506.6	20.1	219.0	198.8	186.3	170.8
	Waneta												
120	Beginning of Year		30.0	30.0	0.0	40.0	40.0	0.0	25.0	25.0	0.0	15.0	0.0
121	Additions		10.0	10.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
122	Recovery		0.0	0.0	0.0	(15.0)	(15.0)	0.0	(10.0)	(10.0)	0.0	(15.0)	0.0
123	End of Year		40.0	40.0	0.0	25.0	25.0	0.0	15.0	15.0	0.0	0.0	0.0
	Environmental Provisions												
124	Beginning of Year		229.0	229.0	0.0	222.1	230.2	8.1	213.7	330.9	117.2	294.9	239.1
125	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	87.8	87.8	0.0	0.0	0.0	0.0	0.0
126	Additions - Deferred Operating	5.0 L85	6.3	11.1	4.8	0.0	46.0	46.0	0.0	1.6	1.6	0.0	0.0
127	Additions - Amortization	7.0 L29	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
128	Additions - Accretion	8.0 L71	0.0	0.0	0.0	6.3	6.1	(0.2)	6.2	6.0	(0.2)	6.0	6.0
129	Transfer to Rock Bay		0.0	(1.7)	(1.7)	0.0	(23.9)	(23.9)	0.0	(22.1)	(22.1)	(46.4)	0.0
130	Transfer to Asbestos		0.0	0.0	0.0	0.0	(8.0)	(8.0)	0.0	(11.3)	(11.3)	(1.8)	(0.9)
131	Recovery	5.0 L90-93	(13.2)	(8.2)	5.0	(14.7)	(7.3)	7.4	(14.9)	(10.2)	4.7	(13.6)	(13.3)
132	End of Year		222.1	230.2	8.1	213.7	330.9	117.2	205.0	294.9	90.0	239.1	230.9
	Rock Bay Remediation												
133	Beginning of Year		2.1	2.1	0.0	2.2	3.8	1.6	2.3	28.6	26.3	52.4	49.4
134	Transfer from Environmental	Line 129	0.0	1.7	1.7	0.0	23.9	23.9	0.0	22.1	22.1	46.4	0.0
135	Additions		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
136	Interest		0.1	0.0	(0.1)	0.1	0.9	0.8	0.1	1.7	1.6	2.1	1.1
137	Recovery	5.0 L99	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(51.5)	(50.5)
138	End of Year		2.2	3.8	1.6	2.3	28.6	26.3	2.4	52.4	50.0	49.4	0.0
	IFRS PP&E												
139	Beginning of Year		0.0	0.0	0.0	186.0	221.8	35.8	341.5	446.7	105.2	617.3	758.2
140	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	32.5	32.5	0.0	0.0	0.0	0.0	0.0
141	Additions - Deferred Operating	5.0 L58	178.0	214.8	36.8	160.2	197.1	36.9	142.4	179.2	36.8	156.8	134.4
142	Additions - IDC	8.0 L75	8.0	7.0	(1.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
143	Interest	N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
144	Recovery	5.0 L38	0.0	0.0	0.0	(4.7)	(4.7)	0.0	(8.7)	(8.7)	0.0	(15.9)	(19.8)
145	End of Year		186.0	221.8	35.8	341.5	446.7	105.2	475.2	617.3	142.1	758.2	872.7
	IFRS Pension												
146	Beginning of Year		0.0	0.0	0.0	0.0	0.0	0.0	723.0	723.0	0.0	688.3	650.1
147	Adjustment to Opening Balance		0.0	0.0	0.0	761.9	761.9	0.0	0.0	0.0	0.0	0.0	0.0
148	Additions	N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
149	Recovery	5.0 L39	0.0	0.0	0.0	(38.9)	(38.9)	0.0	(34.7)	(34.7)	0.0	(38.2)	(38.2)
150	End of Year		0.0	0.0	0.0	723.0	723.0	0.0	688.3	688.3	0.0	650.1	611.8

Other Regulatory Accounts
($ million)

Line	Column	Reference	F2012 RRA	F2012 Actual	F2012 Diff	F2013 RRA	F2013 Actual	F2013 Diff	F2014 RRA	F2014 Forecast	F2014 Diff	F2015 Plan	F2016 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9 = 8 - 7	10	11
	F12-F14 Rate Smoothing												
151	Beginning of Year		0.0	0.0	0.0	(69.7)	(69.7)	0.0	(110.9)	(110.9)	0.0	0.0	0.0
152	Additions	N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
153	Recovery	5.0 L102	(69.7)	(69.7)	0.0	(41.2)	(41.2)	0.0	110.9	110.9	0.0	0.0	0.0
154	End of Year		(69.7)	(69.7)	0.0	(110.9)	(110.9)	0.0	0.0	0.0	0.0	0.0	0.0
	Arrow Water Divestiture Costs												
155	Beginning of Year		7.7	7.7	0.0	8.1	8.1	0.0	8.4	8.5	0.1	8.9	4.4
156	Additions	5.0 L86	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
157	Interest		0.4	0.4	0.0	0.4	0.4	0.0	0.4	0.4	(0.0)	0.3	0.1
158	Recovery	5.0 L100	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(4.7)	(4.5)
159	End of Year		8.1	8.1	0.0	8.4	8.5	0.1	8.8	8.9	0.0	4.4	0.0
	Arrow Water Provision												
160	Beginning of Year		3.3	3.3	0.0	3.9	3.6	(0.3)	4.0	3.4	(0.6)	3.2	3.0
161	Additions	5.0 L87	0.6	0.6	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
162	Additions - Accretion		0.0	0.0	0.0	0.1	0.1	0.0	0.1	0.1	0.0	0.1	0.1
163	Recovery	5.0 L101	0.0	(0.3)	(0.3)	0.0	(0.3)	(0.3)	0.0	(0.3)	(0.3)	(0.3)	(0.3)
164	End of Year		3.9	3.6	(0.3)	4.0	3.4	(0.6)	4.1	3.2	(0.9)	3.0	2.8
	Asbestos Remediation												
165	Beginning of Year		0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.0	8.0	19.3	9.6
166	Transfer from Environmental	Line 130	0.0	0.0	0.0	0.0	8.0	8.0	0.0	11.3	11.3	1.8	0.9
167	Additions		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
168	Interest		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.2
169	Recovery	5.0 L95-98	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(12.1)	(10.8)
170	End of Year		0.0	0.0	0.0	0.0	8.0	8.0	0.0	19.3	19.3	9.6	(0.1)
	Rate Smoothing												
171	Beginning of Year		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	166.2
172	Additions	N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
173	Recovery	5.0 L103	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	166.2	121.2
174	End of Year		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	166.2	287.4
	Real Property Sales												
175	Beginning of Year		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
176	Additions		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
177	Interest		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
178	Recovery		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
179	End of Year		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Other Regulatory Accounts
($ million)

Line	Column	Reference	F2012 RRA	F2012 Actual	F2012 Diff	F2013 RRA	F2013 Actual	F2013 Diff	F2014 RRA	F2014 Forecast	F2014 Diff	F2015 Plan	F2016 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9 = 8 - 7	10	11
	End of Year Balances												
180	Demand-Side Management	Line 7	649.0	638.0	(11.0)	794.5	732.4	(62.0)	963.2	820.6	(142.6)	897.8	945.6
181	First Nations Costs	Line 14	159.0	152.6	(6.3)	167.4	167.9	0.5	180.1	174.9	(5.2)	174.2	154.8
182	First Nations Provisions	Line 19	255.7	390.7	135.0	259.2	385.8	126.6	259.1	415.9	156.8	401.4	405.5
183	F07/F08 RRA Depn Study	Line 23	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
184	Site C	Line 28	230.1	181.1	(49.0)	392.1	258.4	(133.6)	500.2	361.6	(138.6)	376.9	393.7
185	Future Removal	Line 33	(106.1)	(120.4)	(14.4)	(85.2)	(87.4)	(2.2)	(64.2)	(65.7)	(1.6)	(41.1)	(9.9)
186	Foreign Exchange	Line 38	(102.2)	(103.1)	(0.9)	(101.4)	(100.1)	1.3	(101.4)	(96.1)	5.3	(94.4)	(93.8)
187	Pre-1996 Contributions	Line 42	67.3	67.3	0.0	74.8	74.8	0.0	81.1	81.1	0.0	87.4	92.1
188	Storm Restoration	Line 48	(1.5)	0.6	2.1	(1.5)	(2.5)	(1.0)	(1.6)	(2.6)	(1.0)	(1.3)	0.0
189	Procurement Enhancement	Line 55	(0.0)	0.0	0.0	(0.0)	0.0	0.0	(0.0)	0.0	0.0	0.0	0.0
190	Capital Project Investigation	Line 61	44.1	44.3	0.2	39.2	39.5	0.3	34.3	34.7	0.4	29.9	25.0
191	GM Shrum 3	Line 68	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
192	F2010 ROE Adjustment	Line 73	33.8	33.8	0.0	22.6	22.6	0.0	11.3	11.3	0.0	0.0	0.0
193	Net Employment Costs	Line 78	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
194	Total Taxes	Line 83	0.0	(0.0)	(0.0)	0.0	(0.0)	(0.0)	0.0	(0.0)	(0.0)	(0.0)	(0.0)
195	Amortization of Capital Additions	Line 88	0.0	(1.7)	(1.7)	0.0	(5.8)	(5.8)	0.0	(18.5)	(18.5)	(9.3)	(0.1)
196	Total Finance Charges	Line 94	0.0	5.5	5.5	0.0	1.2	1.2	0.0	(51.1)	(51.1)	(25.6)	(0.1)
197	Smart Metering & Infrastructure	Line 105	153.4	91.9	(61.4)	313.9	191.6	(122.3)	435.7	282.0	(153.7)	286.7	286.0
198	Home Option Purchase Plan	Line 111	23.9	20.1	(3.7)	26.7	21.3	(5.4)	28.0	22.2	(5.7)	11.1	0.0
199	Non-Current Pension Cost	Line 119	54.4	54.6	0.2	37.3	543.9	506.6	20.1	219.0	198.8	186.3	170.8
200	Waneta	Line 123	40.0	40.0	0.0	25.0	25.0	0.0	15.0	15.0	0.0	0.0	0.0
201	Environmental Provisions	Line 132	222.1	230.2	8.1	213.7	330.9	117.2	205.0	294.9	90.0	239.1	230.9
202	Rock Bay Remediation	Line 138	2.2	3.8	1.6	2.3	28.6	26.3	2.4	52.4	50.0	49.4	0.0
203	IFRS PP&E	Line 145	186.0	221.8	35.8	341.5	446.7	105.2	475.2	617.3	142.1	758.2	872.7
204	IFRS Pension	Line 150	0.0	0.0	0.0	723.0	723.0	0.0	688.3	688.3	0.0	650.1	611.8
205	F12-F14 Rate Smoothing	Line 154	(69.7)	(69.7)	0.0	(110.9)	(110.9)	0.0	0.0	0.0	0.0	0.0	0.0
206	Arrow Water Divestiture Costs	Line 159	8.1	8.1	0.0	8.4	8.5	0.1	8.8	8.9	0.0	4.4	0.0
207	Arrow Water Provision	Line 164	3.9	3.6	(0.3)	4.0	3.4	(0.6)	4.1	3.2	(0.9)	3.0	2.8
208	Asbestos Remediation	Line 170	0.0	0.0	0.0	0.0	8.0	8.0	0.0	19.3	19.3	9.6	(0.1)
209	Rate Smoothing	Line 174	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	166.2	287.4
210	Real Property Sales	Line 179	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
211	Total		1,853.5	1,893.2	39.8	3,146.4	3,706.7	560.3	3,744.6	3,888.4	143.7	4,160.0	4,375.4
	Summary												
212	Regulatory Account Additions		653.2	701.6	48.4	685.4	573.0	(112.4)	596.4	554.7	(41.7)	359.0	310.3
213	Interest on Regulatory Accounts		14.6	11.2	(3.4)	26.0	18.4	(7.6)	38.7	25.6	(13.1)	37.1	37.9
214	Regulatory Account Recoveries		(134.5)	(138.8)	(4.4)	(180.4)	(233.8)	(53.4)	(36.9)	(45.7)	(8.8)	(124.5)	(132.9)
215	Transfer of Storm Restoration	Line 47	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
216	Transfer of GM Shrum 3	Line 67	(43.2)	(43.2)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
217	Adjustments to Opening Balances		0.0	(0.9)	(0.9)	761.9	1,264.1	502.2	0.0	0.0	0.0	0.0	0.0
218	OCI Deferral (Pension)		0.0	0.0	0.0	0.0	191.7	191.7	0.0	(353.0)	(353.0)	0.0	0.0
219	Regulatory Account Net Transfers		490.2	530.0	39.8	1,292.9	1,813.5	520.5	598.2	181.7	(416.5)	271.6	215.4
220	**Interest Rate**	8.0 L104	4.76%	4.82%	0.05%	4.60%	4.57%	-0.02%	4.62%	4.34%	-0.27%	4.21%	4.47%

Reconciliation of Current and Gross Views
($ million)

Line	Column	Reference	F2012 RRA	F2012 Actual	F2012 Diff	F2013 RRA	F2013 Actual	F2013 Diff	F2014 RRA	F2014 Forecast	F2014 Diff	F2015 Plan	F2016 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9 = 8 - 7	10	11
	Cost of Energy												
1	Total Current	4.0 L58	1,195.6	1,116.7	(78.9)	1,410.1	1,240.7	(169.4)	1,589.4	1,413.6	(175.8)	1,514.1	1,514.3
2	HDA Additions	4.0 L46	0.0	(31.9)	(31.9)	0.0	(123.7)	(123.7)	0.0	10.5	10.5	0.0	0.0
3	NHDA Additions	4.0 L47	65.9	27.9	(38.0)	103.2	102.0	(1.2)	49.8	20.7	(29.1)	0.0	0.0
4	BCTCDA Additions	4.0 L48	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	Deferred GMS 3 COE	4.0 L49	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	GMS 3 Insurance Proceeds	4.0 L50	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	Water License Variances	4.0 L51	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	Deferred Operating HDA	4.0 L52	0.0	(1.5)	(1.5)	0.0	(7.0)	(7.0)	0.0	(4.8)	(4.8)	0.0	0.0
9	Deferred Operating NHDA	4.0 L53	0.0	(11.2)	(11.2)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	Deferred Waneta Costs	4.0 L54	10.0	10.0	0.0	(15.0)	(15.0)	0.0	(10.0)	(10.0)	0.0	(15.0)	0.0
11	HDA Recoveries	4.0 L55	(27.7)	(27.2)	0.5	(60.8)	(55.8)	5.1	(54.4)	(17.9)	36.5	(16.6)	(17.7)
12	NHDA Recoveries	4.0 L56	(40.5)	(39.8)	0.7	(89.2)	(84.0)	5.2	(105.2)	(120.0)	(14.8)	(98.0)	(104.8)
13	BCTCDA Recoveries	4.0 L57	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	Total Gross		1,203.2	1,043.0	(160.2)	1,348.3	1,057.3	(291.0)	1,469.5	1,292.1	(177.4)	1,384.5	1,391.7
	Operating Costs												
15	Total Current	5.0 L124	944.1	945.5	1.4	913.8	929.3	15.4	758.7	763.4	4.6	923.6	977.7
16	Deferral Account Additions	5.0 L48	0.0	12.7	12.7	0.0	7.0	7.0	0.0	4.8	4.8	0.0	0.0
17	Deferral Account Recoveries	5.0 L41	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
18	Regulatory Account Additions	5.0 L61+88	562.1	639.7	77.6	563.4	492.2	(71.2)	485.2	469.6	(15.6)	339.2	290.0
19	Regulatory Account Recoveries	5.0 L40+104	(151.6)	(145.9)	5.6	(129.1)	(120.7)	8.5	23.7	29.2	5.5	(92.0)	(121.1)
20	Total Gross		1,354.7	1,452.0	97.3	1,348.1	1,307.8	(40.3)	1,267.6	1,267.0	(0.6)	1,170.8	1,146.6
	Taxes												
21	Total Current	6.0 L28	170.2	170.2	(0.0)	193.1	194.1	1.0	202.7	202.1	(0.6)	213.8	224.1
22	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	0.0
23	Regulatory Account Recoveries	6.0 L27	13.7	14.0	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
24	Total Gross		183.9	184.2	0.3	193.1	194.1	1.0	202.7	202.1	(0.6)	213.8	224.1
	Amortization												
25	Total Current	7.0 L59	552.5	552.4	(0.2)	629.8	631.7	1.9	657.7	667.5	9.8	731.2	796.0
26	Regulatory Account Additions	7.0 L30+34	52.4	38.8	(13.6)	59.7	36.4	(23.3)	38.3	26.0	(12.3)	0.0	0.0
27	Regulatory Account Recoveries	7.0 L58	10.6	(5.0)	(15.6)	(25.9)	(33.1)	(7.2)	(40.3)	(47.4)	(7.1)	(32.5)	(38.0)
28	Total Gross		615.5	586.2	(29.3)	663.5	635.0	(28.6)	655.8	646.2	(9.6)	698.7	758.0
	Finance Charges												
29	Total Current	8.0 L71	490.2	490.2	0.0	539.7	538.4	(1.3)	575.6	575.2	(0.4)	606.8	726.6
30	Interest on Regulatory Accounts	8.0 L66	54.1	48.0	(6.1)	63.4	54.8	(8.7)	72.7	58.6	(14.1)	67.4	61.7
31	Regulatory Account Additions	8.0 L79	21.6	10.7	(10.9)	45.2	36.8	(8.4)	50.7	46.4	(4.3)	24.6	23.7
32	Regulatory Account Recoveries	8.0 L70	4.1	9.6	5.5	1.0	(53.7)	(54.7)	1.0	(6.2)	(7.2)	26.2	26.2
33	Total Gross		570.0	558.6	(11.5)	649.3	576.3	(73.0)	700.0	674.0	(26.0)	725.0	838.3
	Return on Equity												
34	Total Current	9.0 L56	563.1	567.6	4.5	514.4	510.3	(4.0)	544.8	539.3	(5.4)	592.8	651.9
35	Regulatory Account Additions	9.0 L53	7.1	2.2	(4.9)	17.1	10.3	(6.8)	22.2	16.7	(5.5)	0.0	0.0
36	Regulatory Account Recoveries	9.0 L54	(11.3)	(11.3)	0.0	(11.3)	(11.3)	0.0	(11.3)	(11.3)	0.0	(11.3)	0.0
37	Total Gross		558.9	558.4	(0.5)	520.2	509.3	(10.9)	555.7	544.7	(10.9)	581.5	651.9
	Non-Tariff Revenue												
38	Total Current	15.0 L35	(82.9)	(80.8)	2.1	(110.6)	(116.4)	(5.8)	(113.5)	(116.7)	(3.2)	(116.5)	(123.3)
39	Regulatory Account Additions	15.0 L33+34	0.0	0.0	0.0	0.0	(2.7)	(2.7)	0.0	(4.0)	(4.0)	(4.8)	(3.4)
40	Regulatory Account Recoveries		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
41	Total Gross	15.0 L32	(82.9)	(80.8)	2.1	(110.6)	(119.1)	(8.5)	(113.5)	(120.7)	(7.3)	(121.3)	(126.6)

Reconciliation of Current and Gross Views
($ million)

Line	Column	Reference	F2012 RRA	F2012 Actual	F2012 Diff	F2013 RRA	F2013 Actual	F2013 Diff	F2014 RRA	F2014 Forecast	F2014 Diff	F2015 Plan	F2016 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9 = 8 - 7	10	11
	Inter-Segment Revenue												
42	Powerex - Corporate Allocation	3.1 L17	(2.7)	(2.7)	0.0	(2.8)	(2.8)	0.0	(2.6)	(3.0)	(0.4)	(3.0)	(3.0)
43	Mark to Market Losses (Gains)	3.1 L18	0.0	12.9	12.9	0.0	(3.9)	(3.9)	0.0	7.8	7.8	0.0	0.0
44	Other	3.1 L19	0.7	0.0	(0.7)	0.7	0.0	(0.7)	0.7	0.0	(0.7)	0.0	0.0
45	Powerex PTP Charges	3.4 L18	(25.5)	(27.5)	(2.1)	(26.2)	(21.3)	4.9	(27.0)	(23.4)	3.6	(23.4)	(29.2)
46	BC Hydro PTP Charges	3.4 L19	(11.1)	(12.8)	(1.7)	(11.1)	(35.1)	(24.0)	(11.1)	(20.4)	(9.3)	(26.2)	(21.3)
47	Total		(38.6)	(30.1)	8.5	(39.5)	(63.1)	(23.6)	(40.0)	(39.0)	1.0	(52.6)	(53.5)
	Regulatory Account Transfers												
48	Deferral Accounts	1.0 L12	(16.1)	54.9	71.0	47.9	150.3	102.4	110.3	(94.3)	(204.6)	178.2	199.2
49	Other Regulatory Accounts	1.0 L16	(533.4)	(574.0)	(40.6)	(531.0)	(357.6)	173.4	(598.2)	(534.7)	63.5	(271.6)	(215.4)
50	Total		(549.5)	(519.1)	30.4	(483.1)	(207.3)	275.8	(487.9)	(628.9)	(141.0)	(93.5)	(16.2)
	Powerex Net Income												
51	Total Current		(121.0)	(121.4)	(0.3)	(74.5)	(73.0)	1.5	(78.5)	(64.2)	14.4	(16.1)	(9.6)
52	TIDA Additions	2.1 L18	0.0	(0.0)	(0.0)	0.0	14.8	14.8	0.0	216.9	216.9	0.0	0.0
53	TIDA Recoveries	2.1 L20	(21.0)	(20.6)	0.3	(38.5)	(40.0)	(1.5)	(34.5)	(48.8)	(14.4)	(93.9)	(100.4)
54	Total Gross		(142.0)	(142.0)	(0.0)	(113.0)	(98.2)	14.8	(113.0)	103.9	216.9	(110.0)	(110.0)
55	**Powertech Net Income**	1.0 L18	(1.5)	(2.6)	(1.1)	(2.3)	(2.9)	(0.6)	(5.9)	(3.8)	2.1	(4.2)	(5.1)
56	**Other Utilities Revenue**	14.0 L17	(14.6)	(14.9)	(0.3)	(14.8)	(14.8)	(0.0)	(15.5)	(15.3)	0.2	(16.2)	(16.5)
57	**Deferral Rider Revenue**	14.0 L21	(89.2)	(87.7)	1.5	(188.5)	(179.7)	8.8	(194.1)	(186.8)	7.3	(208.4)	(223.0)
58	**Total Rate Revenue Requirement**		3,568.0	3,505.2	(62.8)	3,770.7	3,594.7	(176.0)	3,881.4	3,735.3	(146.1)	4,168.3	4,459.7
	Summary - Current Rates View												
59	Cost of Energy	Line 1	1,195.6	1,116.7	(78.9)	1,410.1	1,240.7	(169.4)	1,589.4	1,413.6	(175.8)	1,514.1	1,514.3
60	Operating Costs	Line 15	944.1	945.5	1.4	913.8	929.3	15.4	758.7	763.4	4.6	923.6	977.7
61	Taxes	Line 21	170.2	170.2	(0.0)	193.1	194.1	1.0	202.7	202.1	(0.6)	213.8	224.1
62	Amortization	Line 25	552.5	552.4	(0.2)	629.8	631.7	1.9	657.7	667.5	9.8	731.2	796.0
63	Finance Charges	Line 29	490.2	490.2	0.0	539.7	538.4	(1.3)	575.6	575.2	(0.4)	606.8	726.6
64	Return on Equity	Line 34	563.1	567.6	4.5	514.4	510.3	(4.0)	544.8	539.3	(5.4)	592.8	651.9
65	Non-Tariff Revenue	Line 38	(82.9)	(80.8)	2.1	(110.6)	(116.4)	(5.8)	(113.5)	(116.7)	(3.2)	(116.5)	(123.3)
66	Inter-Segment Revenue	Line 47	(38.6)	(30.1)	8.5	(39.5)	(63.1)	(23.6)	(40.0)	(39.0)	1.0	(52.6)	(53.5)
67	Subsididary Net Income	Lines 51+55	(122.5)	(123.9)	(1.4)	(76.8)	(75.9)	0.9	(84.4)	(68.0)	16.4	(20.3)	(14.7)
68	Other Utilities Revenue	Line 56	(14.6)	(14.9)	(0.3)	(14.8)	(14.8)	(0.0)	(15.5)	(15.3)	0.2	(16.2)	(16.5)
69	Deferral Rider Revenue	Line 57	(89.2)	(87.7)	1.5	(188.5)	(179.7)	8.8	(194.1)	(186.8)	7.3	(208.4)	(223.0)
70	Total Rate Revenue Requirement		3,568.0	3,505.2	(62.8)	3,770.7	3,594.7	(176.0)	3,881.4	3,735.3	(146.1)	4,168.3	4,459.7
	Current Costs by Business Group												
71	Generation	3.2 L17	1,565.6	1,596.4	30.8	1,620.8	1,605.1	(15.7)	1,591.8	1,439.1	(152.7)	1,468.4	1,600.8
72	Transmission	3.4 L21	570.4	530.8	(39.6)	599.2	531.4	(67.8)	591.2	550.9	(40.4)	628.2	747.7
73	Distribution	3.5 L13	792.4	788.3	(4.1)	796.6	816.8	20.2	776.9	869.1	92.3	997.3	1,078.0
74	Customer Care	3.3 L16	865.9	816.2	(49.7)	1,034.2	911.7	(122.4)	1,215.6	1,146.3	(69.2)	1,319.3	1,287.4
75	Corporate Groups	3.1 L21	0.0	(0.0)	(0.0)	(0.0)	(0.0)	0.0	0.0	0.0	(0.0)	(0.0)	(0.0)
76	Subsididary Net Income	Line 67	(122.5)	(123.9)	(1.4)	(76.8)	(75.9)	0.9	(84.4)	(68.0)	16.4	(20.3)	(14.7)
77	Other Utilities Revenue	Line 68	(14.6)	(14.9)	(0.3)	(14.8)	(14.8)	(0.0)	(15.5)	(15.3)	0.2	(16.2)	(16.5)
78	Deferral Rider Revenue	Line 69	(89.2)	(87.7)	1.5	(188.5)	(179.7)	8.8	(194.1)	(186.8)	7.3	(208.4)	(223.0)
79	Total Rate Revenue Requirement		3,568.0	3,505.2	(62.8)	3,770.7	3,594.7	(176.0)	3,881.4	3,735.3	(146.1)	4,168.3	4,459.7

Total Current Costs - Corporate Groups
($ million)

Line	Column	Reference	F2012 RRA	F2012 Actual	F2012 Diff	F2013 RRA	F2013 Actual	F2013 Diff	F2014 RRA	F2014 Forecast	F2014 Diff	F2015 Plan	F2016 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9 = 8 - 7	10	11
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	0.0
2	**Current Operating Costs**	5.0 L117-123	299.6	293.0	(6.6)	232.0	201.4	(30.6)	72.3	70.9	(1.5)	144.9	202.6
3	**Taxes**	6.0 L34	11.5	11.8	0.3	12.4	13.5	1.1	12.9	14.0	1.1	14.6	15.8
4	**Current Amortization**	7.0 L64	70.9	70.0	(0.9)	94.2	91.3	(2.9)	93.2	44.7	(48.5)	25.5	30.1
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	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 71	(326.9)	(266.9)	60.0	(290.0)	(192.6)	97.4	(130.7)	(205.8)	(75.1)	(247.1)	(309.2)
8	**Non-Tariff Revenue**	15.0 L31	(14.4)	(13.8)	0.7	(14.4)	(14.0)	0.4	(14.4)	(15.6)	(1.2)	(11.0)	(11.2)
	Internal Allocations												
9	Safety, Health & Environment	3.3 L9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	First Nations Comm Dev Fund	3.4 L14	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	Customer Care & Power Smart	5.1 L4	(15.9)	(81.5)	(65.6)	(14.5)	(75.3)	(60.7)	(13.6)	(74.7)	(61.2)	(73.2)	(73.2)
12	Energy Planning & Procure	5.1 L11	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	IPP Capital Lease Op Costs	5.1 L13	(22.8)	(22.9)	(0.1)	(17.5)	(17.6)	(0.1)	(17.9)	(17.9)	(0.1)	(29.4)	(33.8)
14	Technology - Depreciation		0.0	0.0	0.0	0.0	0.0	0.0	0.0	66.4	66.4	68.1	69.6
15	Technology	5.2 L12	0.0	0.0	0.0	0.0	0.0	0.0	0.0	113.3	113.3	110.6	112.3
16	Total		(38.7)	(104.4)	(65.6)	(32.0)	(92.9)	(60.8)	(31.4)	87.0	118.4	76.1	74.9
	Inter-Segment Revenue												
17	Powerex - Corporate Allocation		(2.7)	(2.7)	0.0	(2.8)	(2.8)	0.0	(2.6)	(3.0)	(0.4)	(3.0)	(3.0)
18	Mark to Market Losses (Gains)		0.0	12.9	12.9	0.0	(3.9)	(3.9)	0.0	7.8	7.8	0.0	0.0
19	Other		0.7	0.0	(0.7)	0.7	0.0	(0.7)	0.7	0.0	(0.7)	0.0	0.0
20	Total		(2.0)	10.2	12.2	(2.1)	(6.7)	(4.6)	(1.9)	4.8	6.7	(3.0)	(3.0)
21	**Total**		0.0	(0.0)	(0.0)	(0.0)	(0.0)	0.0	0.0	0.0	(0.0)	(0.0)	(0.0)
	Corporate Allocation:												
	Building Operations												
22	Generation		2.9	2.9	0.0	2.9	2.9	0.0	3.0	0.0	(3.0)	0.0	0.0
23	Transmission		6.8	6.8	0.0	6.9	6.9	0.0	6.9	0.0	(6.9)	0.0	0.0
24	Distribution		9.4	9.4	0.0	9.4	9.4	0.0	9.5	0.0	(9.5)	0.0	0.0
25	Customer Care		2.1	2.1	0.0	2.1	2.1	0.0	2.1	0.0	(2.1)	0.0	0.0
26	Total		21.2	21.2	0.0	21.2	21.2	0.0	21.4	0.0	(21.4)	0.0	0.0
	ABS Costs												
27	Generation		18.5	18.5	0.0	20.0	20.0	0.0	21.2	0.0	(21.2)	0.0	0.0
28	Transmission		19.5	19.5	0.0	21.1	21.1	0.0	22.2	0.0	(22.2)	0.0	0.0
29	Distribution		26.8	26.8	0.0	28.7	28.7	0.0	30.7	0.0	(30.7)	0.0	0.0
30	Customer Care		6.7	6.7	0.0	7.1	7.1	0.0	7.5	0.0	(7.5)	0.0	0.0
31	Total		71.5	71.5	0.0	76.9	76.9	0.0	81.6	0.0	(81.6)	0.0	0.0

Total Current Costs - Corporate Groups
($ million)

Line		Reference	F2012 RRA	F2012 Actual	F2012 Diff	F2013 RRA	F2013 Actual	F2013 Diff	F2014 RRA	F2014 Forecast	F2014 Diff	F2015 Plan	F2016 Plan
	Column		1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9 = 8 - 7	10	11
	Insurance												
32	Generation		5.0	5.0	0.0	5.3	5.3	0.0	5.4	4.7	(0.7)	5.0	5.0
33	Transmission		1.3	1.3	0.0	1.5	1.5	0.0	1.5	2.6	1.1	2.7	2.7
34	Distribution		1.2	1.2	0.0	1.0	1.0	0.0	1.1	2.5	1.4	2.7	2.7
35	Customer Care		0.3	0.3	0.0	0.3	0.3	0.0	0.3	0.3	(0.0)	0.3	0.3
36	Total		7.8	7.8	0.0	8.2	8.2	0.0	8.3	10.1	1.8	10.7	10.7
	Customer Care Support and Billing System Amortization												
37	Generation		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
38	Transmission		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
39	Distribution		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
40	Customer Care		14.8	14.8	0.0	14.7	14.7	0.0	13.6	0.0	(13.6)	0.0	0.0
41	Total		14.8	14.8	0.0	14.7	14.7	0.0	13.6	0.0	(13.6)	0.0	0.0
	Non-Current Pension Costs												
42	Generation		14.3	14.3	0.0	14.9	14.9	0.0	13.5	17.1	3.6	23.3	17.7
43	Transmission		13.8	13.8	0.0	14.5	14.5	0.0	13.0	16.0	3.0	21.9	16.4
44	Distribution		19.0	19.0	0.0	19.7	19.7	0.0	18.0	17.8	(0.2)	24.3	18.6
45	Customer Care		7.0	7.0	0.0	7.3	7.3	0.0	6.6	1.0	(5.6)	1.3	1.0
46	Total		54.1	54.1	0.0	56.4	56.4	0.0	51.0	51.8	0.8	70.9	53.8
	Fleet												
47	Generation		0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.3	5.3	5.0	5.1
48	Transmission		0.0	0.0	0.0	0.0	0.0	0.0	0.0	11.9	11.9	11.2	11.4
49	Distribution		0.0	0.0	0.0	0.0	0.0	0.0	0.0	24.2	24.2	22.8	23.2
50	Customer Care		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
51	Total		0.0	0.0	0.0	0.0	0.0	0.0	0.0	41.3	41.3	39.0	39.6
	Total Direct Assigments												
52	Generation		40.8	40.8	0.0	43.2	43.2	0.0	43.1	27.0	(16.1)	33.3	27.8
53	Transmission		41.5	41.5	0.0	43.9	43.9	0.0	43.6	30.5	(13.1)	35.9	30.5
54	Distribution		56.3	56.3	0.0	58.9	58.9	0.0	59.2	44.5	(14.8)	49.8	44.5
55	Customer Care		30.8	30.8	0.0	31.5	31.5	0.0	30.0	1.2	(28.8)	1.6	1.3
56	Total		169.3	169.3	0.0	177.4	177.4	0.0	176.0	103.3	(72.7)	120.6	104.1
	Allocators for Balance - %												
57	Generation		24.3%	24.3%	0.0%	24.3%	24.3%	0.0%	24.2%	27.2%	2.9%	27.8%	27.9%
58	Transmission		43.4%	43.4%	0.0%	61.1%	61.1%	0.0%	-28.6%	32.4%	61.0%	32.2%	31.8%
59	Distribution		17.3%	17.3%	0.0%	-0.3%	-0.3%	0.0%	89.4%	31.4%	-58.0%	31.2%	31.6%
60	Customer Care		15.0%	15.0%	0.0%	15.0%	15.0%	0.0%	14.9%	9.0%	-5.9%	8.8%	8.8%
61	Total		100.0%	100.0%	0.0%	100.0%	100.0%	0.0%	100.0%	100.0%	0.0%	100.0%	100.0%
	Allocation of Balance												
62	Generation		38.2	23.7	(14.5)	27.3	3.7	(23.6)	(11.0)	27.9	38.8	35.2	57.2
63	Transmission		68.4	42.4	(26.0)	68.7	9.3	(59.5)	13.0	33.2	20.3	40.7	65.2
64	Distribution		27.3	16.9	(10.4)	(0.4)	(0.0)	0.3	(40.5)	32.2	72.7	39.5	64.8
65	Customer Care		23.6	14.6	(9.0)	16.9	2.3	(14.6)	(6.8)	9.3	16.0	11.1	18.0
66	Total		157.6	97.6	(60.0)	112.6	15.2	(97.4)	(45.3)	102.5	147.9	126.6	205.1

Total Current Costs - Corporate Groups
($ million)

			F2012			F2013			F2014			F2015	F2016
		Reference	RRA	Actual	Diff	RRA	Actual	Diff	RRA	Forecast	Diff	Plan	Plan
Line		Column	1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9 = 8 - 7	10	11
	Total Corporate Allocation												
67	Generation		79.0	64.5	(14.5)	70.5	46.8	(23.6)	32.1	54.9	22.8	68.5	85.0
68	Transmission		109.9	83.9	(26.0)	112.7	53.2	(59.5)	56.6	63.7	7.2	76.6	95.7
69	Distribution		83.6	73.2	(10.4)	58.5	58.8	0.3	18.7	76.7	57.9	89.3	109.3
70	Customer Care		54.4	45.4	(9.0)	48.4	33.8	(14.6)	23.3	10.5	(12.7)	12.7	19.3
71	Total		326.9	266.9	(60.0)	290.0	192.6	(97.4)	130.7	205.8	75.1	247.1	309.2

Total Current Costs - Generation
($ million)

Line	Column	Reference	F2012 RRA	F2012 Actual	F2012 Diff	F2013 RRA	F2013 Actual	F2013 Diff	F2014 RRA	F2014 Forecast	F2014 Diff	F2015 Plan	F2016 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9 = 8 - 7	10	11
1	**Cost of Energy**	4.0 L59	429.9	460.8	30.9	454.6	455.8	1.2	425.6	378.8	(46.8)	328.2	375.3
2	**Current Operating Costs**	5.0 L113	291.1	312.5	21.4	303.6	331.5	27.9	308.4	311.0	2.6	314.6	314.0
3	**Taxes**	6.0 L30	37.0	36.8	(0.3)	40.2	38.2	(2.0)	41.8	39.8	(2.0)	41.5	43.1
4	**Current Amortization**	7.0 L60	192.6	193.3	0.7	216.5	217.1	0.6	230.9	299.2	68.3	312.7	332.4
5	**Current Finance Charges**	8.0 L87	229.0	226.3	(2.7)	251.8	244.3	(7.5)	261.9	258.6	(3.3)	268.8	307.2
6	**Return on Equity**	9.0 L63	263.0	262.0	(1.0)	240.0	231.5	(8.4)	247.9	242.5	(5.4)	262.6	275.6
7	**Corporate Allocation**	3.1 L67	79.0	64.5	(14.5)	70.5	46.8	(23.6)	32.1	54.9	22.8	68.5	85.0
8	**Non-Tariff Revenue**	15.0 L5	(2.5)	(2.5)	(0.0)	(3.0)	(3.6)	(0.6)	(3.0)	(3.1)	(0.1)	(3.0)	(3.1)
	Internal Allocations												
9	GRTA Alloctation	3.4 L9	43.3	43.3	0.0	43.3	43.3	0.0	43.3	43.3	0.0	43.3	43.3
10	Generation Real Time Dispatch	3.4 L11	1.8	1.8	0.0	1.8	1.8	0.0	1.7	1.7	0.0	1.7	1.8
11	Generation Ancillary Services	3.4 L16	(3.9)	(2.3)	1.6	(3.9)	(1.6)	2.3	(3.9)	(1.6)	2.3	(1.8)	(1.8)
12	Aboriginal Relations	3.4 L15	5.3	0.0	(5.3)	5.6	0.0	(5.6)	5.3	4.4	(0.9)	19.4	19.3
13	Energy Planning & Econ Dev		0.0	0.0	0.0	0.0	0.0	0.0	0.0	(10.5)	(10.5)	(9.4)	(9.4)
14	Technology - Depreciation	3.1 L14	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(66.4)	(66.4)	(68.1)	(69.6)
15	Technology	3.1 L15	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(113.3)	(113.3)	(110.6)	(112.3)
16	Total		46.4	42.8	(3.6)	46.7	43.5	(3.2)	46.4	(142.4)	(188.8)	(125.5)	(128.7)
17	**Total**		1,565.6	1,596.4	30.8	1,620.8	1,605.1	(15.7)	1,591.8	1,439.1	(152.7)	1,468.4	1,600.8

Total Current Costs - Customer Care
($ million)

Line	Column	Reference	F2012 RRA	F2012 Actual	F2012 Diff	F2013 RRA	F2013 Actual	F2013 Diff	F2014 RRA	F2014 Forecast	F2014 Diff	F2015 Plan	F2016 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9 = 8 - 7	10	11
1	**Cost of Energy**	4.0 L62	765.7	655.9	(109.8)	955.5	784.9	(170.6)	1,163.8	1,034.8	(129.0)	1,185.9	1,138.9
2	**Current Operating Costs**	5.0 L116	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	**Taxes**	6.0 L33	1.9	1.9	(0.0)	2.0	2.0	0.0	2.1	2.1	(0.0)	4.8	5.8
4	**Current Amortization**	7.0 L63	24.7	24.7	0.0	12.6	13.7	1.1	12.6	13.7	1.1	22.8	25.8
5	**Current Finance Charges**	8.0 L90	0.1	0.0	(0.1)	(0.0)	(0.0)	0.0	(0.0)	(0.0)	0.0	(0.0)	(0.0)
6	**Return on Equity**	9.0 L66	0.1	0.0	(0.1)	(0.0)	(0.0)	0.0	(0.0)	(0.0)	0.0	(0.0)	(0.0)
7	**Corporate Allocation**	3.1 L70	54.4	45.4	(9.0)	48.4	33.8	(14.6)	23.3	10.5	(12.7)	12.7	19.3
8	**Non-Tariff Revenue**	15.0 L24-L34	(19.8)	(20.8)	(1.0)	(16.3)	(20.3)	(3.9)	(17.6)	(18.0)	(0.4)	(18.8)	(18.7)
	Internal Allocations												
9	Safety, Health & Environment	5.3 L4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	Aboriginal Relations	3.4 L15	0.0	4.5	4.5	0.0	4.7	4.7	0.0	0.0	0.0	0.0	0.0
11	Power Smart & Customer Care	3.1 L11	15.9	81.5	65.6	14.5	75.3	60.7	13.6	74.7	61.2	73.2	73.2
12	Energy Planning & Procuremt	3.1 L12	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	IPP Capital Lease Op Costs	3.1 L13	22.8	22.9	0.1	17.5	17.6	0.1	17.9	17.9	0.1	29.4	33.8
14	Energy Planning & Econ Dev	3.2 L13	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.5	10.5	9.4	9.4
15	Total		38.7	108.9	70.2	32.0	97.6	65.5	31.4	103.2	71.8	112.0	116.4
16	**Total**		865.9	816.2	(49.7)	1,034.2	911.7	(122.4)	1,215.6	1,146.3	(69.2)	1,319.3	1,287.4

Total Current Costs - Transmission
($ million)

