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**Revenue Requirement Application**  
**2004/05 and 2005/06**

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**Volume 1**

**Chapter 2A**

**Revised Evidentiary Update**

**Consolidated Revenue Requirements  
and Financial Schedules**

**Revision 1, April 2, 2004**

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1 **1 Introduction**

2 BC Hydro's Revised Evidentiary Update reflects changes in a number of key assumptions  
3 since BC Hydro's Revenue Requirements application was filed on December 15, 2003 (the  
4 Application). The major changes include lower forecast water inflows in F2005, and revised  
5 interest and foreign exchange rate assumptions provided by the Provincial Government in  
6 respect of F2005 and F2006. Based on the January 1, 2004 snowpack levels, water inflows  
7 are expected to be 94 per cent of normal in F2005, whereas the Application was based on  
8 an assumption of normal water inflows. Forecast energy costs have increased as a result of  
9 the impact of the lower expected inflows. Interest rates are forecast lower and Canadian/US  
10 dollar foreign exchange rates are forecast to be higher than those used in the Application.  
11 These changes in the forecast interest and foreign exchange rates result in a lower finance  
12 expenses forecast. These changes are explained in more detail below.

13 It was assumed in the Evidentiary Update, filed on February 20, 2004, that these forecast  
14 changes would be flowed through the deferral accounts that had been proposed in the  
15 Application and that no changes in the proposed rate increases would be required. This  
16 assumption was made because at the time of filing the Evidentiary Update, BC Hydro had  
17 not concluded its consideration of what deferral account mechanisms would be appropriate  
18 in determining BC Hydro's rates. BC Hydro concluded its consideration of the design of the  
19 deferral accounts and filed its proposal as Chapter 2B. BC Hydro proposes that the lower  
20 water inflow levels based on the January 1, 2004 snowpack levels, and the revised interest  
21 rate and Canadian/US dollar foreign exchange rate forecasts, be used as the basis for  
22 determining rates. As a result, this Revised Evidentiary Update does not show any transfers  
23 into the deferral accounts.

24 The net impact of the lower snow pack and lower forecast interest finance expenses is to  
25 increase the revenue requirement for F2005. Accordingly, BC Hydro is amending its  
26 Application for F2005 to seek an additional 1.67% increase (over and above the 7.23%  
27 already approved on an interim basis, for a total of 8.9%) effective 30 days after the  
28 Commission's decision on the Application is issued. For purposes of this forecast, it is  
29 assumed that the additional 1.67% rate increase will take effect on November 1, 2004.  
30 Based on the foregoing, and this Revised Evidentiary Update, the additional 2% increase  
31 applied for to be effective April 1, 2005 is withdrawn. With this revised rate increase  
32 proposal and this current forecast, BC Hydro will fall short of earning its allowed return on

1 equity by \$21 million for F2005. The shortfall in F2005 is caused by BC Hydro not  
2 requesting the required rate increase of 8.9% retroactive to April 1, 2004. BC Hydro  
3 recognizes the significance of changes in its rates to its customers and does not wish to  
4 change those rates approved on an interim basis.

5 All relevant schedules, which have changed from the Application, are included in this  
6 Revised Evidentiary Update.

1 **2 Pro Forma Consolidated Statements**

2 Table 2A-1 (Revised) is a summarized pro forma statement of operations of BC Hydro  
 3 showing a rate increase of 8.9% in F2005 (i.e., 7.23% already approved on an interim basis  
 4 plus an additional 1.67% increase assumed for the purposes of this forecast to be effective  
 5 November 1, 2004). The full income statement is shown in Schedule A-1-A (Revised).

6 **Table 2A-1. Pro forma Statement of Operations (Revised)**

(\$ millions)	F2003 Actual	F2004 Forecast	F2005 Plan	F2006 Plan
<b>Equity</b>	<b>\$2,700</b>	<b>\$2,730</b>	<b>\$3,064</b>	<b>\$3,168</b>
Domestic				
Revenues	2,475	2,552	2,720	2,756
Inter-segment revenues	6	81	125	116
Expenses	(2,267)	(2,551)	(2,528)	(2,528)
	<b>\$214</b>	<b>\$82</b>	<b>\$317</b>	<b>\$344</b>
Trade Income	\$138	\$108	\$89	\$91
<b>Net Income before transfers to RSA/</b>	<b>\$352</b>	<b>\$190</b>	<b>\$406</b>	<b>\$435</b>
Transfer from RSA (Note 1)	66	21	-	-
<b>Net Income</b>	<b>\$418</b>	<b>\$211</b>	<b>\$406</b>	<b>\$435</b>
Allowed rate of return on equity	15.47%	14.33%	13.91%	13.91%
Allowed Net Income	\$418	\$396	\$427	\$442
Requested rate increase (%)	N/A	N/A	8.90%	N/A

7 Notes:

8 It is anticipated that the RSA balance will be nil at the end of F2004.

9

10 Based on this revised rate increase proposal, BC Hydro will fall short of meeting its allowed  
 11 return on equity by \$21 million in F2005.

## 3 Discussion of Financial Forecasts

### 3.1 BC Hydro Equity

The current forecast equity and the components that make up equity for F2004 to F2006 are shown in Table 2A-2 (Revised).

**Table 2A-2. Equity (Revised)**

(\$ millions)	F2004 Forecast	F2005 Plan	F2006 Plan
Retained earnings at beginning of year	\$1,609	\$1,653	\$1,963
Net income	211	406	435
Payment to the province	(167)	(329)	(340)
Asset retirement obligation adjustment	-	233	-
Special dividend to the province for BCTC	-	-	(20)
<b>Retained Earnings at End of Year</b>	<b>\$1,653</b>	<b>\$1,963</b>	<b>\$2,038</b>
Deferred revenue <i>(Note 1)</i>	\$275	\$292	\$312
Contributions arising from the Columbia River Treaty	193	184	175
Contributions in aid of construction	609	625	643
<b>Equity</b>	<b>\$2,730</b>	<b>\$3,064</b>	<b>\$3,168</b>
Forecast rate of return on equity	7.73%	13.25%	13.73%
Allowed rate of return on equity	14.33%	13.91%	13.91%
Allowed net income	\$395	\$427	\$442
Forecast net income	\$211	\$406	\$435

Notes:

1. The changes in forecast deferred revenue from the Application are primarily due to the change in forecast foreign exchange rates. In this Revised Evidentiary Update, the deferred revenue balances are \$1 million, \$4 million and \$8 million lower for F2004 to F2006, respectively.

### 3.2 Domestic Revenues

Changes from the Application in domestic revenues and sales volumes for F2004 are shown in Tables 2A-3 and 2A-4.

1 **Table 2A-3. Domestic Revenues, F2004**

(\$ millions)	F2004 Revised Evidentiary Update Forecast	F2004 Application Forecast	Variance
Residential	\$974	\$959	\$15
Light industrial and commercial	909	901	8
Large industrial	513	503	10
Other energy sales			
Irrigation	3	3	-
Street lighting	24	23	1
City of New Westminster	14	13	1
Aquila Networks Canada	30	27	3
<b>Total Revenue Requirement</b>	<b>\$2,467</b>	<b>\$2,429</b>	<b>\$38</b>
Other utilities <i>(Note 1)</i>	\$18	\$20	\$(2)
Miscellaneous	67	67	-
<b>Total</b>	<b>\$2,552</b>	<b>\$2,516</b>	<b>\$36</b>

2 Notes:

- 3 1. Other utilities under long-term contracts including Seattle City Light pursuant to the Skagit Valley  
4 Treaty agreements.

6 **Table 2A-4. Domestic Sales Volumes, F2004**

(GWh)	F2004 Revised Evidentiary Update Forecast	F2004 Application Forecast	Variance
Residential	15,881	15,654	227
Light industrial and commercial	17,127	16,947	180
Large industrial	15,102	14,801	301
Other energy sales			
Irrigation	89	88	1
Street lighting	214	218	(4)
City of New Westminster	406	401	5
Aquila Networks Canada	747	708	39
Other utilities	309	314	(5)
<b>Total</b>	<b>49,875</b>	<b>49,131</b>	<b>744</b>

7 The increase in residential revenues and volumes are due primarily to weather impacts.

8 Revenues from light industrial and commercial customers increased due to improvements

9 from the prior forecast in the forestry and commercial sectors. The increase in large

10 industrial revenues is a result of increased pulp and paper production and increased lumber

11 production due to a stronger demand from the U.S.

12 Changes from the Application in domestic revenues for F2005 and F2006 are shown in

13 Table 2A-5 and 2A-6.

1 **Table 2A-5. Domestic Revenues, F2005**

(\$ millions)	F2005 Revised Evidentiary Update Forecast	F2005 Application Forecast	Variance
Residential	\$1,050	\$1,041	\$9
Light industrial and commercial	976	970	6
Large industrial	542	539	3
Other energy sales (Note 1)	72	71	1
<b>Total Revenue Requirement</b>	<b>\$2,640</b>	<b>\$2,621</b>	<b>\$19</b>
Other utilities (Note 2)	\$19	\$20	\$(1)
Miscellaneous	61	61	-
<b>Total</b>	<b>\$2,720</b>	<b>\$2,702</b>	<b>\$18</b>

2 Notes:

- 3 1. Includes sales to City of New Westminster, Aquila Networks Canada, Irrigation and Street  
4 Lighting customers.  
5 2. Other utilities under long-term contracts including Seattle City Light pursuant to the Skagit Valley  
6 Treaty agreements.  
7

8 **Table 2A-6. Domestic Revenues, F2006**

(\$ millions)	F2006 Revised Evidentiary Update Forecast	F2006 Application Forecast	Variance
Residential	\$1,073	\$1,077	\$(4)
Light industrial and commercial	996	1,000	(4)
Large industrial	540	543	(3)
Other energy sales (Note 1)	73	74	(1)
<b>Total Revenue Requirement</b>	<b>\$2,682</b>	<b>\$2,694</b>	<b>\$(12)</b>
Other utilities (Note 2)	\$19	\$21	\$(2)
Miscellaneous	55	55	-
<b>Total</b>	<b>\$2,756</b>	<b>\$2,770</b>	<b>\$(14)</b>

9 Notes:

10 Refer to notes for Table 2A-5.  
11

12 Domestic sales volume forecasts remain unchanged for F2005 and F2006 from the  
13 forecasts in the Application. The changes to forecast revenues in F2005 and F2006 are due  
14 to changes in the proposed rate increases and to changes in foreign exchange rate  
15 assumptions. Rate increases of 7.23% in F2005 and 2.00% in F2006 were proposed in the  
16 Application. BC Hydro is amending its Application as described in section 1. The changes in  
17 foreign exchange rate assumptions result in reductions in revenues from the Skagit Valley  
18 Treaty agreements of \$1 million and \$2 million for F2005 and F2006, respectively. Because  
19 revenues from the Skagit Valley Treaty are in US dollars, a stronger Canadian dollar  
20 decreases the Canadian dollar equivalent of these revenues.

1 **3.3 Intersegment Revenues**

2 Table 2A-7 identifies the difference between Intersegment Revenues in the revised forecast  
3 and those included in the Application.

4 **Table 2A-7. Intersegment Revenues, F2004 to F2006, Change from Prior Forecast**

(\$ millions)	F2004 Forecast	F2005 Plan	F2006 Plan
Total Intersegment Revenues – Revised Evidentiary Update	\$81	\$125	\$116
Total Intersegment Revenues – Application	76	124	91
<b>Increase in Intersegment Revenues</b>	<b>\$5</b>	<b>\$1</b>	<b>\$25</b>

5 The forecast of intersegment revenues for F2004 has increased primarily due to a changed  
6 forecast of mark to market gain on the trade account between BC Hydro and Powerex.  
7 Increases in forecast intersegment revenues for F2005 and F2006 are largely due to  
8 increases in the forecasts of net sales to Powerex of trade account energy. In F2005, the  
9 increase in forecast net sales of trade account energy to Powerex is mostly offset by a  
10 decrease in PTP transmission charges to Powerex, which is due to the deferred  
11 commencement of transmission services under the Guichon contract. On December 1,  
12 2003, BC Hydro advised BCTC that, in accordance with Tariff Supplement 30, it was  
13 exercising its right to defer the commencement of transmission services under the Guichon  
14 contract by one year. The contract was originally scheduled to take effect on December 3,  
15 2003 and that date was assumed in the Application. With the one-year deferral to December  
16 3, 2004, the PTP transmission revenues are lower by \$5 million and \$10 million for F2004  
17 and F2005, respectively.