Line	Column	Reference	F2012 RRA	F2012 Actual	F2012 Diff	F2013 RRA	F2013 Actual	F2013 Diff	F2014 RRA	F2014 Forecast	F2014 Diff	F2015 Plan	F2016 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9 = 8 - 7	10	11
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	0.0
2	**Current Operating Costs**	5.0 L114	214.1	207.8	(6.3)	223.8	231.2	7.4	223.2	220.7	(2.5)	240.1	238.0
3	**Taxes**	6.0 L31	101.8	101.8	0.0	113.6	115.5	1.9	119.6	120.6	1.0	126.1	132.0
4	**Current Amortization**	7.0 L61	132.8	134.0	1.2	143.7	143.5	(0.2)	152.5	147.5	(5.0)	158.9	187.1
5	**Current Finance Charges**	8.0 L88	122.5	124.5	2.0	138.2	135.9	(2.3)	157.2	144.8	(12.4)	167.0	233.0
6	**Return on Equity**	9.0 L64	140.7	144.2	3.5	131.7	128.8	(2.9)	148.8	135.8	(13.0)	163.1	209.0
7	**Corporate Allocation**	3.1 L68	109.9	83.9	(26.0)	112.7	53.2	(59.5)	56.6	63.7	7.2	76.6	95.7
8	**Non-Tariff Revenue**	15.0 L12	(30.7)	(26.2)	4.5	(35.7)	(29.5)	6.2	(36.2)	(32.7)	3.5	(34.7)	(39.2)
	Internal Allocations:												
9	GRTA Allocation		(43.3)	(43.3)	0.0	(43.3)	(43.3)	0.0	(43.3)	**(43.3)**	0.0	**(43.3)**	**(43.3)**
10	SDA Allocation		(108.9)	(110.2)	(1.2)	(112.6)	(107.5)	5.2	(115.4)	**(118.8)**	(3.4)	**(123.2)**	**(148.3)**
11	Generation Real Time Dispatch		(1.8)	(1.8)	0.0	(1.8)	(1.8)	0.0	(1.7)	**(1.7)**	0.0	**(1.7)**	**(1.8)**
12	Distribution Real Time Dispatch		(16.5)	(16.5)	0.0	(18.8)	(18.8)	0.0	(19.0)	**(19.0)**	0.0	**(16.7)**	**(17.1)**
13	PTP Allocation to Distribution		(12.3)	(24.9)	(12.6)	(13.3)	(16.4)	(3.1)	(11.6)	(20.2)	(8.6)	(16.8)	(29.4)
14	First Nations Comm Dev Fund		0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**	0.0	**0.0**	**0.0**
15	Aboriginal Relations		(5.3)	(4.5)	0.7	(5.6)	(4.7)	0.9	(5.3)	**(4.4)**	0.9	**(19.4)**	**(19.3)**
16	Generation Ancillary Services		3.9	2.3	(1.6)	3.9	1.6	(2.3)	3.9	**1.6**	(2.3)	**1.8**	**1.8**
17	Total		(184.1)	(198.8)	(14.7)	(191.4)	(190.8)	0.6	(192.3)	(205.8)	(13.5)	(219.4)	(257.4)
	Inter-Segment Revenue												
18	Powerex PTP Charges		(25.5)	(27.5)	(2.1)	(26.2)	(21.3)	4.9	(27.0)	**(23.4)**	3.6	**(23.4)**	**(29.2)**
19	BC Hydro PTP Charges		(11.1)	(12.8)	(1.7)	(11.1)	(35.1)	(24.0)	(11.1)	**(20.4)**	(9.3)	**(26.2)**	**(21.3)**
20	Total		(36.6)	(40.3)	(3.8)	(37.3)	(56.4)	(19.1)	(38.1)	(43.8)	(5.7)	(49.6)	(50.5)
21	**Total Current Costs**		570.4	530.8	(39.6)	599.2	531.4	(67.8)	591.2	550.9	(40.4)	628.2	747.7
	Transmission Revenue Requirement												
22	Total Current Costs	Line 21	570.4	530.8	(39.6)	599.2	531.4	(67.8)	591.2	550.9	(40.4)	628.2	747.7
23	PTP Allocation to Distribution	Line 13	12.3	24.9	12.6	13.3	16.4	3.1	11.6	20.2	8.6	16.8	29.4
24	Inter-Segment Revenue	Line 20	36.6	40.3	3.8	37.3	56.4	19.1	38.1	43.8	5.7	49.6	50.5
25	External OATT Revenue	Line 71	15.3	10.0	(5.2)	15.6	9.1	(6.5)	15.4	8.3	(7.1)	10.1	11.8
26	Total TRR		634.6	606.1	(28.5)	665.4	613.3	(52.1)	656.4	623.2	(33.2)	704.7	839.4

Total Current Costs - Transmission
($ million)

Line	Column	Reference	F2012 RRA	F2012 Actual	F2012 Diff	F2013 RRA	F2013 Actual	F2013 Diff	F2014 RRA	F2014 Forecast	F2014 Diff	F2015 Plan	F2016 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9 = 8 - 7	10	11
	NITS Charge to BC Hydro												
27	Total Current Costs	Line 21	570.4			599.2			591.2			628.2	747.7
28	Internal Ancillary Services	Line 33	(0.1)			(0.1)			(0.1)			0.0	0.0
29	Internal Scheduling & Dispatch	Line 35	(3.1)			(3.1)			(3.1)			(2.9)	(2.9)
30	Total		567.3			596.1			588.1			625.3	744.8
31	NITS Monthly Rate	Line 30 / 12	47.3			49.7			49.0			52.1	62.1
	Long-Term PTP Rate												
32	Total TRR	Line 26	634.6			665.4			656.4			704.7	839.4
33	Internal Ancillary Services		(0.1)	0.0	0.1	(0.1)	0.0	0.1	(0.1)	0.0	0.1	0.0	0.0
34	External Ancillary Services		(3.9)	(2.3)	1.6	(3.9)	(1.6)	2.3	(3.9)	(1.6)	2.3	(1.8)	(1.8)
35	Internal Scheduling & Dispatch		(3.1)	(3.0)	0.1	(3.1)	(3.3)	(0.2)	(3.1)	(3.0)	0.1	(2.9)	(2.9)
36	External Scheduling & Dispatch		(0.3)	(0.2)	0.1	(0.3)	(0.2)	0.1	(0.3)	(0.2)	0.1	(0.1)	(0.1)
37	Total		627.3			658.1			649.1			699.9	834.6
38	Maximum Supply (MW)		12,250			12,300			12,400			13,034	12,846
39	Long-Term Firm PTP Rate ($/MW/year)		51,205			53,504			52,345			53,698	64,968
	Maximum Price for Short-Term Firm and Non-Firm (per MW of Reserved Capacity)												
40	Monthly ($/MW/month)		4,267.12			4,458.65			4,362.10			4,474.87	5,413.99
41	Weekly ($/MW/week)		984.72			1,028.92			1,006.64			1,032.66	1,249.38
42	Daily ($/MW/day)		140.29			146.59			143.41			147.12	177.99
43	Hourly ($/MW/hour)		5.85			6.11			5.98			6.13	7.42
	Scheduling Fee												
44	Scheduling, Control & Dispatch	Lines 35 + 36	3.4			3.4			3.4			3.0	3.0
45	Total Volumne (GWh)		24,250			24,227			24,227			29,356	30,463
46	Scheduling Fee ($/MWh)	Line 44 / 45	0.140			0.139			0.139			0.102	0.099
	Long-Term PTP Volumes (GWh)												
47	Internal		7,106			7,087			7,087			8,926	8,926
48	External		1,318			1,314			1,314			1,314	1,314
49	Total		8,424			8,401			8,401			10,240	10,240
	Long-Term PTP Revenue												
50	Internal	Line 43 * 47	41.6	47.2	5.6	43.3	56.2	12.9	42.4	54.8	12.4	54.7	66.2
51	External	Line 43 * 48	7.7	7.3	(0.4)	8.0	6.5	(1.5)	7.9	6.4	(1.5)	8.1	9.7
52	Total		49.3	54.5	5.2	51.3	62.7	11.4	50.2	61.2	10.9	62.8	76.0
	Long-Term PTP Average Price ($/MWh)												
53	Internal	Line 50 / 47	5.85			6.11			5.98			6.13	7.42
54	External	Line 51 / 48	5.85			6.11			5.98			6.13	7.42
55	Total	Line 52 / 49	5.85			6.11			5.98			6.13	7.42

Total Current Costs - Transmission
($ million)

Line		Reference	F2012 RRA	F2012 Actual	F2012 Diff	F2013 RRA	F2013 Actual	F2013 Diff	F2014 RRA	F2014 Forecast	F2014 Diff	F2015 Plan	F2016 Plan
	Column		1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9 = 8 - 7	10	11
	Short-Term PTP Volumes (GWh)												
56	Internal		2,288			2,288			2,288			6,475	7,582
57	External		948			948			948			53	53
58	Total		3,236			3,236			3,236			6,528	7,635
	Short-Term PTP Revenue												
59	Internal		7.3	14.9	7.6	7.3	16.6	9.3	7.3	9.2	1.9	11.7	13.7
60	External		3.4	0.2	(3.2)	3.4	0.1	(3.3)	3.4	0.1	(3.3)	0.1	0.1
61	Total		10.7	15.1	4.4	10.7	16.7	6.0	10.7	9.3	(1.4)	11.8	13.8
	Short-Term PTP Average Price ($/MWh)												
62	Internal	Line 59 / 56	3.21			3.21			3.21			1.81	1.81
63	External	Line 60 / 57	3.56			3.56			3.56			1.81	1.81
64	Total	Line 61 / 58	3.31			3.31			3.31			1.81	1.81
	Total PTP Revenue												
65	Internal	Line 50 + 59	48.9	62.1	13.2	50.6	72.8	22.2	49.7	64.0	14.3	66.4	79.9
66	External	Line 51 + 60	11.1	7.5	(3.6)	11.4	6.6	(4.8)	11.2	6.5	(4.7)	8.2	9.8
67	Total		60.0	69.6	9.6	62.0	79.4	17.4	60.9	70.5	9.6	74.6	89.8
	Total External OATT Revenue												
68	Total External PTP	Line 66	11.1	7.5	(3.6)	11.4	6.6	(4.8)	11.2	6.5	(4.7)	8.2	9.8
69	External Ancillary Services	Line 34	3.9	2.3	(1.6)	3.9	1.6	(2.3)	3.9	1.6	(2.3)	1.8	1.8
70	External Scheduling & Dispatch	Line 36	0.3	0.2	(0.1)	0.3	0.2	(0.1)	0.3	0.2	(0.1)	0.1	0.1
71	Total		15.3	10.0	(5.3)	15.6	8.4	(7.2)	15.4	8.3	(7.1)	10.1	11.8

BC Hydro
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Total Current Costs - Distribution
($ million)

Line		Reference	F2012 RRA	F2012 Actual	F2012 Diff	F2013 RRA	F2013 Actual	F2013 Diff	F2014 RRA	F2014 Forecast	F2014 Diff	F2015 Plan	F2016 Plan
	Column		1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9 = 8 - 7	10	11
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	0.0
2	**Current Operating Costs**	5.0 L115	139.3	132.2	(7.1)	154.4	165.2	10.8	154.8	160.8	6.0	224.0	223.1
3	**Taxes**	6.0 L32	18.0	17.9	(0.1)	24.9	24.9	(0.1)	26.4	25.7	(0.7)	26.9	27.6
4	**Current Amortization**	7.0 L62	131.5	130.3	(1.2)	162.8	166.1	3.3	168.5	162.4	(6.2)	211.3	220.6
5	**Current Finance Charges**	8.0 L89	138.6	139.4	0.7	149.7	158.3	8.5	156.5	171.8	15.3	171.0	186.4
6	**Return on Equity**	9.0 L65	159.2	161.4	2.1	142.7	150.0	7.3	148.1	161.1	13.0	167.1	167.3
7	**Corporate Allocation**	3.1 L69	83.6	73.2	(10.4)	58.5	58.8	0.3	18.7	76.7	57.9	89.3	109.3
8	**Non-Tariff Revenue**	15.0 L16-L33	(15.5)	(17.5)	(2.0)	(41.1)	(49.0)	(7.9)	(42.2)	(47.4)	(5.2)	(49.0)	(51.1)
	Internal Allocations												
9	SDA Allocation	3.4 L10	108.9	110.2	1.2	112.6	107.5	(5.2)	115.4	118.8	3.4	123.2	148.3
10	Distribution Real Time Dispatch	3.4 L12	16.5	16.5	0.0	18.8	18.8	0.0	19.0	19.0	0.0	16.7	17.1
11	PTP Allocation to Distribution	3.4 L13	12.3	24.9	12.6	13.3	16.4	3.1	11.6	20.2	8.6	16.8	29.4
12	Total		137.7	151.493	13.8	144.7	142.6	(2.1)	146.0	158.0	12.1	156.8	194.8
13	**Total**		792.4	788.3	(4.1)	796.6	816.8	20.2	776.9	869.1	92.3	997.3	1,078.0

Cost of Energy
($ million)

Line	Column	Reference	F2012 RRA	F2012 Actual	F2012 Diff	F2013 RRA	F2013 Actual	F2013 Diff	F2014 RRA	F2014 Forecast	F2014 Diff	F2015 Plan	F2016 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9 = 8 - 7	10	11
	Cost of Energy ($ million)												
	Heritage Energy												
1	Hydroelectric (water rentals)		356.1	377.1	21.0	361.2	373.1	11.9	378.0	405.1	27.1	385.1	384.5
2	Market Electricity Purchases		37.2	18.6	(18.6)	45.7	10.1	(35.6)	23.9	31.9	8.0	44.7	56.6
3	Market Purchases to Non-Heritage		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	Natural Gas for Thermal Generation		29.3	18.3	(11.0)	41.0	17.2	(23.8)	50.4	28.4	(22.0)	26.6	26.9
5	Domestic Transmission		15.3	17.0	1.7	15.3	39.7	24.4	15.4	24.7	9.3	30.5	25.7
6	Non-Treaty Storage Agreement		0.0	0.0	0.0	0.0	(56.8)	(56.8)	0.0	(5.9)	(5.9)	(7.8)	(19.8)
7	Surplus Sales		(3.7)	(12.7)	(9.0)	(34.8)	(80.2)	(45.4)	(65.8)	(70.6)	(4.8)	(122.6)	(84.2)
8	Other		(32.0)	(29.3)	2.7	(34.7)	(33.7)	1.0	(30.8)	(47.0)	(16.2)	(44.9)	(32.1)
9	Total		402.2	389.0	(13.2)	393.8	269.4	(124.4)	371.2	366.6	(4.6)	311.6	357.6
	Non-Heritage Energy												
10	Mkt Purchases From Heritage	Line 3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	Waneta (water rentals)		8.1	8.7	0.6	8.3	8.4	0.1	8.4	7.6	(0.8)	7.7	7.4
12	IPPs and Long-Term Commitments		793.2	735.3	(57.9)	888.9	760.4	(128.5)	1,058.9	859.5	(199.4)	1,028.6	975.5
13	New Capital Leases Under IFRS		0.0	0.0	0.0	8.1	0.0	(8.1)	9.7	0.0	(9.7)	0.0	0.0
14	Non-Integrated Area		27.5	26.6	(0.9)	31.4	26.5	(4.9)	35.4	29.4	(6.0)	32.9	34.3
15	Gas & Other Transportation		14.4	15.3	0.9	13.2	13.7	0.5	12.2	12.5	0.3	11.8	12.1
16	Domestic Transmission		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
17	Net Purchases (Sales) from Powerex		(42.3)	(131.9)	(89.6)	4.7	(21.1)	(25.8)	(26.3)	16.5	42.8	(8.1)	4.8
18	Total		801.0	654.0	(147.0)	954.5	787.9	(166.6)	1,098.4	925.5	(172.9)	1,072.9	1,034.1
19	**Total Gross COE**	Lines 9+18	1,203.2	1,043.0	(160.2)	1,348.3	1,057.3	(291.0)	1,469.5	1,292.1	(177.4)	1,384.5	1,391.7
	Sources of Supply (GWh)												
	Heritage Energy												
20	Hydroelectric (water rentals)		45,252	48,821	3,569	45,167	51,107	5,940	46,514	45,328	(1,186)	46,564	46,312
21	Net Purchases (Sales) from Powerex		(1,304)	(3,993)	(2,689)	(210)	(883)	(673)	(691)	925	1,616	(199)	255
22	Market Electricity Purchases		1,610	840	(770)	1,419	359	(1,060)	660	877	217	1,224	1,553
23	Market Purchases to Non-Heritage		0	0	0	0	0	0	0	0	0	0	0
24	Natural Gas for Thermal Generation		334	143	(191)	517	122	(395)	627	284	(343)	290	301
25	Surplus Sales		(109)	(710)	(601)	(874)	(6,020)	(5,146)	(1,496)	(2,076)	(580)	(3,756)	(2,446)
26	Exchange Net		(211)	(45)	166	(447)	28	475	(572)	(661)	(89)	(530)	(204)
27	Total		45,573	45,056	(517)	45,572	44,713	(859)	45,041	44,677	(364)	43,593	45,771
	Non-Heritage Energy												
28	Waneta (water rentals)		1,008	1,008	0	1,008	1,008	0	1,003	912	(91)	914	594
29	IPPs and Long-Term Commitments		11,618	10,827	(791)	12,367	10,673	(1,694)	13,606	11,263	(2,343)	13,339	12,002
30	Mkt Purchases From Heritage	Line 23	0	0	0	0	0	0	0	0	0	0	0
31	Non-Integrated Area		120	111	(9)	126	113	(13)	132	120	(12)	133	135
32	Total		12,745	11,946	(799)	13,500	11,794	(1,706)	14,741	12,295	(2,446)	14,386	12,731
33	**Total Sources of Supply**	Lines 27+32	58,318	57,002	(1,316)	59,072	56,507	(2,565)	59,783	56,972	(2,811)	57,979	58,502
34	**Less Line Loss and System Use**		(5,399)	(5,515)	(116)	(5,544)	(5,515)	29	(5,427)	(5,135)	292	(4,849)	(4,742)
35	**Total Domestic Sales**	14.0 L9	52,919	51,487	(1,431)	53,527	50,992	(2,535)	54,356	51,837	(2,519)	53,130	53,760
36	**Line Loss as % of Sales**		10.20%	10.71%	0.51%	10.36%	10.82%	0.46%	9.98%	9.91%	-0.08%	9.13%	8.82%

Cost of Energy
($ million)

Line	Column	Reference	F2012 RRA	F2012 Actual	F2012 Diff	F2013 RRA	F2013 Actual	F2013 Diff	F2014 RRA	F2014 Forecast	F2014 Diff	F2015 Plan	F2016 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9 = 8 - 7	10	11
	Unit Costs ($/MWh)												
37	Hydroelectric (water rentals)		7.9	7.7	(0.1)	8.0	7.3	(0.7)	8.1	8.9	0.8	8.3	8.3
38	Waneta (water rentals)		8.1	8.6	0.6	8.2	8.3	0.1	8.4	8.3	(0.1)	8.4	12.5
39	IPPs and Long-Term Commitments		68.3	67.9	(0.4)	71.9	71.2	(0.6)	77.8	76.3	(1.5)	77.1	81.3
40	Market Electricity Purchases		23.1	22.1	(1.0)	32.2	28.1	(4.1)	36.3	36.4	0.1	36.5	36.4
41	Surplus Sales		(34.1)	(17.9)	16.2	(39.8)	(13.3)	26.4	(44.0)	(34.0)	10.0	(32.6)	(34.4)
42	Natural Gas for Thermal Generation		87.8	128.0	40.2	79.3	141.0	61.7	80.5	100.0	19.5	91.7	89.4
43	Non-Integrated Area		229.5	239.6	10.2	249.3	234.5	(14.8)	267.5	245.0	(22.5)	247.4	254.1
44	Total Weighted Cost		22.7	20.3	(2.5)	25.2	20.7	(4.5)	27.0	24.9	(2.1)	26.1	25.9
	Current Cost of Energy												
45	Gross Cost of Energy	Line 19	1,203.2	1,043.0	(160.2)	1,348.3	1,057.3	(291.0)	1,469.5	1,292.1	(177.4)	1,384.5	1,391.7
46	HDA Additions		0.0	31.9	31.9	0.0	123.7	123.7	0.0	(10.5)	(10.5)	0.0	0.0
47	NHDA Additions		(65.9)	(27.9)	38.0	(103.2)	(102.0)	1.2	(49.8)	(20.7)	29.1	0.0	0.0
48	BCTCDA Additions		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
49	Deferred GMS 3 COE		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
50	GMS 3 Insurance Proceeds		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
51	Water License Variances		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
52	Deferred Operating HDA		0.0	1.5	1.5	0.0	7.0	7.0	0.0	4.8	4.8	0.0	0.0
53	Deferred Operating NHDA		0.0	11.2	11.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
54	Deferred Waneta Costs		(10.0)	(10.0)	0.0	15.0	15.0	0.0	10.0	10.0	0.0	15.0	0.0
55	HDA Recoveries		27.7	27.2	(0.5)	60.8	55.8	(5.1)	54.4	17.9	(36.5)	16.6	17.7
56	NHDA Recoveries		40.5	39.8	(0.7)	89.2	84.0	(5.2)	105.2	120.0	14.8	98.0	104.8
57	BCTCDA Recoveries		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
58	Total		1,195.6	1,116.7	(78.9)	1,410.1	1,240.7	(169.4)	1,589.4	1,413.6	(175.8)	1,514.1	1,514.3
	Total Current COE by Function												
59	Generation		429.9	460.8	30.9	454.6	455.8	1.2	425.6	378.8	(46.8)	328.2	375.3
60	Transmission		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
61	Distribution		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
62	Customer Care		765.7	655.9	(109.8)	955.5	784.9	(170.6)	1,163.8	1,034.8	(129.0)	1,185.9	1,138.9
63	Corporate Groups		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
64	Total		1,195.6	1,116.7	(78.9)	1,410.1	1,240.7	(169.4)	1,589.4	1,413.6	(175.8)	1,514.1	1,514.3
	Heritage Payment Obligation												
65	Heritage Energy	Line 9	402.2	389.0	(13.2)	393.8	269.4	(124.4)	371.2	366.6	(4.6)	311.6	357.6
66	Costs in Operating/Amortization		22.4	22.3	(0.1)	19.2	19.0	(0.2)	16.2	16.2	0.0	15.7	13.0
67	Commodity Risk		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
68	Notional Water Rentals		(9.0)	(27.9)	(18.9)	(1.3)	(6.4)	(5.1)	(5.0)	6.7	11.7	(1.4)	1.9
69	Skagit and Ancillary Revenue	14.0 L17	(14.6)	(14.9)	(0.3)	(14.8)	(14.8)	(0.0)	(15.5)	(15.3)	0.2	(16.2)	(16.5)
70	Load Curtailment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
71	Water License Variances	5.0 L41	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
72	Deferred Operating HDA	5.0 L46	0.0	1.5	1.5	0.0	7.0	7.0	0.0	4.8	4.8	0.0	0.0
73	Transfer to GMS 3 Reg Account		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
74	Other		7.7	6.8	(0.9)	7.6	6.6	(1.0)	6.9	5.3	(1.6)	43.5	43.2
75	Total		408.7	376.8	(31.9)	404.5	280.8	(123.7)	373.7	384.2	10.5	353.2	399.2
76	**Total System Inflow (% of Normal)**		100%	108%	8%	100%	109%	9%	100%	98%	-2%	100%	100%

**Cost of Energy
($ million)**

Line	Column	Reference	F2012 RRA	F2012 Actual	F2012 Diff	F2013 RRA	F2013 Actual	F2013 Diff	F2014 RRA	F2014 Forecast	F2014 Diff	F2015 Plan	F2016 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9 = 8 - 7	10	11
	Non-Heritage COE Subject to NHDA												
77	Non-Heritage Cost of Energy	Line 18	801.0	654.0	(147.0)	954.5	787.9	(166.6)	1,098.4	925.5	(172.9)	1,072.9	1,034.1
78	Commodity Risk		0.0	12.9	12.9	0.0	(3.9)	(3.9)	0.0	7.8	7.8	0.0	0.0
79	F/X Gains on Powerex Trade		0.0	2.4	2.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
80	Less Domestic Transmission	Line 16	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
81	Notional Water Rental	Line 68	9.0	27.9	18.9	1.3	6.4	5.1	5.0	(6.7)	(11.7)	1.4	(1.9)
82	Revenue Variance		0.0	62.8	62.8	0.0	176.1	176.1	0.0	146.3	146.3	0.0	0.0
83	ROE Adjustment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
84	ABSU Founding Partner Benefits		(0.4)	0.2	0.6	(0.4)	0.0	0.4	0.0	0.0	0.0	0.0	0.0
85	Deferred Operating NHDA	5.0 L47	0.0	11.2	11.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
86	Other		0.0	0.3	0.3	0.0	(12.2)	(12.2)	0.0	1.4	1.4	0.0	0.0
87	F11 NSA & F12-F14 Adjustments		(65.9)	0.0	65.9	(103.2)	0.0	103.2	(49.8)	0.0	49.8	0.0	0.0
88	Total		743.9	771.7	27.9	852.3	954.3	102.0	1,053.6	1,074.3	20.7	1,074.3	1,032.2
	IPP Summary												
89	IPP Costs in Non-Heritage COE	Line 12	793.2	735.3	(57.9)	888.9	760.4	(128.5)	1,058.9	859.5	(199.4)	1,028.6	975.5
90	Less COE Impact of New Leases	Line 13	0.0	0.0	0.0	8.1	0.0	(8.1)	9.7	0.0	(9.7)	0.0	0.0
	Existing Capital Leases												
91	Operating Costs	5.1 L13	22.8	22.9	0.1	11.7	17.6	5.9	12.0	17.9	6.0	29.4	33.8
92	Taxes	6.0 L12	2.0	2.0	(0.0)	2.0	2.0	0.0	2.1	2.1	(0.0)	4.8	5.8
93	Amortization	7.0 L23	24.7	24.7	0.0	0.5	13.7	13.2	0.5	13.7	13.2	22.8	25.8
94	Finance Charges	8.0 L57	21.0	21.0	0.0	29.1	25.6	(3.5)	27.5	24.1	(3.4)	77.3	93.9
95	Total		70.5	70.6	0.1	43.3	59.0	15.7	42.1	57.8	15.8	134.3	159.2
	New IPP Capital Leases Under IFRS												
96	Operating Costs		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
97	Taxes		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
98	Amortization		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
99	Finance Charges		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
100	Total		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
101	Total Costs in Revenue Requirement		863.8	805.9	(57.9)	940.3	819.4	(120.9)	1,110.7	917.3	(193.3)	1,162.9	1,134.7
102	Total Payments to IPPs		865.5	805.1	(60.4)	961.1	850.1	(111.0)	1,130.2	923.6	(206.6)	1,162.5	1,130.9
103	Difference	Line 101 - 102	(1.7)	0.8	2.5	(20.8)	(30.7)	(9.9)	(19.5)	(6.3)	13.3	0.4	3.8
	IPP Capital Leases												
	Gross Assets in Service												
104	Opening Balance			479.7			479.7			388.2		388.2	1,113.2
105	Adjustment to Opening Balance			0.0			(91.5)			0.0		0.0	0.0
106	Capital Additions			0.0			0.0			0.0		725.0	0.0
107	Retirements & Transfers			0.0			0.0			0.0		0.0	0.0
108	Closing Balance			479.7			388.2			388.2		1,113.2	1,113.2
	Accumulated Amortization												
109	Opening Balance			14.0			38.7			145.8		159.5	182.3
110	Adjustment to Opening Balance			0.0			93.4			0.0		0.0	0.0
111	Amortization			24.7			13.7			13.7		22.8	25.8
112	Retirements & Transfers			0.0			0.0			0.0		0.0	0.0
113	Closing Balance			38.7			145.8			159.5		182.3	208.1
114	**Net Capital Leases (Year-End)**			441.0			242.4			228.7		930.9	905.1

Operating Costs and Provisions - Total Company
($ million)

Line	Reference / Column	F2012 RRA	F2012 Actual	F2012 Diff	F2013 RRA	F2013 Actual	F2013 Diff	F2014 RRA	F2014 Forecast	F2014 Diff	F2015 Plan	F2016 Plan
		1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9 = 8 - 7	10	11
	Operating Costs by Business Group											
1	Generation	286.7	300.3	13.6	294.7	309.9	15.2	299.2	299.4	0.2	298.1	298.5
2	Transmission & Distribution	328.6	319.9	(8.7)	334.0	351.8	17.8	334.4	336.7	2.3	339.3	335.4
3	Customer Care	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	Corporate Groups (excl PEB)	109.6	101.3	(8.3)	108.7	93.0	(15.7)	111.8	116.1	4.3	155.7	193.1
5	Severance Costs	10.1	9.5	(0.6)	5.6	0.0	(5.6)	3.1	0.0	(3.1)	0.0	0.0
6	Non-Current PEB - Pension	17.7	17.9	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	Non-Current PEB - Other	30.3	30.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	F09/F10 RRA Adjustments	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	F11 RRA NSA Adjustment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	F12-F14 RRA Adjustment	4.3	0.0	(4.3)	10.8	0.0	(10.8)	3.6	0.0	(3.6)	0.0	0.0
11	Total Before Regulatory Accounts	787.3	779.2	(8.1)	753.8	754.7	0.9	752.2	752.3	0.1	793.2	826.9
	Operating Costs by Resource											
12	Labour (excl Non-Current PEB)	476.3	461.2	(15.1)	473.4	475.0	1.5	464.7	474.4	9.7	471.3	478.1
13	Services - ABSU	99.3	114.1	14.8	95.2	83.5	(11.6)	99.4	60.1	(39.4)	58.9	59.0
14	Services - BCTC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	Services - Other	363.3	360.7	(2.6)	358.7	399.1	40.4	356.0	401.7	45.7	423.9	427.8
16	Materials	34.8	41.9	7.1	35.5	40.6	5.2	35.6	41.0	5.4	40.2	40.1
17	Buildings & Equipment	62.4	49.8	(12.6)	66.5	49.2	(17.3)	68.7	52.5	(16.1)	48.8	49.6
18	Capitalized Overhead	(281.1)	(281.2)	(0.1)	(265.2)	(259.2)	6.0	(249.3)	(243.3)	5.9	(222.2)	(199.8)
19	External Recoveries	(30.1)	(25.1)	5.0	(26.7)	(33.6)	(6.9)	(29.6)	(34.0)	(4.4)	(27.7)	(27.8)
20	Severance Costs	10.1	9.5	(0.6)	5.6	0.0	(5.6)	3.1	0.0	(3.1)	0.0	0.0
21	Non-Current PEB - Pension	17.7	17.9	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22	Non-Current PEB - Other	30.3	30.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23	F09/F10 RRA Adjustments	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
24	F11 RRA NSA Adjustment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
25	F12-F14 RRA Adjustment	4.3	0.0	(4.3)	10.8	0.0	(10.8)	3.6	0.0	(3.6)	0.0	0.0
26	Total Before Regulatory Accounts	787.3	779.2	(8.1)	753.8	754.7	0.9	752.2	752.3	0.1	793.2	826.9
	Regulatory Account Recoveries											
27	DSM - F11 RRA NSA Adjustment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
28	First Nation Costs	7.0	6.5	(0.5)	7.6	6.8	(0.8)	6.9	5.9	(1.0)	43.5	43.2
29	Site C	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
30	Storm Restoration	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(1.4)	(1.4)
31	PEI - F11 RRA NSA Adjustment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
32	Procurement Enhancement	39.7	39.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
33	Capital Project Investigation	4.9	4.6	(0.3)	4.9	4.4	(0.5)	4.9	4.8	(0.1)	4.8	4.8
34	Net Employment Costs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
35	Smart Metering & Infrastructure	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30.5	31.3
36	Home Purchase Offer Plan	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11.8	11.3
37	Non-Current Pension Cost	17.1	16.9	(0.2)	17.1	17.1	(0.0)	17.1	17.1	0.0	32.6	15.5
38	IFRS PP&E	0.0	0.0	0.0	4.7	4.7	0.0	8.7	8.7	(0.0)	15.9	19.8
39	IFRS Pension	0.0	0.0	0.0	38.9	38.9	0.0	34.7	34.7	0.0	38.2	38.2
40	Total	68.7	67.7	(0.9)	73.2	71.9	(1.3)	72.3	71.2	(1.1)	176.0	162.9
	Deferral Account Recoveries											
41	Water License Variances	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Operating Costs and Provisions - Total Company
($ million)

Line		Reference	F2012 RRA	F2012 Actual	F2012 Diff	F2013 RRA	F2013 Actual	F2013 Diff	F2014 RRA	F2014 Forecast	F2014 Diff	F2015 Plan	F2016 Plan
	Column		1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9 = 8 - 7	10	11
	Current IFRS Impact												
42	New IPP Capital Leases		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
43	Other Operating Costs		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
44	Total		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
45	**Total Current Operating**	L 11+40+41+44	856.0	846.9	(9.0)	827.0	826.6	(0.4)	824.5	823.5	(1.0)	969.1	989.9
	Deferral Account Additions												
46	Transfers to HDA		0.0	1.5	1.5	0.0	7.0	7.0	0.0	4.8	4.8	0.0	0.0
47	Transfers to NHDA		0.0	11.2	11.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
48	Total		0.0	12.7	12.7	0.0	7.0	7.0	0.0	4.8	4.8	0.0	0.0
	Regulatory Account Additions												
49	Demand-Side Management		184.6	173.4	(11.2)	199.8	147.6	(52.2)	236.3	151.3	(85.0)	150.5	131.1
50	First Nations Costs		6.5	1.6	(4.9)	3.3	0.5	(2.8)	3.3	3.6	0.3	3.5	3.0
51	Site C		119.0	71.0	(48.0)	148.0	67.1	(80.9)	88.0	90.0	2.0	0.0	0.0
52	Storm Restoration		0.0	2.1	2.1	0.0	(3.1)	(3.1)	0.0	0.0	0.0	0.0	0.0
53	Procurement Enhancement		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
54	Capital Project Investigation		0.0	(0.1)	(0.1)	0.0	(0.6)	(0.6)	0.0	0.0	0.0	0.0	0.0
55	GM Shrum 3		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
56	Smart Metering & Infrastructure		46.4	14.6	(31.8)	50.4	37.4	(13.0)	15.2	25.5	10.3	28.4	21.5
57	Home Purchase Offer Plan		4.4	0.7	(3.7)	1.7	0.2	(1.5)	0.0	0.0	0.0	0.0	0.0
58	IFRS Capitalized Overhead		178.0	214.8	36.8	160.2	197.1	36.9	142.4	179.2	36.8	156.8	134.4
59	Outsourcing Implementation		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
60	Bad Debt (Meziadin Lake)		0.0	0.5	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
61	Total		538.9	478.6	(60.3)	563.4	446.2	(117.2)	485.2	449.6	(35.6)	339.2	290.0
62	**Total Gross Operating**	L 11+44+48+61	1,326.2	1,270.5	(55.7)	1,317.2	1,207.9	(109.2)	1,237.4	1,206.7	(30.7)	1,132.4	1,116.9
	Current Operating by Business Group												
63	Generation		291.6	304.9	13.3	299.6	314.3	14.7	304.2	304.2	0.1	303.0	303.3
64	Transmission		201.1	195.5	(5.6)	206.1	215.9	9.8	205.7	206.1	0.4	224.4	222.4
65	Distribution		134.5	130.9	(3.6)	135.4	142.6	7.2	135.6	136.5	0.9	187.6	186.2
66	Customer Care		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
67	Corporate Groups (excl PEB)		149.3	141.0	(8.2)	152.3	136.6	(15.7)	155.2	159.5	4.3	221.6	262.5
68	Severance Costs	Line 5	10.1	9.5	(0.6)	5.6	0.0	(5.6)	3.1	0.0	(3.1)	0.0	0.0
69	Non-Current PEB - Pension	Lines 6 + 37	34.8	34.8	(0.0)	17.1	17.1	(0.0)	17.1	17.1	0.0	32.6	15.5
70	Non-Current PEB - Other	Line 7	30.3	30.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
71	F09/F10 RRA Adjustments	Line 8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
72	F11 RRA NSA Adjustment	Line 9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
73	F12-F14 RRA Adjustment	Line 10	4.3	0.0	(4.3)	10.8	0.0	(10.8)	3.6	0.0	(3.6)	0.0	0.0
74	Total		856.0	846.9	(9.0)	827.0	826.6	(0.4)	824.5	823.5	(1.0)	969.1	989.9

Operating Costs and Provisions - Total Company
($ million)

Line		Reference	F2012 RRA	F2012 Actual	F2012 Diff	F2013 RRA	F2013 Actual	F2013 Diff	F2014 RRA	F2014 Forecast	F2014 Diff	F2015 Plan	F2016 Plan
	Column		1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9 = 8 - 7	10	11
	Provisions Before Regulatory Accounts												
75	Generation		(1.3)	7.3	8.6	3.2	16.9	13.7	3.3	6.3	3.0	3.5	3.6
76	Transmission		5.2	5.7	0.5	9.6	9.0	(0.7)	9.4	7.5	(1.9)	8.0	8.3
77	Distribution		0.3	0.1	(0.2)	13.1	21.5	8.4	13.3	21.4	8.1	21.9	22.7
78	Customer Care		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
79	Corporate Groups		1.1	7.6	6.5	5.0	6.5	1.5	4.2	5.1	0.9	15.1	5.1
80	Increase in Mass Asset Rtmts		0.0	0.0	0.0	0.0	0.0	(0.0)	0.0	0.0	(0.0)	0.0	0.0
81	FRSR Write-Off		0.0	(0.4)	(0.4)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
82	Real Property Sales		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(10.0)	(10.0)
83	Total		5.3	20.4	15.1	30.9	53.9	22.9	30.2	40.3	10.1	38.4	29.7
	Deferred Provisions												
84	First Nations Provisions		16.3	149.4	133.1	0.0	0.0	0.0	0.0	18.4	18.4	0.0	0.0
85	Environmental Provisions		6.3	11.1	4.8	0.0	46.0	46.0	0.0	1.6	1.6	0.0	0.0
86	Arrow Water Divestiture Costs		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
87	Arrow Water Provision		0.6	0.6	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
88	Total		23.2	161.1	137.9	0.0	46.0	46.0	0.0	20.0	20.0	0.0	0.0
89	**Total Gross Provisions**	Lines 83 + 88	28.5	181.4	152.9	30.9	99.9	68.9	30.2	60.3	30.1	38.4	29.7
	Recovery of Deferred Provisions												
	PCB Remediation												
90	Generation		0.8	0.0	(0.8)	0.9	0.0	(0.8)	0.9	0.2	(0.7)	0.1	0.3
91	Transmission		7.8	6.6	(1.2)	8.0	6.2	(1.8)	8.1	7.1	(1.0)	7.5	7.1
92	Distribution		4.5	1.6	(2.9)	5.9	1.1	(4.8)	6.0	2.9	(3.1)	5.7	5.6
93	Corporate		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.3	0.2
94	Asbestos Remediation												
95	Generation		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.1	2.0
96	Transmission		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.2
97	Distribution		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.9	8.6
98	Corporate		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
99	Rock Bay Remediation		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	51.5	50.5
100	Arrow Water Divestiture Costs		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.7	4.5
101	Arrow Water Provision		0.0	0.3	0.3	0.0	0.3	0.3	0.0	0.3	0.3	0.3	0.3
102	F12-F14 Rate Smoothing		69.7	69.7	0.0	41.2	41.2	0.0	(110.9)	(110.9)	0.0	0.0	0.0
103	Rate Smoothing		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(166.2)	(121.2)
104	Total		82.9	78.2	(4.7)	55.9	48.8	(7.1)	(96.0)	(100.4)	(4.4)	(84.0)	(41.9)
105	**Total Current Provisions**	Lines 83 + 104	88.2	98.6	10.4	86.8	102.7	15.8	(65.7)	(60.1)	5.7	(45.6)	(12.1)
	Current Provisions by Business Group												
106	Generation		(0.5)	7.6	8.1	4.0	17.2	13.2	4.2	6.8	2.6	11.6	10.8
107	Transmission		13.0	12.3	(0.7)	17.6	15.2	(2.4)	17.5	14.5	(2.9)	15.7	15.6
108	Distribution		4.8	1.4	(3.5)	19.0	22.6	3.6	19.3	24.3	5.0	36.4	36.9
109	Customer Care		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
110	Corporate Groups		70.8	77.3	6.5	46.2	47.7	1.5	(106.7)	(105.7)	1.0	(109.3)	(75.4)
111	Total		88.2	98.6	10.4	86.8	102.7	15.8	(65.7)	(60.1)	5.7	(45.6)	(12.1)
112	**Total Gross Operating & Provisions**		1,354.7	1,452.0	97.3	1,348.1	1,307.8	(40.3)	1,267.6	1,267.0	(0.6)	1,170.8	1,146.6

Operating Costs and Provisions - Total Company
($ million)

		F2012			F2013			F2014			F2015	F2016
	Reference	RRA	Actual	Diff	RRA	Actual	Diff	RRA	Forecast	Diff	Plan	Plan
Line	Column	1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9 = 8 - 7	10	11
	Total Current Operating & Provisions											
113	Generation	291.1	312.5	21.4	303.6	331.5	27.9	308.4	311.0	2.6	314.6	314.0
114	Transmission	214.1	207.8	(6.3)	223.8	231.2	7.4	223.2	220.7	(2.5)	240.1	238.0
115	Distribution	139.3	132.2	(7.1)	154.4	165.2	10.8	154.8	160.8	6.0	224.0	223.1
116	Customer Care	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
117	Corporate Groups (excl PEB)	220.1	218.4	(1.7)	198.5	184.3	(14.2)	48.5	53.8	5.2	112.2	187.1
118	Severance Costs	10.1	9.5	(0.6)	5.6	0.0	(5.6)	3.1	0.0	(3.1)	0.0	0.0
119	Non-Current PEB - Pension	34.8	34.8	(0.0)	17.1	17.1	(0.0)	17.1	17.1	0.0	32.6	15.5
120	Non-Current PEB - Other	30.3	30.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
121	F09/F10 RRA Adjustments	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
122	F11 RRA NSA Adjustment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
123	F12-F14 RRA Adjustment	4.3	0.0	(4.3)	10.8	0.0	(10.8)	3.6	0.0	(3.6)	0.0	0.0
124	Total	944.1	945.5	1.4	913.8	929.3	15.4	758.7	763.4	4.6	923.6	977.7

BC Hydro
F15-F16 RRA

Operating Costs - Corporate Groups
($ million)

Line		Reference	F2012 RRA	F2012 Actual	F2012 Diff	F2013 RRA	F2013 Actual	F2013 Diff	F2014 RRA	F2014 Forecast	F2014 Diff	F2015 Plan	F2016 Plan
	Column		1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9 = 8 - 7	10	11
	Operating Costs by KBU												
1	Executive		3.1	2.8	(0.3)	2.4	0.9	(1.5)	2.4	0.9	(1.6)	**0.9**	**0.9**
2	Sustainability		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	Communications		15.9	15.4	(0.6)	14.5	12.2	(2.3)	13.6	12.3	(1.3)	**12.3**	**12.2**
4	Customer Care and Power Smart		73.8	81.5	7.7	74.2	75.3	1.0	74.7	74.7	0.1	**73.2**	**73.2**
5	Corporate Human Resources		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	Safety, Health & Environment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	Human Resources		50.7	48.7	(1.9)	50.1	49.4	(0.7)	50.6	49.1	(1.5)	**54.5**	**54.6**
8	Finance & Corporate Resources		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	0.0	0.0
9	Finance & Supply Chain		57.1	54.3	(2.8)	54.4	63.6	9.2	55.5	72.3	16.8	**64.7**	**64.6**
10	Corporate Services & General Counsel		50.9	50.8	(0.1)	51.4	50.3	(1.1)	51.0	51.0	(0.0)	**52.7**	**52.6**
11	Energy Planning & Procurement		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	Economic & Business Development		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	IPP Capital Lease Operating Costs		22.8	22.9	0.1	17.5	17.6	0.1	17.9	17.9	0.1	**29.4**	**33.8**
14	Smart Metering & Infrastructure		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	Corporate Costs		(106.7)	(117.4)	(10.7)	(150.2)	(176.3)	(26.0)	(150.6)	(162.0)	(11.4)	**(132.1)**	**(98.7)**
16	Total		167.7	159.0	(8.7)	114.3	93.0	(21.3)	114.9	116.1	1.2	155.7	193.1
	Operating Costs by Resource												
17	Labour		170.1	158.1	(11.9)	114.3	122.0	7.7	97.4	125.2	27.8	125.2	130.9
18	Services - ABSU		57.9	63.2	5.3	51.3	59.4	8.1	52.1	57.8	5.8	56.6	56.8
19	Services - BCTC		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
20	Services - Other		128.4	129.1	0.7	119.2	114.6	(4.6)	118.2	119.7	1.5	142.8	152.3
21	Materials		16.5	15.7	(0.8)	17.1	15.1	(1.9)	17.0	14.4	(2.6)	15.7	15.7
22	Buildings & Equipment		16.0	14.1	(1.9)	15.9	12.2	(3.7)	16.0	10.9	(5.0)	10.4	10.1
23	Capitalized Overhead		(221.3)	(221.3)	(0.1)	(203.5)	(229.1)	(25.6)	(185.7)	(212.0)	(26.3)	(195.1)	(172.7)
24	External Recoveries		0.0	0.0	0.0	0.0	(1.3)	(1.3)	0.0	0.0	0.0	0.0	0.0
25	Total		167.7	159.0	(8.7)	114.3	93.0	(21.3)	114.9	116.1	1.2	155.7	193.1

Operating Costs - Generation
($ million)

		F2012			F2013			F2014			F2015	F2016
	Reference	RRA	Actual	Diff	RRA	Actual	Diff	RRA	Forecast	Diff	Plan	Plan
Line	Column	1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9 = 8 - 7	10	11
	Operating Costs by KBU											
1	Engineering	9.0	7.3	(1.7)	8.9	6.6	(2.3)	9.0	6.4	(2.6)	6.9	6.9
2	Dam Safety	7.3	7.9	0.5	8.5	7.7	(0.8)	8.2	9.4	1.2	9.5	9.5
3	Generation Asset Mgmt.	9.7	8.5	(1.2)	9.6	10.2	0.5	9.6	9.9	0.3	10.3	10.3
4	Generation Project Delivery	6.8	6.0	(0.8)	6.5	7.1	0.6	6.6	6.3	(0.2)	7.3	7.4
5	Generation Operations	86.7	91.8	5.1	92.9	96.8	3.9	96.5	90.5	(6.0)	91.0	91.0
6	Operational Safety	9.1	9.0	(0.0)	10.1	10.0	(0.1)	10.2	10.2	(0.1)	10.5	10.6
7	Environmental Risk Management	31.4	31.1	(0.3)	29.6	28.5	(1.1)	28.1	26.8	(1.3)	25.6	25.6
8	Generation Resource Mgmt	13.3	13.4	0.1	13.7	13.4	(0.3)	13.6	12.8	(0.9)	13.2	13.3
9	Energy Planning & Econ Development	12.1	12.5	0.5	12.3	10.4	(1.8)	11.3	10.5	(0.7)	9.4	9.4
10	Aboriginal Relations	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	Business Support	(0.7)	12.3	13.1	(6.0)	17.5	23.4	(6.5)	3.2	9.7	3.9	2.1
12	Technology	102.1	100.5	(1.6)	108.6	101.7	(6.9)	112.5	113.3	0.8	110.6	112.3
13	Total	286.7	300.3	13.6	294.7	309.9	15.2	299.2	299.4	0.2	298.1	298.5
	Operating Costs by Resource											
14	Labour	134.0	138.3	4.3	132.2	136.4	4.2	133.8	137.4	3.6	136.9	137.2
15	Services - ABSU	39.8	49.0	9.2	42.2	22.2	(20.0)	45.8	0.6	(45.3)	0.5	0.5
16	Services - BCTC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
17	Services - Other	107.2	101.8	(5.3)	106.9	129.6	22.7	107.0	142.6	35.6	140.9	139.7
18	Materials	7.8	10.7	2.9	7.8	13.2	5.4	7.8	11.4	3.6	9.7	9.7
19	Buildings & Equipment	28.5	24.1	(4.4)	32.6	27.6	(5.0)	34.6	32.6	(1.9)	30.3	31.4
20	Capitalized Overhead	(11.3)	(11.3)	(0.0)	(11.7)	(2.1)	9.6	(12.0)	(2.3)	9.7	(2.3)	(2.3)
21	External Recoveries	(19.3)	(12.4)	7.0	(15.3)	(17.0)	(1.7)	(17.8)	(22.9)	(5.1)	(17.9)	(17.9)
22	Total	286.7	300.3	13.6	294.7	309.9	15.2	299.2	299.4	0.2	298.1	298.5

Operating Costs - Customer Care
($ million)

Line	Column	Reference	F2012 RRA	F2012 Actual	F2012 Diff	F2013 RRA	F2013 Actual	F2013 Diff	F2014 RRA	F2014 Forecast	F2014 Diff	F2015 Plan	F2016 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9 = 8 - 7	10	11
	Operating Costs by KBU												
1	Power Smart & Customer Care		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	Energy Planning & Procurement		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	Chief Technology Office		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	Safety, Health & Environment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	Aboriginal Relations & Negotiations		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	Economic & Business Development		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	Business Unit Support		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	IPP Capital Lease Operating Costs		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Total		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Operating Costs by Resource												
10	Labour		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	Services - ABSU		0.0	0.0	0.0	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	0.0
13	Services - Other		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	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	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	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	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	0.0
18	Total		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Operating Costs - Transmission & Distribution
($ million)

Line	Column	Reference	F2012 RRA	F2012 Actual	F2012 Diff	F2013 RRA	F2013 Actual	F2013 Diff	F2014 RRA	F2014 Forecast	F2014 Diff	F2015 Plan	F2016 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9 = 8 - 7	10	11
	Operating Costs by KBU												
1	Distribution Operations		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	Transmission & Construction Services		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	Operational Support Services		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	Transmission Owner		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	Field Operations & Safety		113.5	113.6	0.1	116.3	118.3	2.0	118.9	109.9	(8.9)	110.6	110.4
6	Grid Operations		34.9	32.9	(1.9)	37.2	35.4	(1.7)	39.0	35.5	(3.4)	37.3	37.4
7	Asset Investment Management		163.8	159.8	(4.1)	169.9	164.4	(5.5)	167.7	150.1	(17.6)	148.2	147.1
8	Project & Program Delivery		11.5	11.7	0.2	11.6	13.1	1.5	12.0	13.9	1.9	14.5	14.5
9	Engineering and Design		25.1	21.6	(3.6)	22.4	21.1	(1.3)	22.9	19.4	(3.5)	22.4	22.5
10	Aboriginal Relations		6.0	4.6	(1.4)	6.0	4.4	(1.6)	6.1	5.5	(0.5)	5.0	5.1
11	Smart Metering & Infrastructure		0.0	(0.0)	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	Business Support		(26.3)	(24.3)	2.0	(29.4)	(4.9)	24.5	(32.0)	2.4	34.4	1.3	(1.5)
13	Total		328.6	319.9	(8.7)	334.0	351.8	17.8	334.4	336.7	2.3	339.3	335.4
	Operating Costs by Resource												
14	Labour		230.3	222.4	(7.9)	232.5	216.6	(15.9)	236.6	211.7	(24.9)	209.3	209.9
15	Services - ABSU		1.6	1.8	0.3	1.6	2.0	0.4	1.6	1.7	0.1	1.7	1.7
16	Services - BCTC		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
17	Services - Other		127.7	129.8	2.1	132.7	155.0	22.3	130.7	139.4	8.7	140.2	135.8
18	Materials		10.5	15.5	5.0	10.6	12.2	1.7	10.8	15.2	4.5	14.8	14.7
19	Buildings & Equipment		17.9	11.6	(6.3)	18.0	9.4	(8.6)	18.1	8.9	(9.2)	8.1	8.0
20	Capitalized Overhead		(48.6)	(48.6)	0.0	(50.0)	(28.0)	22.0	(51.6)	(29.1)	22.5	(24.9)	(24.9)
21	External Recoveries		(10.7)	(12.7)	(2.0)	(11.5)	(15.4)	(3.9)	(11.8)	(11.1)	0.6	(9.8)	(9.9)
22	Total		328.6	319.9	(8.7)	334.0	351.8	17.8	334.4	336.7	2.3	339.3	335.4
	Operating Costs by Function												
23	Allocation to Transmission (%)		59.1%	59.1%		59.5%	59.5%		59.5%	59.5%		53.3%	53.4%
24	Transmission		194.1	189.0	(5.2)	198.5	209.1	10.6	198.9	200.2	1.4	180.9	179.1
25	Distribution		134.5	130.9	(3.6)	135.4	142.6	7.2	135.6	136.5	0.9	158.5	156.2
26	Total		328.6	319.9	(8.7)	334.0	351.8	17.8	334.4	336.7	2.3	339.3	335.4

BC Hydro
F15-F16 RRA

Schedule 6.0
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Taxes
($ million)

Line	Column	Reference	F2012 RRA	F2012 Actual	F2012 Diff	F2013 RRA	F2013 Actual	F2013 Diff	F2014 RRA	F2014 Forecast	F2014 Diff	F2015 Plan	F2016 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9 = 8 - 7	10	11
	Generation												
1	Grants in Lieu		19.9	19.9	(0.0)	20.9	20.8	(0.1)	22.0	22.0	0.0	23.1	24.3
2	School Taxes		18.5	18.2	(0.3)	19.3	17.4	(1.9)	19.8	17.7	(2.1)	18.3	18.8
3	Total		38.4	38.1	(0.3)	40.2	38.2	(2.0)	41.8	39.8	(2.0)	41.5	43.1
	Transmission												
4	Grants in Lieu		35.0	35.2	0.2	37.5	38.4	0.9	40.8	42.4	1.6	45.0	46.8
5	School Taxes		73.1	72.9	(0.2)	76.1	77.1	1.0	78.8	78.2	(0.6)	81.1	85.2
6	Total		108.1	108.1	0.0	113.6	115.5	1.9	119.6	120.6	1.0	126.1	132.0
	Distribution												
7	Grants in Lieu		5.4	5.4	0.0	5.9	5.9	(0.0)	6.6	6.4	(0.3)	6.9	7.2
8	School Taxes		18.2	18.1	(0.1)	19.0	19.0	(0.0)	19.7	19.3	(0.4)	20.0	20.4
9	Total		23.6	23.5	(0.1)	24.9	24.9	(0.1)	26.4	25.7	(0.7)	26.9	27.6
	Customer Care												
10	Grants in Lieu		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	School Taxes		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	Existing IPP Capital Leases		2.0	2.0	(0.0)	2.0	2.0	0.0	2.1	2.1	(0.0)	4.8	5.8
13	New Capital Leases Under IFRS		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	Total		2.0	2.0	(0.0)	2.0	2.0	0.0	2.1	2.1	(0.0)	4.8	5.8
	Corporate Groups												
15	Grants in Lieu		7.5	7.6	0.1	7.8	8.4	0.6	8.1	9.0	1.0	9.3	10.2
16	School Taxes		4.5	4.9	0.5	4.6	5.1	0.5	4.8	5.0	0.2	5.3	5.6
17	Total		11.9	12.5	0.6	12.4	13.5	1.1	12.9	14.0	1.1	14.6	15.8
	Total Before Regulatory Accounts												
18	Grants in Lieu		67.7	68.0	0.3	72.1	73.4	1.3	77.5	79.8	2.3	84.4	88.5
19	School Taxes		114.2	114.2	0.0	119.0	118.6	(0.4)	123.1	120.2	(2.9)	124.7	129.9
20	IPP Capital Leases		2.0	2.0	(0.0)	2.0	2.0	0.0	2.1	2.1	(0.0)	4.8	5.8
21	Total		183.9	184.2	0.3	193.1	194.1	1.0	202.7	202.1	(0.6)	213.8	224.1
	Regulatory Account Recoveries												
22	Generation		(1.4)	(1.4)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23	Transmission		(6.3)	(6.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
24	Distribution		(5.6)	(5.6)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
25	Customer Care		(0.1)	(0.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
26	Corporate Groups		(0.4)	(0.7)	(0.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
27	Total		(13.7)	(14.0)	(0.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
28	**Total Current Taxes**	Lines 21+27	170.2	170.2	(0.0)	193.1	194.1	1.0	202.7	202.1	(0.6)	213.8	224.1
29	**Total Gross Taxes**	Line 21	183.9	184.2	0.3	193.1	194.1	1.0	202.7	202.1	(0.6)	213.8	224.1
	Total Current Taxes by Business Group												
30	Generation		37.0	36.8	(0.3)	40.2	38.2	(2.0)	41.8	39.8	(2.0)	41.5	43.1
31	Transmission		101.8	101.8	0.0	113.6	115.5	1.9	119.6	120.6	1.0	126.1	132.0
32	Distribution		18.0	17.9	(0.1)	24.9	24.9	(0.1)	26.4	25.7	(0.7)	26.9	27.6
33	Customer Care		1.9	1.9	(0.0)	2.0	2.0	0.0	2.1	2.1	(0.0)	4.8	5.8
34	Corporate Groups		11.5	11.8	0.3	12.4	13.5	1.1	12.9	14.0	1.1	14.6	15.8
35	Total		170.2	170.2	(0.0)	193.1	194.1	1.0	202.7	202.1	(0.6)	213.8	224.1

Depreciation and Amortization
($ million)

Line		Reference	F2012 RRA	F2012 Actual	F2012 Diff	F2013 RRA	F2013 Actual	F2013 Diff	F2014 RRA	F2014 Forecast	F2014 Diff	F2015 Plan	F2016 Plan
	Column		1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9 = 8 - 7	10	11
	Amortization of Capital Assets												
1	Generation	12.2 L8+9	157.0	157.9	0.9	167.6	169.2	1.5	170.0	242.3	72.3	246.8	257.4
2	Transmission	12.4 L8+9+10	133.7	135.1	1.4	138.2	138.2	(0.0)	145.7	141.2	(4.5)	151.6	178.8
3	Distribution	12.5 L8+9	164.2	163.1	(1.1)	170.3	173.6	3.3	174.9	168.7	(6.2)	217.6	225.3
4	Customer Care	12.3 L8+9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	Corporate Groups	12.1 L8+9	80.6	77.9	(2.7)	94.2	87.5	(6.7)	93.2	32.6	(60.6)	35.3	39.5
6	Total		535.5	534.1	(1.5)	570.4	568.5	(1.9)	583.8	584.8	1.0	651.3	701.0
	Amortization of Contributions												
7	Generation		(2.2)	(2.2)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	Transmission		(5.1)	(5.2)	(0.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Distribution		(24.2)	(24.3)	(0.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	Total		(31.5)	(31.7)	(0.2)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Dismantling Costs												
11	Generation		19.3	4.9	(14.4)	5.9	(0.6)	(6.4)	6.2	**5.5**	(0.7)	**8.7**	**9.5**
12	Transmission		6.1	4.7	(1.4)	6.2	6.0	(0.2)	6.0	**7.2**	1.2	**7.3**	**10.7**
13	Distribution		8.8	10.7	1.8	8.8	10.8	2.0	8.8	**8.9**	0.1	**8.7**	**10.9**
14	Customer Care		0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**	0.0	**0.0**	**0.0**
15	Corporate Groups		0.0	0.0	0.0	0.0	0.2	0.2	0.0	**0.0**	0.0	**0.0**	**0.0**
16	Total		34.3	20.2	(14.1)	20.9	16.4	(4.5)	21.0	21.7	0.7	24.6	31.2
	Capital Asset Write-Offs												
17	Generation		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
18	Transmission		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
19	Distribution		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
20	Customer Care		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
21	Corporate Groups		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22	Total		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	IPP Capital Leases												
23	Existing IPP Capital Leases		24.7	24.7	0.0	12.6	13.7	1.1	12.6	**13.7**	1.1	**22.8**	**25.8**
24	New Capital Leases Under IFRS		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
25	Total		24.7	24.7	0.0	12.6	13.7	1.1	12.6	13.7	1.1	22.8	25.8
26	**Other Net IFRS Impact**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	0.0	0.0
	Regulatory Account Additions												
27	F07/F08 RRA Depn Study		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
28	Deferred SMI Amortization		52.4	38.8	(13.6)	59.7	36.4	(23.3)	38.3	26.0	(12.3)	0.0	0.0
29	Deferred Environmental Liability		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
30	Total		52.4	38.8	(13.6)	59.7	36.4	(23.3)	38.3	26.0	(12.3)	0.0	0.0
31	**Total Gross Amortization**		615.5	586.2	(29.3)	663.5	635.0	(28.6)	655.8	646.2	(9.6)	698.7	758.0

Depreciation and Amortization
($ million)

Line	Column	Reference	F2012 RRA	F2012 Actual	F2012 Diff	F2013 RRA	F2013 Actual	F2013 Diff	F2014 RRA	F2014 Forecast	F2014 Diff	F2015 Plan	F2016 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9 = 8 - 7	10	11
	Other Regulatory Account Additions												
32	Deferred PEI Amortization		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
33	Deferred SMI Amortization		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
34	Total		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Regulatory Account Recoveries												
	DSM Amortization												
35	Generation - 90%	2.2 L5+6	37.8	37.6	(0.2)	48.9	47.9	(1.0)	60.9	56.9	(4.0)	65.9	75.0
36	Transmission - 10%	2.2 L5+6	4.2	4.2	(0.0)	5.4	5.3	(0.1)	6.8	6.3	(0.4)	7.3	8.3
37	Total		42.0	41.8	(0.2)	54.3	53.2	(1.1)	67.6	63.2	(4.4)	73.3	83.3
	Depn Study Amortization												
38	Generation		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
39	Transmission		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
40	Distribution		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
41	Customer Care		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
42	Corporate		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
43	Total		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	FRSR Amortization												
44	Generation	Line 11	(19.3)	(4.9)	14.4	(5.9)	0.6	6.4	(6.2)	(5.5)	0.7	(8.7)	(9.5)
45	Transmission	Line 12	(6.1)	(4.7)	1.4	(6.2)	(6.0)	0.2	(6.0)	(7.2)	(1.2)	(7.3)	(10.7)
46	Distribution	Line 13	(8.8)	(10.7)	(1.8)	(8.8)	(10.8)	(2.0)	(8.8)	(8.9)	(0.1)	(8.7)	(10.9)
47	Customer Care	Line 14	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
48	Corporate Groups	Line 15	0.0	0.0	0.0	0.0	(0.2)	(0.2)	0.0	0.0	0.0	0.0	0.0
49	Adjustment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
50	Total		(34.3)	(20.2)	14.1	(20.9)	(16.4)	4.5	(21.0)	(21.7)	(0.7)	(24.6)	(31.2)
51	**Pre-1996 CIAC Amortization**		(8.6)	(8.6)	0.0	(7.5)	(7.5)	0.0	(6.3)	**(6.3)**	0.0	**(6.3)**	**(4.7)**
	Capital Additions Regulatory Account												
52	Generation		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
53	Transmission		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
54	Distribution		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
55	Customer Care		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
56	Corporate Groups		(9.7)	(7.9)	1.7	0.0	3.8	3.8	0.0	12.2	12.2	**(9.8)**	**(9.4)**
57	Total		(9.7)	(7.9)	1.7	0.0	3.8	3.8	0.0	12.2	12.2	(9.8)	(9.4)
58	**Total Recoveries**		(10.6)	5.0	15.6	25.9	33.1	7.2	40.3	47.4	7.1	32.5	38.0
59	**Total Current Amortization**		552.5	552.4	(0.2)	629.8	631.7	1.9	657.7	667.5	9.8	731.2	796.0
	Current Amortization by Business Group												
60	Generation		192.6	193.3	0.7	216.5	217.1	0.6	230.9	299.2	68.3	312.7	332.4
61	Transmission		132.8	134.0	1.2	143.7	143.5	(0.2)	152.5	147.5	(5.0)	158.9	187.1
62	Distribution		131.5	130.3	(1.2)	162.8	166.1	3.3	168.5	162.4	(6.2)	211.3	220.6
63	Customer Care		24.7	24.7	0.0	12.6	13.7	1.1	12.6	13.7	1.1	22.8	25.8
64	Corporate Groups		70.9	70.0	(0.9)	94.2	91.3	(2.9)	93.2	44.7	(48.5)	25.5	30.1
65	Total		552.5	552.4	(0.2)	629.8	631.7	1.9	657.7	667.5	9.8	731.2	796.0

BC Hydro
F15-F16 RRA

Schedule 8.0
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Finance Charges
($ million)

Line	Column	Reference	F2012 RRA	F2012 Actual	F2012 Diff	F2013 RRA	F2013 Actual	F2013 Diff	F2014 RRA	F2014 Forecast	F2014 Diff	F2015 Plan	F2016 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9 = 8 - 7	10	11
	Increase in Cash												
1	Net Income	9.0 L52	558.9	558.4	(0.5)	520.2	509.3	(10.9)	555.7	544.7	(10.9)	581.5	651.9
2	Dividend (One Year Lag)	9.0 L4	(463.2)	(463.2)	0.0	(146.8)	(230.1)	(83.3)	(89.3)	(215.1)	(125.9)	(154.5)	(278.6)
3	Amortization	7.0 L31	615.5	586.2	(29.3)	663.5	635.0	(28.6)	655.8	646.2	(9.6)	698.7	758.0
4	Deferral Account Additions	2.1 L33	(65.9)	4.0	69.9	(103.2)	6.9	110.1	(49.8)	(248.1)	(198.3)	0.0	0.0
5	Deferral Account Recoveries	2.1 L35	89.2	87.7	(1.5)	188.5	179.7	(8.8)	194.1	186.8	(7.3)	208.4	223.0
6	Regulatory Account Additions	2.2 L212	(653.2)	(701.6)	(48.4)	(685.4)	(573.0)	112.4	(596.4)	(554.7)	41.7	(359.0)	(310.3)
7	Regulatory Account Recoveries	2.2 L214	134.5	138.8	4.4	180.4	233.8	53.4	36.9	45.7	8.8	124.5	132.9
8	First Nations Provisions	2.2 L16	16.3	149.4	133.1	0.0	0.0	0.0	0.0	18.4	18.4	0.0	0.0
9	Environmental Provisions	2.2 L126	6.3	11.1	4.8	0.0	46.0	46.0	0.0	1.6	1.6	0.0	0.0
10	Capital Expenditures	13.0 L17-16	(1,459.6)	(1,679.5)	(219.9)	(2,071.6)	(1,922.6)	149.0	(2,052.8)	(1,985.4)	67.4	(2,252.3)	(1,939.2)
11	Contributions in Aid	11.0 L49	51.3	128.1	76.8	51.7	127.9	76.2	50.7	122.3	71.6	85.1	124.1
12	Change in Sinking Funds	Line 16	(3.4)	(2.8)	0.6	0.2	(1.8)	(2.0)	0.9	(2.9)	(3.8)	(1.0)	0.1
13	Change in Working Cap & Other		(464.0)	(84.5)	379.5	(324.2)	(233.2)	91.0	(361.7)	(115.9)	245.8	(148.5)	(136.9)
14	Total		(1,637.3)	(1,267.9)	369.3	(1,726.7)	(1,222.1)	504.6	(1,655.9)	(1,556.5)	99.4	(1,217.0)	(775.0)
	Sinking Funds												
15	Beginning of Year		96.9	96.9	0.0	103.4	105.0	1.6	106.4	112.3	5.9	120.1	125.2
16	Change in Sinking Funds		3.4	2.8	(0.6)	(0.2)	1.8	2.0	(0.9)	2.9	3.8	1.0	(0.1)
17	Sinking Fund Income		3.1	5.3	2.2	3.2	5.5	2.3	3.2	4.9	1.7	4.1	4.2
18	End of Year		103.4	105.0	1.6	106.4	112.3	5.9	108.7	120.1	11.4	125.2	129.3
19	Mid-Year Balance		100.2	101.0	0.8	104.9	108.7	3.7	107.6	116.2	8.7	122.7	127.3
	Long-Term Debt												
20	Beginning of Year		9,310.7	9,310.7	0.0	10,339.8	10,229.0	(110.8)	11,848.8	11,560.9	(287.9)	11,871.5	12,743.1
21	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	38.1	38.1	0.0	0.0	0.0	0.0	0.0
22	Bonds Retired		(450.0)	(450.0)	0.0	(200.0)	(200.0)	0.0	(699.2)	(706.2)	(7.0)	(325.0)	(150.0)
23	Bonds Issued		0.0	1,350.0	1,350.0	0.0	1,392.6	1,392.6	0.0	1,150.0	1,150.0	0.0	0.0
24	Bonds Planned Issues		1,450.0	0.0	(1,450.0)	1,725.0	0.0	(1,725.0)	1,475.0	0.0	(1,475.0)	1,200.0	800.0
25	Revaluation of US $ Debt		41.0	33.0	(8.0)	(1.7)	19.9	21.6	(10.0)	29.6	39.6	8.8	(1.2)
26	Revaluation to Fair Value		(7.8)	(10.5)	(2.7)	0.4	(34.9)	(35.3)	(15.5)	(11.4)	4.1	0.0	0.0
27	Premiums/(Discounts) on Issues		12.6	12.6	0.0	0.0	135.8	135.8	0.0	(139.2)	(139.2)	0.0	0.0
28	Amortization of Issue Costs		(16.7)	(16.8)	(0.1)	(14.7)	(19.6)	(4.9)	(7.9)	(12.2)	(4.3)	(12.2)	(12.5)
29	End of Year		10,339.8	10,229.0	(110.8)	11,848.8	11,560.9	(287.9)	12,591.2	11,871.5	(719.7)	12,743.1	13,379.4
30	Mid-Year Balance		9,825.3	9,769.9	(55.4)	11,094.3	10,895.0	(199.3)	12,220.0	11,716.2	(503.8)	12,307.3	13,061.3
31	Interest Rate - Planned Issues		3.46%			3.65%			4.30%	3.40%		4.05%	5.00%
32	Debt Costs - Excluding Planned		556.3	579.9	23.6	538.2	600.0	61.8	506.4	612.6	106.2	609.9	608.4
33	Debt Costs - Planned Issues		25.1	0.0	(25.1)	81.7	0.0	(81.7)	144.8	0.0	(144.8)	24.3	68.6
34	Total Long-Term Debt Costs		581.4	579.9	(1.5)	619.9	600.0	(19.9)	651.2	612.6	(38.6)	634.2	677.0

Finance Charges
($ million)

Line	Column	Reference	F2012 RRA	F2012 Actual	F2012 Diff	F2013 RRA	F2013 Actual	F2013 Diff	F2014 RRA	F2014 Forecast	F2014 Diff	F2015 Plan	F2016 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9 = 8 - 7	10	11
	Short-Term Debt												
35	Beginning of Year		2,333.2	2,333.2	0.0	2,941.4	2,682.9	(258.5)	3,159.1	2,573.0	(586.1)	3,818.9	4,164.3
36	Increase in Cash Requirement	Line 14	1,637.3	1,267.9	(369.3)	1,726.7	1,222.1	(504.6)	1,655.9	1,556.5	(99.4)	1,217.0	775.0
37	Change in Long-Term Debt	Line 20-29	(1,029.1)	(918.3)	110.8	(1,509.0)	(1,331.9)	177.1	(742.4)	(310.6)	431.8	(871.6)	(636.3)
38	End of Year		2,941.4	2,682.9	(258.5)	3,159.1	2,573.0	(586.1)	4,072.6	3,818.9	(253.7)	4,164.3	4,303.0
39	Mid-Year Balance		2,637.3	2,508.0	(129.3)	3,050.2	2,627.9	(422.3)	3,615.8	3,196.0	(419.9)	3,991.6	4,233.7
40	Interest Rate		0.97%			1.26%			2.20%	1.09%		1.28%	2.23%
41	Debt Costs - Interest		25.6	21.2	(4.4)	38.4	19.8	(18.6)	79.5	34.8	(44.7)	51.1	94.4
42	Debt Costs - Other		3.2	0.0	(3.2)	(0.3)	0.0	0.3	3.1	(5.5)	(8.6)	(0.6)	(0.2)
43	Total Short-Term Debt Costs		28.8	21.2	(7.6)	38.1	19.8	(18.3)	82.6	29.3	(53.3)	50.5	94.2
	Interest Capitalized												
44	Unfinished Construction	13.0 L51	1,768.6	1,715.8	(52.8)	2,382.6	2,059.6	(322.9)	3,260.1	2,701.0	(559.0)	2,978.6	2,387.4
45	Less Not Subject to IDC		(732.7)	(618.3)	114.4	(786.4)	(566.4)	220.0	(947.2)	(992.6)	(45.4)	(1,345.8)	(1,016.3)
46	Unfinished Subject to IDC		1,035.9	1,097.5	61.6	1,596.2	1,493.3	(102.9)	2,312.8	1,708.4	(604.4)	1,632.8	1,371.1
47	Interest Rate	Line 104	4.76%	4.82%	0.05%	4.60%	4.57%	-0.02%	4.62%	4.34%	-0.27%	4.21%	4.47%
48	Interest Capitalized		49.3	52.9	3.5	73.3	68.3	(5.0)	106.8	74.2	(32.6)	68.8	61.3
	Total Before Regulatory Accounts												
49	Sinking Fund Income	Line 17	(3.1)	(5.3)	(2.2)	(3.2)	(5.5)	(2.3)	(3.2)	(4.9)	(1.7)	(4.1)	(4.2)
50	Long-Term Debt Costs	Line 34	581.4	579.9	(1.5)	619.9	600.0	(19.9)	651.2	612.6	(38.6)	634.2	677.0
51	Short-Term Debt Costs	Line 43	28.8	21.2	(7.6)	38.1	19.8	(18.3)	82.6	29.3	(53.3)	50.5	94.2
52	Interest Capitalized	Line 48	(49.3)	(52.9)	(3.5)	(73.3)	(68.3)	5.0	(106.8)	(74.2)	32.6	(68.8)	(61.3)
53	Swaps		(19.4)	(14.3)	5.1	(7.2)	(4.9)	2.3	(0.6)	(4.0)	(3.4)	0.0	0.0
54	Other (Income) / Loss		6.3	5.4	(0.9)	8.2	(23.1)	(31.3)	12.2	(0.4)	(12.6)	7.1	13.6
55	Deferred SMI Finance Charges		(9.1)	(0.1)	9.0	(22.8)	(12.0)	10.8	(29.2)	(16.1)	13.1	0.0	0.0
56	Deferred HPOP Finance Charges		(0.1)	(0.1)	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
57	Existing IPP Capital Leases		21.0	21.0	0.0	19.9	25.6	5.7	18.9	24.1	5.2	77.3	93.9
58	New Capital Leases Under IFRS		0.0	0.0	0.0	9.2	0.0	(9.2)	8.6	0.0	(8.6)	0.0	0.0
59	IFRS Reduced IDC Capitalized		(8.0)	(7.0)	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
60	Accretion - ARO		0.0	0.0	0.0	1.7	1.3	(0.4)	1.7	1.3	(0.4)	1.3	1.3
61	Non-Current PEB		0.0	0.0	0.0	13.7	6.5	(7.2)	13.8	59.0	45.2	2.9	0.1
62	F2013 Correction		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.9	0.9	0.0	0.0
63	Total		548.4	547.9	(0.6)	604.1	539.5	(64.6)	649.3	627.5	(21.8)	700.4	814.6
	Interest on Regulatory Accounts												
64	Interest on Deferral Accounts	2.1 L34	(39.5)	(36.8)	2.6	(37.4)	(36.3)	1.1	(34.0)	(32.9)	1.1	(30.2)	(23.8)
65	Interest on Other Reg Accounts	2.2 L213	(14.6)	(11.2)	3.4	(26.0)	(18.4)	7.6	(38.7)	(25.6)	13.1	(37.1)	(37.9)
66	Total		(54.1)	(48.0)	6.1	(63.4)	(54.8)	8.7	(72.7)	(58.6)	14.1	(67.4)	(61.7)
	Regulatory Account Recoveries												
67	Amort. of FX Gains/Losses		(0.1)	(0.1)	0.0	(1.0)	(1.0)	(0.0)	(1.0)	(0.9)	0.1	(0.7)	(0.7)
68	Non-Current Pension		0.0	0.0	0.0	0.0	7.2	7.2	0.0	(45.2)	(45.2)	0.0	0.0
69	Total Finance Charges		(4.0)	(9.5)	(5.5)	0.0	47.6	47.6	0.0	52.3	52.3	(25.5)	(25.5)
70	Total		(4.1)	(9.6)	(5.5)	(1.0)	53.7	54.7	(1.0)	6.2	7.2	(26.2)	(26.2)
71	**Total Current Finance Chrgs**	L 63+66+70	490.2	490.2	0.0	539.7	538.4	(1.3)	575.6	575.2	(0.4)	606.8	726.6

BC Hydro
F15-F16 RRA

Finance Charges
($ million)

Line	Column	Reference	F2012 RRA	F2012 Actual	F2012 Diff	F2013 RRA	F2013 Actual	F2013 Diff	F2014 RRA	F2014 Forecast	F2014 Diff	F2015 Plan	F2016 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9 = 8 - 7	10	11
	Regulatory Account Additions												
72	FX Gains/Losses		4.4	3.5	(0.9)	(0.2)	2.0	2.2	(1.0)	3.1	4.1	1.0	(0.1)
73	Net SMI Impact		9.1	0.1	(9.0)	22.8	12.0	(10.8)	29.2	16.1	(13.1)	0.0	0.0
74	Deferred HPOP Finance Chges	Line 56	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
75	IFRS Reduced IDC Capitalized		8.0	7.0	(1.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
76	Accretion - First Nations		0.0	0.0	0.0	16.2	16.7	0.5	16.2	21.1	4.9	17.5	17.7
77	Accretion - Environmental		0.0	0.0	0.0	6.3	6.1	(0.2)	6.2	6.0	(0.2)	6.0	6.0
78	Accretion - Arrow Water		0.0	0.0	0.0	0.1	0.1	0.0	0.1	0.1	0.0	0.1	0.1
79	Total		21.6	10.7	(10.9)	45.2	36.8	(8.4)	50.7	46.4	(4.3)	24.6	23.7
80	**Total Gross Finance Charges**	Lines 63+79	570.0	558.6	(11.5)	649.3	576.3	(73.0)	700.0	674.0	(26.0)	725.0	838.3
	Portion of Rate Base												
81	Generation	10.0 L28	46.7%	46.2%	-0.5%	46.7%	45.4%	-1.3%	45.5%	45.0%	-0.5%	44.3%	42.3%
82	Transmission	10.0 L29	25.0%	25.4%	0.4%	25.6%	25.2%	-0.4%	27.3%	25.2%	-2.1%	27.5%	32.1%
83	Distribution	10.0 L30	28.3%	28.4%	0.1%	27.7%	29.4%	1.7%	27.2%	29.9%	2.7%	28.2%	25.7%
84	Customer Care	10.0 L31	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
85	Corporate Groups		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
86	Total		100.0%	100.0%	0.0%	100.0%	100.0%	0.0%	100.0%	100.0%	0.0%	100.0%	100.0%
	Allocation of Current Finance Charges												
87	Generation		229.0	226.3	(2.7)	251.8	244.3	(7.5)	261.9	258.6	(3.3)	268.8	307.2
88	Transmission		122.5	124.5	2.0	138.2	135.9	(2.3)	157.2	144.8	(12.4)	167.0	233.0
89	Distribution		138.6	139.4	0.7	149.7	158.3	8.5	156.5	171.8	15.3	171.0	186.4
90	Customer Care		0.1	0.0	(0.1)	(0.0)	(0.0)	0.0	(0.0)	(0.0)	0.0	(0.0)	(0.0)
91	Corporate Groups		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
92	Total		490.2	490.2	0.0	539.7	538.4	(1.3)	575.6	575.2	(0.4)	606.8	726.6
	Net Debt												
93	Sinking Funds	Line 18	(103.4)	(105.0)	(1.6)	(106.4)	(112.3)	(5.9)	(108.7)	(120.1)	(11.4)	(125.2)	(129.3)
94	Temporary Investments		(10.0)	(11.6)	(1.6)	(10.0)	(60.4)	(50.4)	(10.0)	(10.0)	0.0	(10.0)	(10.0)
95	Long-Term Debt	Line 29	10,339.8	10,229.0	(110.8)	11,848.8	11,560.9	(287.9)	12,591.2	11,871.5	(719.7)	12,743.1	13,379.4
96	Short-Term Debt	Line 38	2,941.4	2,682.9	(258.5)	3,159.1	2,573.0	(586.1)	4,072.6	3,818.9	(253.7)	4,164.3	4,303.0
97	Subtotal		13,167.8	12,795.3	(372.5)	14,891.5	13,961.2	(930.3)	16,545.1	15,560.3	(984.8)	16,772.2	17,543.1
98	IDC Adjustments		92.9	34.1	(58.8)	130.2	99.9	(30.3)	150.8	78.3	(72.5)	87.8	96.2
99	End of Year		13,260.7	12,829.3	(431.4)	15,021.7	14,061.1	(960.6)	16,695.9	15,638.6	(1,057.3)	16,860.0	17,639.3
100	Mid-Year Balance		12,399.6	12,183.9	(215.7)	14,141.2	13,445.2	(696.0)	15,858.8	14,849.8	(1,008.9)	16,249.3	17,249.7
	Weighted Average Cost of Debt												
101	Total Gross Finance Charges		570.0	558.6	(11.5)	649.3	576.3	(73.0)	700.0	674.0	(26.0)	725.0	838.3
102	IDC Adjustments		20.4	28.3	7.8	0.5	38.7	38.2	32.2	(29.0)	(61.2)	(40.3)	(67.1)
103	Total		590.5	586.8	(3.6)	649.8	615.0	(34.8)	732.2	645.0	(87.2)	684.7	771.2
104	Weighted Average Cost of Debt		4.76%	4.82%	0.05%	4.60%	4.57%	-0.02%	4.62%	4.34%	-0.27%	4.21%	4.47%

Return on Equity
($ million)

Line	Column	Reference	F2012 RRA	F2012 Actual	F2012 Diff	F2013 RRA	F2013 Actual	F2013 Diff	F2014 RRA	F2014 Forecast	F2014 Diff	F2015 Plan	F2016 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9 = 8 - 7	10	11
	Shareholder's Equity												
1	Retained Earnings - Begining of Year		2,806.9	2,806.9	0.0	3,218.9	3,135.2	(83.7)	3,649.9	3,429.4	(220.5)	3,819.7	4,122.6
2	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	Gross Return on Equity	Line 52	558.9	558.4	(0.5)	520.2	509.3	(10.9)	555.7	544.7	(10.9)	581.5	651.9
4	Dividend to Province	Line 16	(146.8)	(230.1)	(83.3)	(89.3)	(215.1)	(125.9)	(142.3)	(154.5)	(12.2)	(278.6)	(459.1)
5	Distribution to Province		0.0	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		3,218.9	3,135.2	(83.7)	3,649.9	3,429.4	(220.5)	4,063.3	3,819.7	(243.6)	4,122.6	4,315.4
7	Accum Other Comp Income		73.0	63.4	(9.6)	73.0	(121.3)	(194.3)	73.0	423.4	350.4	70.4	70.4
8	OCI Deferred (Pension)		0.0	0.0	0.0	0.0	191.7	191.7	0.0	(353.0)	(353.0)	0.0	0.0
9	Total Shareholder's Equity		3,291.9	3,198.6	(93.3)	3,722.9	3,499.8	(223.1)	4,136.3	3,890.1	(246.2)	4,193.1	4,385.8
	Dividend to Province												
10	Net Income	Line 52	558.9			520.2			555.7	544.7		581.5	651.9
11	IDC (net of amortization)		0.0			0.0			0.0	0.0		0.0	0.0
12	Distributable Surplus		558.9			520.2			555.7	544.7		581.5	651.9
13	Maximum Dividend Percentage		85.0%			85.0%			85.0%	85.0%		85.0%	85.0%
14	Maximum Dividend Amount		475.1			442.2			472.3	463.0		494.3	554.1
15	Minimum Equity Percentage		20.0%			20.0%			20.0%	20.0%		20.0%	20.0%
16	Dividend to Province		146.8			89.3			142.3	154.5		278.6	459.1
	Deferred Revenue												
17	Skagit - Beginning of Year												
18	Payments Received												
19	Interest												
20	Revenues Earned												
21	Skagit - End of Year												
	Return on Equity												
22	Shareholder's Equity	Line 9											
23	Deferred Revenue	Line 21											
24	Contributions - Columbia River												
25	Contributions - EARG												
26	Contributions - Field Operations												
27	Contributions - Transmission												
28	Pre-1996 CIAC Adjustment												
29	Total Equity												
	Capitalization												
30	Net Debt	8.0 L97	13,167.8	12,795.3	(372.5)	14,891.5	13,961.2	(930.3)	16,545.1	15,560.3	(984.8)	16,772.2	17,543.1
31	Shareholder's Equity	Line 9	3,291.9	3,198.6	(93.3)	3,722.9	3,499.8	(223.1)	4,136.3	3,890.1	(246.2)	4,193.1	4,385.8
32	Total		16,459.7	15,993.9	(465.9)	18,614.4	17,461.0	(1,153.4)	20,681.4	19,450.4	(1,231.0)	20,965.3	21,928.9
	Capital Structure												
33	Net Debt		80.0%	80.0%	0.0%	80.0%	80.0%	0.0%	80.0%	80.0%	0.0%	80.0%	80.0%
34	Equity		20.0%	20.0%	0.0%	20.0%	20.0%	0.0%	20.0%	20.0%	0.0%	20.0%	20.0%
35	Total		100.0%	100.0%	0.0%	100.0%	100.0%	0.0%	100.0%	100.0%	0.0%	100.0%	100.0%

Return on Equity
($ million)

Line	Column	Reference	F2012 RRA	F2012 Actual	F2012 Diff	F2013 RRA	F2013 Actual	F2013 Diff	F2014 RRA	F2014 Forecast	F2014 Diff	F2015 Plan	F2016 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9 = 8 - 7	10	11
	Deemed Equity												
36	Rate Base	10.0 L26	13,846.3	14,030.2	183.9	14,579.1	14,713.3	134.2	15,352.2	15,250.4	(101.8)	17,116.0	19,215.9
37	Pre-1996 Customer Contns	2.2 L42	(67.3)	(67.3)	0.0	(74.8)	(74.8)	0.0	(81.1)	(81.1)	0.0	(87.4)	(92.1)
38	Powerex & Powertech Assets		21.8	14.0	(7.8)	27.8	23.6	(4.2)	29.2	22.3	(6.9)	24.4	26.6
39	Columbia River Treaty Contns	11.0 L10	(105.7)	(105.7)	(0.0)	(104.0)	0.0	104.0	(102.2)	0.0	102.2	0.0	0.0
40	Allowance for Working Capital		250.0	250.0	0.0	250.0	250.0	0.0	250.0	250.0	0.0	250.0	250.0
41	Total		13,945.2	14,121.2	176.1	14,678.1	14,912.1	234.0	15,448.1	15,441.6	(6.5)	17,303.0	19,400.4
42	Deemed Equity Percentage		30.0%	30.0%	0.0%	30.0%	30.0%	0.0%	30.0%	30.0%	0.0%	30.0%	30.0%
43	Year-End Deemed Equity		4,183.6	4,236.4	52.8	4,403.4	4,473.6	70.2	4,634.4	4,632.5	(2.0)	5,190.9	5,820.1
44	Mid-Year Deemed Equity		4,075.2	4,101.6	26.4	4,293.5	4,355.0	61.5	4,518.9	4,553.1	34.1	4,911.7	5,505.5
45	Achieved ROE			13.61%			11.70%			11.96%			
46	Allowed ROE		14.38%			11.73%			11.84%			11.84%	11.84%
47	Return on Equity		586.0	556.3	(29.7)	503.6	499.1	(4.6)	535.0	528.0	(7.0)	581.5	651.9
48	F11 RRA NSA Adjustment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
49	Amortize PEI Reg Acct		(34.2)	0.0	34.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
50	IFRS ROE Impact		0.0	0.0	0.0	(0.5)	0.0	0.5	(1.6)	0.0	1.6	0.0	0.0
51	Deferred SMI ROE		7.1	2.2	(4.9)	17.1	10.3	(6.8)	22.2	16.7	(5.5)	0.0	0.0
52	Gross Return on Equity		558.9	558.4	(0.5)	520.2	509.3	(10.9)	555.7	544.7	(10.9)	581.5	651.9
	F2010 ROE Regulatory Account Transfers												
53	Additions		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
54	Recoveries		(11.3)	(11.3)	0.0	(11.3)	(11.3)	0.0	(11.3)	(11.3)	0.0	(11.3)	0.0
55	Total		(11.3)	(11.3)	0.0	(11.3)	(11.3)	0.0	(11.3)	(11.3)	0.0	(11.3)	0.0
56	**Current Return on Equity**		563.1	567.6	4.5	514.4	510.3	(4.0)	544.8	539.3	(5.4)	592.8	651.9
	Portion of Rate Base												
57	Generation	10.0 L28	46.7%	46.2%	-0.5%	46.7%	45.4%	-1.3%	45.5%	45.0%	-0.5%	44.3%	42.3%
58	Transmission	10.0 L29	25.0%	25.4%	0.4%	25.6%	25.2%	-0.4%	27.3%	25.2%	-2.1%	27.5%	32.1%
59	Distribution	10.0 L30	28.3%	28.4%	0.1%	27.7%	29.4%	1.7%	27.2%	29.9%	2.7%	28.2%	25.7%
60	Customer Care	10.0 L31	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
61	Corporate Groups		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
62	Total		100.0%	100.0%	0.0%	100.0%	100.0%	0.0%	100.0%	100.0%	0.0%	100.0%	100.0%
	Allocation of ROE												
63	Generation		263.0	262.0	(1.0)	240.0	231.5	(8.4)	247.9	242.5	(5.4)	262.6	275.6
64	Transmission		140.7	144.2	3.5	131.7	128.8	(2.9)	148.8	135.8	(13.0)	163.1	209.0
65	Distribution		159.2	161.4	2.1	142.7	150.0	7.3	148.1	161.1	13.0	167.1	167.3
66	Customer Care		0.1	0.0	(0.1)	(0.0)	(0.0)	0.0	(0.0)	(0.0)	0.0	(0.0)	(0.0)
67	Corporate Groups		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
68	Total		563.1	567.6	4.5	514.4	510.3	(4.0)	544.8	539.3	(5.4)	592.8	651.9