18 Table 2A-8 summarizes the foregoing.

1 **Table 2A-8. Intersegment Revenues, F2004 to F2006**

(\$ millions)	F2004 Forecast	F2005 Plan	F2006 Plan
Net sales to Powerex - Future Use <i>(Note 1)</i>	\$ -	\$61	\$49
Point-to-point wheeling charge to Powerex <i>(Note 2)</i>	44	50	53
Point-to-point wheeling charge to BC Hydro <i>(Note 3)</i>	12	12	12
Allocation of BC Hydro corporate costs to Powerex <i>(Note 4)</i>	2	2	2
Foreign exchange gain on Trade Payable balance – BC Hydro to Powerex <i>(Note 5)</i>	15	-	-
Mark to market gain on Trade Account – BC Hydro to Powerex <i>(Note 6)</i>	8	-	-
<b>Total Inter-segment Revenues</b>	<b>\$81</b>	<b>\$125</b>	<b>\$116</b>

2 **Notes:**

- 3 1. These sales relate to a return of energy bought by Powerex in prior periods to enable future sale.  
 4 These revenues are eliminated against trade cost of energy on consolidation.
- 5 2. These transmission revenues relate to an allocation of BC Hydro's cost of purchases of point-to-  
 6 point transmission within BC for export and some import transactions. These revenues are  
 7 eliminated against trade cost of energy on consolidation.
- 8 3. These transmission revenues relate to an allocation of BC Hydro's cost of purchases of point-to-  
 9 point transmission relating to BC Hydro's Skagit Valley Treaty commitment. These revenues are  
 10 eliminated against domestic cost of energy on consolidation.
- 11 4. These revenues relate to an allocation of corporate costs to Powerex and are eliminated against  
 12 trade income on consolidation.
- 13 5. This relates to the foreign exchange gain on the payable to Powerex. Powerex would have a  
 14 corresponding loss on their receivable. The receivable relates to energy purchased to enable  
 15 future sale by Powerex and sold to BC Hydro when brought into the system.
- 16 6. This relates to a mark to market gain on the trade account. Powerex would have a corresponding  
 17 loss.

18 **3.4 Domestic Cost of Energy**

19 The most significant difference between the Application and this Revised Evidentiary Update  
 20 is the change in forecast water inflows for the February to September 2004 water year.

21 Water inflows in the updated forecast are expected to be 94 per cent of normal for this  
 22 period based on January 1, 2004 snowpack levels. In the Application, normal water inflows  
 23 were assumed. The decrease in forecast water inflows results in a reduction in forecast  
 24 hydro generation.

25 Table 2A-9 (Revised) shows the difference between the domestic cost of energy in this  
 26 Revised Evidentiary Update and the domestic cost of energy in the Application. The  
 27 breakdown of the domestic cost of energy forecast is provided in Schedule A-9-A (Revised).

1 **Table 2A-9. Domestic Cost of Energy, F2004 to F2006 (Revised)**

(\$ millions)	F2004 Forecast	F2005 Plan	F2006 Plan
Domestic cost of energy – Revised Evidentiary Update	\$968	\$906	\$865
Domestic cost of energy – Application	944	824	808
<b>Increase in domestic cost of energy</b>	<b>\$24</b>	<b>\$82</b>	<b>\$57</b>

2 The increase in the forecast of domestic cost of energy in F2004 is largely due to the  
 3 increase in sales volumes of approximately 750 GWh, as explained in Section 3.2. The  
 4 majority of the increase in load is met by energy purchases.

5 The increase in the forecast of domestic cost of energy in F2005 is primarily due to the  
 6 impact of lower forecast water inflows. Due to lower forecast water inflows, hydro generation  
 7 including exchange net<sup>1</sup> is forecast to decrease by approximately 1,650 GWh in F2005 from  
 8 the previous forecast and to be replaced by market electricity purchases to meet load. As  
 9 the cost of market electricity purchases is significantly greater than the incremental cost of  
 10 hydro generation, the cost of energy is forecast to increase.

11 The increase in the forecast of domestic cost of energy in F2006 is largely due to the impact  
 12 of the lower forecast water inflows in F2005 (reservoir management is undertaken on a  
 13 multiple-year basis) and to a change in the exchange net<sup>1</sup> assumptions. The forecasts in this  
 14 Revised Evidentiary Update and the Application both assume normal water inflows for  
 15 F2006. Hydro generation including exchange net is currently forecast to be approximately  
 16 710 GWh less than previously forecast. It is expected that the 710 GWh will be replaced by  
 17 market electricity purchases.

18 The increase in the proposed rate increase in F2005 will also increase the water rental fees,  
 19 which are indexed to BC Hydro's electricity rates, by \$1 million and \$3 million for F2005 and  
 20 F2006, respectively. The water rental rates increase on January 1 of the year following the  
 21 rate increase.

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<sup>1</sup> Exchange net relates to non-treaty storage agreements with Bonneville Power Administration, Kootenay Canal Plant Agreement with Aquila Networks Canada and Keenleyside Entitlement Agreement with Columbia Power Corporation. The exchange net forecasts have also been revised due to changes in forecast Kootenay Canal Entitlement, and are reflected in Schedule A-9-A.

1 **3.5 Operations, Maintenance, and Administration Costs**

2 Maintenance costs decreased from those in the Application by \$1.3 million in F2006 due to  
 3 a reclassification of cost recoveries. These cost recoveries were shown as part of BCTC in  
 4 the Application but should have also been shown as part of BC Hydro. This reclassification  
 5 is explained in more detail in Chapter 6A, page 6A-3.

6 **3.6 Finance Charges**

7 The Provincial Government provided revised interest and foreign exchange rate forecasts  
 8 for F2005 to F2006 in January 2004. These forecast rates are used by all Crown  
 9 corporations and the Government itself in forecasting the Provincial budget. This Revised  
 10 Evidentiary Update reflects the revised rates, which are shown in Table 2A-10.

11 **Table 2A-10. Updated Interest Rate and Foreign Exchange Rate Forecast, F2004 to**  
 12 **F2006**

<i>(Note 1)</i>	<b>F2004 Forecast</b>	<b>F2005 Plan</b>	<b>F2006 Plan</b>
Canadian Short-term Interest Rates	3.00%	2.81%	4.03%
U.S. Short-term Interest Rates	1.20%	1.74%	3.78%
Canadian Long-term Interest Rates	5.41%	5.68%	6.26%
U.S. Long-term Interest Rates	5.00%	5.70%	6.49%
USD/CAD FX Rate	0.7454	0.7941	0.8006

13 **Notes:**

14 1. Provincial Government Forecast, January 22, 2004.

15  
 16 For convenience, Table 2A-11 shows the interest and foreign exchange rates used in the  
 17 Application.

1 **Table 2A-11. December 2003 Application Interest Rate and Foreign Exchange Rate**  
 2 **Forecast, F2004 to F2006**

<i>(Note 1)</i>	<b>F2004 Forecast</b>	<b>F2005 Forecast</b>	<b>F2006 Forecast</b>
Canadian Short-term Interest Rates	3.15%	3.63%	5.06%
U.S. Short-term Interest Rates	1.26%	2.00%	4.00%
Canadian Long-term Interest Rates	5.45%	5.91%	6.64%
U.S. Long-term Interest Rates	5.06%	5.78%	6.54%
USD/CAD FX Rate	0.7324	0.7490	0.7500

3 Notes:

4 1. Provincial Government Forecast, August 2003.