Rate Base
($ million)

Line		Reference	F2012 RRA	F2012 Actual	F2012 Diff	F2013 RRA	F2013 Actual	F2013 Diff	F2014 RRA	F2014 Forecast	F2014 Diff	F2015 Plan	F2016 Plan
	Column		1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9 = 8 - 7	10	11
	Generation												
1	Net Assets in Service	12.2 L15	5,599.0	5,599.6	0.6	5,727.5	5,613.0	(114.5)	5,677.6	5,876.7	199.1	6,315.8	6,732.6
2	Net Contributions	11.0 L21	(3.9)	(3.9)	0.0	(3.5)	(3.5)	0.0	(3.1)	(3.1)	(0.0)	(2.7)	(2.3)
3	90% of Net DSM	2.2 L7	584.1	574.2	(9.9)	715.0	659.2	(55.8)	866.8	738.5	(128.3)	808.0	851.0
4	Total		6,179.2	6,169.9	(9.3)	6,439.1	6,268.7	(170.3)	6,541.3	6,612.1	70.8	7,121.1	7,581.3
5	Mid-Year		5,828.3	5,988.3	160.0	6,309.1	6,219.3	(89.8)	6,490.2	6,440.4	(49.8)	6,866.6	7,351.2
	Transmission												
6	Net Assets in Service	12.4 L15	3,407.3	3,513.4	106.1	3,680.0	3,696.7	16.7	4,244.1	3,875.3	(368.8)	5,043.4	6,535.7
7	Net Contributions	11.0 L32	(152.8)	(187.6)	(34.7)	(153.5)	(240.0)	(86.5)	(154.2)	(274.2)	(120.0)	(285.9)	(324.3)
8	10% of Net DSM	2.2 L7	64.9	63.8	(1.1)	79.4	73.2	(6.2)	96.3	82.1	(14.3)	89.8	94.6
9	Total		3,319.4	3,389.7	70.3	3,605.9	3,529.9	(76.0)	4,186.2	3,683.1	(503.0)	4,847.3	6,306.0
10	Mid-Year		3,118.0	3,295.8	177.8	3,462.7	3,459.8	(2.9)	3,896.1	3,606.5	(289.5)	4,265.2	5,576.6
	Distribution												
11	Net Assets in Service	12.5 L16	4,494.9	4,671.7	176.7	4,638.7	5,114.8	476.0	4,773.8	5,244.3	470.4	5,363.4	5,493.8
12	Net Contributions	11.0 L46	(809.2)	(850.9)	(41.7)	(822.0)	(877.4)	(55.4)	(833.4)	(922.5)	(89.1)	(949.0)	(984.6)
13	Total		3,685.8	3,820.8	135.1	3,816.8	4,237.4	420.6	3,940.4	4,321.7	381.3	4,414.4	4,509.2
14	Mid-Year		3,528.7	3,687.9	159.2	3,751.3	4,029.1	277.9	3,878.6	4,279.6	401.0	4,368.1	4,461.8
	Customer Care												
15	Net Assets in Service	12.3 L14	(0.0)	(0.0)	0.0	(0.0)	(0.0)	0.0	(0.0)	(0.0)	0.0	(0.0)	(0.0)
16	Net Contributions	N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
17	Total		(0.0)	(0.0)	0.0	(0.0)	(0.0)	0.0	(0.0)	(0.0)	0.0	(0.0)	(0.0)
18	Mid-Year		2.6	0.3	(2.3)	(0.0)	(0.0)	0.0	(0.0)	(0.0)	0.0	(0.0)	(0.0)
	Corporate Groups												
19	Net Assets in Service	12.1 L14	662.0	649.9	(12.1)	717.3	677.3	(40.1)	684.3	633.5	(50.9)	733.2	819.4
20	Net Contributions	N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
21	Total		662.0	649.9	(12.1)	717.3	677.3	(40.1)	684.3	633.5	(50.9)	733.2	819.4
22	Mid-Year		546.1	604.9	58.8	689.7	663.6	(26.1)	700.8	655.4	(45.5)	683.3	776.3
	Total												
23	Net Assets in Service	12.0 L17	14,163.3	14,434.5	271.3	14,763.6	15,101.8	338.2	15,379.8	15,629.7	249.9	17,455.9	19,581.6
24	Net Contributions	11.0 L60	(965.9)	(1,042.3)	(76.4)	(979.0)	(1,120.9)	(141.9)	(990.8)	(1,199.9)	(209.1)	(1,237.7)	(1,311.3)
25	Net DSM	2.2 L7	649.0	638.0	(11.0)	794.5	732.4	(62.0)	963.2	820.6	(142.6)	897.8	945.6
26	Total		13,846.3	14,030.2	183.9	14,579.1	14,713.3	134.2	15,352.2	15,250.4	(101.8)	17,116.0	19,215.9
27	Mid-Year		13,023.7	13,577.2	553.5	14,212.7	14,371.8	159.1	14,965.6	14,981.8	16.2	16,183.2	18,165.9
	Portion of Rate Base												
28	Generation		46.7%	46.2%	-0.5%	46.7%	45.4%	-1.3%	45.5%	45.0%	-0.5%	44.3%	42.3%
29	Transmission		25.0%	25.4%	0.4%	25.6%	25.2%	-0.4%	27.3%	25.2%	-2.1%	27.5%	32.1%
30	Distribution		28.3%	28.4%	0.1%	27.7%	29.4%	1.7%	27.2%	29.9%	2.7%	28.2%	25.7%
31	Customer Care		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
32	Corporate Groups		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
33	Total		100.0%	100.0%	0.0%	100.0%	100.0%	0.0%	100.0%	100.0%	0.0%	100.0%	100.0%

Contributions
($ million)

Line	Column	Reference	F2012 RRA	F2012 Actual	F2012 Diff	F2013 RRA	F2013 Actual	F2013 Diff	F2014 RRA	F2014 Forecast	F2014 Diff	F2015 Plan	F2016 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9 = 8 - 7	10	11
	Contributions - Columbia River Treaty												
1	Gross Contns - Beginning of Year		377.1	377.1	0.0	377.1	377.1	0.0	377.1	0.0	(377.1)	0.0	0.0
2	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	(377.1)	(377.1)	0.0	0.0	0.0	0.0	0.0
3	Retirements		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	Gross Contns - End of Year		377.1	377.1	0.0	377.1	0.0	(377.1)	377.1	0.0	(377.1)	0.0	0.0
5	Accum Amort - Beginning of Year		269.7	269.7	0.0	271.4	271.4	(0.0)	273.2	0.0	(273.2)	0.0	0.0
6	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	(271.4)	(271.4)	0.0	0.0	0.0	0.0	0.0
7	Amortization		1.7	1.7	(0.0)	1.7	0.0	(1.7)	1.7	0.0	(1.7)	0.0	0.0
8	Retirements		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Accum Amort - End of Year		271.4	271.4	(0.0)	273.2	0.0	(273.2)	274.9	0.0	(274.9)	0.0	0.0
10	Net Contribution - End of Year		105.7	105.7	0.0	104.0	0.0	(104.0)	102.2	0.0	(102.2)	0.0	0.0
	Contributions in Aid - Generation												
11	Gross Contns - Beginning of Year		8.9	8.9	0.0	8.9	8.9	0.0	8.9	8.9	0.0	8.9	8.9
12	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	Additions		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	Retirements & Transfers		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	Gross Contns - End of Year		8.9	8.9	0.0	8.9	8.9	0.0	8.9	8.9	0.0	8.9	8.9
16	Accum Amort - Beginning of Year		4.5	4.5	0.0	5.0	5.0	0.0	5.4	5.4	0.0	5.8	6.2
17	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	(0.0)	(0.0)	0.0	0.0	0.0	0.0	0.0
18	Amortization		0.4	0.4	0.0	0.4	0.4	0.0	0.4	**0.4**	(0.0)	**0.4**	**0.4**
19	Retirements & Transfers		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
20	Accum Amort - End of Year		5.0	5.0	0.0	5.4	5.4	0.0	5.8	5.8	(0.0)	6.2	6.6
21	Net Contributions - End of Year		3.9	3.9	0.0	3.5	3.5	0.0	3.1	3.1	0.0	2.7	2.3
	Contributions in Aid - Transmission												
22	Gross Contns - Beginning of Year		221.0	221.0	0.0	225.4	260.3	34.9	231.3	317.8	86.5	358.1	377.8
23	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	(0.4)	(0.4)	0.0	0.0	0.0	0.0	0.0
24	Additions		4.4	38.7	34.3	5.9	58.1	52.2	6.1	**40.4**	34.3	**19.8**	**49.3**
25	Retirements & Transfers		0.0	0.6	0.6	0.0	(0.1)	(0.1)	0.0	**(0.1)**	(0.1)	**(0.1)**	**(0.1)**
26	Gross Contns - End of Year		225.4	260.3	34.9	231.3	317.8	86.5	237.4	358.1	120.7	377.8	427.0
27	Accum Amort - Beginning of Year		67.5	67.5	0.0	72.6	72.7	0.1	77.8	77.8	0.0	83.9	91.9
28	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	(0.1)	(0.1)	0.0	0.0	0.0	0.0	0.0
29	Amortization		5.1	5.2	0.1	5.2	5.5	0.3	5.4	**6.1**	0.7	**8.0**	**10.8**
30	Retirements & Transfers		0.0	0.0	0.0	0.0	(0.3)	(0.3)	0.0	0.0	0.0	0.0	0.0
31	Accum Amort - End of Year		72.6	72.7	0.1	77.8	77.8	0.0	83.2	83.9	0.7	91.9	102.7
32	Net Contributions - End of Year		152.8	187.6	34.7	153.5	240.0	86.5	154.2	274.2	120.0	285.9	324.3

Contributions
($ million)

Line	Column	Reference	F2012 RRA	F2012 Actual	F2012 Diff	F2013 RRA	F2013 Actual	F2013 Diff	F2014 RRA	F2014 Forecast	F2014 Diff	F2015 Plan	F2016 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9 = 8 - 7	10	11
	Contributions in Aid - Distribution												
33	Gross Contns - Beginning of Year		1,290.2	1,290.2	0.0	1,337.1	1,378.9	41.8	1,382.9	1,435.9	53.0	1,515.3	1,578.0
34	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	(4.4)	(4.4)	0.0	0.0	0.0	0.0	0.0
35	Additions		46.9	89.4	42.5	45.8	69.8	24.0	44.6	**81.9**	37.3	**65.3**	**74.8**
36	SMI Legacy Meters		0.0	0.0	0.0	0.0	(4.0)	(4.0)	0.0	0.0	0.0	0.0	0.0
37	Retirements & Transfers		0.0	(0.7)	(0.7)	0.0	(4.5)	(4.5)	0.0	**(2.5)**	(2.5)	**(2.6)**	**(2.7)**
38	Gross Contns - End of Year		1,337.1	1,378.9	41.8	1,382.9	1,435.9	53.0	1,427.5	1,515.3	87.8	1,578.0	1,650.1
39	Accum Amort - Beginning of Year		495.1	495.1	0.0	527.9	528.0	0.1	560.9	558.5	(2.4)	592.7	628.9
40	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	(0.7)	(0.7)	0.0	0.0	0.0	0.0	0.0
41	Amortization		24.2	24.3	0.1	25.5	25.7	0.2	26.8	**27.9**	1.1	**29.9**	**31.8**
42	Amortization of Pre-1996 CIAC	2.2 L41	8.6	8.6	0.0	7.5	7.5	0.0	6.3	6.3	0.0	6.3	4.7
43	SMI Legacy Meters		0.0	0.0	0.0	0.0	(1.3)	(1.3)	0.0	0.0	0.0	0.0	0.0
44	Retirements & Transfers		0.0	0.0	0.0	0.0	(0.8)	(0.8)	0.0	0.0	0.0	0.0	0.0
45	Accum Amort - End of Year		527.9	528.0	0.1	560.9	558.5	(2.4)	594.1	592.7	(1.3)	628.9	665.4
46	Net Contributions - End of Year		809.2	850.9	41.7	822.0	877.4	55.4	833.4	922.5	89.1	949.0	984.6
	Contributions in Aid - Total												
47	Gross Contns - Beginning of Year		1,520.1	1,520.1	0.0	1,571.4	1,648.1	76.6	1,623.1	1,762.6	139.5	1,882.3	1,964.7
48	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	(4.8)	(4.8)	0.0	0.0	0.0	0.0	0.0
49	Additions		51.3	128.1	76.8	51.7	127.9	76.2	50.7	122.3	71.6	85.1	124.1
50	SMI Legacy Meters		0.0	0.0	0.0	0.0	(4.0)	(4.0)	0.0	0.0	0.0	0.0	0.0
51	Retirements & Transfers		0.0	(0.1)	(0.1)	0.0	(4.6)	(4.6)	0.0	(2.6)	(2.6)	(2.7)	(2.8)
52	Gross Contns - End of Year		1,571.4	1,648.1	76.6	1,623.1	1,762.6	139.5	1,673.8	1,882.3	208.5	1,964.7	2,086.0
53	Accum Amort - Beginning of Year		567.2	567.2	0.0	605.5	605.7	0.2	644.1	641.7	(2.4)	682.4	727.0
54	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	(0.8)	(0.8)	0.0	0.0	0.0	0.0	0.0
55	Amortization		29.7	30.0	0.2	31.1	31.6	0.5	32.6	34.4	1.8	38.3	43.0
56	Amortization of Pre-96 CIAC		8.6	8.6	0.0	7.5	7.5	0.0	6.3	6.3	0.0	6.3	4.7
57	SMI Legacy Meters		0.0	0.0	0.0	0.0	(1.3)	(1.3)	0.0	0.0	0.0	0.0	0.0
58	Retirements & Transfers		0.0	0.0	0.0	0.0	(1.1)	(1.1)	0.0	0.0	0.0	0.0	0.0
59	Accum Amort - End of Year		605.5	605.7	0.2	644.1	641.7	(2.4)	683.1	682.4	(0.7)	727.0	774.7
60	Net Contributions - End of Year		965.9	1,042.3	76.4	979.0	1,120.9	141.9	990.8	1,199.9	209.1	1,237.7	1,311.3

Assets - Total (Excluding DSM and IPP Capital Leases)
($ million)

			F2012			F2013			F2014			F2015	F2016
		Reference	RRA	Actual	Diff	RRA	Actual	Diff	RRA	Forecast	Diff	Plan	Plan
Line	Column		1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9 = 8 - 7	10	11
	Gross Assets in Service												
1	Opening Balance		21,573.9	21,573.9	0.0	22,638.1	22,911.7	273.6	23,704.2	16,201.5	(7,502.7)	17,340.1	19,817.5
2	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	(8,019.9)	(8,019.9)	0.0	(0.1)	(0.1)	0.0	0.0
3	Capital Additions		1,134.6	1,460.7	326.1	1,168.6	1,454.3	285.7	1,200.8	1,170.9	(29.9)	2,511.7	2,862.2
4	Retirements & Transfers		(70.5)	(122.9)	(52.5)	(102.5)	(144.6)	(42.1)	(86.8)	(32.2)	54.7	(34.2)	(35.4)
5	Closing Balance		22,638.1	22,911.7	273.6	23,704.2	16,201.5	(7,502.7)	24,818.2	17,340.1	(7,478.1)	19,817.5	22,644.3
	Accumulated Amortization												
6	Opening Balance		8,003.1	8,003.1	0.0	8,474.8	8,477.1	2.3	8,940.6	1,099.7	(7,840.9)	1,710.4	2,361.7
7	Adjustment to Opening Balance		0.0	9.0	9.0	0.0	(7,883.5)	(7,883.5)	0.0	(0.1)	(0.1)	0.0	0.0
8	Amort on March 2014 Assets		512.8	534.1	21.3	492.4	570.2	77.8	469.1	488.1	19.0	616.6	594.3
9	Amortization on Additions		22.8	0.0	(22.8)	67.9	0.0	(67.9)	108.8	96.7	(12.2)	34.7	106.7
10	Amort on CRT Contribution		0.0	0.0	0.0	0.0	(1.7)	(1.7)	0.0	0.0	0.0	0.0	0.0
11	SMI New Assets		0.0	0.0	0.0	0.0	17.3	17.3	0.0	26.0	26.0	0.0	0.0
12	SMI Legacy Meters		0.0	38.8	38.8	0.0	19.1	19.1	0.0	0.0	0.0	0.0	0.0
13	Capital Asset Write-Offs		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	Depn Study Adjustment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	Retirements & Transfers		(63.9)	(107.9)	(44.0)	(94.5)	(98.8)	(4.3)	(80.1)	0.0	80.1	0.0	0.0
16	Closing Balance		8,474.8	8,477.1	2.3	8,940.6	1,099.7	(7,840.9)	9,438.3	1,710.4	(7,728.0)	2,361.7	3,062.7
17	**Net Assets in Service (Year-End)**		14,163.3	14,434.5	271.3	14,763.6	15,101.8	338.2	15,379.8	15,629.7	249.9	17,455.9	19,581.6

Assets - Corporate Groups
($ million)

Line	Column	Reference	F2012 RRA	F2012 Actual	F2012 Diff	F2013 RRA	F2013 Actual	F2013 Diff	F2014 RRA	F2014 Forecast	F2014 Diff	F2015 Plan	F2016 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9 = 8 - 7	10	11
	Gross Assets in Service												
1	Opening Balance		1,079.1	1,079.1	0.0	1,249.2	1,181.5	(67.7)	1,356.1	831.5	(524.6)	725.8	860.9
2	Adjustment to Opening Balance		1.7	1.7	0.0	0.0	(453.5)	(453.5)	0.0	**(174.4)**	(174.4)	0.0	0.0
3	Capital Additions	13.0 L44	182.1	161.2	(20.9)	148.6	122.3	(26.3)	58.2	68.8	10.6	135.1	125.7
4	Retirements & Transfers		(13.7)	(60.5)	(46.8)	(41.7)	(18.8)	22.9	(13.4)	**0.0**	13.4	**0.0**	**0.0**
5	Closing Balance		1,249.2	1,181.5	(67.7)	1,356.1	831.5	(524.6)	1,400.9	725.8	(675.1)	860.9	986.6
	Accumulated Amortization												
6	Opening Balance		519.2	519.2	0.0	587.2	531.6	(55.6)	638.7	154.2	(484.5)	92.4	127.7
7	Adjustment to Opening Balance		1.0	1.0	0.0	0.0	(451.4)	(451.4)	0.0	**(94.4)**	(94.4)	0.0	0.0
8	Amort on March 2014 Assets		70.7	77.9	7.2	62.2	87.5	25.3	46.8	**(0.0)**	(46.9)	**32.8**	**31.7**
9	Amortization on Additions	13.0 L78	9.9	0.0	(9.9)	30.0	0.0	(30.0)	44.4	32.6	(11.8)	2.5	7.8
10	Capital Asset Write-Offs		0.0	0.0	0.0	0.0	0.0	0.0	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	0.0
12	Retirements & Transfers		(13.7)	(66.6)	(52.9)	(40.6)	(13.5)	27.1	(13.4)	**0.0**	13.4	**0.0**	**0.0**
13	Closing Balance		587.2	531.6	(55.6)	638.7	154.2	(484.5)	716.6	92.4	(624.2)	127.7	167.2
14	**Net Assets in Service (Year-End)**		662.0	649.9	(12.1)	717.3	677.3	(40.1)	684.3	633.5	(50.9)	733.2	819.4

BC Hydro
F15-F16 RRA

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Assets - Generation
($ million)

Line		Reference	F2012 RRA	F2012 Actual	F2012 Diff	F2013 RRA	F2013 Actual	F2013 Diff	F2014 RRA	F2014 Forecast	F2014 Diff	F2015 Plan	F2016 Plan
	Column		1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9 = 8 - 7	10	11
	Gross Assets in Service												
1	Opening Balance		8,025.6	8,025.6	0.0	8,423.6	8,398.3	(25.3)	8,709.1	5,934.8	(2,774.3)	6,558.3	7,244.2
2	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	(2,747.7)	(2,747.7)	0.0	**343.3**	343.3	0.0	0.0
3	Capital Additions	13.0 L40	402.6	419.8	17.2	291.0	299.6	8.6	115.8	283.7	167.9	689.5	677.9
4	Retirements & Transfers		(4.6)	(47.1)	(42.5)	(5.5)	(15.4)	(9.9)	(20.5)	**(3.5)**	17.0	**(3.6)**	**(3.7)**
5	Closing Balance		8,423.6	8,398.3	(25.3)	8,709.1	5,934.8	(2,774.3)	8,804.5	6,558.3	(2,246.1)	7,244.2	7,918.4
	Accumulated Amortization												
6	Opening Balance		2,670.3	2,670.3	0.0	2,824.6	2,798.7	(25.9)	2,981.6	321.8	(2,659.8)	681.6	928.4
7	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	(2,641.2)	(2,641.2)	0.0	**117.5**	117.5	0.0	0.0
8	Amort on March 2014 Assets		151.6	157.9	6.3	146.6	170.9	24.3	145.4	**217.9**	72.5	**234.5**	**220.8**
9	Amortization on Additions	13.0 L74	5.3	0.0	(5.3)	13.9	0.0	(13.9)	18.4	24.4	6.1	12.3	36.6
10	Amort on CRT Contribution		0.0	0.0	0.0	0.0	(1.7)	(1.7)	0.0	0.0	0.0	0.0	0.0
11	Capital Asset Write-Offs		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	Depn Study Adjustment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	Retirements & Transfers		(2.6)	(29.4)	(26.8)	(3.5)	(4.9)	(1.4)	(18.5)	**0.0**	18.5	**0.0**	**0.0**
14	Closing Balance		2,824.6	2,798.7	(25.9)	2,981.6	321.8	(2,659.8)	3,126.9	681.6	(2,445.3)	928.4	1,185.8
15	**Net Assets in Service (Year-End)**		5,599.0	5,599.6	0.6	5,727.5	5,613.0	(114.5)	5,677.6	5,876.7	199.1	6,315.8	6,732.6

Assets - Customer Care
($ million)

Line		Reference	F2012 RRA	F2012 Actual	F2012 Diff	F2013 RRA	F2013 Actual	F2013 Diff	F2014 RRA	F2014 Forecast	F2014 Diff	F2015 Plan	F2016 Plan
	Column		1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9 = 8 - 7	10	11
	Gross Assets in Service												
1	Opening Balance		1.7	1.7	0.0	(0.0)	(0.0)	0.0	(0.0)	(0.0)	0.0	(0.0)	(0.0)
2	Adjustment to Opening Balance		(1.7)	(1.7)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	Capital Additions	13.0 L43	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	Retirements & Transfers		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	Closing Balance		(0.0)	(0.0)	0.0	(0.0)	(0.0)	0.0	(0.0)	(0.0)	0.0	(0.0)	(0.0)
	Accumulated Amortization												
6	Opening Balance		1.0	1.0	0.0	(0.0)	(0.0)	0.0	(0.0)	(0.0)	0.0	(0.0)	(0.0)
7	Adjustment to Opening Balance		(1.0)	(1.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	Amort on March 2014 Assets		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Amortization on Additions	13.0 L77	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	Capital Asset Write-Offs		0.0	0.0	0.0	0.0	0.0	0.0	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	0.0
12	Retirements & Transfers		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	Closing Balance		(0.0)	(0.0)	0.0	(0.0)	(0.0)	0.0	(0.0)	(0.0)	0.0	(0.0)	(0.0)
14	**Net Assets in Service (Year-End)**		(0.0)	(0.0)	0.0	(0.0)	(0.0)	0.0	(0.0)	(0.0)	0.0	(0.0)	(0.0)

Assets - Transmission
($ million)

Line	Column	Reference	F2012 RRA	F2012 Actual	F2012 Diff	F2013 RRA	F2013 Actual	F2013 Diff	F2014 RRA	F2014 Forecast	F2014 Diff	F2015 Plan	F2016 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9 = 8 - 7	10	11
	Gross Assets in Service												
1	Opening Balance		5,973.2	5,973.2	0.0	6,198.0	6,312.4	114.4	6,596.2	3,971.4	(2,624.8)	4,291.2	5,611.0
2	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	(2,659.2)	(2,659.2)	0.0	(42.5)	(42.5)	0.0	0.0
3	Capital Additions	13.0 L41	240.8	312.0	71.2	414.0	405.6	(8.4)	714.5	370.6	(343.9)	1,328.4	1,680.1
4	Retirements & Transfers		(16.0)	27.2	43.2	(15.8)	(87.4)	(71.6)	(28.1)	(8.3)	19.8	(8.7)	(9.0)
5	Closing Balance		6,198.0	6,312.4	114.4	6,596.2	3,971.4	(2,624.8)	7,282.6	4,291.2	(2,991.4)	5,611.0	7,282.1
	Accumulated Amortization												
6	Opening Balance		2,668.4	2,668.4	0.0	2,790.7	2,799.0	8.3	2,916.2	274.7	(2,641.5)	415.9	567.5
7	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	(2,656.4)	(2,656.4)	0.0	0.0	0.0	0.0	0.0
8	Amort on March 2014 Assets		130.9	135.1	4.2	125.9	138.2	12.3	121.9	120.7	(1.2)	137.1	132.5
9	Amortization on Additions	13.0 L75	2.8	0.0	(2.8)	10.5	0.0	(10.5)	23.8	20.5	(3.3)	14.5	46.3
10	Amortization Adjustment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	Capital Asset Write-Offs		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	Depn Study Adjustment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	Retirements & Transfers		(11.4)	(4.5)	6.9	(10.8)	(6.1)	4.8	(23.4)	0.0	23.4	0.0	0.0
14	Closing Balance		2,790.7	2,799.0	8.3	2,916.2	274.7	(2,641.5)	3,038.5	415.9	(2,622.6)	567.5	746.3
15	**Net Assets in Service (Year-End)**		3,407.3	3,513.4	(8.3)	3,680.0	3,696.7	2,641.5	4,244.1	3,875.3	2,622.6	5,043.4	6,535.7

Assets - Distribution
($ million)

Line	Column	Reference	F2012 RRA	F2012 Actual	F2012 Diff	F2013 RRA	F2013 Actual	F2013 Diff	F2014 RRA	F2014 Forecast	F2014 Diff	F2015 Plan	F2016 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9 = 8 - 7	10	11
	Gross Assets in Service												
1	Opening Balance		6,494.4	6,494.4	0.0	6,767.3	7,019.5	252.2	7,042.8	5,463.8	(1,579.0)	5,764.7	6,101.5
2	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	(2,159.5)	(2,159.5)	0.0	**(126.4)**	(126.4)	0.0	0.0
3	Capital Additions	13.0 L42	309.1	567.7	258.6	315.0	626.9	311.9	312.3	447.8	135.5	358.6	378.5
4	Retirements & Transfers		(36.2)	(42.5)	(6.4)	(39.5)	(23.1)	16.4	(24.9)	**(20.4)**	4.5	**(21.9)**	**(22.7)**
5	Closing Balance		6,767.3	7,019.5	252.2	7,042.8	5,463.8	(1,579.0)	7,330.2	5,764.7	(1,565.4)	6,101.5	6,457.2
	Accumulated Amortization												
6	Opening Balance		2,144.3	2,144.3	0.0	2,272.4	2,347.8	75.5	2,404.0	349.0	(2,055.0)	520.5	738.1
7	Adjustment to Opening Balance		0.0	9.0	9.0	0.0	(2,134.5)	(2,134.5)	0.0	**(23.2)**	(23.2)	0.0	0.0
8	Amort on March 2014 Assets		159.6	163.1	3.6	157.6	173.6	16.0	154.9	**149.6**	(5.3)	**212.2**	**209.3**
9	Amortization on Additions	13.0 L76	4.7	0.0	(4.7)	13.6	0.0	(13.6)	22.3	19.1	(3.2)	5.4	16.0
10	SMI New Assets		0.0	0.0	0.0	0.0	17.3	17.3	0.0	**26.0**	26.0	0.0	0.0
11	SMI Legacy Meters		0.0	38.8	38.8	0.0	19.1	19.1	0.0	0.0	0.0	0.0	0.0
12	Capital Asset Write-Offs		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	Depn Study Adjustment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	Retirements & Transfers		(36.2)	(7.4)	28.8	(39.5)	(74.3)	(34.8)	(24.9)	**0.0**	24.9	**0.0**	**0.0**
15	Closing Balance		2,272.4	2,347.8	75.5	2,404.0	349.0	(2,055.0)	2,556.3	520.5	(2,035.9)	738.1	963.4
16	**Net Assets in Service (Year-End)**		4,494.9	4,671.7	176.7	4,638.7	5,114.8	476.0	4,773.8	5,244.3	470.4	5,363.4	5,493.8

Capital Expenditures and Additions
($ million)

Line	Column	Reference	F2012 RRA	F2012 Actual	F2012 Diff	F2013 RRA	F2013 Actual	F2013 Diff	F2014 RRA	F2014 Forecast	F2014 Diff	F2015 Plan	F2016 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9 = 8 - 7	10	11
	Capital Expenditures												
1	Hydroelectric Generation		314.0	334.3	20.3	409.2	397.6	(11.6)	501.8	473.4	(28.4)	620.5	586.9
2	Thermal Generation - Diesel		11.7	11.5	(0.2)	13.8	13.6	(0.2)	8.3	9.3	1.0	8.7	12.7
3	Thermal Generation - Natural Gas		50.8	75.4	24.6	6.3	10.0	3.7	2.8	8.5	5.7	3.6	7.4
	Transmission												
4	Transmission Lines		348.5	278.8	(69.7)	726.4	465.4	(261.0)	685.2	525.8	(159.4)	710.8	427.9
5	Transmission Substations		203.0	254.6	51.6	442.9	293.1	(149.8)	362.4	330.9	(31.5)	266.5	305.6
6	SDA Substations		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	Subtotal		551.5	533.4	(18.1)	1,169.3	758.5	(410.8)	1,047.6	856.7	(190.9)	977.3	733.5
8	Distribution		329.7	294.9	(34.8)	318.6	309.4	(9.2)	314.7	287.3	(27.4)	343.5	356.0
	IT & Telecom												
9	Information Technology		81.4	68.9	(12.5)	66.5	65.8	(0.7)	63.9	76.4	12.5	114.2	90.5
10	Telecommunications		4.0	13.0	9.0	4.0	9.5	5.5	6.0	6.7	0.7	49.8	18.7
11	Subtotal		85.4	81.9	(3.5)	70.5	75.3	4.8	69.9	83.1	13.2	164.0	109.3
12	Vehicles		32.0	33.5	1.5	7.0	5.1	(1.9)	15.0	9.0	(6.0)	15.0	24.2
13	Properties and Other Capital		97.2	93.3	(3.9)	76.9	94.8	17.9	92.7	114.3	21.6	119.7	109.2
14	Smart Metering & Infrastructure		0.0	234.1	234.1	0.0	258.3	258.3	0.0	143.8	143.8	0.0	0.0
15	HPOP Properties for Resale		(12.7)	(12.7)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
16	Demand Side Management	5.0 L49	184.6	173.4	(11.2)	199.8	147.6	(52.2)	236.3	151.3	(85.0)	150.5	131.1
17	Total		1,644.2	1,852.9	208.7	2,271.4	2,070.2	(201.2)	2,289.1	2,136.7	(152.4)	2,402.8	2,070.3
	Total Capital Additions												
18	Hydroelectric Generation		259.1	249.7	(9.4)	283.7	290.0	6.3	113.1	188.5	75.4	597.9	587.3
19	Thermal Generation - Diesel		8.9	4.7	(4.2)	19.2	4.6	(14.6)	8.0	10.2	2.2	8.9	11.9
20	Thermal Generation - Natural Gas		143.5	170.1	26.6	7.3	9.1	1.8	2.7	8.7	6.0	6.4	5.2
21	Transmission Lines		83.7	104.2	20.5	201.3	156.0	(45.3)	303.3	100.7	(202.6)	766.6	1,302.7
	Substations												
22	Transmission Substations		144.3	188.4	44.1	204.5	248.2	43.7	402.3	257.0	(145.3)	552.1	366.3
23	SDA Substations		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
24	Distribution		259.2	370.5	111.3	277.3	322.9	45.6	278.0	287.4	9.4	314.9	347.2
	Information Technology												
25	Generation		0.0	0.0	0.0	0.0	0.5	0.5	0.0	78.5	78.5	76.0	73.1
26	Transmission		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
27	Distribution		0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.0	0.0	6.9	4.7
28	Customer Care		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
29	Corporate Groups		89.7	77.0	(12.7)	104.7	67.6	(37.1)	45.7	0.9	(44.8)	3.3	7.2
30	Vehicles		32.0	24.0	(8.0)	7.1	19.6	12.5	15.1	8.2	(6.9)	13.8	22.4
	Telecom, Properties and Other												
31	Generation		0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.0	8.0	9.2	12.4
32	Transmission		12.8	19.4	6.6	8.2	1.4	(6.8)	8.9	12.9	4.0	9.8	11.1
33	Distribution		9.0	12.0	3.0	11.4	6.2	(5.2)	11.2	10.6	(0.6)	27.9	14.6
34	Customer Care		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
35	Corporate Groups		105.1	96.9	(8.2)	43.9	54.6	10.7	12.5	59.7	47.2	118.0	96.1
36	Smart Metering & Infrastructure		0.0	156.5	156.5	0.0	273.5	273.5	0.0	139.6	139.6	0.0	0.0
37	HPOP Properties for Resale	Line 15	(12.7)	(12.7)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
38	Demand Side Management	Line 16	184.6	173.4	(11.2)	199.8	147.6	(52.2)	236.3	151.3	(85.0)	150.5	131.1
39	Total		1,319.2	1,634.1	314.9	1,368.4	1,602.0	233.6	1,437.1	1,322.2	(114.9)	2,662.2	2,993.3

Capital Expenditures and Additions
($ million)

Line	Column	Reference	F2012 RRA	F2012 Actual	F2012 Diff	F2013 RRA	F2013 Actual	F2013 Diff	F2014 RRA	F2014 Forecast	F2014 Diff	F2015 Plan	F2016 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9 = 8 - 7	10	11
	Summary of Additions												
40	Generation		402.6	419.8	17.2	291.0	299.6	8.6	115.8	283.7	167.9	689.5	677.9
41	Transmission		240.8	312.0	71.2	414.0	405.6	(8.4)	714.5	370.6	(343.9)	1,328.4	1,680.1
42	Distribution		309.1	567.7	258.6	315.0	626.9	311.9	312.3	447.8	135.5	358.6	378.5
43	Customer Care		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
44	Corporate Groups		182.1	161.2	(20.9)	148.6	122.3	(26.3)	58.2	68.8	10.6	135.1	125.7
45	Demand Side Management		184.6	173.4	(11.2)	199.8	147.6	(52.2)	236.3	151.3	(85.0)	150.5	131.1
46	Total		1,319.2	1,634.1	314.9	1,368.4	1,602.0	233.6	1,437.1	1,322.2	(114.9)	2,662.2	2,993.3
	Unfinished Construction												
47	Beginning of Year		1,606.1	1,606.1	0.0	1,931.1	1,825.5	(105.6)	2,834.1	2,293.8	(540.3)	3,108.3	2,848.9
48	Adjustment to Opening Balance		0.0	0.6	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
49	Change in Unfinished		325.0	218.9	(106.1)	903.0	468.3	(434.7)	852.0	814.5	(37.5)	(259.4)	(923.0)
50	End of Year		1,931.1	1,825.5	(105.6)	2,834.1	2,293.8	(540.3)	3,686.1	3,108.3	(577.8)	2,848.9	1,925.9
51	Mid-Year Balance		1,768.6	1,715.8	(52.8)	2,382.6	2,059.6	(322.9)	3,260.1	2,701.0	(559.0)	2,978.6	2,387.4
	Amortization on Additions												
52	Hydroelectric Generation	2.12%	2.8	3.4	0.6	8.7	8.1	(0.6)	13.0	14.9	1.9	6.3	18.9
53	Thermal Generation - Diesel	3.36%	0.1	0.1	(0.1)	0.6	0.2	(0.4)	1.1	0.5	(0.6)	0.1	0.5
54	Thermal Generation - Nat Gas	3.09%	2.5	1.5	(1.0)	5.2	5.8	0.6	5.4	3.4	(2.0)	0.1	0.3
55	Transmission	1.91%	0.8	0.7	(0.0)	3.5	3.3	(0.2)	8.3	5.4	(2.9)	7.3	27.1
	Substations												
56	Transmission Substations	2.55%	2.0	2.7	0.6	7.0	8.3	1.3	15.5	14.9	(0.6)	7.0	18.7
57	SDA Substations	2.55%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
58	Distribution	2.40%	3.1	3.5	0.4	9.5	12.1	2.6	16.2	18.1	1.9	3.8	11.7
	Information Technology												
59	Generation	15.05%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.0	6.0	5.7	16.9
60	Transmission	15.05%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
61	Distribution	15.05%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5	1.4
62	Customer Care	15.05%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
63	Corporate Groups	15.05%	8.0	6.6	(1.3)	25.3	18.7	(6.6)	38.7	23.5	(15.2)	0.2	1.0
64	Vehicles	6.42%	1.1	0.8	(0.3)	2.5	2.3	(0.2)	3.2	3.2	(0.0)	0.4	1.6
	Telecom, Properties and Other												
65	Generation	3.10%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.5
66	Transmission	3.10%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.5
67	Distribution	6.78%	0.3	0.1	(0.2)	1.0	1.0	0.0	1.8	0.5	(1.3)	0.9	2.4
68	Customer Care	3.10%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
69	Corporate Groups	3.10%	1.9	1.6	(0.3)	4.7	4.3	(0.4)	5.7	5.9	0.2	1.8	5.1
70	Smart Metering & Infrastructure	5.00%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
71	HPOP Properties for Resale	0.00%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
72	Demand Side Management	6.67%	0.0	0.0	0.0	12.3	11.6	(0.7)	25.6	21.4	(4.2)	0.0	10.0
73	Total		22.8	21.0	(1.7)	80.2	75.7	(4.5)	134.5	118.1	(16.4)	34.7	116.7
	Summary of Amortization on Additions												
74	Generation		5.3	4.8	(0.5)	13.9	13.9	0.1	18.4	24.4	6.1	12.3	36.6
75	Transmission		2.8	3.4	0.6	10.5	11.6	1.1	23.8	20.5	(3.3)	14.5	46.3
76	Distribution		4.7	4.5	(0.2)	13.6	15.6	2.0	22.3	19.1	(3.2)	5.4	16.0
77	Customer Care		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
78	Corporate Groups		9.9	8.3	(1.6)	30.0	23.0	(7.0)	44.4	32.6	(11.8)	2.5	7.8
79	Demand Side Management		0.0	0.0	0.0	12.3	11.6	(0.7)	25.6	21.4	(4.2)	0.0	10.0
80	Total		22.8	21.0	(1.7)	80.2	75.7	(4.5)	134.5	118.1	(16.4)	34.7	116.7

Domestic Energy Sales and Revenue

Line	Column	Reference	F2012 RRA	F2012 Actual	F2012 Diff	F2013 RRA	F2013 Actual	F2013 Diff	F2014 RRA	F2014 Forecast	F2014 Diff	F2015 Plan	F2016 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9 = 8 - 7	10	11
	Domestic Energy Sales (GWh)												
1	Residential		18,213	18,395	182	18,210	17,703	(507)	18,057	18,305	248	18,805	18,743
2	Light Industrial and Commercial		18,209	18,005	(204)	17,930	18,384	455	17,681	18,356	675	18,277	18,346
3	Large Industrial		14,451	13,522	(929)	15,315	13,508	(1,807)	16,519	13,557	(2,962)	14,444	15,032
4	Irrigation		91	63	(28)	92	70	(22)	92	68	(25)	79	79
5	Street Lighting		221	222	1	223	222	(1)	225	226	1	228	230
6	New Westminster & Tongass		450	455	5	454	455	1	458	460	1	470	476
7	Fortis		971	514	(458)	993	340	(654)	1,013	560	(452)	516	541
8	Seattle City Light		312	311	(1)	310	310	(0)	310	305	(6)	310	312
9	Total		52,919	51,487	(1,431)	53,527	50,992	(2,535)	54,356	51,837	(2,519)	53,130	53,760
	Domestic Revenues ($ million)												
10	Residential		1,509.2	1,542.7	33.5	1,579.5	1,529.6	(49.9)	1,591.8	1,614.7	22.9	1,662.5	1,659.7
11	Light Industrial and Commercial		1,302.7	1,294.6	(8.2)	1,341.1	1,368.0	26.9	1,341.9	1,401.2	59.3	1,387.5	1,392.1
12	Large Industrial		652.3	583.6	(68.7)	735.0	610.9	(124.1)	801.7	628.0	(173.7)	682.5	715.0
13	Irrigation		5.1	3.9	(1.2)	5.4	4.5	(0.9)	5.5	4.8	(0.7)	5.2	5.2
14	Street Lighting		30.2	30.2	(0.1)	31.9	31.6	(0.3)	32.7	32.6	(0.0)	33.0	33.2
15	New Westminster & Tongass		21.2	21.6	0.4	22.4	22.5	0.1	22.9	22.9	(0.0)	23.4	23.7
16	Fortis		47.1	28.6	(18.5)	50.1	22.1	(28.0)	52.3	31.1	(21.2)	30.1	31.0
17	Seattle City Light		14.6	14.9	0.3	14.8	14.8	0.0	15.5	15.3	(0.2)	16.2	16.5
18	F11 Credit Rider		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
19	SMI Impact		0.1	0.0	(0.1)	5.5	5.5	0.0	32.9	0.0	(32.9)	0.0	0.0
20	Subtotal		3,582.6	3,520.1	(62.5)	3,785.5	3,609.5	(176.1)	3,897.1	3,750.6	(146.4)	3,840.4	3,876.5
21	Revenue from Deferral Rider		89.2	87.7	(1.5)	188.5	179.7	(8.8)	194.1	186.8	(7.3)	208.4	223.0
22	Total		3,671.8	3,607.7	(64.1)	3,974.1	3,789.2	(184.9)	4,091.2	3,937.4	(153.8)	4,048.8	4,099.5
23	**F11 Credit Rider**												
24	**Deferral Account Rate Rider**		2.50%	2.50%		5.00%	5.00%		5.00%	5.00%		5.00%	5.00%
	Average Revenues ($/MWh)												
25	Residential		82.9	83.9	1.0	86.7	86.7	(0.0)	88.2	88.2	0.1	88.4	88.6
26	Light Industrial and Commercial		71.5	71.9	0.4	74.8	74.4	(0.4)	75.9	76.3	0.4	75.9	75.9
27	Large Industrial		45.1	43.2	(2.0)	48.0	45.2	(2.8)	48.5	46.3	(2.2)	47.3	47.6
28	Irrigation		56.4	61.4	5.0	59.0	64.8	5.8	59.8	71.1	11.3	66.0	66.0
29	Street Lighting		136.8	136.0	(0.8)	143.0	142.3	(0.7)	145.0	144.3	(0.7)	144.6	144.6
30	New Westminster & Tongass		47.1	47.5	0.4	49.3	49.4	0.2	50.0	49.8	(0.2)	49.7	49.7
31	Fortis		48.5	55.7	7.2	50.4	65.0	14.6	51.6	55.5	3.9	58.4	57.4
32	Seattle City Light		46.8	47.9	1.1	47.6	47.6	0.0	50.0	50.3	0.3	52.1	52.9
33	Total (Excluding Misc Rev)		69.4	70.1	0.7	74.2	74.3	0.1	75.3	76.0	0.7	76.2	76.3
	Peak Demand (MW)												
34	Distribution		7,779	7,792	13	7,789	7,068	(721)	7,684	7,979	295	7,976	7,920
35	Transmission		1,692	1,455	(237)	1,706	1,474	(232)	1,829	1,503	(326)	1,575	1,657
36	Other		414	348	(66)	417	351	(66)	422	428	6	429	431
37	Losses		851	828	(23)	854	717	(137)	856	797	(59)	803	805
38	Total		10,736	10,423	(313)	10,766	9,610	(1,156)	10,791	10,707	(84)	10,783	10,813

Miscellaneous Revenue
($ million)

Line	Column	Reference	F2012 RRA	F2012 Actual	F2012 Diff	F2013 RRA	F2013 Actual	F2013 Diff	F2014 RRA	F2014 Forecast	F2014 Diff	F2015 Plan	F2016 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9 = 8 - 7	10	11
	Generation												
1	Interconnected Operations Services		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	FX Loss - Cost of Energy		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	Amortization of Contributions	11.0 L18	0.0	0.0	0.0	0.4	0.4	0.0	0.4	0.4	(0.0)	0.4	0.4
4	Other		2.5	2.5	0.0	2.6	3.2	0.6	2.6	2.7	0.1	2.6	2.7
5	Total		2.5	2.5	0.0	3.0	3.6	0.6	3.0	3.1	0.1	3.0	3.1
	Transmission												
6	External OATT	3.4 L71	15.3	10.0	(5.2)	15.6	9.1	(6.5)	15.4	8.3	(7.1)	10.1	11.8
7	FortisBC Wheeling Agreement		4.3	3.6	(0.7)	4.9	4.8	(0.0)	5.3	5.2	(0.1)	5.0	4.8
8	Secondary Revenue		3.5	6.5	3.0	3.5	6.6	3.1	3.5	7.2	3.7	7.4	7.5
9	Interconnections		6.6	2.8	(3.8)	6.6	3.7	(2.9)	6.6	5.7	(0.9)	4.0	4.2
10	Amortization of Contributions	11.0 L29+30-25	0.0	0.0	0.0	5.2	5.3	0.1	5.4	6.2	0.8	8.1	10.9
11	Other		1.0	3.3	2.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	Total		30.7	26.2	(4.5)	35.7	29.5	(6.2)	36.2	32.7	(3.5)	34.7	39.2
	Distribution												
13	Secondary Use Revenue & Other		15.5	17.5	2.0	15.6	19.6	4.0	15.4	17.0	1.6	16.5	16.6
14	Amortization of Contributions	11.0 L41+44-37	0.0	0.0	0.0	25.5	29.4	3.9	26.8	30.4	3.6	32.5	34.5
15	Legacy Meter Contributions	11.0 L36+43	0.0	0.0	0.0	0.0	2.7	2.7	0.0	0.0	0.0	0.0	0.0
16	Total		15.5	17.5	2.0	41.1	51.7	10.6	42.2	47.4	5.2	49.0	51.1
	Customer Care												
17	Meter/Trans Rents & Power Factor Surcharges		9.3	9.8	0.5	9.3	10.4	1.1	9.3	10.2	1.0	10.4	10.5
18	Terasen Meter Reading		3.1	2.8	(0.3)	2.5	1.7	(0.8)	0.7	0.0	(0.7)	0.0	0.0
19	SMI Impact		0.1	0.0	(0.1)	(2.8)	0.8	3.6	0.2	4.0	3.9	4.8	3.4
20	Diversion Net Recoveries		1.2	0.8	(0.3)	1.2	0.6	(0.6)	1.2	0.8	(0.4)	1.2	0.9
21	FX Loss - Cost of Energy		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22	Other Operating Recoveries		5.1	4.9	(0.2)	5.2	4.7	(0.5)	5.2	5.7	0.5	5.8	5.9
23	Other		1.1	2.5	1.4	1.1	2.1	1.1	1.1	1.3	0.2	1.5	1.5
24	Total		19.8	20.8	1.0	16.3	20.3	3.9	17.6	22.0	4.4	23.6	22.1
	Corporate Groups												
25	Corporate General Rents		5.8	6.5	0.7	5.8	6.3	0.5	5.8	6.7	0.9	3.5	3.6
26	Diversion Net Recoveries		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
27	Net Gains on Property Sales		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
28	Late Payment Charges		7.2	7.0	(0.2)	7.2	7.0	(0.2)	7.2	7.3	0.1	7.5	7.6
29	BCTC Recoveries		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
30	Other		1.4	0.3	(1.1)	1.4	0.7	(0.7)	1.4	1.5	0.1	0.1	(0.0)
31	Total		14.4	13.8	(0.7)	14.4	14.0	(0.4)	14.4	15.6	1.2	11.0	11.2
32	**Total Gross Non-Tariff Revenue**		82.9	80.8	(2.1)	110.6	119.1	8.5	113.5	120.7	7.3	121.3	126.6
	Regulatory Account Additions												
33	Legacy Meter Contributions	Line 15	0.0	0.0	0.0	0.0	2.7	2.7	0.0	0.0	0.0	0.0	0.0
34	SMI Impact	Line 19	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.0	4.0	4.8	3.4
35	**Total Current Non-Tariff Revenue**		82.9	80.8	(2.1)	110.6	116.4	5.8	113.5	116.7	3.2	116.5	123.3

F2015 to F2016 Revenue Requirements
Rate Application

Appendix D

Direction No. 6

PROVINCE OF BRITISH COLUMBIA

ORDER OF THE LIEUTENANT GOVERNOR IN COUNCIL

Order in Council No. 096 *, Approved and Ordered* March 05, 2014

Lieutenant Governor

Executive Council Chambers, Victoria

On the recommendation of the undersigned, the Lieutenant Governor, by and with the advice and consent of the Executive Council, orders that the attached Direction No. 6 to the British Columbia Utilities Commission is made.