5  
 6 Table 2A-12 (Revised) identifies finance charges during the test periods. The detailed  
 7 components of the updated finance charge forecasts are shown in Schedule A-10-A  
 8 (Revised).

9 **Table 2A-12. Finance Charges, F2004 to F2006 (Revised)**

(\$ millions)	<b>F2004 Forecast</b>	<b>F2005 Plan</b>	<b>F2006 Plan</b>
Finance Charges – Revised Evidentiary Update	\$444	\$430	\$461
Finance Charges – Application	454	463	497
<b>Decrease in finance charges</b>	<b>\$10</b>	<b>\$33</b>	<b>\$36</b>

10 Forecast finance charges are less than in the Application due primarily to the lower forecast  
 11 interest rates. The current forecast Canadian short-term interest rates are 82 basis points  
 12 less in F2005 and 103 basis points less in F2006 than as indicated in the Application. The  
 13 current forecast of a stronger Canadian dollar also contributes to the decrease in finance  
 14 charges.

### 15 **3.7 Depreciation and Amortization**

16 There are no changes to forecast depreciation and amortization.

### 17 **3.8 Taxes**

18 There are no changes to forecast taxes.

1 **3.9 Restructuring Costs**

2 There are no changes to forecast restructuring costs.

3 **3.10 Charges from the British Columbia Transmission Corporation**

4 There are no changes to forecast BCTC charges.

5

SCHEDULE A-1-A (Revised)

Consolidated Statement of Operations with Proposed Rate Increases For the Years Ended March 31 (\$ millions)				
	A	B	C	D
	F2003	F2004	F2005	F2006
	Actual	Forecast	Plan	Plan
<b>REVENUES</b>				
Domestic				
Residential	\$ 923	\$ 974	\$ 1,050	\$ 1,073
Light industrial and commercial	893	909	976	996
Large industrial	516	513	542	540
Other energy sales	88	89	91	92
Miscellaneous	55	67	61	55
	<u>2,475</u>	<u>2,552</u>	<u>2,720</u>	<u>2,756</u>
Intersegment revenues	6	81	125	116
	<u>2,481</u>	<u>2,633</u>	<u>2,845</u>	<u>2,872</u>
<b>EXPENSES</b>				
Domestic energy costs	708	968	906	865
BCTC wholesale transmission service	-	-	-	61
BCTC asset management fee	-	-	-	117
Operations expense	138	169	171	129
Maintenance expense	207	227	244	138
Administration expense	161	162	162	140
Depreciation and amortization	414	428	470	470
Taxes	145	142	145	147
	<u>1,773</u>	<u>2,096</u>	<u>2,098</u>	<u>2,067</u>
<b>INCOME BEFORE FINANCE CHARGES, RESTRUCTURING COSTS, TRANSFER FROM RSA AND TRADE INCOME</b>	708	537	747	805
Finance charges	457	444	430	461
<b>INCOME BEFORE RESTRUCTURING COSTS, TRANSFER FROM RSA AND TRADE INCOME</b>	251	93	317	344
Restructuring Costs	37	11	-	-
<b>INCOME BEFORE TRANSFER FROM RSA AND TRADE INCOME</b>	214	82	317	344
Transfer from RSA	66	21	-	-
<b>DOMESTIC NET INCOME</b>	<u>280</u>	<u>103</u>	<u>317</u>	<u>344</u>
<b>TRADE NET INCOME</b>	<u>138</u>	<u>108</u>	<u>89</u>	<u>91</u>
<b>TOTAL NET INCOME</b>	<u>\$ 418</u>	<u>\$ 211</u>	<u>\$ 406</u>	<u>\$ 435</u>
<b>PAYMENT TO THE PROVINCE</b>	<u>\$ 338</u>	<u>\$ 167</u>	<u>\$ 329</u>	<u>\$ 340</u>
<b>ACTUAL/FORECAST RETURN ON EQUITY</b>	15.47%	7.73%	13.25%	13.73%
<b>ALLOWED RETURN ON EQUITY</b>	<u>15.47%</u>	<u>14.33%</u>	<u>13.91%</u>	<u>13.91%</u>
<b>BALANCE IN RSA</b>	<u>\$ 21</u>	<u>\$ -</u>	<u>\$ -</u>	<u>\$ -</u>
<b>RATE INCREASE</b>	<u>0.00%</u>	<u>0.00%</u>	<u>8.90%</u>	<u>0.00%</u>
<b>CUMULATIVE RATE INCREASE</b>	<u>0.00%</u>	<u>0.00%</u>	<u>8.90%</u>	<u>8.90%</u>

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SCHEDULE A-2-A (Revised)

**Consolidated Balance Sheet**  
As at March 31  
(\$ millions)

	A	B	C	D
	F2003	F2004	F2005	F2006
	Actual	Forecast	Plan	Plan
<b>Capital Assets</b>				
Capital assets in service	\$ 14,940	\$ 15,513	\$ 16,092	\$ 16,492
Less accumulated depreciation	5,816	6,030	6,329	6,641
	<u>9,124</u>	<u>9,483</u>	<u>9,763</u>	<u>9,851</u>
Unfinished construction	669	517	552	817
	<u>9,793</u>	<u>10,000</u>	<u>10,315</u>	<u>10,668</u>
<b>Current Assets</b>				
Temporary investments	4	4	4	4
Accounts receivable and accrued revenue	362	422	449	455
Materials and supplies	88	88	88	88
Prepaid expenses	86	95	87	68
Unrealized gains on mark-to-market transactions	10	-	-	-
	<u>550</u>	<u>609</u>	<u>628</u>	<u>615</u>
<b>Other Assets and Deferred Charges</b>				
Loan receivable	23	2	2	2
Sinking funds	1,037	979	984	844
Demand-Side Management programs	123	215	289	346
Deferred debt costs	385	142	84	52
	<u>1,568</u>	<u>1,338</u>	<u>1,359</u>	<u>1,244</u>
	<u>\$ 11,911</u>	<u>\$ 11,947</u>	<u>\$ 12,302</u>	<u>\$ 12,527</u>
Long term debt net of sinking funds	\$ 6,853	\$ 6,990	\$ 7,118	\$ 7,436
Sinking funds presented as assets	1,037	979	984	844
<b>Long-Term Debt</b>	<u>7,890</u>	<u>7,969</u>	<u>8,102</u>	<u>8,280</u>
<b>Foreign Currency Contracts</b>	<u>2</u>	<u>75</u>	<u>65</u>	<u>60</u>
<b>Current Liabilities</b>				
Accounts payable and accrued liabilities	689	707	606	538
Accrued interest	108	119	117	121
Accrued Payment to the Province	338	167	329	340
Unrealized losses on mark-to-market transactions	10	-	-	-
	<u>1,145</u>	<u>993</u>	<u>1,052</u>	<u>999</u>
<b>Deferred Credits and Other Liabilities</b>				
Provision for future removal and site restoration costs	174	180	-	-
Asset Retirement Obligation	-	-	19	20
Deferred revenue	258	275	292	312
Rate stabilization account	21	-	-	-
Contributions arising from the Columbia River Treaty	203	193	184	175
Contributions in aid of construction	609	609	625	643
	<u>1,265</u>	<u>1,257</u>	<u>1,120</u>	<u>1,150</u>
<b>Retained Earnings</b>	<u>1,609</u>	<u>1,653</u>	<u>1,963</u>	<u>2,038</u>
	<u>\$ 11,911</u>	<u>\$ 11,947</u>	<u>\$ 12,302</u>	<u>\$ 12,527</u>
<b>Debt to Equity Ratio</b>	<u>71.7:28.3</u>	<u>71.9:28.1</u>	<u>69.9:30.1</u>	<u>70.1:29.9</u>