DEPOSITED

March 6, 2014

B.C. REG. **29/2014**

Minister of Energy and Mines and
Minister Responsible for Core Review

Presiding Member of the Executive Council

(This part is for administrative purposes only and is not part of the Order.)

Authority under which Order is made:

Act and section: *Utilities Commission Act*, R.S.B.C. 1996, c. 473, s. 3

Other: OIC 1123/2003; OIC 1125/2003

February 18, 2014 R/112/2014/27

DIRECTION NO. 6 TO THE BRITISH COLUMBIA UTILITIES COMMISSION

Contents

Definitions

1 In this direction:

"Act" means the *Utilities Commission Act*;

"amortization of capital additions" means the portion of the authority's annual amortization expense that is subject to the amortization of capital additions regulatory account;

"amortization of capital additions regulatory account" means the regulatory account established under commission order G-16-09 and the direction in section 5.5.7 of the reasons that accompany that order;

"arrow water divestiture costs regulatory account" means the regulatory account established under paragraph 1 of commission order G-90-11;

"arrow water provision regulatory account" means the regulatory account established under paragraph 2 of commission order G-90-11;

"asbestos remediation costs" has the same meaning as in Direction No. 7 to the British Columbia Utilities Commission;

"asbestos remediation regulatory account" has the same meaning as in Direction No. 7 to the British Columbia Utilities Commission;

"deemed equity" has the same meaning as in Direction No. 7 to the British Columbia Utilities Commission;

"electric tariff rates" means the rates in the schedules to the authority's electric tariff;

"F2014" has the same meaning as in Direction No. 7 to the British Columbia Utilities Commission;

"F2015" has the same meaning as in Direction No. 7 to the British Columbia Utilities Commission;

"F2016" has the same meaning as in Direction No. 7 to the British Columbia Utilities Commission;

"first nations costs regulatory account" means the regulatory account established under commission order G-53-02;

"heritage payment obligation" has the same meaning as in Direction No. 7 to the British Columbia Utilities Commission;

"home purchase option plan regulatory account" means the regulatory account established under commission order G-55-09;

"IFRS pension regulatory account" means the regulatory account established under paragraph 1 (xxii) of commission order G-77-12A;

"IFRS PP&E regulatory account" means the regulatory account established under paragraph 1 (xxi) of commission order G-77-12A;

"non-current pension costs" has the same meaning as in Direction No. 7 to the British Columbia Utilities Commission;

"non-current pension costs regulatory account" has the same meaning as in Direction No. 7 to the British Columbia Utilities Commission;

"non-heritage cost of energy subject to deferral" means the portion of the authority's annual cost of energy that is subject to the non-heritage deferral account;

"non-heritage deferral account" has the same meaning as in Direction No. 7 to the British Columbia Utilities Commission;

"OATT rates" means the rates in schedules 00, 01 and 03 to the authority's open access transmission tariff;

"rate smoothing regulatory account" has the same meaning as in Direction No. 7 to the British Columbia Utilities Commission;

"real property gain/loss" means the net gain or net loss in a fiscal year incurred by the authority from the sale of its real property;

"related equipment" means the related equipment described in section 3 (b) of the Smart Meters and Smart Grid Regulation;

"Rock Bay costs" has the same meaning as in Direction No. 7 to the British Columbia Utilities Commission;

"Rock Bay remediation regulatory account" has the same meaning as in Direction No. 7 to the British Columbia Utilities Commission;

"Site C regulatory account" means the regulatory account established under commission order G-143-06 and section 25 of Appendix A attached to that order;

"smart meter" has the same meaning as in section 17 of the *Clean Energy Act*;

"smart metering and infrastructure program" means the authority's program to install and operate smart meters and related equipment and the program referred to in section 17 (4) of the *Clean Energy Act*;

"SMI regulatory account" has the same meaning as in Direction No. 7 to the British Columbia Utilities Commission;

"storm restoration costs" means the costs that are subject to the storm restoration regulatory account;

"storm restoration regulatory account" means the regulatory account established under commission order G-16-09 and the direction in section 5.5.4 of the reasons that accompany that order;

"total finance charges" means the portion of the authority's annual finance charges that is subject to the total finance charges regulatory account;

"total finance charges regulatory account" means the regulatory account established under commission order G-16-09 and the direction in section 5.5.2 of the reasons that accompany that order;

"total rate revenue" means the portion of the authority's annual revenues that is subject to the non-heritage deferral account;

"trade income" has the same meaning as in Direction No. 7 to the British Columbia Utilities Commission.

Application

2 This direction is issued to the commission under section 3 of the Act.

Orders

3 Within 20 days of the date on which the authority files an application with the commission to request final orders in regard to the authority's F2014, F2015 and F2016 rates, the commission must issue final orders as follows:

- (a) the commission must accept the schedule of expenditures in regard to demand-side measures for F2014, F2015 and F2016 as set out in Appendix A to this direction;
- (b) the commission must confirm the authority's rates for F2014, set by commission order G-77-12A, as final and no longer subject to refund;
- (c) the commission must set the electric tariff rates for F2015 and F2016 as set out in Appendix B to this direction;
- (d) the commission must set the OATT rates for F2015 and F2016 as set out in Appendix C to this direction;
- (e) the commission must approve the following forecasts and planned expenditures for F2015:
  - (i) heritage payment obligation: $353.2 million;
  - (ii) non-heritage cost of energy subject to deferral: $1 074.3 million;
  - (iii) total rate revenue: $4 168.3 million;
  - (iv) trade income: $110.0 million;
  - (v) non-current pension costs: $2.9 million;
  - (vi) storm restoration costs: $3.9 million;
  - (vii) total finance charges: $602.6 million;
  - (viii) amortization of capital additions: $34.7 million;
  - (ix) real property gain/loss: $10.0 million;
  - (x) asbestos remediation costs: $1.8 million;
- (f) the commission must approve the following forecasts and planned expenditures for F2016:

(i) heritage payment obligation: $399.2 million;

(ii) non-heritage cost of energy subject to deferral: $1 032.2 million;

(iii) total rate revenue: $4 459.7 million;

(iv) trade income: $110.0 million;

(v) non-current pension costs: $0.1 million;

(vi) storm restoration costs: $3.9 million;

(vii) total finance charges: $725.2 million;

(viii) amortization of capital additions: $106.7 million;

(ix) real property gain/loss: $10.0 million;

(x) asbestos remediation costs: $0.9 million;

(g) the commission must order, in regard to the first nations costs regulatory account, that the authority amortize from that account $43.5 million and $43.3 million in F2015 and F2016, respectively;

(h) the commission must order, in regard to the Site C regulatory account, that the authority defer to that account operating costs it incurs in regard to the Site C project in F2015 and F2016;

(i) the commission must order, in regard to the storm restoration regulatory account, that the authority amortize from that account $1.4 million in each of F2015 and F2016;

(j) the commission must order, in regard to the amortization of capital additions regulatory account, that the authority amortize from that account $9.8 million and $9.4 million in F2015 and F2016, respectively;

(k) the commission must order, in regard to the total finance charges regulatory account, that the authority amortize from that account $25.5 million in each of F2015 and F2016;

(l) the commission must order, in regard to the SMI regulatory account, that

(i) the authority amortize from that account $30.5 million and $31.3 million in F2015 and F2016, respectively, and

(ii) the authority defer to that account net operating costs incurred in F2015 and F2016 arising from the smart metering and infrastructure program and net operating costs arising from commission order G-166-13;

(m) the commission must order, in regard to the home purchase option plan regulatory account, that the authority amortize from that account $11.8 million and $11.3 million in F2015 and F2016, respectively;

(n) the commission must order, in regard to the non-current pension costs regulatory account, that the authority amortize from that account $32.6 million and $15.5 million in F2015 and F2016, respectively;

(o) the commission must order, in regard to the Rock Bay remediation regulatory account, that the authority amortize from that account $51.5 million and $50.5 million in F2015 and F2016, respectively;

(p) the commission must order, in regard to the IFRS PP&E regulatory account, that

(i) the authority amortize from that account \$15.9 million and \$19.8 million in F2015 and F2016, respectively, and

(ii) the authority defer to that account \$156.8 million and \$134.4 million in F2015 and F2016, respectively;

(q) the commission must order, in regard to the IFRS pension regulatory account, that the authority amortize from that account \$38.2 million in each of F2015 and F2016;

(r) the commission must order, in regard to the arrow water divestiture costs regulatory account, that the authority amortize from that account \$4.7 million and \$4.5 million in F2015 and F2016, respectively;

(s) the commission must order, in regard to the arrow water provision regulatory account, that the authority amortize from that account \$0.3 million in each of F2015 and F2016;

(t) the commission must order, in regard to the asbestos remediation regulatory account, that the authority amortize from that account \$12.1 million and \$10.7 million in F2015 and F2016, respectively;

(u) the commission must order, in regard to the rate smoothing regulatory account, that the authority defer to that account \$166.2 million and \$121.2 million in F2015 and F2016, respectively;

(v) the commission must, despite section 5 of Direction No. 3 to the British Columbia Utilities Commission, direct the authority to defer to the non-heritage deferral account the amount that is determined by subtracting the amount in subparagraph (ii) from the amount in subparagraph (i)

(i) the forecast return on deemed equity in F2014 calculated on the basis of an annual rate of return on deemed equity in that year of 11.84%, and

(ii) the forecast return on deemed equity in F2014 calculated on the basis of an annual rate of return on deemed equity in that year that is greater than or less than 11.84% as a result of the commission's order arising from the generic cost of capital proceeding initiated by commission order G-20-12.

APPENDIX A

F2014 – F2016 DSM Expenditure Schedule

$ MILLION	F2014	F2015	F2016
Codes and Standards	2.4	4.0	4.2
Rate Structures	6.5	2.0	1.7
Programs			
Residential	30.4	17.7	18.9
Commercial	66.4	39.5	40.0
Industrial	101.9	64.3	42.9
Total Programs	198.7	121.5	101.8
Supporting Initiatives	28.7	20.6	20.3
Total Energy Efficiency Portfolio	236.3	148.0	128.0
Capacity Focused DSM	0.0	2.4	3.1
Total	236.3	150.5	131.1

APPENDIX B

Electric Tariff Rates – F2015 and F2016

Rate Class	Rate Schedule	Rate	F2015	F2016
Residential	1101/1121	Basic Charge($/day)	0.1664	0.1764
		Step 1 energy rate ($/kWh)	0.0752	0.0797
		Step 2 energy rate ($/kWh)	0.1127	0.1195
Residential	1105 (closed)	Energy rate ($/kWh)	0.0492	0.0522
		Energy rate during period of interruption ($/kWh)	0.2865	0.3037
Residential Zone II	1107/1127	Basic Charge ($/day)	0.1775	0.1882
		Step 1 energy rate ($/kWh)	0.0901	0.0955
		Step 2 energy rate ($/kWh)	0.1548	0.1641
Residential	1148 (closed)	Basic Charge($/day)	0.1775	0.1882
		Energy rate ($/kWh)	0.0901	0.0955
Residential	1151/1161	Basic Charge ($/day)	0.1775	0.1882
		Energy rate ($/kWh)	0.0901	0.0955
Exempt General Service	1200/1201/ 1210/1211	Basic Charge($/day)	0.2129	0.2257
		Demand rate – Step 1 ($/kW)	0	0
		Demand rate – Step 2 ($/kW)	5.19	5.50
		Demand rate – Step 3 ($/kW)	9.95	10.55

Rate Class	Rate Schedule	Rate	F2015	F2016
		Energy Rate – Tier 1 ($/kWh)	0.1012	0.1073
		Energy Rate – Tier 2 ($/kWh)	0.0486	0.0515
General Service	1205/1206/ 1207	Energy rate – Tier 1 ($/kWh)	0.0492	0.0522
		Energy rate – Tier 2 ($/kWh)	0.0323	0.0342
		Energy rate during period of interruption ($/kWh)	0.2865	0.3037
Small General Service Zone II	1234	Basic Charge ($/day)	0.2129	0.2257
		Energy rate – Tier 1 ($/kWh)	0.1012	0.1073
		Energy rate – Tier 2 ($/kWh)	0.1686	0.1787
Distribution Service	1253	Monthly Minimum energy charge ($/month)	39.03	41.37
Distribution Service	1268	Energy charge ($/kWh)	0.00157	0.00166
Power Service	1278 (Closed)	$/kVA	2.526	2.678
		Energy charge ($/kWh)	0.06604	0.07
		Monthly minimum greater of $/kVA or ($)	4.93 9868.64	5.23 10460.76
Large General Service Zone II	1255/1256/ 1265/1266	Basic Charge ($/day)	0.2129	0.2257
		Energy charge – Tier 1 ($/kWh)	0.1012	0.1073
		Energy charge – Tier 2 ($/kWh)	0.1686	0.1787
Net Metering Service	1289	Energy rate ($/kWh)	0.0999	0.0999
Small General Service	1300/1301/ 1310/1311	Basic Charge ($/day)	0.2129	0.2257
		Energy Charge ($/kWh)	0.1012	0.1073
Irrigation	1401/1402	Irrigation season energy rate ($/kWh)	0.0487	0.0516
		Non-irrigation season energy charge – Tier 1 ($/kWh)	0.0487	0.0516
		Non-irrigation season energy rate Tier 2 ($/kWh)	0.3864	0.4096

Rate Class	Rate Schedule	Rate	F2015	F2016
		Minimum charge irrigation season ($/kW)	4.87	5.16
		Non-irrigation season if consumption >500 kWh ($per kW)	38.98	41.32
Medium General Service	1500/1501/ 1510/1511	Basic Charge ($/day)	0.2129	0.2257
		Demand rate – Step 1 ($/kW)	0.00	0.00
		Demand rate – Step 2 ($/kW)	5.19	5.50
		Demand rate – Step 3 ($/kW)	9.95	10.55
		Part 1 Energy Rate – Tier 1 ($/kWh)	0.0934	0.0989
		Part 1 Energy Rate – Tier 2 ($/kWh)	0.0651	0.0690
		Part 2 Energy Rate ($/kWh)	0.0971	0.0990
		Minimum Energy Rate ($/kWh)	0.0311	0.0330
Large General Service	1600/1601/ 1610/1611	Basic Charge ($/day)	0.2129	0.2257
		Demand rate – Step 1 ($/kW)	0.00	0.00
		Demand rate – Step 2 ($/kW)	5.19	5.50
		Demand rate – Step 3 ($/kW)	9.95	10.55
		Part 1 Energy Rate Tier 1 ($/kWh)	0.1010	0.1066
		Part 1 Energy Rate– Tier 2 ($/kWh)	0.0486	0.0513
		Part 2 Energy Rate ($/kWh)	0.0971	0.0990
		Minimum Energy Charge ($/kWh)	0.0311	0.0330
Large General Service (150kW and over) for Distribution Utilities	2600/2601/ 2610/2611	Basic Charge ($/day)	0.2129	0.2257

Rate Class	Rate Schedule	Rate	F2015	F2016
		Demand rate – Step 1 ($/kW)	0.00	0.00
		Demand rate – Step 2 ($/kW)	5.19	5.50
		Demand rate – Step 3 ($/kW)	9.95	10.55
		Part 2 Energy Rate $/kWh (RS1600)	0.0971	0.0990
		Embedded Cost Rate $/kWh	0.0501	0.0531
		Discount ($/kWh)	-0.0037	-0.0039
Street Lighting	1701	100 SV fixture rate ($/month)	15.61	16.55
		150 SV fixture rate ($/month)	18.61	19.73
		200 SV fixture rate ($month)	21.49	22.78
		175 MV fixture rate ($/month)	17.15	18.18
		250 MV fixture rate ($/month)	19.76	20.95
		400 MV fixture rate ($/month)	25.48	27.01
Street Lighting	1702	Each Unmetered Fixture ($/watt per month)	0.03	0.0318
		Each Metered Fixture ($/kWh)	0.0901	0.0955
Street Lighting	1703	Energy rate ($/watt per month)	0.03	0.0318
		Contact rate ($/contact per month)	0.9057	0.96
Street Lighting	1704	Energy rate ($/kWh)	0.0901	0.0955
Street Lighting	1755 (closed)	1. Pole owned by Customer		
		175 MV or 100SV fixture charge ($ per month)	14.63	15.51
		400 MV or 150SV fixture charge ($ per month)	25.22	26.73
		2. Pole on public property		
		175 MV or 100SV fixture charge ($ per month)	15.54	16.47
		400 MV or 150SV fixture charge ($ per month)	26.13	27.70
		3. Pole paid by BC Hydro		
		175 MV or 100SV fixture charge ($ per month)	19.13	20.28
		400 MV or 150SV fixture charge ($ per month)	30.11	31.92

Rate Class	Rate Schedule	Rate	F2015	F2016
Transmission Service	1823	Demand rate ($/kVA)	6.925	7.341
		Energy rate A ($/kWh)	0.04059	0.04303
		Energy rate B Tier 1 ($/kWh)	0.03619	0.03836
		Energy rate B Tier 2 ($/kWh)	0.08022	0.08503
		Minimum demand ($/kVA)	6.925	7.341
Transmission Service	1825	Demand rate ($/kVA)	6.925	7.341
		Winter HLH energy rate (below 90%) ($/kWh)	0.03619	0.03836
		Winter HLH energy rate (above 90%) ($/kWh)	0.08952	0.09489
		Winter LLH energy rate (below 90%) ($/kWh)	0.03619	0.03836
		Winter LLH energy rate (above 90%) ($/kWh)	0.08113	0.08600
		Spring energy rate (below 90%) ($/kWh)	0.03619	0.03836
		Spring energy rate (above 90%) ($/kWh)	0.07226	0.07660
		Remaining energy rate (below 90%) ($/kWh)	0.03619	0.03836
		Remaining energy rate (above 90%) ($/kWh)	0.07923	0.08398
Transmission Service	1827	Demand rate ($/kVA)	6.925	7.341
		Energy rate ($/kWh)	0.04059	0.04303
		Minimum demand ($/kVA)	6.925	7.341
Transmission Service	1852	Excess demand rate ($/kVA)	6.925	7.341
Transmission Service	1853	Minimum Monthly Charge ($/month)	39.03	41.37
Transmission Service	1880	Administrative Charge per Period of Use ($)	150.00	150.00
		Energy charge ($/kWh)	0.08022	0.08503
Transmission Service FortisBC	3808	Demand Charge ($/kW)	6.925	7.341

Rate Class	Rate Schedule	Rate	F2015	F2016
		Energy rate ($/kWh)	4.059	4.303

APPENDIX C
BC Hydro OATT Rates – F2015 and F2016

Service	Rate Schedule in Authority's Open Access Transmission Tariff	F2015 Rate	F2016 Rate
Network Integration Transmission Service	00	$52.1 million/month	$62.1 million/month
Long-term Firm Point to Point Transmission Service	01	$53 698/MW/year	$64 968/MW/year
Monthly Short-term Firm and Non-firm Point to Point Transmission Service	01	$4 474.87/MW/month	$5 413.99/MW/month
Weekly Short-term Firm and Non-firm Point to Point Transmission Service	01	$1 032.66/MW/week	$1 249.38/MW/week
Daily Short-term Firm and Non-firm Point to Point Transmission Service	01	$147.12/MW/day	$177.99/MW/day
Hourly Short-term Firm and Non-firm Point to Point Transmission Service	01	$6.13/MW/hour	$7.42/MW/hour
Scheduling, System Control, and Dispatch Service Fee	03	$0.102/MWh	$0.099/MWh

BC hydro

F2015 to F2016 Revenue Requirements Rate Application

Appendix E

Direction No. 7

PROVINCE OF BRITISH COLUMBIA

ORDER OF THE LIEUTENANT GOVERNOR IN COUNCIL

Order in Council No. 097 *, Approved and Ordered* March 05, 2014

Judith Guichon
Lieutenant Governor

Executive Council Chambers, Victoria

On the recommendation of the undersigned, the Lieutenant Governor, by and with the advice and consent of the Executive Council, orders that

(a) the Heritage Special Direction No. HC2 to the British Columbia Utilities Commission, B.C. Reg. 158/2005, is repealed, and

(b) the attached Direction No. 7 to the British Columbia Utilities Commission is made.

DEPOSITED
March 6, 2014
B.C. REG. 28/2014

W.R. Bennett
Minister of Energy and Mines and Minister Responsible for Core Review

Teresa Wat
Presiding Member of the Executive Council

(This part is for administrative purposes only and is not part of the Order.)

Authority under which Order is made:

Act and section: *Utilities Commission Act*, R.S.B.C. 1996, c. 473, s. 3;
BC Hydro Public Power Legacy and Heritage Contract Act, S.B.C. 2003, c. 86, s. 4

Other: OIC 1123/2003

February 18, 2014 R/113/2014/27

DIRECTION NO. 7 TO THE BRITISH COLUMBIA UTILITIES COMMISSION

Contents

Definitions

1 In this direction:

"Act" means the *Utilities Commission Act*;

"asbestos remediation costs" means the costs that are subject to the asbestos remediation regulatory account;

"asbestos remediation regulatory account" means the regulatory account established under commission order G-7-13;

"base line rate change" means, for each of F2017, F2018 and F2019, the year-over-year increase in the authority's average rates that the commission determines it would have ordered but for section 9 (1) of this direction, expressed as a percentage;

"Burrard costs" means the costs incurred by the authority in F2014 or a later fiscal year arising from the decommissioning of those portions of Burrard Thermal that are not required for transmission support services, including, without limitation, employee retention costs incurred as a result of the decommissioning, costs incurred as penalties or damages that arise in consequence of the decommissioning, and the net increase in amortization expense in F2015 and F2016 arising from a commission order under section 15 of this direction;

"Burrard Thermal" has the same meaning as in the *Clean Energy Act*;

"California settlements" means the settlement of litigation between Powerex Corp. and various California parties arising from events and transactions in the

California power market during 2000 and 2001, as approved by the Federal Energy Regulatory Commission (US) on October 4, 2013;

"debt" has the same meaning as in Heritage Special Directive No. HC1 to the British Columbia Hydro and Power Authority;

"deemed equity" means, for any fiscal year, the product obtained by multiplying the rate base relating to that year by 30%;

"deferral account rate rider" means the surcharge, expressed as a percentage, as set out in rate schedule 1901 of the authority;

"distributable surplus" has the same meaning as in Heritage Special Directive No. HC1 to the British Columbia Hydro and Power Authority;

"DSM regulatory account" means the regulatory account of the authority established under commission order G-55-95;

"F2014" means the authority's fiscal year commencing April 1, 2013 and ending March 31, 2014;

"F2015" means the authority's fiscal year commencing April 1, 2014 and ending March 31, 2015;

"F2016" means the authority's fiscal year commencing April 1, 2015 and ending March 31, 2016;

"F2017" means the authority's fiscal year commencing April 1, 2016 and ending March 31, 2017;

"F2018" means the authority's fiscal year commencing April 1, 2017 and ending March 31, 2018;

"F2019" means the authority's fiscal year commencing April 1, 2018 and ending March 31, 2019;

"First Nations settlements" means the settlement of litigation between the authority and the Tsay Keh Dene and Kwadacha First Nations, and the settlement of damages claims by the St'at'imc First Nation against the authority, as agreed to between the authority and the first nation on August 31, 2009, November 27, 2008 and May 10, 2011, respectively;

"government policy directive" means a directive in writing to the authority from the minister responsible for the administration of the *Hydro and Power Authority Act*;

"heritage contract" means the document attached as Appendix A to this direction;

"heritage deferral account" means the Heritage Payment Obligation Deferral Account established under commission order G-96-04 and the direction in section 4.5 of the reasons that accompany that order;

"heritage energy" has the same meaning as in the heritage contract;

"heritage payment obligation" has the same meaning as in the heritage contract;

"heritage resources" has the same meaning as in the heritage contract;

"non-current pension costs" means the costs that are subject to the non-current pension costs regulatory account;

"non-current pension costs regulatory account" means the regulatory account established under commission order G-16-09 and the direction in section 5.5.5 of the reasons that accompany that order;

"non-heritage deferral account" means the Non Heritage Deferral Account established under commission order G-96-04 and the direction in section 4.5 of the reasons that accompany that order;

"public awareness program" has the same meaning as in the Demand-Side Measures Regulation;

"rate base" means, in relation to a fiscal year of the authority, the amount determined in accordance with the following equation and notes:

$$RB = WCA + (A+B+C)/2 - (D + E + F)/2$$

where

RB = rate base;

WCA = working capital amount of $250 million;

A, B, D, E and F = the sum of an amount the authority forecasts will be listed as follows in the authority's audited financial statements at the end of the previous fiscal year and the amount the authority forecasts will be similarly listed at the end of the applicable fiscal year:

A is the amount listed as property, plant and equipment in service, less accumulated amortization;

B is the amount listed as intangible assets in service, less accumulated amortization;

D is the amount listed as contributions in aid of construction;

E is the amount listed as contributions arising from the Columbia River Treaty;

F is the amount listed as leased assets included in A, less accumulated amortization;

C = the sum of the balance the authority forecasts for DSM regulatory account at the beginning of the fiscal year and the balance the authority forecasts for the same account at the end of the fiscal year.

Notes:

1 In determining rate base for a fiscal year, the amounts A, B and F must have subtracted from them any amount included in them that is an expenditure incurred by the authority on or after April 1, 2011, that the commission determines under the Act must not be recovered by the authority in rates.

2 In determining rate base for a fiscal year, the amount D must have subtracted from it any amount included in it that is related to an expenditure referred to in note 1;

"rate smoothing regulatory account" means the regulatory account the commission must allow the authority to establish under section 7 (h) (i) of this direction;

"real property sales regulatory account" means the regulatory account the commission must allow the authority to establish under section 7 (h) (ii) of this direction;

"retail access program" has the same meaning as in commission order G-39-12;

"Rock Bay costs" means the costs of the authority in F2014 or a later fiscal year subject to the Rock Bay remediation regulatory account;

"Rock Bay remediation regulatory account" means the regulatory account established under commission order G-75-11;

"Rock Bay settlement" means the settlement of litigation between the authority and the Attorney General of Canada as concluded through the issuance of a consent dismissal order in favour of the authority on June 1, 2012;

"SMI regulatory account" means the regulatory account established under commission order G-64-09;

"specified demand-side measure" has the same meaning as in the Demand-Side Measures Regulation;

"trade income" means,

(a) for all of the authority's fiscal years except F2014, the greater of the following:

(i) the amount that is equal to the authority's consolidated net income, less the authority's net income, less the net income of the authority's subsidiaries except Powerex Corp., less the amount that the authority's consolidated net income changes due to foreign currency translation gains and losses on intercompany balances between the authority and Powerex Corp;

(ii) zero, and

(b) for F2014, the amount that is equal to the authority's consolidated net income, less the authority's net income, less the net income of the authority's subsidiaries except Powerex Corp., less the amount that the authority's consolidated net income changes due to foreign currency transaction gains and losses on intercompany balances between the authority and Powerex Corp.;

"trade income deferral account" means the regulatory account established under commission order G-96-04 and the direction in section 4.6 of the reasons that accompany that order;

"transmission rate customers" means industrial or commercial customers of the authority who are eligible for service under rates designed by the commission under section 3 (1).

Application

2 This direction is issued to the commission under section 3 of the Act.

Consideration in designing rates for transmission rate customers

3 (1) In designing rates for the authority's transmission rate customers, the commission must ensure that those rates are consistent with recommendations #8 to #15 inclusive in the commission's report and recommendations to the Lieutenant Governor in Council dated October 17, 2003.

(2) Without limiting subsection (1), the commission must ensure the following:

(a) the rates for the authority's transmission rate customers are subject to

(i) the terms and conditions found in Supplements 5 and 6 to the authority's tariff, and

(ii) any other terms and conditions the commission considers appropriate for those rates;

(b) customers who own multiple plants under common ownership may engage in load aggregation for energy, if each plant

(i) is in operation, and

(ii) meets the requirements to be a transmission rate customer that are set out in the authority's electric tariff, or is otherwise authorized by the commission to be treated as a transmission rate customer.

Basis for establishing authority revenue requirements

4 Subject to section 7, in regulating and setting rates for the authority, the commission must ensure that those rates allow the authority to collect sufficient revenue in each fiscal year to enable the authority to

(a) provide reliable electricity service,

(b) meet all of its debt service, tax and other financial obligations,

(c) comply with government policy directives, including, without limitation, government policy directives requiring the authority to construct, operate or extend a plant or system, and

(d) achieve an annual rate of return on deemed equity

(i) for F2015, F2016 and F2017, that is equal to 11.84%,

(ii) for F2018 and subsequent fiscal years the annual rate of return on deemed equity that would be necessary to yield a distributable surplus in the applicable fiscal year equal to the product of

(A) the distributable surplus in the immediately preceding fiscal year, and

(B) 100% plus the percentage change in the British Columbia consumer price index in the applicable fiscal year.

Determining the cost of energy

5 In setting the authority's rates, the commission

(a) must treat the heritage contract as if it were a legally binding agreement between 2 arms-length parties,

(b) must determine the energy required by the authority to meet its domestic service obligations and must determine the cost to the authority of the portion of that required energy that is in excess of the energy supplied under the heritage contract,

(c) may employ any mechanism, formula or other method authorized by section 60 (1) (b.1) of the Act, and

(d) unless a different mechanism, formula or method is employed under paragraph (c), must ensure that electricity used by the authority to meet its domestic service obligations is provided to customers on a cost-of-service basis.

Use of trade income in setting rates

6 In setting rates for the authority, the commission must include the net income of the authority's subsidiaries, assuming that the net income of Powerex Corp. equals trade income.

Regulatory accounts

7 When regulating and setting rates for the authority, the commission

(a) must allow the authority to continue to defer to the heritage deferral account the variances between the actual and forecast heritage payment obligation,

(b) must allow the authority to continue to defer to the trade income deferral account the variances between actual and forecast trade income,

(c) must, in regard to the non-heritage deferral account, allow the authority to

(i) continue to defer to that account the variances between actual and forecast cost of energy arising from differences between actual and forecast domestic customer load, and

(ii) defer to that account the Burrard costs,

(d) must, in regard to the DSM regulatory account, allow the authority to

(i) defer to that account the authority's costs arising from its development, implementation and administration of demand-side measures, including costs arising from specified demand-side measures and public awareness programs, and

(ii) amortize from that account in each fiscal year an amount equal to the sum of

(A) the amount amortized in the immediately preceding fiscal year less the amortization in that year associated with costs incurred more than 15 fiscal years prior to that year, and

(B) the product of the amount deferred to that account in the immediately preceding fiscal year and 1/15,

(e) must allow the authority to continue to defer to the Rock Bay remediation regulatory account the Rock Bay costs,

(f) must allow the authority to continue to defer to the asbestos remediation regulatory account the variances between actual and forecast asbestos remediation costs,

(g) must allow the authority to continue to defer to the non-current pension costs regulatory account the variances between actual and forecast non-current pension costs,

(h) must allow the authority to establish the following regulatory accounts:

(i) an account to defer for recovery in rates in future fiscal years of the authority those portions of the authority's allowed revenue requirement in a particular fiscal year that were not or are not to be recovered in rates in that particular fiscal year;

(ii) an account to defer the variances between the authority's actual and forecast real property gain/loss,

(i) must allow the following regulatory accounts to accrue interest in a fiscal year at the authority's weighted average cost of debt in that year:

(i) the first nations costs regulatory account;

(ii) the real property sales regulatory account,

(j) may allow the authority to establish one or more other regulatory accounts for other purposes, and

(k) subject to section 9 (1) of this direction, must set the authority's rates in such a way as to allow the regulatory accounts to be cleared from time to time and within a reasonable period.

Annual distributable surpluses allowed

8 When regulating and setting rates for the authority, the commission must ensure that those rates allow the authority to allocate annual distributable surpluses in the manner specified by the Lieutenant Governor in Council under section 4 of the *BC Hydro Public Power Legacy and Heritage Contract Act* or section 35 of the *Hydro and Power Authority Act.*

F2017, F2018 and F2019 rates

9 (1) When regulating and setting rates for the authority for F2017, F2018 and F2019, under sections 4, 5, 6, 7, 9 (2), 10 (3) and 11 of this direction, the commission must not allow the rates to increase by more than 4% in F2017, 3.5% in F2018 and 3% in F2019, on average, compared to the rates of the authority immediately before the increase.

(2) If the base line rate change exceeds 4% in F2017, 3.5% in F2018 or 3% in F2019, the commission must order the authority to defer to the rate smoothing regulatory account the amount that is determined by subtracting the amount in paragraph (b) from the amount in paragraph (a)

(a) the forecast revenue that the authority would have earned under a base line rate change, and

(b) the forecast revenue that the authority is expected to earn under this direction.

Deferral account rate rider

10 (1) The commission must set the deferral account rate rider for F2015 and future fiscal years of the authority at 5%.

(2) The commission must not order any change to the deferral account rate rider, except on application by the authority.

(3) The commission must allow the authority, in regard to a fiscal year of the authority, to account for the forecast revenue from the deferral account rate rider as follows:

(i) a portion of the forecast revenue from the deferral account rate rider is to be accounted for as revenue in that fiscal year in accordance with equation 1 and the following table;

(ii) a portion of the forecast revenue from the deferral account rate rider is to be amortized from the forecast net balance of the heritage deferral account, the non-heritage deferral account and the trade income deferral account at the end of the immediately preceding fiscal year in accordance with equation 2 and the following table:

Equation 1: DARR (Rev) = DARR – (X/5) x DARR

Equation 2: DARR(DA) = (X/5) x DARR

where

DARR (Rev) = the portion of forecast revenue from the deferral account rate rider in the applicable fiscal year of the authority that is to be accounted for as revenue;

DARR(DA) = the portion of forecast revenue from the deferral account rate rider in the applicable fiscal year of the authority that is to be amortized from the net balance of the heritage deferral account, the non-heritage deferral account and the trade income deferral account at the end of the immediately preceding fiscal year;

DARR = forecast revenue from the deferral account rate rider in the applicable fiscal year of the authority;

X = the number in column X of the following table that corresponds to the forecast net balances of the heritage deferral account, the non-heritage deferral account and the trade income deferral account at the end of the immediately preceding fiscal year that is between the values shown in columns A and B of the following table:

Table		
A ($ million)	B ($ million)	X
< -500	-500	-5.0
-500	-450	-4.5
-450	-400	-4.0

Table		
A ($ million)	B ($ million)	X
-400	-350	-3.5
-350	-300	-3.0
-300	-250	-2.5
-250	-200	-2.0
-200	-150	-1.5
-150	-100	-1.0
-100	-50	-0.5
-50	0	0.0
0	50	0.0
50	100	0.5
100	150	1.0
150	200	1.5
200	250	2.0
250	300	2.5
300	350	3.0
350	400	3.5
400	450	4.0
450	500	4.5
500	> 500	5.0

(iii) the portion of forecast revenue from the deferral account rate rider in the applicable fiscal year of the authority that is amortized from the net balance of the heritage deferral account, the non-heritage deferral account and the trade income deferral account at the end of the immediately preceding fiscal year must be amortized from the respective balances of those accounts in proportion to the ratios of the balances of those accounts to the net balance of all 3.

Commission reviews

11 When setting rates for the authority under the Act, the commission must not disallow for any reason the recovery in rates of the costs that were incurred by the authority or Powerex Corp. in consequence of decisions of either with respect to

(a) the construction of extensions to the authority's plant or system that come into service before F2017,

(b) energy supply contracts entered into before F2017,

(c) the Rock Bay settlement,

(d) the First Nations settlements,

(e) the California settlements,

(f) the Burrard costs, and

(g) the costs deferred to the SMI regulatory account.

Expenditures for export

12 The commission must refrain from performing its duty under section 4 (5) of the *Clean Energy Act* when setting rates for the authority for F2014, F2015, F2016, F2017 and F2018.

Powerex Corp.

13 The commission may not exercise any power under Part 3 of the Act in regard to the gas and electricity trading activities of Powerex Corp.

Retail access

14 (1) By March 23, 2014, the commission must issue orders as follows:

(a) the commission must accept a withdrawal by the authority of any obligation to offer unbundled transmission services under the authority's open access transmission tariff to retail customers in British Columbia, and a withdrawal of any obligation to offer such services to those who supply such customers;

(b) the commission must order the cancellation of the retail access program.

(2) Except on application by the authority, the commission must not set rates for the authority that would result in the direct or indirect provision of unbundled transmission services to retail customers in British Columbia, or to those who supply such customers.

Burrard Thermal

15 On application by the authority the commission must

(a) grant permission to the authority under section 41 of the Act to cease operating those portions of Burrard Thermal that are not required for transmission support services, and

(b) set depreciation rates for the classes of property, plant and equipment at Burrard Thermal as shown in Appendix B to this direction.

Rates

16 (1) The commission may not reconsider, vary or rescind the orders it issues under this direction or Direction No. 6 to the British Columbia Utilities Commission, except on application by the authority.

(2) For F2014, F2015 and F2016, the commission must not issue any orders in regard to the authority's regulatory accounts, except on application by the authority.

(3) In setting the authority's rates for F2015, F2016, F2017, F2018 and F2019, the commission must exercise its powers and perform its duties consistently with the orders it issues under Direction No. 6 to the British Columbia Utilities Commission, except on application by the authority.

(4) Nothing in this section prevents the commission from making determinations on applications made by the authority respecting revenue-cost ratios, rate design and regulatory accounts, including interim rate orders in regard to one or more of the authority's customers.