SCHEDULE A-3-A (Revised)

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**Consolidated Statement of Retained Earnings**  
**For the Years ended March 31**  
**(\$ millions)**

	A	B	C	D
	F2003	F2004	F2005	F2006
	Actual	Forecast	Plan	Plan
Retained earnings at beginning of year	\$ 1,529	\$ 1,609	\$ 1,653	\$ 1,963
Net income	418	211	406	435
Payment to the Province	(338)	(167)	(329)	(340)
Asset Retirement Obligation Adjustment <sup>(Note 1)</sup>	-	-	233	-
Special Dividend to the Province for BCTC <sup>(Note 2)</sup>	-	-	-	(20)
Retained earnings at end of year	<u>\$ 1,609</u>	<u>\$ 1,653</u>	<u>\$ 1,963</u>	<u>\$ 2,038</u>

**Notes:**

1. This adjustment is explained in Chapter 2, Section 3.7.3, page 2-17, of the Application.
2. The Special Dividend to the Province for BCTC was paid in F2004. It is shown in F2006 because BCTC is consolidated with BC Hydro in F2004 and F2005.

SCHEDULE A-4-A (Revised)

<b>Consolidated Statement of Cash Flows</b>				
<b>For the Years ended March 31</b>				
<b>(\$ millions)</b>				
	A	B	C	D
	F2003	F2004	F2005	F2006
	Actual	Forecast	Plan	Plan
<b>Operating Activities</b>				
Net income	\$ 418	\$ 211	\$ 406	\$ 435
Adjustments for:				
Depreciation and amortization	417	432	474	474
Rate stabilization account	(66)	(21)	-	-
Other non-cash items	24	(27)	(18)	(20)
	<u>793</u>	<u>595</u>	<u>862</u>	<u>889</u>
Working capital changes	1	(40)	(122)	(51)
Cash provided by operating activities	<u>794</u>	<u>555</u>	<u>740</u>	<u>838</u>
<b>Investing Activities</b>				
Capital asset expenditures	(680)	(652)	(716)	(894)
Contributions in aid of construction	62	47	51	54
Demand side management programs	(45)	(116)	(105)	(94)
Future removal and site restoration costs	(12)	(15)	-	-
Net asset dismantling costs	-	-	(17)	(17)
Loan receivable	(8)	21	-	-
Proceeds from property and asset sales	1	13	4	79
Cash used for investing activities	<u>(682)</u>	<u>(702)</u>	<u>(783)</u>	<u>(872)</u>
<b>Financing Activities</b>				
Bonds, notes and debentures				
Issued	1,007	790	600	700
Retired	(1,019)	(450)	(598)	(607)
Revolving borrowings changes	147	74	173	104
Sinking funds	48	54	35	186
Deferred debt costs	3	6	-	-
Settlement of financial instruments	22	11	-	-
Cash provided by financing activities	<u>208</u>	<u>485</u>	<u>210</u>	<u>383</u>
Payment to the Province	(333)	(338)	(167)	(329)
Special Dividend to the Province for BCTC	-	-	-	(20)
Increase (decrease) in cash	<u>(13)</u>	<u>-</u>	<u>-</u>	<u>-</u>
Cash at beginning of year	17	4	4	4
Cash at end of year	<u>\$ 4</u>	<u>\$ 4</u>	<u>\$ 4</u>	<u>\$ 4</u>

SCHEDULE A-5-A

**Residential Revenues**  
**For the Years Ended March 31**  
**(\$ millions)**

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	A		B		C		D	
	F2003	F2004		F2005		F2006		
	Actual	Forecast	%	Plan	%	Plan	%	
<b>Revenue</b>								
Residential revenue	\$923	\$974	6%	\$1,050	8%	\$1,073	2%	
Revenue variance	n/a	\$51		\$76		\$23		
<b>Variance</b>								
Rate increase:		n/a		79		8		
Volume:								
Number of customers	n/a	16		16		17		
Usage per customer	n/a	38		(14)		2		
Power Smart savings	n/a	(3)		(5)		(4)		
Total Variance	n/a	\$51		\$76		\$23		
<b>Sales Volume (in GW·h)</b>	15,024	15,881	6%	15,836	0%	16,063	1%	
<b>Number of Customers</b>	1,442,597	1,465,057	2%	1,489,254	2%	1,515,170	2%	

( ) represents a negative variance.

The usage variance in fiscal year 2002 is high due to the cooler weather in March 2002 (coldest March in over 20 years), and higher average consumption per customer.

The usage variance in fiscal year 2003 is low due to the return of normal temperatures in fiscal 2003.

Residential revenues are expected to increase primarily due to the proposed rate increase and customer growth which is expected to be an average of 1.70% over the period from 2004 to 2006.

The usage variance in fiscal year 2004 is high due to the cooler weather in April and May affecting the heating load and the extreme warm weather in July and August affecting the cooling load. Fiscal 2003 was a warmer than normal year. Forecast 2005 and 2006 assumes normal weather.

SCHEDULE A-6-A

**Light Industrial And Commercial Revenue**  
**For the Years Ended March 31**  
**(\$ millions)**

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	A	B		C		D	
	F2003	F2004		F2005		F2006	
	Actual	Forecast	%	Plan	%	Plan	%
<b>Revenue</b>							
Light industrial & commercial	\$893	\$909	2%	\$976	7%	\$996	2%
Revenue variance	n/a	\$16		\$67		\$20	
<b>Variance</b>							
Rate increase:		n/a		73		9	
Volume:							
GDP & Employment*	n/a	20		6		20	
Power Smart savings	n/a	(4)		(12)		(9)	
Total Variance	n/a	\$16		\$67		\$20	
<b>Sales Volume (in GW·h)</b>	16,757	17,127	2%	17,003	-1%	17,202	1%
<b>Number of Customers</b>	183,188	184,233	1%	185,231	1%	186,214	1%

\* includes floor stock growth rates and end-use building intensities

( ) represents an unfavourable variance

Light industrial and commercial customers is comprised of small and large accounts. Small customers are defined as those with a monthly demand of less than 35 kilowatts and includes small retail operations, offices, schools and warehouses. Large accounts include retail, industrial and manufacturing customers whose monthly demand is 35 kilowatts or more.