APPENDIX A – HERITAGE CONTRACT

Definitions

1 In this Agreement:

"Agreement" means this Heritage Contract including Schedule A;

"Ancillary Service Requirements" means services necessary to deliver energy;

"BC Hydro" means the British Columbia Hydro and Power Authority;

"BCH Distribution" means BC Hydro's distribution line-of-business;

"BCH Generation" means BC Hydro's generation line-of-business;

"Commission" means the British Columbia Utilities Commission;

"heritage electricity" means the capacity, energy and ancillary services that BCH Generation is required to supply to BCH Distribution under this Agreement;

"heritage energy" means

(a) subject to paragraph (b), 49 000 GW.h per year less the energy generated for delivery under the Skagit Valley Treaty, or

(b) the quantity of energy determined by the Commission under section 8 of this Agreement to be heritage energy;

"heritage payment obligation" means

(a) subject to paragraph (b), the annual payment determined in accordance with the procedure set out in Schedule A to this Agreement, or

(b) the annual payment determined by the Commission under section 8 of this Agreement to be the heritage payment obligation;

"heritage resources" means the Electric Facilities and Thermal Facilities described in Schedule A to the Terms of Reference, together with

(a) the related civil works and plant, and

(b) potential future investments that increase the capacity, energy or ancillary service capability of such facilities, including potential future units 5 and 6 at Mica and potential future units 5 and 6 at Revelstoke;

"Order" means an order of the Commission;

"Terms of Reference" means Schedule A, Terms of Reference, to Order in Council 253/2003;

"Transfer Pricing Agreement" means the Transfer Pricing Agreement for Electricity and Gas dated April 1, 2003 between BC Hydro and Powerex Corp. as amended from time to time;

"Year" means fiscal year.

Electricity supply

2 BCH Generation must provide the full capacity of the heritage resources to BCH Distribution on a priority call basis.

Obligation to supply

3 BCH Generation must supply to BCH Distribution, in each Year, the heritage energy or such lesser amount of energy as may be required by BCH Distribution.

Obligation to deliver

4 BCH Generation will deliver the heritage energy to BCH Distribution at the various points of interconnection of the generating stations included in the heritage resources with the BC Hydro transmission grid or at points of interconnection with other utilities, as appropriate.

Responsibility for obtaining transmission services

5 BCH Distribution will be responsible for obtaining transmission services for energy provided to BCH Distribution.

Ancillary services

6 The parties may use the capacity available to them under section 2 to deliver energy to meet customer demand and to satisfy the parties' Ancillary Service Requirements, regardless of whether provision for self-supply is made under any tariff.

Payment

7 BCH Distribution must, on or before the end of each Year, pay to BCH Generation an amount equal to the heritage payment obligation.

Adjustment

8 The parties acknowledge that

(a) the Commission may, by Order, modify one or both of the definitions of "heritage energy" and "heritage payment obligation" if the Commission is satisfied that a change in circumstances has permanently affected

(i) the capability of the heritage resources to provide one or both of capacity and energy, or

(ii) the authority's cost of generating the heritage energy, and

(b) any such modification will automatically modify the heritage energy or the heritage payment obligation, as the case may be, without further action by the parties.

Information exchange and cooperation

9 Each party will continue to freely provide the other with any requested information to facilitate the coordinated and optimal operation of the BC Hydro system.

Dispute resolution

10 (1) The parties will make reasonable efforts to resolve disputes arising in relation to this Agreement at the staff level.

(2) As needed, issues may be dealt with by management levels within each party to achieve timely resolution.

(3) Issues that cannot be resolved in a timely manner at senior management levels may be referred by either party to the commission for resolution.

Term

11 This Agreement commenced on April 1, 2004.

SCHEDULE A TO APPENDIX A – HERITAGE PAYMENT OBLIGATION

1 The heritage payment obligation for any Year is the amount determined by

(a) adding those of the following costs incurred by BCH Generation in the Year that the Commission orders may be included in the heritage payment obligation:

(i) cost of energy such as the cost of water rentals and energy purchases, including purchases of gas and electricity, required to supply heritage electricity;

(ii) operating costs such as the costs of operating and maintaining the heritage resources, including an allocation of corporate costs;

(iii) all costs of owning the heritage resources, including, without limitation, depreciation, interest, finance charges and other asset related expenses;

(iv) all costs or payments related to generation-related transmission access required by the heritage resources, and

(b) subtracting from the sum obtained under paragraph (a) any revenues BCH Generation receives from other services provided from the heritage resources, including, without limitation,

(i) revenues related to Skagit Valley Treaty obligations,

(ii) revenues from provision of ancillary services to the transmission operator in respect of third party use of the transmission system, and

(iii) revenues from the sale of surplus hydro electricity under section 5 of the Transfer Pricing Agreement.

APPENDIX B – BURRARD DEPRECIATION RATES

Class of Property, Plant and Equipment at Burrard Thermal	F2015 Depreciation Rate (%/year)	F2016 Depreciation Rate (%/year)
C12101 Tracks, Railway	100.0%	N/A
C12401 Drainage System Yard	9.1%	10.0%
C21901 Roofs	9.1%	10.0%
C22001 Plant Concrete Steel	15.8%	18.8%
C22002 Comm Concrete Steel	9.1%	10.0%
C22005 Building, Comp Pool	9.1%	10.0%
C22006 Equipment Shelter	19.0%	23.5%
C22009 Building-HVAC Sys&Cp	10.1%	11.1%
C22101 Off Trailer/Mob Home	9.3%	10.0%
C23801 Cranes	9.1%	10.0%
C24402 Ramp, Boat/Barge	85.7%	100.0%
C25101 Structure Supp Steel	9.1%	10.0%
C25301 Foundations	9.1%	10.0%
C25401 Ducts & Trenches	9.1%	10.0%
C25601 Barriers & Enclos	20.0%	25.0%
C30101 Casing, Boiler	50.0%	100.0%
C30102 Insulation, Boiler	14.3%	16.7%
C30103 Roof, Boiler	50.0%	100.0%
C30203 Superheater HighTemp	50.0%	100.0%
C30204 Superheater Low Temp	54.5%	100.0%
C30205 Reheater, Boiler	50.0%	100.0%
C30301 Header / Drum	50.3%	100.0%
C30401 Valves, Safety	14.5%	17.0%
C30501 Piping, High Press	33.4%	41.5%
C30601 Fan, Forced Draft	50.0%	100.0%
C30602 Breaching / Flue Sys	54.5%	100.0%
C30603 Stack, Flue Gases	50.0%	100.0%
C30605 Burner, Fuel	50.0%	100.0%
C30606 Instrument, Boiler	51.3%	98.6%
C30607 DNU - Asbe Abatement	9.1%	10.0%
C30611 Desuperheater System	50.0%	100.0%
C30612 Refractory, Boiler	54.5%	100.0%
C30613 Boiler, Package	54.5%	100.0%

Class of Property, Plant and Equipment at Burrard Thermal	F2015 Depreciation Rate (%/year)	F2016 Depreciation Rate (%/year)
C30701 Equip, Water Treat	50.0%	100.0%
C30801 Transfer Sys Ammonia	92.3%	100.0%
C30802 Water Sys Ammonia	92.3%	100.0%
C30803 Vapouriser, Ammonia	92.3%	100.0%
C30804 Comp Vapour, Ammonia	92.3%	100.0%
C30805 Piping Sys, Ammonia	50.0%	100.0%
C30901 Monitor Equip, Cem	54.5%	100.0%
C30903 Deliver Sys, Ammonia	55.5%	100.0%
C31001 Water Intk/DisStruct	9.1%	10.0%
C31002 Protection, Cathodic	9.1%	10.0%
C31003 Gates, Inlet/Outlet	9.1%	10.0%
C31005 Conduit, Intake/Disc	9.1%	10.0%
C33001 Heat Exch, Shell Tube	50.0%	100.0%
C33002 Pump And Motor	50.0%	100.0%
C33004 Condenser, Boiler	50.0%	100.0%
C34004 Turbine, Comp Pool	22.2%	28.5%
C34005 Coils, Stator	9.3%	10.3%
C34006 Rotor, Generator	9.1%	10.0%
C34007 Generator, Comp Pool	28.6%	40.1%
C34008 Supervisory Sys Turb	70.9%	55.8%
C34009 Cooling Sys Hydrogen	15.8%	18.7%
C34015 Turbine Blades Sets	31.7%	46.4%
C42004 Major Maint.-Rewedge	25.3%	33.8%
C42102 Exciter, Static	42.7%	74.6%
C46701 Heat Exchanger	50.0%	100.0%
C47201 Turbine, Gas	50.0%	100.0%
C47202 Major Maint.-Gas Tur	80.0%	100.0%
C48003 Generator, Composite	29.7%	42.3%
C48004 Generator, Diesel	25.8%	34.8%
C49001 Pump	44.4%	77.8%
C49002 Motor	12.3%	14.1%
C51001 Condensor, SyncRotary	9.1%	10.0%
C52104 Transformer, <100Mva	50.0%	100.0%
C52105 Transformer, Stn Ser	10.5%	10.0%
C52302 Reactor, Dry Type	99.9%	100.0%
C52405 Transformer, Curr, Com	35.3%	54.6%

Class of Property, Plant and Equipment at Burrard Thermal	F2015 Depreciation Rate (%/year)	F2016 Depreciation Rate (%/year)
C52504 Trans, Volt, Encaps.	9.1%	10.0%
C54101 Breaker, Air/Magnetic	9.1%	10.0%
C54201 Use Ind Disconnect	20.0%	25.0%
C55401 Buswork & StnConduct	9.1%	10.0%
C55501 Grounding Systems	9.1%	10.0%
C56001 Insulators	9.1%	10.0%
C59001 Power Supp Uninterr	39.4%	65.1%
C59101 Regulator FeederCirc	9.1%	10.0%
C59201 Charger System, Batt	13.3%	15.3%
C61001 Fencing	9.1%	10.0%
C61101 Alarm/Security Sys	9.1%	10.0%
C62001 Fire Protection Sys	12.0%	13.6%
C62501 Firefighting Equip	33.3%	50.0%
C65001 Panels/Cubicles, P&C	13.0%	14.9%
C67003 Contain Fac, Concret	9.1%	10.0%
C67005 Oil Spill Containmen	9.1%	10.0%
C68202 Term Unit, Rem(Slave)	23.1%	30.0%
C68204 Distributed Ctrl Sys	30.4%	42.9%
C68301 Radio, MW, Analog	9.1%	10.0%
C68901 Tele Equip, Pbx/Pax	100.0%	N/A
C70104 Instrumentation-Digi	9.1%	10.0%
C74001 Motor-Generator Sets	92.3%	100.0%
C75104 Compressor, Air	18.3%	21.3%
C75201 Tanks, Steel, Air/Fuel	9.1%	10.0%
C75202 Tank, Fibrglas, DblB	9.1%	10.0%
C75301 Water Supply System	9.1%	10.0%
C82504 Loader/Backhoe	8.3%	9.0%
C82513 Manlift	66.7%	100.0%
C82550 Tools/Work EquipMisc	12.3%	14.0%
C82551 DNU - Tools/Work Equ	21.7%	27.1%
C82601 Test/Calibration	43.9%	73.2%
C82603 Manufacturing/Test	24.4%	12.5%
C88002 Lab Equipment, Misc	30.8%	27.3%

F2015 to F2016 Revenue Requirements Rate Application

Appendix F

Amendment to Heritage Special Directive No. HC1

PROVINCE OF BRITISH COLUMBIA

ORDER OF THE LIEUTENANT GOVERNOR IN COUNCIL

Order in Council No. 095 *, Approved and Ordered* March 05, 2014

Lieutenant Governor

Executive Council Chambers, Victoria

On the recommendation of the undersigned, the Lieutenant Governor, by and with the advice and consent of the Executive Council, orders that the Heritage Special Directive No. HC1 to the British Columbia Hydro and Power Authority, Order in Council 1125/2003, is amended as set out in the attached Appendix.

Minister of Energy and Mines and
Minister Responsible for Core Review

Presiding Member of the Executive Council

(This part is for administrative purposes only and is not part of the Order.)

Authority under which Order is made:

Act and section: *Hydro and Power Authority Act*, R.S.B.C. 1996, s. 212, s. 35

Other:

February 18, 2014 O/79/2014/27

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Appendix

1 ***Section 3 of the Heritage Special Directive No. HC1 to the British Columbia Hydro and Power Authority, Order in Council 1125/2003, is repealed and the following substituted:***

Annual payment

3 (1) On or before June 30 of the years 2014, 2015, 2016 and 2017, the directors of the authority must cause the authority to pay to the government an amount equal to

(a) 85% of the distributable surplus for the previous fiscal year of the authority, or

(b) if the payment required under this section would result in the debt/equity ratio of the authority exceeding 80:20, the greatest amount that can be paid by the authority without causing the authority's debt/equity ratio, after the payment is made, to exceed 80:20.

(2) On or before June 30 of each year after 2017, until and including the year in which the payment required by this Special Directive equals zero, the directors of the authority must cause the authority to pay to the government the greater of the following 2 amounts:

(a) zero;

(b) the payment required by this Special Directive in the immediately preceding year less $100 million.

(3) On or before June 30 of each year after the year in which the payment required by this Special Directive equals zero, the directors of the authority must cause the authority to pay to the government an amount equal to

(a) 85% of the distributable surplus for the previous fiscal year of the authority, or

(b) if the payment required under this section would result in the debt/equity ratio of the authority exceeding 60:40, the greatest amount that can be paid by the authority without causing the authority's debt/equity ratio, after the payment is made, to exceed 60:40.

F2015 to F2016 Revenue Requirements Rate Application

Appendix G

DSM Expenditures and Savings

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1 DSM Expenditures and Savings

This appendix responds to the BCUC's direction in Order No. G-77-12A of the F12-F14 ARRA that BC Hydro provide a discussion of its accounting practices and policies concerning DSM expenditures. It also provides, for information only, a discussion of BC Hydro's DSM initiatives, along with identification of the expenditures and savings from initiatives undertaken in F2014, and for those anticipated for F2015 and F2016.

1.1 DSM Initiatives

BC Hydro employs three DSM tools and a number of supporting initiatives to achieve targeted energy and capacity savings. The long range plan, articulated in the November 2013 Integrated Resource Plan (**IRP**) is to target 7,800 GWh/year in energy savings with an estimated 1,400 MW in associated capacity savings by F2021. The DSM tools and supporting initiatives are:

- Codes and Standards: BC Hydro supports the development of, and relies on government implementation of, a suite of changes to energy efficiency requirements in product/equipment regulations and building codes. Once government implementation has occurred, BC Hydro also works with industry and trades on education to improve codes and standards compliance. During F2015 and F2016, BC Hydro will continue to work with government and standard agencies to develop and promote energy efficiency codes and standards that can be used to regulate efficient products and equipment in the marketplace, and per Recommended Action 3 from the IRP, explore additional codes and standards opportunities.
- Rate Structures: BC Hydro has implemented conservation rate structures in all major customer sectors representing the vast majority of its domestic load. BC Hydro will continue to implement and adjust conservation rates in all

customer sectors in order to send price signals to customers regarding the incremental cost of electricity.

- Programs: BC Hydro designs and implements a suite of DSM programs and sector enabling activities targeting the residential, commercial and industrial sectors. Programs are designed to complement codes and standards and rate structures. BC Hydro plans to continue with the existing suite of programs, working with trade allies, other utilities, government agencies and customer groups. Per Recommended Action 2 from the IRP, investigation is also planned to pilot capacity-focused programs over the near term to assess the capability of these types of programs to deliver reliable capacity savings over the long term.
- Supporting Initiatives: In addition to the three DSM tools described above, there are a number of supporting initiatives – public awareness and education, community engagement, technology innovation, information technology, and indirect and portfolio enabling – that provide a critical foundation for awareness, engagement and other conditions to support the success of DSM. These initiatives provide external market and community support along with general internal management and infrastructure development. As such, these initiatives are integral to the success of the overall DSM portfolio and achievement of electricity savings. These supporting initiatives also address requirements contained within the Demand Side Measures Regulation (B.C. Reg. 228/2011 (Ministerial Order M335)).

1.2 DSM Expenditures

Table G-1 below shows the DSM expenditures for F2014 to F2016 as specified for approval in Direction No. 6 and as set out in schedule A of the draft order to this application.

Table G-1 F14-F16 DSM Expenditures ($ million)

	F2014 Plan	F2014 Forecast	F2015 Plan	F2016 Plan
Codes and Standards[1]	**2.4**	**2.7**	**4.0**	**4.2**
Rate Structures	**6.5**	**2.0**	**2.0**	**1.7**
Programs				
Residential	30.4	17.4	17.7	18.9
Commercial[2]	66.4	49.5	39.5	40.0
Industrial	101.9	57.1	64.3	42.9
Total Programs	**198.7**	**123.9**	**121.5**	**101.8**
Supporting Initiatives	**28.7**	**22.7**	**20.6**	**20.3**
Total EE Portfolio	**236.3**	**151.3**	**148.0**	**128.0**
Capacity Focused DSM[3]	**0.0**	**0.0**	**2.4**	**3.1**
Total EE & Capacity Focused	**236.3**	**151.3**	**150.5**	**131.1**

1.3 DSM Energy and Capacity Savings

F2014 was a year in transition for BC Hydro's DSM initiatives, with development of the IRP providing revised direction for the DSM savings activities over the next few years, while still preserving the ability to achieve the long-term targets. As explored in the IRP, DSM is a flexible resource. To some degree, DSM activity can be ramped up or down over time to better match BC Hydro's resource requirements. Given these considerations, the IRP recommended a moderation in DSM program and supporting initiative expenditures in the near term (starting with F2014) and then ramping back to the long term DSM target by F2021. Table G-2 below shows the new savings outlook established by the government approved IRP.

1 In previous DSM plans, Codes and Standards activities were included as a Supporting Initiative.
2 F2014 Cross Sectoral program expenditures are included in the Commercial sector value.
3 The IRP recommended this new activity starting in F2015.

Table G-2 Cumulative Savings Targets[4] (Base Year F2013)

	F2014 Forecast	F2015 Plan	F2016 Plan
Energy Savings (GWh/year)			
Codes and Standards	**419**	**569**	**1149**
Rate Structures	**766**	**885**	**987**
Programs			
Residential	125	189	239
Commercial	275	366	442
Industrial	448	601	721
Total Programs	**848**	**1,156**	**1,402**
Total	**2,033**	**2,611**	**3,537**
Associated Capacity Savings (MW)[5]			
Codes and Standards	**72**	**110**	**215**
Rate Structures	**102**	**131**	**154**
Programs			
Residential	24	37	48
Commercial	29	46	57
Industrial	43	63	81
Total Programs	**96**	**146**	**186**
Total	**270**	**386**	**555**

1.4 DSM Accounting Treatment

This section provides a discussion of the accounting practices for DSM expenditures.

As background, BC Hydro's accounting policies establishing the deferral of DSM expenditures are based upon BCUC Order No. G-55-95, which specifies:

> "Direct program costs, indirect administration costs and allocated overhead, shall be deferred according to the intent of section 3450 - Research and Development, of the Canadian

4 Source: 2013 IRP.

5 Peak demand savings are estimated using an average peak-to-energy ratio (capacity factor) based on customer class or end-use load shapes. This may add uncertainty to the estimates of peak demand savings.

> Institute of Chartered Accountants, Accounting Recommendations Handbook. Generally speaking, those criteria treat research costs as expenses and treat as assets, those development costs that have a high probability of achieving net financial benefits."

Under this approach, BC Hydro has deferred all costs arising from the development, implementation and administration of DSM initiatives. This includes costs for applicable groups within customer care and corporate communications for their activities that relate to DSM.

As outlined in the IRP, DSM expenditures fund both DSM tools (such as codes and standards, rate structures, and programs) and supporting initiatives (such as public awareness and education, community engagement, technology innovation, information technology, and indirect and portfolio enabling).[6] Both expenditure categories are integral to the achievement of the savings portfolio and accordingly are deferred to the DSM regulatory account and amortized over 15 years, based on the useful life of the DSM expenditure.

The 15-year useful life comes from the calculation of the weighted average persistence of DSM program savings, as described in the F12-F14 ARRA.[7] The amortization of the DSM regulatory account therefore provides intergenerational equity by matching DSM cost recovery and savings benefits over time.

Paragraphs 7(d)(i) and (ii) of Direction No. 7 now require the BCUC to allow BC Hydro to defer to the DSM Regulatory Account the scope of DSM costs described above, and amortize them over 15 years, in both cases consistent with BC Hydro's previous practices and policies.

[6] Pages 3-14 and 3-15.
[7] Amended New Appendix II, Attachment 6, section 3 (pages 193 to 195 of 271).

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Appendix H

Regulatory Accounts Report

Regulatory Accounts Report

Fiscal F2013 to F2024

February 28, 2014

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1 Executive Summary

This report describes BC Hydro's regulatory accounts, its plan to reduce the total balance and number of accounts, and its principles regarding potential new accounts and the application of interest to the accounts. It is provided in the context of the Province's 10-Year plan for BC Hydro (the **10-Year Plan**) announced on November 26, 2013, and Directions No. 6 and 7, issued on March 6, 2014 to the British Columbia Utilities Commission (**BCUC**).

BC Hydro uses various regulatory accounts, in compliance with BCUC orders, in order to:

1. Better match costs and benefits for different generations of customers
2. Smooth out the rate impact of a large non-recurring cost or to smooth out rate increases
3. Defer to a future period the differences between forecast and actual costs or revenues

BC Hydro is aware of concerns about the growth in the balances of its regulatory accounts, the length of time that will be required to recover the significant balances in the accounts, and potential impacts on intergenerational equity. This report addresses these concerns and sets out how the balances in BC Hydro's regulatory accounts will be recovered in a manner that reflects the nature of each regulatory account.

This report looks out to the end of F2024, at which time BC Hydro's regulatory accounts are forecast to total approximately $4.06 billion, a reduction of just over $1 billion from the forecast maximum of $5.1 billion in F2018 and F2019. The number of regulatory accounts stands at 27 at the beginning of F2014, and based on the forecast amortization periods, 13 regulatory accounts will have been fully amortized by F2024. It should be noted that several of the regulatory accounts are designed to capture costs on an ongoing basis and therefore may not be drawn down to zero within a 10-year period. Of the $4.4 billion balance at the beginning of F2014, BC Hydro is already collecting in its rates 19 of the 27 regulatory accounts representing account balances of $3.5 billion, or 80 per cent of the total balance. As well, by the end of F2024 just over 84 per cent of the outstanding regulatory account balances (approximately $3.4 billion) consist of five regulatory accounts that either match costs with associated benefits (Demand Side Management (**DSM**), Site C and Smart Metering & Infrastructure) or that relate to the transition to International Financial Reporting Standards (**IFRS**, – IFRS Property, Plant & Equipment and IFRS Pension) and 14 per cent (approximately $550 million) will consist of two non-cash provision accounts that are not recovered in rates until such time as an actual cash expenditure is made against the provision.

There are two caveats that should be considered with regard to the balances shown in this report, relating primarily to the fact that the balances are forecasts and actual balances will be different and impacted by sensitivities that are further described in section 6. First, the forecast of regulatory account balances shown in Table 6 indicates that the cost of energy variance accounts will have been fully paid down at the end of F2023. However, due to the nature of these regulatory accounts, which is described more fully in section 3.1.1 of the report, BC Hydro expects that there will likely be balances in these accounts in each of the years of the forecast. These accounts capture the variances between forecast and actual energy costs in each year, which can be positive or negative. Due to the nature and number of variables that determine actual energy costs, it is not possible to accurately forecast energy costs in any given year.

A second caveat is that the balance in the Non-Current Pension Cost regulatory account is based on a calculation of the unrecognized actuarial gains and losses at the end of F2014**.** The annual actuarial experience is subject to large positive and negative fluctuations as actuarial experience is very sensitive to changes in market discount rates. For example, a 1 per cent increase/decrease in the market discount rate for valuing the pension liability will give rise to an actuarial gain/loss on the pension liability of approximately $300 million. Therefore, BC Hydro expects that the balances in this account will also vary from those currently forecast.

Regulatory accounts are not uncommon in the utility industry, and BC Hydro is not alone in their use. Regulatory accounts are often used to reflect timing differences between when a utility spends money to provide a service or acquire an asset, and when that expenditure is recovered from ratepayers. The benefit of a particular service or asset may accrue to ratepayers over a long period of time, and regulatory accounts can serve to match the benefit with the cost, thereby supporting intergenerational equity for current and future ratepayers. In other words, BC Hydro's current customers are not required to pay for the full cost of an asset or service that will provide benefits to customers over periods of 10, 20 or 30 years. A good example is DSM costs. BC Hydro is spending money in current years to reduce the amount of electricity that customers would otherwise use, resulting in lower future energy costs and delayed or reduced infrastructure costs. The benefit of such reduced costs through DSM impacts future customers and the cost of the DSM programs is properly matched to the benefits enjoyed by those future customers by deferring and amortizing those costs over 15 years, which is the average term of DSM program benefits.

In some cases, regulatory accounts may also be used to transfer uncontrollable risks and benefits to customers, in particular the differences between forecast and actual costs due to changes in items such as water inflow levels, interest rates, and market prices of energy, which cannot be accurately forecast. Expenditures deferred for this reason are generally recovered over a shorter time period than those associated with longer term benefits. This shorter recovery also supports intergenerational equity, in that the benefits associated with the deferred cost are generally much more immediate - for example, the cost of the energy which is used by current rather than future customers. In this case the deferred costs should be recovered from ratepayers over a relatively short period.

A further, potentially overriding concern with the recovery of regulatory accounts is the rate increases that may be required in any particular year due to their recovery. Mitigation of rate increases may result in longer recovery periods than would be the case if rate mitigation was not an issue. In addition, concerns about rate impacts may also lead to the establishment of a regulatory account for the sole purpose of smoothing the rate impact of a large one-time expenditure. The period of time over which a one-time expenditure is recovered takes into consideration the amount of the expenditure, its nature and other rate increase pressures that may exist at the time.

As a Crown Corporation, BC Hydro has different priorities and risk considerations than would be found with many investor-owned utilities (**IOUs**). In particular, while there is a focus on providing service and value to its customers, there is also a goal of keeping rates as low as practical; immediate cost recovery or share price are not the paramount concerns to BC Hydro that they would be to an IOU. BC Hydro therefore believes that an appropriate balance needs to be struck between keeping rates low and recovering the regulatory account balances over a period of time that accords with the nature of the expense being deferred, as discussed further in section 3 of the report.

BC Hydro is also backed by the financial support of the Government of British Columbia, which provides BC Hydro with the benefit of low borrowing costs and avoids the need for it to access the financial markets directly for its financing needs. This support allows BC Hydro to finance the balances in its regulatory accounts almost entirely with debt, which an IOU would find difficult to sustain, as such large balances could impair the ability of an IOU to access debt financing at low interest rates.

BC Hydro's regulatory accounts are subject to review and approval, both externally and within BC Hydro. In most cases, BC Hydro has sought BCUC approval for establishing regulatory accounts and the BCUC has approved BC Hydro's requests for a deferral after analysis and enquiry into the need and use of the regulatory account. In some cases, the BCUC has been directed by Government to allow costs to be recorded in a regulatory account, as discussed further in section 2.1. The BCUC itself has also directed that certain regulatory accounts be set up, as was the case with the DSM regulatory account, which is forecast to have the largest balance of all of BC Hydro's regulatory accounts by F2024 (forecast to be approximately $1.4 billion at the end of F2024). Interveners have also explicitly agreed to the creation of regulatory accounts in some cases. BC Hydro also provides details of its regulatory account balances in its public quarterly and annual financial statements, which can be found on its website.

BC Hydro's benefit-matching regulatory accounts are capital-like, in that they capture costs that are similar to capital assets, as they will provide long term benefits to BC Hydro's current and future customers. Also similar to capital assets, the amounts deferred in these accounts are subject to management oversight and governance processes. For major expenditures such as Site C, DSM and SMI, business cases have been developed, reviewed and approved by BC Hydro's senior management and board.

The annual budget planning process also ensures that expenditures are prioritized and reviewed before being spent and placed into regulatory accounts. BC Hydro's planning and budgeting framework includes both top-down and bottom-up elements. The top-down element, which is strategic in nature, includes a review of BC Hydro's strategic objectives and performance measures. The bottom-up elements, which are operational in nature, involve reviews by the business groups of their needs, the identification of projects and initiatives and resourcing of work plans. Trade-offs, including cost reductions and productivity improvements to offset cost pressures, are made to stay within the overall business groups operating cost target set by the top-down approach. BC Hydro's senior management reviews the operating plans for consistency and alignment with BC Hydro's priorities and strategic objectives from an overall consolidated view.

With respect to the capital-like accounts, there is a matching of costs incurred with the long-term benefits that are being delivered to future generations of customers. Shortening the amortization periods of these accounts to reduce the balances sooner would be counter to one of BC Hydro's goals of achieving intergenerational equity and the matching of costs and benefits.

For these reasons, and as discussed further in this report, BC Hydro believes that the account balances remaining at the end of F2024 are acceptable and do not cause BC Hydro undue concern in terms of intergenerational equity nor in terms of its financial health.

However, if there was a concern about the overall level of BC Hydro's regulatory account balances, deviations from this approach could be considered, though it would be contrary to BC Hydro's principles guiding the recovery of the regulatory account balances.

Three points are worth noting with respect to the regulatory account recovery periods that BC Hydro is proposing in this report. In the report, accounts currently subject to the Deferral Account Rate Rider (**DARR**) will continue to be recovered at amounts determined through the existing mechanism, as discussed in section 3.1.1. Although, in accordance with Directions No. 6 and 7, and as further discussed in section 3.1.1, the DARR itself will remain at 5 per cent in each year, regardless of the balances of the three energy deferral accounts. In addition, BC Hydro proposes that the recovery mechanisms are to be applied consistently over the life of the regulatory account. As well, there is an alignment between costs and benefit recognition to achieve intergenerational equity.

BC Hydro still expects to seek approval of new regulatory accounts over the period of this report, if warranted by one or more of the following three guiding criteria (discussed further in section 2.2): a) to better match costs and benefits for future generations of customers; b) to smooth out the rate impacts of large non-recurring costs or to smooth out rate increases; or c) to defer to a future period differences between forecast and actual costs or revenues. However, BC Hydro only plans to apply for new regulatory accounts in exceptional cases or for un-forecasted or uncontrollable material expenditures that would have a significant impact on BC Hydro's net income if not recovered from customers. BC Hydro considers that cumulative expenditures that would have a net income impact of $10 million or more in a year would be material.

The report begins by setting out a brief history of regulatory account use at BC Hydro and then describes BC Hydro's main regulatory accounts and their particular reasons for being in place. This is followed by a discussion of the rationale for the recovery plan for each regulatory account. The application of interest to the regulatory accounts and a forecast of regulatory account balances is then provided, followed by a discussion on the sensitivity of the regulatory account balances to changes in key earnings variables. Finally, in Appendix A, BC Hydro discusses the issues and concerns regarding the regulatory accounts that have been raised by the BCUC and interveners, the Auditor General of B.C., and by the Government Review Panel and in Appendix B, BC Hydro provides a detailed explanation of each regulatory account.

2 Regulatory Accounts at BC Hydro

2.1 History

BC Hydro must apply to the BCUC in order to establish regulatory accounts, and must also seek approval for the timeline and mechanism to recover the balances in the accounts from ratepayers. BC Hydro can also be directed by the BCUC to establish regulatory accounts.

BC Hydro has used various forms of regulatory accounts since the 1980s. In 1982, the BCUC directed BC Hydro to create a Rate Stabilization Account to capture revenue from export sales of surplus energy less associated expenses. In 1990, the BCUC rescinded the export sales rate stabilization account and replaced it with a new rate stabilization account to mitigate the impact of volatile earnings. Transfers were made to this new account during high income years to reduce the need for rate increases in lower income years.

During the period F1995 to F2003 BC Hydro was under a rate freeze; however, during this time BC Hydro was directed to establish, or requested the approval of, several regulatory accounts.

In 1995, the BCUC directed all regulated gas, electric and steam heat utilities in British Columbia to defer and amortize into rates, costs associated with DSM activities that achieve energy savings. The DSM activities and associated costs generate energy savings to customers over a period of time longer than the year of expenditure, so the deferral and amortization of these costs aligns the recognition of costs with the period that customers receive benefits.

In 2002 BC Hydro applied for and received approval for a regulatory account to capture foreign exchange gains and losses due to the translation of foreign currency denominated long-term monetary items. Foreign exchange gains and losses are subject to external market forces over which BC Hydro has no control.

In 2004, subsequent to an inquiry into BC Hydro's heritage generation assets, Heritage Special Direction No. HC2 was issued by the Province. It required the BCUC to direct the establishment of the Heritage Deferral Account and the Trade Income Deferral Account. The former captures the variances between BC Hydro's actual and forecast cost of supply from heritage assets, and the latter captures variances between the actual and forecast net income of Powerex.

The BCUC directed the establishment of the Heritage Deferral Account and the Trade Income Deferral Account in its final order regarding BC Hydro's F05/F06 RRA. By the same order, the BCUC directed the establishment of the Non-Heritage Deferral Account to capture and defer variances between the forecast and actual energy costs that are not associated with the heritage assets.

BC Hydro must apply to the BCUC in order to establish regulatory accounts, and must also seek approval for the timeline and mechanism to recover the balances in the accounts from ratepayers. Since F2005 BC Hydro has sought and received approval from the BCUC for a number of regulatory accounts.

2.2 Description of Regulatory Accounts

Regulatory accounts can either be regulatory assets (amounts potentially to be recovered from BC Hydro ratepayers) or regulatory liabilities (amounts potentially to be refunded to BC Hydro ratepayers).

As BC Hydro has previously stated to the BCUC[1], the purpose of a regulatory account is to defer, for potential future recovery or refund, costs or revenues that would otherwise be recorded in the current accounting period. BC Hydro continues to believe that there are three situations where a regulatory account may be warranted:

- To better match costs and benefits for different generations of customers
- To smooth out the rate impact of a large non-recurring cost or to smooth out rate increases

[1] BC Hydro Amended F12-F14 RRA – section 7.1.2.

- To defer to future periods, differences between forecast and actual costs or revenues

With respect to the deferral of differences between forecast and actual costs, BC Hydro remains of the view that it should assume financial responsibility for controllable risks and create regulatory accounts for uncontrollable risks. However, to address concerns around the proliferation of regulatory accounts, BC Hydro also believes that with regard to the establishment of new regulatory accounts, there should be an objective measure used as a hurdle.

BC Hydro will only propose that a new regulatory account be established for amounts that are material and un-forecast or uncontrollable, and that should be collected from ratepayers. BC Hydro proposes that an un-forecast expenditure with a net income impact of greater than $10 million would be considered material and be deferred for future recovery upon approval by the BCUC. BC Hydro also expects that there may also be circumstances in which a regulatory account may be required to address a required accounting treatment of costs and to ensure proper recovery of those costs in rates, in which case the net impact test would not apply.

In its F2005/F2006 Revenue Requirements Application (**F05/F06 RRA**), BC Hydro set out the criteria that were to be used to assess whether a risk was controllable or uncontrollable as follows:

1. BC Hydro's ability to directly or indirectly influence the cost category
2. The volatility of the cost category
3. The predictability of the cost category
4. The materiality of the cost category to the revenue requirement
5. The frequency of major exceptions within the cost category[2]

[2] BC Hydro F05/F06 RRA Final Argument, page 7.

6. The BCUC, in its Decision concerning the F05/F06 RRA, accepted these criteria but also concluded that risk/reward considerations were a relevant criterion

3 Recovery of Regulatory Account Balances

3.1 Categorization of Regulatory Accounts

For the purpose of establishing appropriate recovery mechanisms, BC Hydro categorizes its regulatory accounts into the following categories, which also align with the three purposes for which BC Hydro uses regulatory accounts, as previously stated:

1. Variance Accounts (defer to a future period the differences between forecast and actual costs):
   (a) Cost of Energy Variance Accounts
   (b) Other Cash Variance Accounts
   (c) Non-Cash Variance Accounts
2. Benefit Matching Accounts (matching of costs to benefits for future generations)
3. Rate Smoothing Accounts (smooth out rate impact of large non-recurring costs or rate increases)
4. IFRS Transition Accounts (both smooth out the impacts of transition to IFRS and match benefits to future generations)

In addition, BC Hydro also has three regulatory accounts that are Non-Cash Provisions and which are required under Canadian Generally Accepted Accounting Principles (**CGAAP**) in order to create a regulatory asset to match an accounting liability.

The amortization period for the recovery of individual regulatory accounts is first dependent on which of the above categories the account falls into (with the exception of the Non-Cash Provision accounts, which are drawn down as expenses are actually incurred) as different recovery mechanisms have been developed for each category which consider the characteristics of that category, as further described below.

Three points are worth noting regarding the recovery of regulatory accounts over the ten-year period of this report. First, accounts currently subject to the DARR will continue to be recovered through that mechanism, as modified by Directions No. 6 and 7 and as discussed further in section 3.1.1. BC Hydro believes that the DARR remains an appropriate recovery mechanism that minimizes the risk of not achieving intergenerational equity. Second, BC Hydro proposes that the recovery mechanisms are applied consistently over the life of the regulatory account. Finally, there is an alignment of costs and benefit recognition to address intergenerational equity concerns. This latter point is reflected in the contrasting shorter and longer recovery periods for different regulatory accounts based on the nature of the costs in the accounts. BC Hydro notes that these objectives may, from time to time need to be balanced with the objective of keeping rates low, which may give rise to rate mitigation or smoothing mechanisms or regulatory accounts, as discussed in the Executive Summary of this report.

The recovery mechanisms for each category of regulatory account is next discussed in further detail, with a summary of the rationale for each account, in Table 3 and a summary of the amortization periods for each account in Table 4.

3.1.1 Variance Accounts

Variance accounts capture the difference between forecast costs and revenues, on which rates are set in BC Hydro's revenue requirements applications, and the actual costs and revenues that are incurred or received by BC Hydro. Not all forecast costs will be subject to variance account treatment. For those costs that BC Hydro has control over, it generally accepts the financial risk of the difference between the forecasted and actual costs. However, for those costs that BC Hydro does not have control over, it can be difficult to accurately forecast them and therefore regulatory accounts are often set up to capture the difference between the forecast and actual costs and recover or refund the variance, through the rates charged to ratepayers.

This effectively transfers the forecast cost risk of these uncontrollable costs to customers. BC Hydro considers that it is appropriate that these costs be paid by ratepayers, as the costs are being incurred in the provision of service to its ratepayers.

With regard to forecast revenue variances, it can also be difficult for BC Hydro to forecast exactly when some revenues will be received. The current example of this situation is the Real Property Sales Regulatory Account which will be set up in F2015. The 10-Year Plan sets rates in F2015 and F2016 on the forecast assumption that BC Hydro will earn $10 million per year in real estate sales. In actual fact, real estate sales may be greater or lesser than that amount in each of F2015 and F2016 and the Real Property Sales Regulatory Account will capture the difference between the forecast and actual sales.

Cost of Energy Variance Accounts:

The cost of energy variance accounts are made up of the Heritage Deferral Account, the Non-Heritage Deferral Account and the Trade Income Deferral Account. The Heritage Deferral Account and Trade Income Deferral Account were created pursuant to Heritage Special Direction No. HC2 and BC Hydro included in the F05/F06 RRA a request to also set up the Non-Heritage Deferral Account to capture variances between the forecast and actual energy costs that are not associated with heritage assets.

The purpose of the cost of energy variance accounts (the three of which are also referred to as the “Deferral Accounts”) is to defer the difference between forecast and actual costs of energy and trade income, for recovery in a future period. For example, the Deferral Accounts are used to smooth net income when energy costs are unexpectedly higher or lower than forecast. This may happen due to variations in reservoir water levels (due to more or less precipitation and snow melt in any given year), resulting in the requirement for BC Hydro to change its mix of energy resources to meet load demand. While rates are set assuming average water inflow levels, the lower cost Hydro generation levels can fluctuate by +/- 5,000 GWh between low and high water years, resulting in the need to sell surplus power or purchase energy from the market. As water inflow levels are uncontrollable it is appropriate that the risk of this cost should be borne by BC Hydro’s customers and recovered in rates.

BC Hydro recovers the balances in the cost of energy Deferral Accounts using the DARR. In the F09/F10 RRA Decision, the BCUC approved BC Hydro’s proposal that the level of the DARR, to be effective on April 1 of a given year, be based on the net balance in the Deferral Accounts as of September 30 of the previous year in accordance with Table 1 (this methodology is referred to as the **DARR Table Mechanism**).

Table 1 Deferral Account Rate Rider

Net Forecast Balance at March 31		% Rate Rider
>$ million	**<=$ million**	**Following April 1st**
< -500	-500	(5.0)
-500	-450	(4.5)
-450	-400	(4.0)
-400	-350	(3.5)
-350	-300	(3.0)
-300	-250	(2.5)
-250	-200	(2.0)
-200	-150	(1.5)
-150	-100	(1.0)
-100	-50	(0.5)
-50	0	0.0
0	50	0.0
50	100	0.5
100	150	1.0
150	200	1.5
200	250	2.0
250	300	2.5
300	350	3.0
350	400	3.5
400	450	4.0
450	500	4.5
500	> 500	5.0

The BCUC also determined in the F09/F10 RRA Decision that if BC Hydro considers a deviation from the DARR Table Mechanism is warranted due to special circumstances then BC Hydro should seek BCUC approval of such deviation. In the Amended F12-14 RRA Decision Order No. G-77-12A, the BCUC determined that the DARR was to be set at 5 per cent for F2013 and F2014. In addition, on March 6, 2014 the Province issued Directives No. 6 and 7 which require that the DARR be maintained at 5 per cent and the amount collected in excess of what would otherwise be collected under the DARR Table Mechanism be used to offset general rate increases. The DARR percentages that are expected to be applied to the Deferral Accounts over the next 10 years are shown in Table 2. Table 2 indicates that the DARR percentages applied to Deferral Accounts will be nil for F2024, however, as noted in the Executive Summary, BC Hydro expects that due to the nature of these cost of energy Deferral Accounts, there will likely be balances in these accounts in each of the forecast years. The amounts shown in Table 2 are based on the forecast of balances shown in Table 6

Table 2 DARR Percentages Applied to Deferral Accounts

	F15 (%)	F16 (%)	F17 (%)	F18 (%)	F19 (%)	F20 (%)	F21 (%)	F22 (%)	F23 (%)	F24 (%)
DARR	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Amount applied to Deferral Accounts	5.0	5.0	4.5	3.5	1.5	1.0	0.5	0.5	0.5	0
Amount applied to general revenues	0	0	0.5	1.5	3.5	4.0	4.5	4.5	4.5	5.0

Also, in Appendix H of the Amended F12-F14 RRA, BC Hydro provided an analysis and simulation of the DARR mechanism. The analysis looked at the probability of the cost of energy Deferral Account balances becoming zero at some point due to the revenues from the DARR and the fluctuations, positive and negative, in multi-year variations in water inflows. The analysis concluded that by using the DARR table mechanism there was an 80 per cent probability that the total balance in the deferral accounts would reach zero in the next 10 years, and almost a 100 per cent probability that the total balance in the deferral accounts would reach zero in the next 20 years.

Other Cash Variance Accounts:

Other Cash Variance Accounts capture the difference between forecast and actual costs for other non-energy related costs that BC Hydro considers to be uncontrollable, and for which it should not carry the risk. Examples of such accounts are the Storm Restoration and the Total Finance Charges regulatory accounts. Balances in these accounts are generally recovered in the next test period, as they represent costs that do not provide long-lasting benefits to future generations of ratepayers and that therefore should be recovered from current ratepayers.

Non-Cash Variance Accounts:

The purpose of these accounts is to capture the differences between forecast and actual uncontrollable costs, which are non-cash in nature, for recovery from or refund to ratepayers in a future period. There are two regulatory accounts in this category: 1) the Foreign Exchange Gain/Losses and 2) Non-Current Pension Cost regulatory accounts. The recovery period for these accounts should match the underlying attribute. For example, the non-current pension cost account is amortized over the average remaining service life of employees and the foreign exchange gain/loss account is amortized on a straight-line pool basis over the weighted average life of the related debt.