The volume variance for fiscal 2002 and fiscal 2003 is high due to better economic conditions.

The major change in revenues in fiscal 2005 and fiscal 2006 is due to the proposed rate increase and to increased volum from GDP, employment, floor stock building growth rates and end-use building intensities partially offset by expected Power Smart savings.

## SCHEDULE A-7-A

### Large Industrial Revenue For the Years Ended March 31 (\$ millions)

	A		B		C		D	
	F2003 Actual	F2004 Forecast	%	F2005 Plan	%	F2006 Plan	%	
<b>Revenue</b> (in millions)								
Large industrial	\$516	\$513	-1%	\$542	6%	\$540	0%	
Revenue variance	n/a	\$(3)		\$29		\$(2)		
<b>Variance</b>								
Rate increase:		n/a		41		3		
Volume:								
Power Smart savings	n/a	(4)		(9)		(6)		
Usage per customer	n/a	1		(3)		1		
Total Variance	n/a	\$(3)		\$29		\$(2)		
<b>Sales Volume</b> (in GW-h)	15,179	15,102	-1%	14,733	-2%	14,604	-1%	
<b>Number of Customers</b>	133	135	2%	136	1%	136	0%	

( ) represents and unfavourable variance

The usage variance in fiscal year 2002 is due to unfavourable pulp & paper market conditions and mine closures. The rate variance in fiscal year 2002 is due to special rate programs including Rate 1854, Power For Jobs, Job Protection Commission, and Time of Use.

The usage variance in fiscal year 2003 is due to improved market conditions for pulp & paper and pulp chemicals. The rate variance in fiscal year 2003 is due to the termination of the special rate programs.

Large industrial revenues are expected to increase largely due to the impact of the proposed rate increases. The decrease in 2004 is due primarily to reduced sales to metal mining customers, pulp and paper customers, wood manufacturing customers and pulp chemical customers. The metal mines, pulp and paper mills and wood manufacturers are commodity exporters whose sales have been negatively impacted by the rise in the Canadian dollar. The pulp chemical sales are dependent on the pulp and paper sector and therefore have also been negatively impacted.

Fiscal 2005 and fiscal 2006 revenues are expected to increase largely due to the impact of the proposed rate increases.

For fiscal 2005 and fiscal 2006, a major customer in the Pulp and Paper sector is expected to return to normal production levels after a strike during fiscal 2004. New coal mines coming on line are also expected to increase demand. The increase in consumption from the above is partially offset by the fact that commodity exporters are expected to remain under pressure from the continued strong Canadian dollar, foreign competition from Chile and Asia, as well as newer, more efficient mines and mills.

SCHEDULE A-9-A (Revised)

<b>Domestic Cost Of Energy</b>					
<b>For the Years Ended March 31</b>					
<b>(\$ millions)</b>					
	A	B	C	D	
	F2003	F2004	F2005	F2006	
	Actual	Forecast	Plan	Plan	Reference
<b>Domestic cost of energy :</b>					
Water rentals	\$258	\$248	\$258	\$281	D1-2-A
Independent Power Producers and long-term purchase commitments	290	380	380	395	C2-A
Market electricity purchases	54	251	183	112	D1-2-A
Net Purchases from Powerex (Note 1)	50	14			D1-2-A
Natural gas for thermal generation (Note 2)	28	32	36	26	D1-2-A
Domestic cost of energy - Non-integrated Areas	14	14	15	15	C4-A
Domestic transmission	5	16	16	16	D1-2-A
Gas transportation	5	9	13	13	C2-A
Cost of market (Note 3)	1	1	1		C3-A
Other	3	3	4	7	D1-2-A
<b>Total Domestic cost of energy</b>	<b>\$708</b>	<b>\$968</b>	<b>\$906</b>	<b>\$865</b>	
	<b>F2003</b>	<b>F2004</b>	<b>F2005</b>	<b>F2006</b>	
	<b>Actual</b>	<b>Forecast</b>	<b>Plan</b>	<b>Plan</b>	
<b>Domestic energy:</b>					
<b>GW-h's</b>					
Water rentals	47,665	44,882	44,980	46,045	
Independent Power Producers and long-term purchase commitments	4,950	6,165	6,540	6,951	
Market electricity purchases	896	5,001	4,266	2,757	
Net Purchases from Powerex (Note 1)	1,113				
Thermal generation	251	277	338	233	
Non-integrated Areas	96	92	105	105	
Exchange net	(1,605)	(1,203)	54	199	
	<u>53,366</u>	<u>55,214</u>	<u>56,283</u>	<u>56,290</u>	
Less: Line loss and system use	(4,689)	(5,008)	(5,447)	(5,483)	
Net sales to Powerex		(331)	(1,550)	(1,200)	
<b>Domestic sales volumes</b>	<b>48,677</b>	<b>49,875</b>	<b>49,286</b>	<b>49,607</b>	
<b>\$/MW-h</b>					
Water rentals	\$ 5.413	\$ 5.526	\$ 5.736	\$ 6.103	
Independent Power Producers and long-term purchase commitments	58.586	61.638	58.104	56.826	
Market electricity purchases	60.268	50.190	42.897	40.624	
Net Purchases from Powerex	44.924				
Natural gas for thermal generation	111.554	115.523	106.509	111.588	
Domestic cost of energy - Non-integrated Areas	145.833	152.174	142.857	142.857	
<b>Total weighted average cost (Note 4)</b>	<b>\$ 14.545</b>	<b>\$ 19.409</b>	<b>\$ 18.383</b>	<b>\$ 17.437</b>	

**Notes:**

1. In F2004, Powerex is expected to draw down the trade account by 331 GWh, which is made up of 1,792 GWh out of the trade account and 1,461 GWh into the trade account. The value of the energy going into the trade account is more expensive than the current average cost of the trade account. This difference results in a net cost to domestic cost of energy of \$14 million. (i.e., The revenues BC Hydro would record from Powerex when the trade account is drawn down is less than the cost BC Hydro records from Powerex when the trade account is increased.) This does not have an impact on the Heritage Contract.
2. This includes fixed transportation costs of approximately \$10 million related to the Bypass Transportation Agreement between Terasen and BC Hydro.
3. Domestic cost of energy transmission which includes congestion management cost.
4. Calculated as total cost divided by sales volumes.