3.1.2 Benefit Matching Accounts

The purpose of these accounts is to better match current costs to future benefits, so that each generation of customers pays its fair share of the costs. Benefit matching accounts include those regulatory accounts with some of the most significant balances. The largest balances are forecast for the DSM, SMI and Site C regulatory accounts, all of which are related to long-lasting assets that should not be paid entirely by current customers, but whose cost should be spread out for recovery from future customers to ensure intergenerational equity. Even though CGAAP accounting rules (that now include IFRS)[3] may not permit the capitalizing of these costs, BC Hydro believes that capturing these amounts in a regulatory account provides for cost matching and a degree of rate smoothing for large expenditures

[3] Government Organization Accounting Standards Regulation 257/2010 requires BC Hydro to adopt IFRS, subject to United Stated Financial Accounting Standards Board Accounting Standards Codification 980 (**ASC 980**), effective April 1, 2012 (F2013). ASC 980 provides for the use of regulatory accounting where directed by a rate-regulated utility's rate regulator.

that have a lasting benefit. For example, the Site C Regulatory Account was established to provide a better matching of the up-front investigation costs with the future benefits from this project. If the Site C investigation costs were expensed as required under IFRS, it would cause an unfair rate impact on current customers, considering the long development period before the Site C dam will be completed and placed into service and the fact that customers over many decades after the completion of the project will be receiving the benefits that incurring these costs today will have allowed.

3.1.3 Non-cash Provisions

Non-cash provisions are regulatory accounts set up in response to loss provision liabilities required under CGAAP. As such, these provisions are not recovered in rates until such time as actual cash expenditures are made against the provision. These regulatory accounts will remain until the requirement for the provision is no longer required under CGAAP. The regulatory assets preserve BC Hydro's right to collect in rates, subject to BCUC approval, any actual amounts paid in respect of these provisions. The three non-cash provision regulatory accounts that BC Hydro currently has are the First Nations Provisions, Environmental Provisions and Arrow Water Provision regulatory accounts. These accounts are forecast to still have significant balances at the end of F2024 totalling $427 million in the First Nations Provisions regulatory account (after accounting for actual costs and accretion over the 10-year period)[4] and $131 million in the Environmental Provisions regulatory account (drawdowns of this account extend out to F2045).

3.1.4 Rate Smoothing Accounts

Rate Smoothing accounts serve to mitigate the rate impact of either large one-time expenditures or overall general rate increases that may otherwise be required to recover BC Hydro's approved revenue requirements. During the period of the

[4] The balance in the First Nations Provision Regulatory account also reflects the fact that some of the First Nations Settlement Agreements include payments in perpetuity.

F12-F14 ARRA, BC Hydro had two rate smoothing accounts 1) the Waneta rate smoothing account; and 2) the F12-F14 rate smoothing account. Both of these accounts will have expired by the end of F2015.

The Province, as part of the 10-Year Plan, by way of Directive No. 7 to the BCUC requires BC Hydro to establish a rate smoothing regulatory account in F2015 in order to smooth the impacts of the rate increases that would otherwise be applicable in order to mitigate rate shock in any particular year. BC Hydro is forecasting that the balance in the F2015 rate smoothing regulatory account will be nil at the end of F2024.

3.1.5 IFRS Transition Accounts

Finally, IFRS Transition regulatory accounts have been put in place to smooth the impact of the transfer to IFRS accounting rules, which came into effect at the start of F2013. The move to IFRS does not create new costs nor increase financial risks; rather the move to IFRS changes the timing of the recognition of revenues and costs into income. The two IFRS Transition Accounts are the IFRS Pension and the IFRS Property Plant & Equipment (**PP&E**) regulatory accounts. The IFRS Pension regulatory account is required due to the different treatment under IFRS of unamortized experience gains and losses on BC Hydro's pension and other post-employment benefit plans. IFRS requires recognition of these amounts on the balance sheet, which was not required under the previous accounting rules. The IFRS PP&E regulatory account will phase in overhead costs of capital projects that can no longer be capitalized under IFRS. These costs were previously recorded on the balance sheet as property, plant and equipment, and will be amortized on the same schedule as the assets they are associated with.

The IFRS Transition regulatory accounts have been set up under the criteria of rate smoothing and benefit matching of asset costs with their useful lives. If BC Hydro were to have recognized the impact of the transition to IFRS in its rates at the time of the transition, the rate impact for customers would have been significant followed by a drop in rates the following year. The IFRS Transition regulatory accounts also act to recover the transition costs of pension and capital assets over the same period of time as if the IFRS rules had not come into being, and therefore have very long recovery periods of 20 years for the IFRS Pension regulatory account and 40 years for the IFRS PP&E regulatory account. The IFRS Transition regulatory accounts are forecast to have significant balances remaining at the end of F2024; the IFRS Pension regulatory account balance is forecast to be $306 million, while the IFRS PP&E regulatory account balance is forecast to be $976 million.

Table 3 provides a summary of the rationale for determining appropriate recovery mechanisms for BC Hydro's regulatory accounts, based on the foregoing discussion regarding the nature of the accounts, and BC Hydro's objectives in recovering the account balances.

Table 3 Rationale for Regulatory Account Recovery

Type of Regulatory Account	Rationale for Recovery Mechanism
Variance Accounts:	
Cost of Energy Variance Accounts	The DARR mechanism minimizes intergenerational inequity by being responsive to the changing net balance in the cost of energy variance accounts, while maintaining rate stability for customers to the extent practicable.
Other Cash Variance Accounts	To minimize intergenerational inequity, cash variance accounts should be recovered in the subsequent test period.
Non-Cash Variance Accounts	Non-cash variances should be recovered over the remaining period of the associated asset or liability (e.g. remaining service life of employees or remaining term of debt issues).
Benefit Matching Accounts	To achieve intergenerational equity, the recovery period should match the future benefit period of the expenditure.
Non-Cash Provisions	Since non-cash provisions are not recovered in rates, no recovery mechanism is required. The provision is drawn down when actual expenditures are charged to the deferral account.
Rate Smoothing Accounts	To balance the concerns of rate shock and intergenerational equity, the balances in rate smoothing accounts should be recovered over a period not exceeding 10 years.
IFRS Transition Accounts	To smooth in the impact of the transition to IFRS, the balances in these accounts should be recovered on the same basis as they would have been recovered in the absence of IFRS.

3.2 Summary of Regulatory Account Recovery Mechanisms

Table 4 provides a summary of the recovery mechanisms for each of BC Hydro's regulatory accounts.

Table 4 Recovery Mechanisms for Regulatory Accounts

	Recovery Mechanism
Cost of Energy Variance Accounts	
Heritage Deferral Account	DARR
Non-Heritage Deferral Account	DARR
Trade Income Deferral Account	DARR
Other Cash Variance Accounts	
Storm Restoration	**Next Test Period**
Amortization of Capital Additions	**Next Test Period**
Total Finance Charges	**Next Test Period**
Rock Bay Remediation Costs	**Next Test Period**
Arrow Water Divestiture Costs	**Next Test Period**
Asbestos Remediation Costs	**Next Test Period**
Home Purchase Option Plan	**Next Test Period**
Real Property Sales **(new)**	**Next Test Period**
Non-Cash Variance Accounts	
Foreign Exchange Losses (Gains)	Straight-line Pool Method
Non-Current Pension Cost	Average Remaining Service Life
Benefit Matching Accounts	
Demand-Side Management	15 Years
First Nations Costs	10 Years (see Note 1, below)
Site C	To Be Determined
Future Removal & Site Restoration	As Dismantling Costs Are Incurred
Pre-1996 Contributions	45 Years (to F2040)
Capital Project Investigation (closed)	10 Years (to F2021)
Smart Metering & Infrastructure	**15 Years (starting in F2015)**
Non-Cash Provisions	
First Nations Provisions	N/A
Environmental Provisions	N/A
Arrow Water Provision	N/A
Rate Smoothing Accounts	
F2010 ROE Adjustment (closed)	6 Years (to F2015)
Waneta (closed)	5 Years (to F2015)
F12-F14 Rate Smoothing (closed)	3 Years (to F2014)
Rate Smoothing **(new)**	**10 years**
IFRS Transition Accounts	
IFRS PP&E	40 Years (to F2061)
IFRS Pension	20 Years (to F2032)

Note 1: BC Hydro proposes for the First Nations Costs regulatory account that the F2014 closing balance related to settlement payments and negotiation costs will be amortized over 10 years beginning in F2015. Future lump sum settlement payments are to be amortized over 10 years and annual negotiation costs and settlement payments will be expensed in the year of expenditure.

As shown in Table 4 above, BC Hydro will be adding two new regulatory accounts as part of the 10-Year Plan related to the following:

- Real Property Sales – Due to the uncertainty in the timing of transactions, variances related to actual gain on sales compared to the gains included in the forecast used to set rates would be captured in this new account
- Rate Smoothing - As part of the Province's rate plan a Rate Smoothing regulatory account is needed to mitigate rate increases in the short-term

4 Application of Interest to Regulatory Accounts

The same principle of matching costs with benefits results in some regulatory accounts also attracting interest, as the carrying costs of maintaining the account balances may have a real cost in any particular period that needs to be recovered in rates. For cash variance regulatory accounts that come about through a direct cash outlay from BC Hydro, the related interest costs are generally included as part of the regulatory accounts. BC Hydro incurs financing charges to carry amounts that were paid in cash but not recovered in rates in the same test period. This category of account is recovered over a short period of time. For some accounts, the interest cost may be immediately expensed from the regulatory account to rates, rather than being carried over and amortized for recovery in future rates.

Variance regulatory accounts such as energy deferral accounts also attract interest because BC Hydro does not forecast variances in the accounts. When borrowing costs are incurred to fund these unplanned expenditures, they are deferred to keep ratepayers and the shareholder cost-neutral in the test period. For the remaining regulatory accounts, interest is generally applied when there is a working capital effect on BC Hydro.

Generally, benefit-matching accounts such as Site C also attract interest because of their similarities to PP&E under construction and Interest During Construction (**IDC**).

BC Hydro incurs financing charges as a result of not immediately recovering the costs of construction of large assets. It is therefore fair that these costs be recovered from future ratepayers, rather than be recovered from current ratepayers, so that there is intergenerational equity between current and future ratepayers who will be enjoying the benefits of the earlier expenditures.

Interest applied to regulatory accounts does not have the effect of increasing or decreasing BC Hydro's allowed net income, as the capitalized interest merely offsets the unbudgeted incremental interest costs. BC Hydro uses the weighted average cost of debt of the current period as the interest rate for regulatory accounts and IDC. The current interest rate is 4.73 per cent, and is applied on a monthly basis to the regulatory accounts.

Based on the forgoing criteria, BC Hydro applies interest to all regulatory accounts, with the exception of the following accounts:

(a) Non-cash regulatory accounts (such as provisions)

(b) Rate-smoothing regulatory accounts (since the annual transfers to a rate-smoothing regulatory account already reflect the impact of the account on finance charges)

(c) The Total Finance Charges Regulatory Account (since interest costs are part of total finance charges)

(d) Regulatory accounts that capture timing differences (such as pre-1996 Contributions)

BC Hydro has three accounts that should attract interest based on the above criteria, but which have not been subject to interest historically:

(a) The Future Removal and Site Restoration Regulatory Account (**FRSR Regulatory Account**)

(b) The Capital Project Investigation Costs Regulatory Account (**CPI Regulatory Account**)

(c) The First Nations Costs Regulatory Account (**FNC Regulatory Account**)

The FRSR Regulatory Account is expected to be depleted by F2016 and the CPI Regulatory Account was closed in F2011 with the balance being amortized over 10 years beginning in F2012. Therefore, BC Hydro is not proposing any change to these accounts.

In addition, interest is not charged to the DSM regulatory account, as DSM expenditures generally go into service in the year of expenditure, and BC Hydro does not defer interest on capital projects after they enter service, similar to the treatment for PP&E.

However, in accordance with the above criteria for the charging of interest and as directed by Directive No. 6, BC Hydro will begin to apply interest to the FNC Regulatory Account commencing in F2015. The interest forecast to be charged to the FNC Regulatory Account will be added to the forecast annual amortization for the account.

Table 5 below summarizes the application of interest to BC Hydro's regulatory accounts.

Table 5 Application of Interest to Regulatory Accounts

	Interest Applied	Rationale
Cost of Energy Variance Accounts		
Heritage Deferral Account	Yes	
Non-Heritage Deferral Account	Yes	
Trade Income Deferral Account	Yes	
Other Cash Variance Accounts		
Storm Restoration	Yes	
Amortization of Capital Additions	Yes	
Total Finance Charges	No	Finance Charges
Rock Bay Remediation Costs	Yes	
Arrow Water Divestiture Costs	Yes	
Asbestos Remediation Costs	Yes	
Home Purchase Option Plan	Yes	
Real Property Sales **(new)**	Yes	
Non-Cash Variance Accounts		
Foreign Exchange Losses (Gains)	No	Non-Cash
Non-Current Pension Cost	No	Non-Cash
Benefit Matching Accounts		
Demand-Side Management	No	Similar to PP&E
First Nations Costs	**Yes**	**Starting in F2015**
Site C	Yes	
Future Removal & Site Restoration	No	Exception
Pre-1996 Contributions	No	Timing Difference
Capital Project Investigation (closed)	No	Exception
Smart Metering & Infrastructure	Yes	
Non-Cash Provisions		
First Nations Provisions	No	Non-Cash
Environmental Provisions	No	Non-Cash
Arrow Water Provision	No	Non-Cash
Rate Smoothing Accounts		
F2010 ROE Adjustment (closed)	No	Rate Smoothing
Waneta (closed)	No	Rate Smoothing
F12-F14 Rate Smoothing (closed)	No	Rate Smoothing
IFRS Transition Accounts		
IFRS PP&E	No	Rate Smoothing
IFRS Pension	No	Non-Cash

5 Forecast of Regulatory Account Balances

At the beginning of F2014, BC Hydro's regulatory accounts had a combined net balance of $4.4 billion.[5] The overall net balance will continue to increase by $700 million billion to a forecasted maximum net balance in F2018 and F2019 of $5.1 billion. As noted earlier in the Executive Summary, of the $4.4 billion balance at the beginning of F2014, BC Hydro is already collecting in its rates 19 of the 27 regulatory accounts representing account balances of $3.5 billion, or 80 per cent of the total balance.

The following Figure 1 illustrates the actual and forecast regulatory account balances over the 20-year period from F2005 to F2024. As the amounts shown for F2014 forward are forecasts, actual results in future years will be different than those discussed in this report. Figure 1 illustrates that there has been significant growth in the total regulatory account balances, the largest increase occurring in F2013, when the two IFRS Transition regulatory accounts and the Non-Current Pension Cost regulatory account added almost $1.4 billion, as a result of the transition to IFRS accounting. As noted earlier, the move to IFRS does not create new costs nor increase financial risks, it merely changes the timing of the recognition of revenues and costs into income.

[5] Forecast amounts will be updated in F15-F16 RRA.

Figure 1 BC Hydro – Actual and Forecast Regulatory Account Balances ($ million)

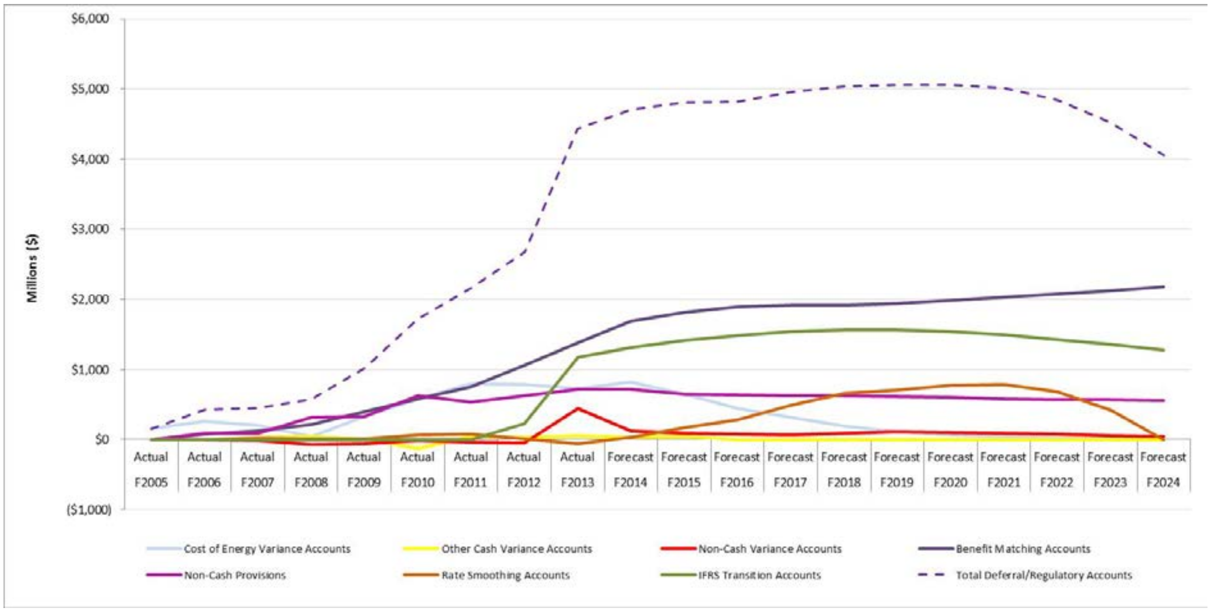

Table 6 **Regulatory Account Balances – Actual F2005 to F2013 and Forecast F2014 to F2024 ($ million)**

		F2005	F2006	F2007	F2008	F2009	F2010	F2011	F2012	F2013	F2014	F2015	F2016	F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2024
	($ million)	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast
	Cost of Energy Variance Accounts																				
1	Heritage Deferral Account	$138	$241	$178	$78	$329	$325	$248	$244	$70	$65	$51	$35	$70	$41	$26	$15	$10	$4	-	-
2	Non-Heritage Deferral Account	131	205	209	52	74	119	362	367	468	386	303	209	129	75	47	27	18	7	-	-
3	Trade Income Deferral Account	(115)	(213)	(202)	(103)	(80)	122	188	175	190	370	290	200	124	71	45	26	17	7	-	-
4	BCTC Deferral Account	N/A	25	13	22	10	19	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Total	154	257	198	49	333	585	798	786	728	822	644	445	323	187	117	69	45	18	-	-
	Other Cash Variance Accounts																				
5	Storm Restoration	N/A	N/A	33	43	(2)	(5)	(1)	1	(3)	(3)	(1)	-	-	-	-	-	-	-	-	-
6	Amortization on Capital Additions	N/A	N/A	N/A	N/A	(3)	(6)	(10)	(2)	(6)	(18)	(9)	-	-	-	-	-	-	-	-	-
7	Total Finance Charges	N/A	N/A	N/A	N/A	1	(104)	(4)	6	1	(51)	(26)	-	-	-	-	-	-	-	-	-
8	Rock Bay Remediation Costs	N/A	N/A	N/A	N/A	N/A	N/A	2	4	29	52	49	-	-	-	-	-	-	-	-	-
9	Arrow Water Divestiture Costs	N/A	N/A	N/A	N/A	N/A	N/A	8	8	8	9	4	-	-	-	-	-	-	-	-	-
10	Asbestos Remediation	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-	8	19	10	-	-	-	-	-	-	-	-	-
11	Total Taxes (closed)	N/A	N/A	N/A	N/A	(2)	(7)	(13)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
12	GM Shrum 3 (closed)	N/A	N/A	N/A	N/A	42	41	43	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
13	Net Employment Costs (closed)	N/A	N/A	N/A	N/A	(29)	(62)	-	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
14	Home Option Purchase Plan	N/A	N/A	N/A	N/A	1	11	18	20	21	22	11	-	-	-	-	-	-	-	-	-
15	Real Property Sales	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-	-	-	-	-	-	-	-	-	-	-
	Total	-	-	33	43	8	(131)	43	37	58	30	38	-	-	-	-	-	-	-	-	-
	Non-Cash Variance Accounts																				
16	Foreign Exchange Losses (Gains)	(2)	2	(16)	(66)	(57)	(101)	(107)	(103)	(100)	(96)	(94)	(94)	(91)	(50)	(10)	(8)	(6)	(4)	(3)	(3)
17	Non-Current Pension Cost	N/A	N/A	N/A	N/A	N/A	86	72	55	544	219	186	171	155	140	124	109	93	78	62	47
	Total	(2)	2	(16)	(66)	(57)	(15)	(35)	(49)	444	123	92	77	64	90	115	100	87	74	59	44
	Benefit Matching Accounts																				
18	Demand-Side Management	207	269	282	309	362	443	506	638	732	821	898	946	982	1,012	1,065	1,126	1,197	1,266	1,327	1,389
19	First Nations Costs	29	33	36	41	62	91	99	153	168	175	174	155	137	118	98	79	59	39	20	0
20	Site C	N/A	N/A	4	9	35	59	103	181	258	362	377	394	412	434	459	486	515	545	576	610
21	Future Removal & Site Restoration	(238)	(227)	(211)	(192)	(172)	(159)	(140)	(120)	(88)	(66)	(41)	(10)	-	-	-	-	-	-	-	-
22	Pre-1996 Contributions	N/A	N/A	14	27	38	49	59	67	75	81	87	92	95	96	91	86	81	76	71	65
23	Smart Metering & Infrastructure	N/A	N/A	N/A	N/A	9	19	34	92	192	282	287	286	264	242	220	198	176	154	132	110
24	Capital Project Investigation (closed)	N/A	N/A	N/A	12	32	43	49	44	40	35	30	25	20	15	10	6	1	-	-	-
25	Procurement Enhancement (closed)	N/A	N/A	N/A	7	29	40	38	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Total	(2)	75	125	213	396	585	747	1,055	1,377	1,689	1,812	1,887	1,911	1,917	1,944	1,980	2,029	2,079	2,126	2,175
	Non-Cash Provisions																				
26	First Nations Provisions	N/A	88	90	319	326	308	300	391	386	416	401	405	407	413	418	420	413	418	422	427
27	Arrow Water Provision	N/A	N/A	N/A	N/A	N/A	N/A	3	4	3	3	3	3	4	4	3	2	1	0	-	-
28	Environmental Provisions	N/A	N/A	N/A	N/A	N/A	321	229	230	331	295	239	231	220	208	195	181	166	151	141	131
	Total	0	88	90	319	326	629	533	625	720	714	644	640	631	625	616	602	581	569	564	557
	Rate Smoothing Accounts																				
29	F07/F08 Depreciation Study (closed)	N/A	N/A	19	14	10	5	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
30	Waneta (closed)	N/A	N/A	N/A	N/A	N/A	N/A	30	40	25	15	-	-	-	-	-	-	-	-	-	-
31	F2010 ROE Adjustment (closed)	N/A	N/A	N/A	N/A	N/A	56	45	34	23	11	-	-	-	-	-	-	-	-	-	-
32	F12-F14 Rate Smoothing (closed)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	(70)	(111)	-	-	-	-	-	-	-	-	-	-	-
33	Rate Smoothing	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-	166	287	491	663	703	775	785	686	425	-
	Total	-	-	19	14	10	61	75	4	(63)	26	166	287	491	663	703	775	785	686	425	-
	IFRS Transition Accounts																				
34	IFRS Pension	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-	723	688	650	612	574	535	497	459	421	382	344	306
35	IFRS PP&E	N/A	N/A	N/A	N/A	N/A	N/A	N/A	222	447	617	758	873	962	1,025	1,064	1,079	1,071	1,039	1,007	976
	Total	-	-	-	-	-	-	-	222	1,170	1,306	1,408	1,485	1,535	1,561	1,561	1,538	1,491	1,421	1,352	1,282
	Total	**$ 150**	**$ 422**	**$ 449**	**$ 573**	**$ 1,016**	**$ 1,713**	**$ 2,160**	**$ 2,679**	**$ 4,434**	**$ 4,710**	**$ 4,804**	**$ 4,821**	**$ 4,955**	**$ 5,041**	**$ 5,055**	**$ 5,064**	**$ 5,017**	**$ 4,848**	**$ 4,525**	**$ 4,058**

As shown in Table 7, by the end of F2024 almost 84 per cent of the total balance in the regulatory accounts will be in five accounts, three that are benefit matching and two that relate to the transition to IFRS. In addition, $557 million of the balance is comprised of non-cash provision accounts, which are not recovered in rates until such time as an actual cash expenditure is made against the provision.

Table 7 BC Hydro's Five Major Regulatory Accounts F2013 to F2024

Regulatory Accounts - Year-End balances ($ million)	F2013 Actual	F2014 Forecast	F2024 Forecast
Demand-Side Management	732	821	1,389
Site C	258	362	610
Smart Metering & Infrastructure	192	282	110
IFRS Property, Plant & Equipment	447	617	976
IFRS Pension	723	688	306
Subtotal	2,352	2,770	3,390
Cost of Energy Variance Accounts	728	822	(0)
Non-Cash Provisions	720	714	557
Other Regulatory Accounts	634	404	110
Total	4,434	4,710	4,058
Subtotal as Per Cent of Total	53%	59%	84%

Further detail on each of the three benefit-matching and two IFRS Transition regulatory accounts is provided below.

DSM

This regulatory account captures expenditures made on DSM activities related to achieving customer energy savings. The 2002 and 2007 BC Energy Plans established DSM savings targets for BC Hydro, which were subsequently updated in the *Clean Energy Act*. The current targets are to reduce the expected increase in demand for electricity by the year 2020 by at least 66 per cent. The level of DSM expenditures has been set to achieve the targets set in the *Clean Energy Act*. As noted in section 2.1, in 1995 the BCUC directed that electric utilities in British Columbia were to defer and amortize into rates costs associated with DSM activities that achieve energy savings. BC Hydro's historical and future DSM costs are amortized over 15 years in accordance with the ARRA Decision, BCUC Order No. G-77-12A. The DSM forecasted amounts in Table 6 and Table 7, above, are based on the amounts in the 2013 Integrated Resource Plan and expenditure levels may vary from the current forecast depending on targets established in the future. As a result, the DSM regulatory account balance could be greater or less in 10 years than is currently forecast.

Site C

This regulatory account captures the pre-capitalization Site C project expenditures. These costs are not eligible for capitalization under previous CGAAP nor IFRS as the Site C project has not completed the feasibility assessment phase and BC Hydro has not made the decision to proceed with the project. BC Hydro will apply to the BCUC to recover the costs through rates at a future time and over an appropriate time frame, when the asset is completed and benefits to the ratepayers from the investment are being realized. The expected in-service date for the project is F2024.

Smart Metering & Infrastructure

As directed by Government Direction No. 4 issued on September 25, 2013, this regulatory account will commence amortization in F2015, when the SMI program is fully implemented and in operation across BC Hydro's system. BC Hydro is proposing in this report that the SMI account be amortized over a 15-year period, based on the weighted average life of SMI assets.

*IFRS Property, Plant & Equipment (**PP&E**)*

This regulatory account enables the deferral of overhead costs that can no longer be capitalized under IFRS as they are not directly attributable to the construction of an asset. In the Amended F12-F14 RRA, BC Hydro proposed that overhead costs that can no longer be capitalized should not be immediately absorbed in rates as it would result in a significant rate impact, but rather should be deferred and transitioned into operating expenditures over 10 years. In order to transition the overhead costs that can no longer be capitalized under IFRS into rates over a 10-year period, BC Hydro will reduce the amount of ineligible overhead costs that it would otherwise charge to this deferral account by 10 per cent per year, and instead charge the corresponding amount to operating costs. For example, BC Hydro charged 100 per cent of ineligible overhead costs to the PP&E regulatory account in F2012, and starting in F2013 will reduce the percentage of ineligible overhead costs that will be charged to the deferral account by 10 per cent each year. The amounts not charged to the deferral account will be included in current year operating costs.

BC Hydro is amortizing the additions to the regulatory account over 40 years, based on the composite life of BC Hydro's assets and to match the overhead costs with the benefits of the underlying assets.

IFRS Pension

Under previous CGAAP, BC Hydro recognized actuarial gains and losses related to pension costs in net income over the remaining service period of employees.

On the transition to IFRS, BC Hydro had to recognize all unamortized experience gains and losses on the pension and other post-employment benefit plans not previously recognized in its financial statements. To maintain its ability to recover this amount from customers, BC Hydro placed the amount that would otherwise be charged to its retained earnings on the transition to IFRS, into the IFRS Pension regulatory account.

BC Hydro is amortizing the amount in the IFRS Pension account over 20 years. This level of amortization results in approximately the same total revenue requirement under IFRS as under previous CGAAP.

6 Sensitivity Analysis

As was mentioned in the Executive Summary, one of the caveats to be considered with regard to the regulatory account balances shown in this report is that they are forecast amounts as of the end of F2014 and subject to change. The actual balances will be subject to sensitivities. The following table shows the effect on BC Hydro's costs of changes in some key variables. Each of the changes in costs shown will have an impact on regulatory account balances. For example, changes in hydro generation will impact actual energy costs and result in additions or reductions to the energy deferral accounts. Electricity trade margins will have a direct impact on forecasted balances in the trade income deferral account. One of the most dramatic impacts is due to market discount rates and their impact on BC Hydro's non-current pension costs regulatory account. A 1 per cent change in the market discount rate will result in a difference of approximately $300 million in the non-current pension cost regulatory account balance.

Table 8 Cost Sensitivities

Factor	Change	Approximate change in costs before regulatory account transfers ($ million)
Hydro Generation (GWh)[6]	+/- 1%	+/- 15
Electricity trade margins	+/- 10%	+/- 20
Interest rates	+/- 1%	+/- 50
Exchange rates (CAN$ relative to US$)	+/- $0.01	+/- 5
Weather	+/- 1 degree C (in average temperature)	+/- 20 (colder weather decreases costs)
Market discount rate applicable to pension obligations	+/- 1%	+/- 300

[6] Hydro generation levels can fluctuate by as much as +/- 5,000 GWh from average based on higher or lower water inflow levels. Average hydro generation levels are approximately 45,000 GWh/year.

7 Conclusion

In this report, BC Hydro has described and summarized its regulatory accounts, discussed the differing regulatory account categories and the recovery mechanisms that apply to each category, and set out the individual recovery period for each regulatory account.

The report shows that at the end of F2024, BC Hydro forecasts that it will have total regulatory account balances of $4.06 billion, which is slightly less than the actual balance at the beginning of F2014 of $4.4 billion. However, this is a reduction of just over $1 billion from the forecast maximum amount of $5.1 billion in F2019. In addition, over the 10-year period thirteen of the existing regulatory accounts will have their balances reduced to zero. Not included in those thirteen accounts are the three energy deferral accounts, which will be expected to have balances in them at the end of F2024, even though the forecast of the reductions of the current balances through the DARR mechanism show the balances being eliminated in F2023. As well, at the end of F2024 almost 84 per cent of the outstanding regulatory account balances (approximately $3.4 billion) will be in five regulatory accounts that either match costs with associated benefits (DSM, Site C and SMI), or that relate to the transition to IFRS (IFRS PP&E and IFRS Pension) and 14 per cent will be comprised of non-cash provision accounts that are not recovered in rates until such time as an actual cash expenditure is made against the provision. In addition, of the $4.4 billion balance at the beginning of F2014, BC Hydro is already collecting in its rates 19 of the 27 regulatory accounts representing account balances of $3.5 billion, or 80 per cent of the total balance.

Finally, it should be noted that the forecast of regulatory account balances is subject to revisions as a result of changing spending priorities and changes in Government energy policy that may come about over the next 10 years. In addition, as the balances are forecasts, actual balances will be different and are subject to sensitivities to various factors, some which are described in section 6.

Although large, BC Hydro views the balances in its regulatory accounts as acceptable and a reflection of BC Hydro's goals and objectives of ensuring intergenerational equity and maintaining low rates for its customers. Regulatory accounts are not uncommon in the utility industry; however, BC Hydro is aware of the concerns about the growth in the balances of its regulatory accounts and their potential effects on intergenerational equity. As a Crown Corporation, BC Hydro has differing priorities and risk considerations than many IOUs. One of BC Hydro's primary goals is to keep rates as low as practical, in addition to providing reliable service and value. The goal of low rates is assisted by a matching of the costs of major programs and projects such as DSM and SMI with the long-lasting benefits that each deliver to future generations of ratepayers. BC Hydro believes that the use of regulatory accounts is necessary to ensure that there is proper intergenerational equity between its current and future customers. This growth has occurred, for the most part, with approvals from the BCUC and full disclosure by BC Hydro.

In terms of financial risk, BC Hydro is backed by the full support of the Government of British Columbia, which provides BC Hydro with the benefit of low borrowing costs and avoids the need for it to directly access the financial markets for financing needs. This support allows BC Hydro to carry balances in its regulatory accounts that an IOU may find difficult to sustain, as large balances could impair the ability of an IOU to access financing at low interest rates.

Looking at each regulatory account in isolation, there is a clear purpose for its existence and a clear matching of costs incurred either to be recovered from ratepayers over the short term for those costs that do not have a lasting benefit or over a longer term for those costs with long-term benefits that are being delivered to future generations of customers. Changing the amortization periods of these accounts to reduce the balances sooner would violate BC Hydro's principled approach of addressing intergenerational equity concerns and the proper matching of costs and benefits. However, BC Hydro also recognizes that there are concerns about the growth in the balances of its regulatory accounts and the length of time that will be required to recover those balances.

In summary, BC Hydro acknowledges the concerns that have been raised by interveners and stakeholders and does not dismiss them out of hand. However, BC Hydro believes that the number and balances contained in its regulatory accounts, and the recovery periods as set out in this report are not unreasonable and are a reflection of BC Hydro's goals and objectives of ensuring intergenerational equity and maintaining low rates for its customers.

Regulatory Accounts Report

Appendix A

Discussion of Issues Raised by Interveners/BCUC in RRA, the B.C. Government Review Panel and the Auditor General of B.C.

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1 Use of DARR Table Mechanism

Background

In the F09/F10 RRA Decision, the BCUC approved BC Hydro's proposal to implement the DARR Table Mechanism. At that time, it was expected that the net balance in the Deferral Accounts would not exceed the range of plus or minus $500 million, and that the net balance in the Deferral Accounts would be both positive and negative over a reasonable period of time. However, there has never been a net credit balance in the Deferral Accounts, and the net debit balance has grown to be well in excess of $500 million. The reasons for the growth in the net debit balance include:

1. Losses on energy hedges in F2009
2. Trade Income that was lower in F2010 than the forecast established by the BCUC in the F09/F10 RRA Decision, and that was lower in F2011 than the forecast established in the F11 RRA NSA
3. The debiting to the Trade Income Deferral Account in F2014 of the California Settlement amount of $214 million
4. Transfers to the Non-Heritage Deferral Account in F2011 through F2014 of forecast increases in the cost of energy
5. Constraining the DARR below the level of the DARR that would result from application of the DARR Table Mechanism in F2011 and F2012

BCUC and Intervener Concerns with Current DARR Table Mechanism

Through information requests and intervener evidence, the BCUC and interveners have raised various concerns with the current DARR Table Mechanism, including:

1. The view that since variations from normal water inflows will be symmetric over time the Deferral Accounts should be self-clearing, or at a minimum should be cleared over a long period of time. In provision 9(i) of the F11 RRA NSA, BC Hydro committed to analyze a DARR based on a five-year amortization of the Trade Income Deferral Account and a ten-year amortization of the Heritage and Non-Heritage Deferral Accounts (the “Alternate DARR Mechanism”). BC Hydro responded to this commitment in Amended Appendix H of the Amended F12-F14 RRA. The analysis demonstrated that even though variations in water inflows might be symmetric over time, the additions to Deferral Accounts are not symmetric over time. Furthermore, under the Alternate DARR Mechanism, the net balance in the Deferral Account reaches plus or minus $1 billion, and there is almost a 50 per cent probability that the total balance in the Deferral Accounts would not reach zero even once during the next 20 years. Conversely, the current DARR Table Mechanism would maintain the net balance in the Deferral Accounts in the range of plus or minus $500 million and there is almost a 100 per cent probability that the total balance in the Deferral Accounts would reach zero at least once within the next 20 years.
2. Given the current net balance in the Deferral Accounts, it was suggested that the DARR table be expanded beyond the current range of plus or minus $500 million. As discussed above, the net balance in the Deferral Accounts should return to the range anticipated in the design of the current DARR Table Mechanism.
3. It was noted that the DARR applies to a customer’s total bill (which includes distribution costs for customers served at distribution voltage) even though the Deferral Accounts relate only to generation costs. This has the effect of under-recovering costs from Transmission customers and over-recovering costs from smaller customers. Furthermore, the DARR applies to all components of a customer’s bill, potentially distorting marginal cost-based energy price signals.

While these concerns are valid, if the net balance in the Deferral Accounts returns to lower levels, and if the net balance is both positive and negative over a reasonable period of time, then these concerns would be mitigated to a large degree.

4. It was also suggested that a quarterly adjustment to the DARR might be appropriate, as is commonly done with cost of energy type riders in other jurisdictions. However, since water inflows and Powerex net income can vary widely from month to month, setting the DARR more frequently than annually could result in unstable customer bills.

5. Variations on the current DARR Table Mechanism, including the Revenue Stabilization Mechanism used by Pacific Northern Gas Ltd. and incorporating the deferral account recovery in base rates, were explored in information requests, but none offered any material improvement over the current DARR Table Mechanism

6. It was suggested that the interest on the net balance in the Deferral Accounts be expensed in the current period rather than deferred. However, the annual interest on the net balance in the Deferral Accounts is not material, and furthermore all differences between forecast and actual finance charges are subject to deferral through the Total Finance Charges Regulatory Account.

7. It has been pointed out that due to load growth and rate increases the average recovery period for the net balance in the Deferral Accounts will shorten over time. This is mathematically correct, and may need to be addressed in future. However, given the large debit balances that have been experienced, and recognizing that the net balance in the Deferral Accounts was expected to be both positive and negative over time, it is recommended that the current DARR Table Mechanism be retained until the balance clears at least once.

8. In its decision on the Amended F12-14 RRA, the BCUC directed BC Hydro to include in its next RRA, as per Order No. G-77-12A, section 4:

    a. an analysis of, and a proposal for, a formulaic method for clearing the net balance in the Deferral Accounts that considers the forecast changes to the balance and does not contain a maximum/minimum limit in a range which has already been surpassed;

    e. an analysis as to whether the Trade Income Deferral Account should be treated as one of the Deferral Accounts. BC Hydro must also show what the rate relief would be in the absence of the TIDA being treated as one of the Deferral Accounts.

The response to Directive 4 (a) is discussed in item 2, above. With respect to item 4 (e), BC Hydro notes that Direction No. 7, issued on March 6, 2014 continues to treat the Trade Income Deferral Account as one of the Deferral Accounts that is subject to the DARR Table Mechanism.

However, for illustrative purposes, BC Hydro has undertaken the analysis and the impact of the suggested treatment of the Trade Income Deferral Account is shown in Table A-1 Trade Income Deferral Account Analysis below which provides the rate impact analysis of removing the Trade Income Deferral Account from the DARR mechanism and amortizing the Trade Income Deferral Account balance to rates over five years. The analysis indicates that removing the TIDA from the DARR mechanism results in a rate increase of 0.9 per cent in F0215 and then rate decreases or no rate impacts for the remainder of the years to F2024.

Table A-1 Trade Income Deferral Account Analysis

Options	$ millions	Deferral / Regulatory Account Balance									
		F2015	F2016	F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2024
1. Remove TIDA from DARR; Amortize over 5 years (F15-F19)	Change in Account Balances:										
	Heritage Deferral Account	(1)	(0)	0	(0)	(0)	(1)	(0)	(0)	(0)	(0)
	Non-Heritage Deferral Account	(48)	(20)	3	(9)	(16)	(31)	(0)	(0)	(0)	(0)
	Trade Income Deferral Account	15	25	24	7	(14)	(9)	-	-	-	-
	Total	(35)	4	27	(2)	(31)	(40)	(0)	(0)	(0)	(0)
	Change in Rate Increase:										
	Annual	0.9%	-0.1%	-0.1%	-0.1%	0.0%	-0.5%	0.0%	0.0%	0.0%	0.0%
	Cumulative	0.9%	0.9%	0.8%	0.7%	0.7%	0.1%	0.0%	0.0%	0.0%	0.0%
	Rate Rider change	0.0%	-1.5%	-1.0%	0.0%	0.0%	0.1%	-0.6%	0.0%	0.0%	0.0%

With respect to item 4 (e), BC Hydro agrees with Direction No. 7 that the Trade Income Deferral Account should continue to be treated as one of the Deferral Accounts that are subject to recovery through the DARR Table Mechanism, for the following reasons:

- The balance in the Trade Income Deferral Account could be in a credit position while the overall balance in the Deferral Accounts is in a debit position. For example, as shown in Table 1 of Appendix H of the Amended F12-F14 RRA, in five of the seven years from F2005 to F2011 the Trade Income Deferral Account had a credit balance whereas there was an overall debit balance in the Deferral Accounts in every year. Had the Trade Income Deferral Account been treated separately, there would have been a refund of a portion of the Trade Income Deferral Account balance in those five years, thereby increasing the Deferral Account balances to be recovered through the DARR. Since balances in the individual Deferral Accounts may offset, it would be appropriate to continue to manage the overall balance in the Deferral Accounts on a net basis.
- Since there is overlap between the drivers of the balances in the Heritage Deferral Account, the Non-Heritage Deferral Account and the Trade Income Deferral Account, including uncertainty in both water inflows and the cost of

market energy, it would be appropriate to continue to manage the overall balance in the Deferral Accounts using a single recovery mechanism

- The Trade Income Deferral Account exists because of the volatility of Trade Income. If recovery and/or refund amounts for the Trade Income Deferral Account were fixed for a particular test period as part of an approved revenue requirement, there would be no opportunity to vary these amounts in response to changing circumstances (such as a change in the balance in the Trade Income Deferral Account from a debit to a credit, or vice versa). Fixing the recovery and/or refund amounts for the test period as part of the approved revenue requirement could therefore increase the actual balance in the Trade Income Deferral Account at the end of the test period.

2 Issues Raised by the Auditor General of B.C.

The Auditor General of B.C. raised a number of concerns regarding BC Hydro's use of regulatory accounts in the Report: ***BC Hydro: The Effects of Rate Regulated Accounting***, including the following issues:

- The growth in BC Hydro's regulatory accounts to date and the forecast continued growth in the future
- Lack of a plan to recover the net deferred costs in its regulatory accounts
- Preference that BC Hydro fully adopt IFRS reporting, and ending the use of rate-regulated accounting, to ensure financial transparency

As discussed in section 5, the growth in BC Hydro's regulatory accounts over the next ten years is primarily in benefit matching accounts, including DSM and Site C which will provide benefits to ratepayers in the future, and in regulatory accounts related to the transition to IFRS, including the IFRS PP&E and IFRS Pension accounts. The balance in all other regulatory accounts is forecast to decrease by almost $1.3 billion over the ten years to the end of F2024, primarily due to recoveries from the DARR mechanism (refer to Table 6).

BC Hydro believes that its recovery plan for the regulatory accounts will result in the recovery of existing regulatory account balances over a reasonable time frame. In addition, as discussed in section 2.2 of the report, BC Hydro will be limiting requests for new regulatory accounts that are material and unforecasted or uncontrollable and that should be collected from ratepayers, with material defined as have a net income impact greater than $10 million.

The Auditor General also raised several issues with respect to the operation of the regulatory accounts themselves, including:

- The use of regulatory accounts for expenditures that would otherwise be expensed impacts the presentation of BC Hydro's financial results, and could mislead users of the financial reports as to BC Hydro's performance.

  BC Hydro Response: BC Hydro publishes audited financial reports in compliance with prescribed accounting regulations (reflecting current CGAAP with modified IFRS standards), in addition to reporting using regulatory accounting, for regulatory proceedings. BC Hydro therefore does not agree that the comprehensive disclosures in its financial statements are misleading to users.

- The inclusion of notional interest on regulatory account balances in its financial statements, which would give rise to an increase in the regulatory account balances and a longer time frame for the recovery of the account balance. In addition, the Auditor stated that this notional interest has the effect of increasing net income, and also influences calculations on return on equity, and dividend payments to government.

BC Hydro Response: BC Hydro agrees that inclusion of interest on certain regulatory accounts will result in an increase in the balance to be recovered from ratepayers at a later date. However, as discussed in section 4 of the report, interest applied to regulatory accounts does not increase or decrease BC Hydro’s allowed net income, as the interest added to the regulatory account offsets the unbudgeted incremental interest costs.