SCHEDULE A-10-A (Revised)

**Finance Charges**  
**For the Years Ended March 31**  
**(\$ millions)**

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	A	B	C	D
	F2003	F2004	F2005	F2006
	Actual	Forecast	Plan	Plan
<b>Interest on debt securities</b>				
Bonds, notes and debentures	\$ 536	\$ 505	\$ 484	\$ 507
Revolving borrowings	5	10	16	25
Amortization of deferred debt costs and other expenses	26	37	30	34
	<u>567</u>	<u>552</u>	<u>530</u>	<u>566</u>
<b>Less:</b>				
Sinking fund income	(60)	(60)	(55)	(50)
Other income (Note 1)	(26)	(28)	(20)	(14)
Finance charges capitalized to unfinished construction	(24)	(20)	(25)	(41)
	<u>(110)</u>	<u>(108)</u>	<u>(100)</u>	<u>(105)</u>
<b>Total</b>	<u>\$ 457</u>	<u>\$ 444</u>	<u>\$ 430</u>	<u>\$ 461</u>

Note:

1. Other income largely relates to income on interest rate and cross currency swaps.

Average interest rates

Long-term debt				
Canadian	8.3%	7.8%	7.4%	7.3%
Foreign	4.5%	4.4%	4.7%	5.6%
Short-term debt	2.4%	3.0%	2.8%	4.0%
Average exchange rate in U.S. dollars	0.65	0.75	0.79	0.80

Average interest rates relate to the weighted average interest rate and represents the effective rate of interest on fixed-rate bonds and notes and the current interest rate in effect at March 31 for floating-rate bonds and notes, all before considering the effect of derivative financial instrument used to manage interest rate risk.

SCHEDULE A-12-A (Revised)

	<b>Composition of Long-term Debt</b>				
	<b>As at March 31</b>				
	<b>(\$ millions)</b>				
		A	B	C	D
		F2003	F2004	F2005	F2006
		Actual	Forecast	Plan	Plan
8	Bonds, notes and debentures				
9	Canadian	\$ 4,888	\$ 4,938	\$ 5,150	\$ 5,437
10	Foreign	2,671	2,627	2,374	2,161
11		7,559	7,565	7,524	7,598
12	Less:				
13	Sinking funds	1,037	979	984	844
14					
15	Net bonds, notes and debentures	6,522	6,586	6,540	6,754
16					
17	Revolving borrowings	331	404	578	682
18					
19	Long-term debt net of sinking funds	6,853	6,990	7,118	7,436
20					
21	Sinking funds presented as assets	1,037	979	984	844
22					
23	Long-term debt	\$ 7,890	\$ 7,969	\$ 8,102	\$ 8,280
24					
25					
26	Foreign currency contracts (Dr)	(13)	-	-	-
27					
28	Foreign currency contracts Cr	15	75	65	60

SCHEDULE A-12-1-A(Revised)

**Net Long-term Debt**  
**For the Years Ended March 31**  
**(\$ millions)**

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Long-term debt consists of bond, notes and debentures and revolving borrowings obtained under a borrowing agreement with the Province. Long-term debt is presented net of sinking funds.

	A	B	C	D
	F2003	F2004	F2005	F2006
	Actual	Forecast	Plan	Plan
<b>Balance at Beginning of Year</b>	\$ 6,906	\$ 6,853	\$ 6,990	\$ 7,118
<b>Add (less):</b>				
New financing	1,007	790	600	700
Retirements	(1,019)	(450)	(598)	(607)
Revolving borrowings	147	74	173	104
	135	414	175	197
Exchange and other adjustments	(179)	(266)	(27)	(15)
Sinking fund (increase) decrease	(9)	(11)	(20)	136
<b>Balance at End of Year</b>	<b>\$ 6,853</b>	<b>\$ 6,990</b>	<b>\$ 7,118</b>	<b>\$ 7,436</b>

SCHEDULE A-16-A

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## Return on Equity For the Years Ended March 31 (\$ millions)

	A	B	C	D
	F2003	F2004	F2005	F2006
	Actual	Forecast	Plan	Plan
<b>Actual/forecast return on equity</b>	15.47%	7.73%	13.25%	13.73%
<b>Allowed return on equity <sup>1</sup></b>	15.47%	14.33%	13.91%	13.91%
<b>Numerator</b>				
Consolidated net income after rate stabilization account transfer	\$ 418	\$ 211	\$ 406	\$ 435
<b>Denominator</b>				
Retained earnings - end of year	\$ 1,609	\$ 1,653	\$ 1,963	\$ 2,038
Deferred credits - end of year	1,091	1,077	1,101	1,130
Equity - end of year	\$ 2,700	\$ 2,730	\$ 3,064	\$ 3,168

Note:

1. Return on equity is calculated in accordance with HSD #2 - see Chapter 2, section 3.1.

### Definition of Return on Equity

Return on equity = Consolidated Net Income / Ending Equity

Where Equity = Retained earnings + Deferred credits

Where Deferred credits = Deferred revenue + Contributions arising from the Columbia River

Treaty and Contributions in aid of construction + RSA balance

	F2003	F2004	F2005	F2006
	Actual	Forecast	Plan	Plan
<b>Deferred Credits</b>				
Deferred revenue	\$ 258	\$ 275	\$ 292	\$ 312
Contributions arising from the Columbia River Treaty	203	193	184	175
Contributions in aid of construction	609	609	625	643
Rate stabilization account	21	-	-	-
	\$ 1,091	\$ 1,077	\$ 1,101	\$ 1,130

SCHEDULE A-17-A

**Debt To Equity Ratio**  
**For the Years Ended March 31**  
**(\$ millions)**

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	A	B	C	D
	F2003	F2004	F2005	F2006
	Actual	Forecast	Plan	Plan
<b>Debt to equity</b>	72:28	72:28	70:30	70:30
<b>Debt</b>				
Long term debt net of sinking funds	\$6,853	\$6,990	\$7,118	\$7,436
Temporary investments	(4)	(4)	(4)	(4)
	<u>\$6,849</u>	<u>\$6,986</u>	<u>\$7,114</u>	<u>\$7,432</u>
<b>Equity</b>				
Deferred credits	\$1,091	\$1,077	\$1,101	\$1,130
Retained earnings	1,609	1,653	1,963	2,038
	<u>\$2,700</u>	<u>\$2,730</u>	<u>\$3,064</u>	<u>\$3,168</u>

**Definition of Debt to Equity**

$$\frac{\text{Debt}}{\text{Debt} + \text{Equity}} \times 100: \frac{\text{Equity}}{\text{Debt} + \text{Equity}} \times 100$$

Where Debt = Bonds + Notes + Debentures + Revolving borrowings - Sinking funds -  
 Term debentures - Temporary investments

Where Equity = Retained earnings + Deferred credits

Where Deferred credits = Deferred revenue + Contributions arising from the Columbia  
 River Treaty + Contributions in Aid of Construction + RSA balance