- The Auditor General also raised questions about BC Hydro’s relatively long, or in some cases the undetermined, time period for recovery of several of the regulatory account balances, and whether this gives rise to intergenerational equity issues, whereby future ratepayers pay for the benefits received by earlier generations of ratepayers.

BC Hydro Response: BC Hydro shares concerns about anything that would give rise to intergenerational inequity. However, BC Hydro believes that generational equity can be enhanced through the appropriate use and recovery of regulatory accounts. The greatest forecast growth in the regulatory accounts and the largest regulatory account balances are for those accounts in which the matching of costs and benefits for different generations is the basis of the deferral and amortization of costs.

3 BC Government Review Recommendations

Recommendation No. 53 directed BC Hydro to:

> “Work with the province to perform a more in-depth review of the growth of regulatory accounts and determine a more sustainable approach to utilizing them over the long term.”

BC Hydro has worked with the Province in the development of this Regulatory Accounts Report, which the Province has accepted as responsive to the above recommendation.

Regulatory Accounts Report

Appendix B

Detailed Description of Existing Regulatory Accounts

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1 Introduction

This appendix provides a detailed description of BC Hydro's regulatory accounts.

Table B-1 below provides a summary of the actual balances in each of BC Hydro's regulatory accounts for the period F2007 to F2013.

Table B-2 summarizes the currently approved recovery mechanism and applicability of interest for each of BC Hydro's regulatory accounts, and provides the BCUC Orders establishing or amending each account.[1]

The remaining sections in this appendix describe each of BC Hydro's regulatory accounts that were active at the beginning of F2014, in the order presented in Table B-2.

[1] Three of the regulatory accounts on Table 1 which are closed and have had zero balances for the last three years are not included on Table 2: the BCTC Deferral Account, the Net Employment Costs Regulatory Account and the F07/F08 RRA Depreciation Study Regulatory Account.

Table B-1 Historical Regulatory Account Balances

Line	End of Year Balance ($ million)	F2007	F2008	F2009	F2010	F2011	F2012	F2013
	Cost of Energy Variance Accounts							
1	Heritage Deferral Account	178.1	78.0	328.9	324.9	247.7	243.8	69.9
2	Non-Heritage Deferral Account	208.8	51.6	74.4	119.5	362.1	367.0	467.5
3	Trade Income Deferral Account	(202.2)	(102.6)	(79.9)	121.7	187.5	174.7	190.2
4	BCTC Deferral Account (closed)	13.3	21.5	9.7	18.6	0.0	0.0	0.0
5	Total	198.1	48.5	333.2	584.7	797.3	785.6	727.6
	Other Cash Variance Accounts							
6	Storm Restoration Costs	32.9	43.2	(2.0)	(4.8)	(1.4)	0.6	(2.5)
7	GM Shrum 3 (closed)	0.0	0.0	42.4	41.5	43.2	0.0	0.0
8	Net Employment Costs (closed)	0.0	0.0	(29.1)	(61.6)	0.0	0.0	0.0
9	Total Taxes (closed)	0.0	0.0	(1.7)	(7.4)	(13.4)	(0.0)	(0.0)
10	Amortization of Capital Additions	0.0	0.0	(2.8)	(5.7)	(9.5)	(1.7)	(5.8)
11	Total Finance Charges	0.0	0.0	0.6	(104.1)	(4.0)	5.5	1.2
12	Rock Bay Remediation Costs	0.0	0.0	0.0	0.0	2.1	3.8	28.6
13	Arrow Water Divestiture Costs	0.0	0.0	0.0	0.0	7.7	8.1	8.5
14	Asbestos Remediation Costs	0.0	0.0	0.0	0.0	0.0	0.0	8.0
15	Home Purchase Option Plan	0.0	0.0	0.7	11.0	18.4	20.1	21.3
16	Total	32.9	43.2	8.2	(131.2)	43.1	36.4	59.2
	Non-Cash Variance Accounts							
17	Foreign Exchange Losses (Gains)	(15.8)	(66.0)	(57.0)	(100.8)	(106.7)	(103.1)	(100.1)
18	Non-Current Pension Costs	0.0	0.0	0.0	85.6	71.5	54.6	543.9
19	Total	(15.8)	(66.0)	(57.0)	(15.2)	(35.2)	(48.6)	443.8
	Benefit Matching Accounts							
20	Demand Side Management	282.1	309.3	362.4	442.9	506.4	638.0	732.4
21	First Nations Costs	36.3	40.9	62.4	91.2	98.6	152.6	167.9
22	Site C	3.7	8.7	34.7	59.4	103.3	181.1	258.4
23	Future Removal & Site Restoration	(210.9)	(192.2)	(172.2)	(159.4)	(140.3)	(120.4)	(87.4)
24	Pre-1996 Contributions	14.0	26.7	38.3	49.0	58.7	67.3	74.8
25	Procurement Enhancement (closed)	0.0	7.3	29.2	40.3	38.0	0.0	0.0
26	Capital Project Investigation (closed)	0.0	12.2	32.0	42.8	49.0	44.3	39.5
27	Smart Metering & Infrastructure	0.0	0.0	8.9	18.5	34.0	91.9	191.6
28	Total	125.2	212.9	395.6	584.7	747.8	1,054.9	1,377.2
	Non-Cash Provisions							
29	First Nations Provisions	89.9	319.4	326.2	308.1	300.2	390.7	385.8
30	Environmental Provisions	0.0	0.0	0.0	320.5	229.0	230.2	330.9
31	Arrow Water Systems Provision	0.0	0.0	0.0	0.0	3.3	3.6	3.4
32	Total	89.9	319.4	326.2	628.6	532.5	624.5	720.2
	Rate Smoothing Accounts							
33	F07/F08 RRA Depn Study (closed)	19.2	14.4	9.6	4.8	0.0	0.0	0.0
34	F2010 ROE Adjustment (closed)	0.0	0.0	0.0	56.4	45.1	33.8	22.6
35	Waneta Rate Smoothing (closed)	0.0	0.0	0.0	0.0	30.0	40.0	25.0
36	F12-F14 Rate Smoothing (closed)	0.0	0.0	0.0	0.0	0.0	(69.7)	(110.9)
37	Total	19.2	14.4	9.6	61.2	75.1	4.1	(63.3)
	IFRS Transition Accounts							
38	IFRS PP&E	0.0	0.0	0.0	0.0	0.0	221.8	446.7
39	IFRS Pension & OPEB	0.0	0.0	0.0	0.0	0.0	0.0	723.0
40	Total	0.0	0.0	0.0	0.0	0.0	221.8	1,169.7
41	**Total**	449.5	572.4	1,015.8	1,712.8	2,160.6	2,678.8	4,434.3

Table B-2 Recovery Mechanism, Applicability of Interest and BCUC Order Numbers

Regulatory Accounts	Recovery Mechanism	Interest	BCUC Order No.
Cost of Energy Variance Accounts			
Heritage Deferral Account	DARR	Yes	G-96-04, G-143-06
Non-Heritage Deferral Account	DARR	Yes	G-96-04, G-143-06
Trade Income Deferral Account	DARR	Yes	G-96-04, G-143-06
Other Cash Variance Accounts			
Storm Restoration	Next Test Period	Yes	G-16-09
Amortization of Capital Additions	Next Test Period	Yes	G-16-09, G-180-10, G-77-12A
Total Finance Charges	Next Test Period	No	G-16-09, G-180-10, G-77-12A
Rock Bay Remediation Costs	Next Test Period	Yes	G-75-11, G-55-12, G-57-13
Arrow Water Divestiture Costs	Next Test Period	Yes	G-90-11
Asbestos Remediation Costs	Next Test Period	Yes	G-7-13
Home Purchase Option Plan	Next Test Period	Yes	G-55-09, G-180-10, G-77-12A
Non-Cash Variance Accounts			
Foreign Exchange Losses (Gains)	Straight-line Pool Method	No	G-47-02
Non-Current Pension Cost	Average Remaining Service Life	No	G-16-09, G-180-10, G-77-12A
Benefit Matching Accounts			
Demand-Side Management	15 Years	No	G-55-95, G-91-09
First Nations Costs	10 Years	**Yes**	G-53-02, G-11-08
Site C	To Be Determined	Yes	G-143-06, G-16-09, G-180-10, G-77-12A
Future Removal & Site Restoration	As Dismantling Costs Are Incurred	No	G-96-04
Pre-1996 Contributions	45 Years (to F2040)	No	G143-06
Capital Project Investigation (closed)	10 Years (to F2021)	No	G-16-09, G-180-10, G-77-12A
Smart Metering & Infrastructure	15 Years (starting in F2016)	Yes	G-55-09, G67-10, G115-11, G-77-12A
Non-Cash Provisions			
First Nations Provisions	N/A	No	G-56-06, G-11-08
Environmental Provisions	N/A	No	G-88-10, G-7-13
Arrow Water Provision	N/A	No	G-90-11
Rate Smoothing Accounts			
F2010 ROE Adjustment (closed)	6 Years (to F2015)	No	G-16-09
Waneta (closed)	5 Years (to F2015)	No	G-180-10
F12-F14 Rate Smoothing (closed)	3 Years (to F2014)	No	G-77-12A
IFRS Transition Accounts			
IFRS PP&E	40 Years (to F2061)	No	G-77-12A
IFRS Pension	20 Years (to F2032)	No	G-77-12A

Note 1: Interest to be charged on the First Nations Costs Regulatory Account effective F2015.

2 Cost of Energy Variance Accounts

In 2004, subsequent to an inquiry into BC Hydro's heritage generation assets, Heritage Special Direction No. HC2 was issued by the Province. It required the BCUC to direct the establishment of the Heritage Deferral Account and the Trade Income Deferral Account. The former captures the variances between BC Hydro's actual and forecast cost of supply from heritage assets, and the latter captures variances between the actual and forecast net income of Powerex.

The BCUC directed the establishment of the Heritage Deferral Account and the Trade Income Deferral Account in its final order regarding BC Hydro's F05/F06 RRA. By the same order, the BCUC directed the establishment of the Non-Heritage Deferral Account to capture and defer variances between the forecast and actual energy costs that are not associated with the heritage assets.

The purpose of the cost of energy variance accounts (also referred to as the Deferral Accounts) is to defer the difference between forecast and actual costs of energy and trade income, for recovery in a future period. The cost of energy variance accounts are used to smooth BC Hydro's net income as energy costs are always higher or lower than forecast. This happens, for example, due to variations in reservoir water levels (as a result of more or less precipitation and snow melt in any given year), resulting in the requirement for BC Hydro to change its mix of energy resources to meet load demand. While rates are set assuming average water inflow levels, the lower-cost hydro generation levels can fluctuate by +/- 5,000 GWh between low and high water years, resulting in the need to sell surplus power or purchase energy from the market. As water inflow levels are uncontrollable, it is appropriate that the risk of this cost should be borne by BC Hydro's customers and recovered in rates.

BC Hydro recovers the balances in the cost of energy variance accounts using the Deferral Account Rate Rider (**DARR**) and section 3.1.1 of the Regulatory Accounts Report describes how the DARR is used to pay down those accounts.

Each of the Deferral Accounts is described in greater detail below.

2.1 Heritage Deferral Account

The Heritage Deferral Account (**HDA**) captures variances between the forecast and actual cost for the following components of the Heritage Payment Obligation:

(a) Cost of energy. This item is expanded in greater detail below to provide clarification on the methodology used to determine variances:

  (i) The total Heritage Energy volume (including Skagit/Seattle City Light commitments) is limited to 49,000 GWh per year. If the Heritage Energy volume including all market electricity purchases exceeds the Heritage Energy limit, the excess is transferred to Non-Heritage Energy in order to reduce the Heritage Energy volume to the Heritage Energy limit.

  (ii) Cost of energy variances resulting from changes to compensation and mitigation costs, water rental remissions, or Skagit energy transportation contracts are eligible for deferral. These are price variances as they do not vary with volume.

  (iii) All load curtailment costs are included as part of the Heritage Payment Obligation

  (iv) Gains/losses on energy derivatives and financial instruments used to minimize energy costs are included as part of total energy costs

(b) Variable costs related to thermal generation

(c) Significant unplanned major maintenance costs greater than $1 million related to single event equipment or infrastructure failure or caused by weather related events

(d) Significant unplanned major capital expenditures having an incremental annual impact on BC Hydro's income statement greater than $1 million related to single event equipment or infrastructure failure or caused by weather related events

(e) Amortization of unplanned deferred capital costs pursuant to BCUC Order No. G-53-02.

(f) All net revenues from surplus hydro electricity sales

(g) Skagit Valley Treaty revenues and ancillary services revenue

Notable changes in the balance in the HDA include the following:

- The balance increased from $78 million in F2008 to $329 million in F2009 due to purchases of high cost energy to offset lower than forecast hydro-generation due to low water inflows.
- The balance decreased from $244 million in F2012 to $70 million in F2013 primarily due to released water from BC Hydro's portion of the Non-Treaty Storage Agreement, higher surplus sales and rate rider recoveries.

2.2 Non-Heritage Deferral Account

The Non-Heritage Deferral Account (**NHDA**) captures variances between forecast and actual net energy costs in excess of the Heritage Energy limit of 49,000 GWh.

Specifically, the NHDA captures variances between the forecast and the actual cost for the following components of the Non-Heritage Cost of Energy:

(a) Cost of energy - all non-Heritage energy costs. This item is expanded in greater detail below to provide clarification on the methodology used to determine variances:

 (i) Any variances relating to fixed price gas transportation contracts flow through the NHDA as they do not vary with volume

(ii) Future Trade: when Powerex purchases energy for future trade the cost of the purchase from the external party and the sale to BC Hydro of this energy is recorded in Powerex and is included as part of Trade Income. The BC Hydro side of the entry is shown as part of domestic energy costs (on consolidation, the Powerex revenue from BC Hydro and the BC Hydro energy costs from Powerex are eliminated). The difference between forecast and actual on the BC Hydro side relating to energy for future trade flows through the NHDA. The Powerex side of the transaction, which is part of Trade Income, flows through the Trade Income Deferral Account. Similar treatment is made when the energy is returned to Powerex.

(iii) Future Trade: when Powerex purchases energy for future trade, the Heritage Payment Obligation (**HPO**) is charged with a notional water rental charge for the use of this energy. The other side of this entry is shown as part of Non-Heritage energy. These entries are eliminated on consolidation. The difference between the forecast and actual notional water rentals that is part of the HPO flows through the HDA. The opposite variance relating to the Non-Heritage side of the notional water rental transaction flows through the NHDA.

(iv) Gains/losses on energy derivatives and financial instruments used to minimize energy costs are included as part of total energy costs.

(b) Significant unplanned major maintenance costs greater than $1 million related to single event equipment or infrastructure failure.

(c) Significant unplanned major capital expenditures having an incremental annual impact on BC Hydro’s income statement greater than $1 million related to single event equipment or infrastructure failure or caused by weather related events

(d) Founding Partner Benefits and any CIS Credits under the ABS Contract

(e) Impact of load variance

In 2010, the Province issued the *Clean Energy Act* which consolidated BCTC and BC Hydro effective July 5, 2010. As part of the consolidation process, the BCUC issued Order No. G-16-11 dated February 10, 2011 which approved the transfer of BC Hydro's portion of the regulatory account balances on the books of BCTC and the remaining balance in BC Hydro's BCTC Deferral Account to the NHDA, and subsequent termination of the BCTC Deferral Account. At the time of the BC Hydro and BCTC integration, BCTC had the following 11 deferral accounts:

1. Revenue Deferral Account
2. Cost of Market Deferral Account
3. Emergency Maintenance Deferral Account
4. Regulatory Expenditure Deferral Account
5. International Financial Reporting Standards Deferral Account
6. Section 5 Transmission Inquiry Deferral Account
7. Polychlorinated Biphenyls Mitigation Deferral Account
8. Aboriginal Relations Deferral Account
9. F2011 BCTC Capital Portfolio Sustaining Cost Deferral Account
10. F2011 External Communications Regulatory Account
11. F2011 Labour Contracts Regulatory Account

BCUC Order No. G-16-11 also allowed for BC Hydro, on a go forward basis after the integration of BCTC and BC Hydro, to capture variances associated with the difference between forecast and actual transmission services revenues in the NHDA, as previously captured in the former BCTC Deferral Account. This order also allowed BC Hydro to capture transmission asset expenditures for significant unplanned major maintenance costs greater than $1 million related to a single event equipment or infrastructure failure in the NHDA.

Notable changes in the balance in the NHDA include the following:

- The balance decreased from $209 million in F2007 to $52 million in F2008 primarily due to lower market electricity purchases and higher transactions with Powerex
- The balance increased from $119 million in F2010 to $362 million in F2011 primarily due to an adjustment of $233 million in accordance with the terms of the F11 RRA NSA
- The balance increased from $367 million in F2012 to $468 million in F2013 primarily due to a $62 million IFRS conversion adjustment (approved by BCUC Order No. G-77-12A and confirmed by letter from the BCUC dated April 10, 2013) and the deferral of an increase in the cost of energy of $103 million as set out in the F12-F14 RRA Decision

2.3 Trade Income Deferral Account (TIDA)

This deferral account was created pursuant to Heritage Special Direction No. HC2 which directed the BCUC to approve, if requested by BC Hydro, a deferral account to record variances between actual and forecast Trade Income.

Trade Income is defined as the net income of Powerex, as included in BC Hydro's consolidated financial statements, adjusted for rate-setting purposes to be no less than zero.

Prior to May 22, 2012, Trade Income was defined as the net income of Powerex adjusted for rate-setting purposes to be no less than zero and no greater than $200 million.

On March 6, 2014, the Government issued Directive No. 7 which allows for the inclusion in the Trade Income Deferral account of any F2014 trading net loss from Powerex.

3 Other Cash Variance Accounts

3.1 Storm Restoration Costs

In the F09/F10 RRA Decision, the BCUC approved the ongoing deferral of the difference between actual storm-related restoration costs and the forecast storm-related costs included in each revenue requirements application. The forecast storm-related costs included in a revenue requirements application are average of the actual storm-related restoration costs for the five most recent “normal weather” years available at the time of that application.

Notable changes in the balance in this regulatory account include the following:

- The balance increased from zero in F2006 to $33 million in F2007 due to restoration costs incurred as a result of major winter storms during the October 2006 to January 2007 period
- The balance increased from $33 in F2007 to $43 million in F2008 due to approved incremental operating expenditures to improve BC Hydro’s response to future storms
- The balance decreased from a $43 million debit in F2008 to a $2 million credit in F2009 due to the transfer of the F2008 closing balance to the NHDA

3.2 Amortization of Capital Additions

Due to uncertainty in the forecast timing of capital additions, in the F09/F10 RRA Decision the BCUC directed BC Hydro to defer in a regulatory account any differences between forecast and actual amortization of capital additions. The F11 RRA NSA and the F12-F14 RRA Decision extended this regulatory account to the end of F2014.Government Directive No. 6 extends this regulatory account to F2015 and future years. At the end of F2014, the account is forecasted to have a credit balance of $18 million.

3.3 Total Finance Charges

As a result of economic uncertainty and the potential volatility of interest rates, in the F09/F10 RRA Decision the BCUC directed BC Hydro to establish a regulatory account to defer any differences between forecast and actual finance charges for F2009 and F2010. The F11 RRA NSA and the F12-F14 RRA Decision extended this regulatory account to the end of F2014. Government Directive No. 6 extends this regulatory account to F2015 and future years.

Notable changes in the balance in this regulatory account include the following:

- The balance changed from a debit of $1 million at the end of F2009 to a credit of $104 million at the end of F2010. Due to global economic weakness, the Bank of Canada cut interest rates to unprecedented levels in 2009. As a result, BC Hydro’s actual weighted average cost of debt in F2009 was 4.47 per cent compared to BC Hydro forecast of 6.04 per cent.
- The balance in the account changed from a credit of $104 million at the end of F2010 to a credit of $4 million at the end of F2011 primarily because the credit balance in the account at the end F2010 was refunded to customers in F2011
- BC Hydro is forecasting a credit at the end of F2014 of $51 million.

3.4 Rock Bay Remediation Costs

In F2011 and following years, BC Hydro will incur expenditures to remediate properties at the Rock Bay area on Vancouver Island. Remediation costs are difficult to forecast and vary considerably from year to year. Since F2011 remediation costs were not included in the F11 RRA NSA, BC Hydro applied to the BCUC for approval of a regulatory account to defer for future recovery the actual costs incurred in F2011 in relation to remediation activities at Rock Bay.

By Order No. G-75-11, the BCUC approved the establishment of the Rock Bay Remediation Regulatory Account to defer F2011 actual remediation expenditures. By Order Nos. G-55-12 and G-57-13, the regulatory account was extended to defer actual remediation costs incurred in F2012 and F2013 respectively.

The balance in the Rock Bay Remediation Regulatory Account increased from $4 million in F2012 to $29 million in F2013 primarily due to the settlement of legal action with Transport Canada and the balance at the end of F2014 is forecast to be $52 million as significant remediation expenses have been incurred in F2014. Government Directive No. 6 requires that BC Hydro fully amortize the account balances over F2015 and F2016.

3.5 Arrow Water Systems Divestiture Costs

In the mid-1960s, BC Hydro relocated residents affected by the creation of the Hugh L. Keenleyside Dam and Arrow Lakes Reservoir to the newly constructed towns of Edgewood, Fauquier and Burton, and also to West Robson, all now part of the Regional District of Central Kootenay. BC Hydro built the drinking water systems in Burton, Fauquier and Edgewood when the towns were constructed, and upgraded and assumed control of the West Robson drinking water system to compensate for impacts related to construction of the Keenleyside Dam.

On January 4, 2011, BC Hydro divested the assets of the Arrow water systems to the Regional District of Central Kootenay at a nominal price. Costs related to the divestiture, including the write-down of assets, were not included in the F11 RRA NSA. Therefore, BC Hydro applied to the BCUC for approval to establish a regulatory account to defer for later recovery the costs associated with the divestiture of the Arrow water systems.

By Order No. G-90-11, the BCUC approved the establishment of the Arrow Water Systems Divestiture Costs Regulatory Account and the Arrow Water Systems Provision Regulatory Account. The Arrow Water Systems Divestiture Costs Regulatory Account has a forecasted balance of $9 million at the end of F2014 will be fully amortized at the end of F2016.

3.6 Asbestos Remediation Costs

In F2013 and following years, BC Hydro will incur expenditures related to asbestos remediation at its facilities.

BC Hydro applied to the BCUC for approval of a regulatory account to defer the actual costs incurred for asbestos remediation that were not included in the Amended F12-F14 RRA.

In Order No. G-7-13, the BCUC approved the establishment of the Asbestos Remediation Regulatory Account for unplanned costs in F2013 and F2014 related to asbestos remediation of BC Hydro’s facilities. The account is forecasted to have a balance of $9 million at the end of F2014. Government Directive No. 6 continues this account for F2015 and future years, as BC Hydro expects to be incurring asbestos remediation expenditures for the foreseeable future.

3.7 Home Purchase Option Program

BC Hydro, through BCTC, undertook to upgrade the existing transmission lines that run through Ladner, Tsawwassen and Galiano, Parker and Salt Spring Islands, and which serve Vancouver Island.

By letter dated December 17, 2008 the Minister of Energy, Mines and Petroleum Resources directed BC Hydro to carry out a Home Purchase Option Program (**HPOP**) in relation to affected owners of residential properties in the Tsawwassen area.

By OIC No. 205 dated March 12, 2009, the Lieutenant Governor in Council made Direction No. 1 to the BCUC to allow BC Hydro to establish a regulatory account for the purpose of recovering from its ratepayers, in a subsequent period, the net HPOP costs incurred by BC Hydro.

In Order No. G-55-09 the BCUC approved the establishment of a regulatory account to defer the net costs of the HPOP in F2009 and F2010, plus interest. The F11 RRA NSA and the F12-F14 RRA Decision extended this regulatory account to the end of F2014 at which time it is forecasted to have a balance of $22 million. This account will be fully amortized by F2016.

4 Non-Cash Variance Accounts

4.1 Foreign Exchange Gains and Losses

Foreign Exchange gains and losses are subject to external market forces over which BC Hydro has no control.

In Order No. G-47-02 the BCUC approved the deferral and amortization of foreign exchange gains and losses on the translation of foreign denominated long-term monetary items, using the straight-line pool method, for the fiscal year beginning April 1, 2002 and future periods.

The balance in this regulatory account changed from a debit of $2 million in F2006 to a credit of $107 million in F2011 primarily due to significant foreign exchange translation gains on un-hedged US debt as a result of the strengthening of the Canadian dollar relative to the US dollar. During this period, the Canadian dollar gained nearly 16 per cent in value relative to the US dollar. BC Hydro is forecasting a credit balance of $96 million at the end of F2014.

4.2 Non-Current Pension Costs

Prior to International Financial Reporting Standards (**IFRS**) being adopted, experience gains and losses related to both pension and other post- employment benefits plans were not recognized immediately on BC Hydro's balance sheet. Rather, they were amortized over the expected average remaining service life of the employee group as part of non-current pension costs. Experience gains and losses include the difference between the estimated return on the plan assets and the actual amounts earned, the impact of the change in the market discount rate on the benefit obligations, and other impacts on the future benefits to be paid.

In the F09/F10 RRA Decision, the BCUC approved the establishment of a regulatory account to defer the difference between forecast and actual non-current pension costs in F2010 due to the economic crisis that occurred in 2008 and the resulting large negative impact on these costs. The F11 RRA NSA provided that this regulatory account be extended for F2011 and that the closing F2011 balance in the regulatory account be amortized over a five-year period beginning in F2012.

In the F12-F14 RRA Decision, the Non-Current Pension Costs Regulatory Account was continued for the F2012 to F2014 period because of the continuing uncertainty and potential volatility of the capital markets. In addition, the Non-Current Pension Costs Regulatory Account was expanded to include:

1. the difference between forecast and actual non-current other post-employment benefit costs, beginning in F2013
2. the actual amount of experience gains or losses related to BC Hydro's pension and other post-employment benefit plans, beginning in F2012

The balance in this regulatory account changed from a debit of $55 million in F2012 to a debit of $544 million in F2013 primarily due to (i) a $322 million experience loss in F2012 and (ii) an addition of $184 million for F2013 due to an experience loss in

F2013 and the difference between forecast and actual F2013 non-current pension costs related to other post-employment benefits. At the end of F2014, this account is forecast to have a balance of $219 million.

5 Benefit Matching Accounts

5.1 Demand Side Management

Under previous CGAAP and IFRS, demand side management (**DSM**) expenditures do not qualify for capitalization.

In 1995, the BCUC directed all regulated gas, electric and steam heat utilities in British Columbia to defer and amortize into rates, costs associated with DSM activities that achieve energy savings. The DSM activities and associated costs generate energy savings to customers over a period of time longer than the year of expenditure, so the deferral and amortization of these costs aligns the recognition of costs with the period that customers receive benefits.

The costs in the DSM Regulatory Account reflect expenditures made on DSM activities, and include the direct and indirect expenditures related to achieving energy savings. Prior to F2013, these costs were amortized over a ten-year period, in accordance with BCUC Order Nos. G-55-95 and G-91-09. In the F12-F14 RRA Decision, the amortization period for historical and future DSM costs was increased from 10 years to 15 years. At the end of F2014, this account is forecast to have a balance of $821 million.

5.2 First Nations Negotiation and Settlement Costs

In Order No. G-53-02, the BCUC approved the capitalization of actual negotiation and settlement costs related to First Nations settlements and the amortization of actual negotiation costs and approved settlement costs over a ten-year period. In accordance with BCUC Order No. G-11-08, BC Hydro must submit an application to the BCUC for a determination that settlement costs may be recovered in rates. Beginning in F2015, the F2014 balance in the First Nations Negotiation and Settlement Costs regulatory account will be amortized over 10 years and also beginning in F2015, annual negotiation and settlement payments will be expensed in the year incurred. At the end of F2014 the balance in this account is forecast to have a balance of $175 million.

5.3 Site C

In Order No. G-143-06, the BCUC approved the creation of a regulatory account in respect of Site C expenditures incurred in F2007 and F2008. The F09/F10 RRA Decision, the F11 RRA NSA and the F12-F14 RRA Decision extended the Site C Regulatory Account to the end of F2014 and Government Directive No. 6 further extended the account to the end of F2016.

This regulatory account captures the pre-capitalization Site C project expenditures. These costs are not eligible for capitalization under previous CGAAP nor IFRS as the Site C project has not completed the feasibility assessment phase and BC Hydro has not made the decision to proceed with the project. BC Hydro will apply to the BCUC to recover the costs through rates at a future time and over an appropriate time frame, when the asset is completed and benefits to the ratepayers from the investment are being realized. At the end of F2014 the account is forecasted to have a balance of $362 million.

5.4 Future Removal and Site Restoration

Prior to 1995, future dismantling costs were accrued in amortization expense and recovered in rates. In F2005, the accounting rules changed with the introduction of asset retirement obligations, and future dismantling costs are no longer accrued in amortization expense.

In the F05/F06 RRA Decision, the BCUC directed BC Hydro to establish a Future Removal and Site Restoration (**FRSR**) regulatory liability equal to the future dismantling costs that had been previously recovered in rates, and to charge future dismantling costs for assets for which an asset retirement obligation has not been recorded against this regulatory account.

This regulatory account is drawn down as actual expenditures on dismantling costs are incurred. This account is forecast to have a credit balance at the end of F2014 in the amount of $66 million.

5.5 Pre-1996 Contributions in Aid of Construction

In F2006 BC Hydro engaged Gannett Fleming to complete a depreciation study, which was filed as part of the F07/08 RRA. Gannett Fleming recommended that the amortization period for assets referred to as “Profile ID 99403 Distribution Pre-1996 Contributions in Aid” be increased from the then-approved period of 25 years to 45 years. Section 7(iv) of the F07/F08 RRA NSA provided that the amortization period for these assets would be retained at 25 years. In its financial records BC Hydro changed the amortization period for these assets from 25 to 45 years, and implemented the F07/F08 NSA commitment by creating a regulatory account to capture the difference in the revenue requirement impacts of a 45-year amortization period and a 25-year amortization period.

This regulatory account has a 45-year life and will be fully amortized at the end of F2040. This account is forecast to have a balance at the end of F2014 of $81 million.

5.6 Capital Project Investigation (CPI) Costs (Closed)

Under previous CGAAP and IFRS, capital project investigation costs are to be treated as operating costs. In the F09/10 RRA, BC Hydro proposed the establishment of a regulatory account to defer capital project investigation costs and recover these costs over the useful life of the related assets. In the F09/F10 RRA

Decision, the BCUC approved the establishment of a regulatory account for CPI costs for F2009 and F2010. The F11 RRA NSA provided that additions to the CPI Regulatory Account would be discontinued at the end of F2011, and that the closing F2011 balance would be amortized beginning in F2012.

In the F12-F14 RRA, BC Hydro proposed that the balance in the CPI Regulatory Account be amortized over a ten-year period beginning in F2012. The F12-F14 RRA Decision approved the amortization of the F2011 closing balance in this regulatory account over 10 years commencing in F2012.

This regulatory account is closed and will be fully amortized by the end of F2023. At the end of F2014 the balance is forecast to be $35 million.

5.7 Smart Metering and Infrastructure Program

The Smart Metering and Infrastructure Regulatory Account is used to capture costs associated with the SMI Program.

In BCUC Order Nos. G-55-09 and G-67-10, the BCUC approved the establishment of a regulatory account to defer the operating costs incurred by BC Hydro with respect to the SMI Program in F2009 and F2010 respectively. By Order No. G-115-11, the BCUC authorized BC Hydro to include its actual F2011 SMI Program operating costs up to $5.8 million in the SMI Regulatory Account. BC Hydro's actual F2011 SMI Program operating costs were $5.1 million.

In accordance with CGAAP, BC Hydro began amortizing existing revenue meter assets at an accelerated rate once the SMI Program received BC Hydro Board approval on September 16, 2010. In Order No. G-115-11, the BCUC authorized BC Hydro to accelerate the rate of depreciation on its existing meters and to include the increased amortization incurred in F2011 in the SMI Regulatory Account.

In the F12-F14 RRA Decision, BC Hydro was authorized to defer all net SMI costs over the F2012 to F2014 period to allow for a better matching of the timing of the costs and benefits of the SMI Program. Specifically, BC Hydro was authorized to defer actual net operating costs, amortization of capital assets, finance charges and return on equity related to the SMI Program from F2012 to F2014. Government Directive No. 6 extends the deferral of these costs, including the costs of the meter choices program, to the end of F2016. BC Hydro will seek approval to recover these costs in F2017.

6 Non-Cash Provisions

6.1 First Nations Provisions

BC Hydro is required under CGAAP to record a loss provision to recognize any claims related to past grievances made against it by First Nations when certain conditions are met in respect of anticipated settlements.

In Order No. G-56-06, the BCUC approved the establishment of a regulatory account in the amount of a loss provision BC Hydro recorded as required under CGAAP in respect of two First Nations claims. In Order No. G-11-08, the BCUC amended the First Nations Provision regulatory asset to allow the balance of the regulatory account to reflect loss provisions as required under CGAAP related to any First Nations claim, and to allow the periodic adjustment of the balance of the regulatory account to reflect adjustments to the loss provisions required under CGAAP.

The recording of the loss provision liability and the corresponding First Nations Provision regulatory asset preserves BC Hydro’s ability to seek recovery of actual settlement costs in rates in a future period.

BC Hydro reached settlements with the Kwadacha and Tsay Keh Dene First Nations which both included a lump sum payment in F2010 and ongoing annual payments starting in F2010. BC Hydro also reached a settlement with the St’at’imc First Nation which included a lump sum payment in F2012 and ongoing annual payments.

Settlement payments are transferred to the First Nations Negotiation and Settlement Costs Regulatory Account.

A loss provision liability can change due to the underlying circumstances of the loss exposure. BC Hydro from time to time re-evaluates the loss provision liability to determine whether the amount continues to be reasonable or whether further adjustment is required.

A loss provision liability can also change due to accretion expense. Under IFRS, loss provisions are measured on a present value basis and accretion expense reflects the adjustments required with the passage of time so that the balance of the loss provision liability will be equal to the amount needed to settle the liability provision. The forecast balance in this account at the end of F2014 is $416 million.

6.2 Environmental Provisions

BC Hydro is required under CGAAP to record a loss provision to recognize environmental liabilities related to new PCB Regulations and the remediation of environmental contamination at Rock Bay.

The new PCB regulations require the removal of equipment contaminated with PCB contamination concentrations of at least 50 mg/kg but less than 500 mg/kg. If the PCB concentration is 50 mg/kg or less, the regulation requires appropriate disposal when the asset is removed from service.

The Environmental Provisions Regulatory Account preserves BC Hydro’s ability to seek recovery of actual environmental costs in rates in a future period.

By Order No. G-88-10 the BCUC approved the establishment of the Environmental Provisions Regulatory Account in the amount of the loss provision liability recognized by BC Hydro in respect of compliance with the PCB Regulations and the remediation of environmental contamination at Rock Bay, and to periodically adjust the amounts in the regulatory account to match the changes required under CGAAP in the loss provision liability.

In Order No. G-7-13, the BCUC approved BC Hydro's application to include in the Environmental Provision Regulatory Account provisions required under CGAPP related to the remediation of asbestos at its facilities. The need for the provision of asbestos remediation is a result of the requirement that BC Hydro immediately identify and remediate asbestos in compliance with recent WorkSafe BC orders concerning the management of asbestos at its facilities.

Actual costs associated with compliance with PCB Regulations are expensed as incurred. Actual costs associated with remediation activities at Rock Bay are deferred and included in the Rock Bay Environmental Costs Regulatory Account. Actual costs associated with asbestos remediation activities at BC Hydro facilities are deferred and included in the Asbestos Remediation Regulatory Account.

Notable changes in the balance in the Environmental Provisions Regulatory Account include:

- The decrease in the balance from $321 million in F2010 to $229 million in F2011 was primarily due to a reduction in the environmental provision for PCB remediation based on a review of BC Hydro's PCB remediation requirements
- The increase in the balance from $230 million in F2012 to $331 million in F2013 was primarily due to a new asbestos provision of $43 million and $61 million related to re-measurement of the discount rate used for the PCB provision

The forecasted balance in this account at the end of F2014 is $295 million.

6.3 Arrow Water Systems Provision

As described in section 3.7, by Order No. G-90-11 the BCUC approved the establishment of the Arrow Water Systems Divestiture Costs Regulatory Account and the Arrow Water Systems Provision Regulatory Account.

BC Hydro is required under IFRS to record a loss provision liability in regards to the divestiture of the Arrow Water System. The recording of the loss provision liability and the corresponding Arrow Water Systems Provision regulatory asset preserves BC Hydro's ability to seek recovery of actual costs in rates in a future period.

In F2011, the actual provision included in the Arrow Water Systems Provision Regulatory Account was $3.3 million representing the present value of water rates and parcel tax levies that BC Hydro has agreed to pay until eligible Arrow Water Systems customer property is transferred or there is a change in use. An additional $0.5 million was added to the regulatory account in F2012 for contingency payments. As payments are made, this account is drawn down and amounts are recovered in rates, subject to approval by the BCUC. This account is forecasted to have a balance at the end of F2014 of $3 million.

7 Rate Smoothing Accounts

7.1 F2010 ROE Adjustment (Closed)

On February 17, 2009, the B.C. Government issued OIC No. 074 amending sections 4 and 7 of HC2, effective February 17, 2009. The effect of OIC No. 074 was twofold:

- First it required the BCUC to increase BC Hydro's revenue requirements for F2010, F2011 and F2012 in order to afford BC Hydro the opportunity to earn its previously determined pre-income tax annual return on equity plus an additional 1.63 per cent (the ROE adder)

- Secondly, the BCUC was required to allow BC Hydro to establish a regulatory account to defer for recovery in a later fiscal year or years the difference between the F2010 revenue required pre-February 17, 2009 and the F2010 revenue required after the issuance of OIC No. 074

In the F09/F10 RRA Decision the BCUC approved the establishment of the F2010 ROE Adjustment Regulatory Account to defer the impact on BC Hydro's F2010 revenue requirement of the incremental rate of return on deemed equity as prescribed by HSD#2 as amended by OIC No. 074.

The F11 RRA NSA provided that the closing F2010 balance in this regulatory account be amortized over five years beginning in F2011. The regulatory account will be fully amortized by the end of F2015.

7.2 Waneta Rate Impact Smoothing (Closed)

The F11 RRA NSA provided that the initial rate impact of the large one-time $850 million capital addition related to the Waneta Transaction would be smoothed as set out in the following table:

Table B-3 Waneta Rate Impact Smoothing

($ million)	Deferral/ (Recovery)
F2011	30.0
F2012	10.0
F2013	(15.0)
F2014	(10.0)
F2015	(15.0)
Total	0.0

This regulatory account is closed and will be fully amortized by the end of F2015.

8 IFRS Transition Accounts

8.1 IFRS Property, Plant and Equipment

The IFRS Property, Plant and Equipment (**IFRS PP&E**) Regulatory Account enables the deferral of overhead costs that can no longer be capitalized under IFRS as they are not directly attributable to the construction of an asset.

Prior to IFRS, costs related to indirect overheads such as IT system maintenance and operating costs, HR support costs, finance support costs, building operations costs, training costs and system planning costs could be capitalized as property, plant and equipment. Under IFRS, these costs can no longer be capitalized.

In the Amended F12-F14 RRA, BC Hydro proposed that overhead costs that can no longer be capitalized not be immediately absorbed in rates as it would result in a significant rate impact, but rather be deferred and transitioned into operating expenditures over ten years. In order to transition the overhead costs that can no longer be capitalized under IFRS into rates over a ten-year period, BC Hydro proposed to charge 100 per cent of ineligible overhead costs to the IFRS PP&E Regulatory Account in F2012, and starting in F2013 reduce the percentage of ineligible overhead costs that would be charged to the regulatory account by 10 per cent each year.

BC Hydro also proposed to amortize the additions to the regulatory account over 40 years based on the composite life of BC Hydro's assets, in order to match the overhead costs with the benefits of the underlying assets.

In the Amended F12-F14 RRA, BC Hydro proposed an addition to the IFRS PP&E Regulatory Account for F2012 of $178 million, plus $8 million for related IDC.

In the F12-F14 RRA Decision, the IFRS PP&E Regulatory Account was approved as proposed by BC Hydro.

Subsequent to the F12-F14 RRA Decision, BC Hydro completed a capital cost allocation study which identified a further $37 million of ineligible capital overheads in F2012, above the amount of $178 million included in the Amended F12-F14 RRA. For F2012, BC Hydro recorded $222 million in the IFRS PP&E Regulatory Account, consisting of the $178 million included in the Amended F12-F14 RRA, the additional $37 million identified in the capital cost allocation study, and $7 million of related IDC. By letter dated April 10, 2013, the BCUC approved this $222 million addition to the IFRS PP&E Regulatory Account for F2012.

On May 3, 2013, BC Hydro wrote to the BCUC seeking approval to include in the IFRS PP&E Regulatory Account the reduction to retained earnings on transition to IFRS related to the accounting for mass asset retirements and asset componentization, in the amounts of $26 million and $7 million respectively. The increase in the balance of the IFRS PP&E Regulatory Account from $222 million in F2012 to $447 million in F2013 is comprised of these amounts of $26 million and $7 million, plus F2013 ineligible overheads of $197 million, less amortization of $5 million.

The IFRS PP&E Regulatory Account will be fully amortized by F2061.

8.2 IFRS Pension and Other Post-Employment Benefits

Prior to the adoption of IFRS, experience gains and losses on the pension and other post-employment benefit plans were amortized over the average remaining service life of the employee group, but were not recognized on BC Hydro's balance sheet.

On transition to IFRS, BC Hydro was required to recognize on its balance sheet all unamortized experience gains and losses on the pension and other post-employment benefit plans not previously recognized in its financial statements. To maintain BC Hydro's ability to recover this amount from customers, BC Hydro proposed the establishment of the IFRS Pension Regulatory Account with an opening liability balance in F2013 equal to the actual unamortized experience gains and losses on the pension and other post-employment benefit plans that BC Hydro had to recognize in its financial statements at the time of conversion to IFRS.

BC Hydro also proposed to amortize the balance in the IFRS Pension Regulatory Account over a period of twenty years, which results in approximately the same revenue requirement impact as would have resulted under previous CGAAP.

The amount of the unamortized experience gains and losses recognized on transition to IFRS was $762 million.

The establishment of the IFRS Pension Regulatory Account was approved in the F12-F14 RRA Decision. The balance in the IFRS Pension Regulatory Account will be fully amortized by F2032.

F2015 to F2016 Revenue Requirements Rate Application

Appendix I

Rock Bay Remediation Project Status Update

ROCK BAY REMEDIATION PROJECT STATUS UPDATE

BC Hydro has used a phased approach at Rock Bay in assessing the contamination and delivering cost-effective remediation, a common industry practice for complex contaminated sites. Phase 1 remediation was completed in December, 2013 and post-remedial sampling related to Phase 1 will end in September, 2015. Phase 2 remediation work is underway and expected to be completed by December, 2014 and post remedial sampling related to Phase 2 will end in June, 2016.

At this time BC Hydro has completed or is undertaking the following work:

- completed removal of the high risk contamination on BC Hydro's Stage 1 lands and adjacent City of Victoria roadways and demobilized from the work site
- continued with post remediation sampling of Stage 1 lands
- continued with the water and vapour monitoring program to verify post remediation site conditions and assess seasonality
- awarded contracts for the second phase of soil remediation construction work
- commenced demolition of the SuperSave building
- continued with investigation of the coal tar contaminated bay bottom sediment outside of the current foreshore, for example across Government Street.

Transport Canada continues with their plans to start remediation of their property in 2014, including the bay itself, and BC Hydro is on schedule to remediate all high-risk contamination ahead of Transport Canada in order to ensure that groundwater migration from BC Hydro and off-site properties does not re-contaminate Transport Canada-owned property.