## SCHEDULE B-2-A

### Functionalized Costs F2005

(\$ millions)	Corporate Energy Supply less Heritage Payment Obligation <sup>1</sup>	Generation (Heritage Contract) <sup>2</sup>	Transmission Chapter 6	Electricity Distribution & NIA <sup>8</sup>	Customer Care <sup>1</sup>	Service Orgs and Subsidiaries	Consolidated
	Chapter 3	Chapter 4	Chapter 5	Chapter 7	Chapter 8	Chapter 9	
B1	Domestic cost of energy	393.0	496.5	1.0	15.0		905.5
	OMA Expenses						
	Operations, maintenance, and administration (net)	70.4	125.4	167.5	107.4	101.5	577.1
	Corporate Allocations	(131.0)	12.8	42.9	25.9	8.5	
B2	Adjusted OMA including Corporate Allocations	(60.6)	35.4	168.3	133.3	110.0	577.1
B4	Depreciation	54.2	27.9	130.2	89.6		469.8
B3	Taxes	7.4		28.6	18.8		145.4
B5	Finance charges	9.5	4.2	193.0	102.2		430.0
B6	Allowed net income (return on equity)		4.3	196.0	103.7		427.0
C3	Other <sup>3</sup>			43.3	67.7		111.0
A-1	Restructuring costs						
A-8	Miscellaneous external revenues	(10.5)		(119.0)	(4.5)	(4.2)	(275.0)
	Cost of Service by Function	464.8	1,140.7	550.4	525.8	105.8	2,790.8
A-8	Transmission 3rd party wheeling revenues <sup>4</sup>						(5.5)
A-1	Intersegment revenues <sup>5</sup>						(125.0)
	Total Revenue Requirement <sup>6</sup>						2,660.3

Schedule to cross reference

Notes:

1. Power Smart and Energy Management costs are discussed in Chapter 8 "Power Smart, Customer Care and Energy Management" but are included together with Energy Supply costs as discussed in Chapter 4.
2. The Generation (Heritage Contract) component of the domestic cost of energy does not equal the cost of energy component of the Heritage Payment Obligation for reasons explained in the notes to schedule D1-2 -A.
3. Relates to Generation Related Transmission Asset charges from BC Hydro Transmission to BC Hydro Distribution.
4. Relates to external transmission wheeling revenues which are not deducted in determining the Transmission Cost of Service.
5. See Chapter 2 Section 3.3 for details.
6. Small differences from Chapter 1 Table 3 relate to rounding differences.
7. Domestic cost of energy for Transmission is from cost of market for transmission (see schedule C3-A).
8. Domestic cost of energy for Electricity Distribution & NIA is from Domestic Cost of Energy - Non-Integrated Areas (see line 1, schedule C4-A).

**SCHEDULE B-3-A**

**Functionalized Costs  
F2006**

(\$ millions)	Corporate		Energy Supply		Generation		Transmission		Electricity		Customer		Service		Consolidated	
	Chapter 3	Chapter 4	Chapter 5	Chapter 6	Chapter 7	Chapter 8	Chapter 9	Chapter 10	Chapter 11	Chapter 12	Chapter 13	Chapter 14	Chapter 15	Chapter 16	Chapter 17	Chapter 18
B1	Domestic cost of energy	408.0	441.6	15.0	864.6											
	OMA Expenses															
	Operations, maintenance, and administration (net)	69.8	126.0	3.5	97.3	(18.2)										
	Corporate Allocations	(132.3)	12.6	43.8	16.2	25.8	8.4	25.5								
B2	Adjusted OMA including Corporate Allocations	(62.5)	33.5	169.8	19.7	133.4	105.7	7.3	406.9							
B4	Depreciation	57.0	32.9	126.3	142.7	93.4	17.2	17.2	469.5							
B3	Taxes	7.5		29.0	90.5	19.1	1.0		147.1							
B5	Finance charges	8.1	4.6	205.0	129.1	114.2			461.0							
B6	Allowed net income (return on equity)		4.7	199.0	126.0	112.3			442.0							
C3	Other <sup>2</sup>			43.3		69.0			112.3							
A-1	Restructuring Costs															
A-8	Miscellaneous external revenues	(10.1)		(118.8)	(118.0)	(4.5)	(4.2)	(22.5)	(278.1)							
	Cost of Service by Function		483.7	1,095.2	390.0	551.9	101.5	3.0	2,625.3							
BCTC	Asset Management Fee to BCTC															116.7
BCTC	WTS Charges from BCTC															61.0
A-1	Intersegment revenues															(116.0)
	Total Revenue Requirement															2,687.0

Schedule to cross reference

Notes:

1. Power Smart and Energy Management costs are discussed in Chapter 8 "Power Smart, Customer Care and Energy Management" but are included together with Energy Supply costs as discussed in Chapter 4.
2. The Generation (Heritage Contract) component of the domestic cost of energy does not equal the cost of energy component of the Heritage Payment Obligation for reasons explained in the notes to schedule D1-2-A.
3. Relates to Generation Related Transmission Asset charges from BC Hydro Transmission to BC Hydro Generation and to Substation Distribution Asset Management charges from BC Hydro Transmission to BC Hydro Distribution.
4. Relates to charges from BCTC
5. See Chapter 2 Section 3.3 for details.
6. Small differences from Chapter 1 Table 3 relate to rounding differences.
7. Domestic cost of energy for Electricity Distribution & NIA is from Domestic Cost of Energy - Non-Integrated Areas (see line 1, schedule C4-A).

**SCHEDULE B1-A**

**Domestic Cost of Energy**  
(\$ millions)

<u>Line</u>	<u>Reference</u>	<u>F2005</u> Plan	<u>F2006</u> Plan
1 Domestic Cost of Energy <sup>1</sup>	A-9-A	<u>906</u>	<u>865</u>
Domestic Cost of Energy			
2 Domestic Cost of Energy-Generation	D1-2-A	496.5	441.6
3 Domestic Cost of Energy-Energy Supply less Heritage Payment Obligation	C2-A	393.0	408.0
4 Domestic Cost of Energy-Transmission	C3-A	1.0	-
5 Domestic Cost of Energy-Non-integrated areas	C4-A	<u>15.0</u>	<u>15.0</u>
6 Total Domestic Cost of Energy		<u>905.5</u>	<u>864.6</u>

Notes:

1. The figures from Schedule A-9-A have been rounded to the nearest \$ million.

## SCHEDULE B2-A

### Operations, Maintenance, and Administration (\$ millions)

<u>Line</u>	<u>Reference</u>	<u>F2005</u>	<u>F2006</u>
		Plan	Plan
	Operations, Maintenance, and Administration <sup>1</sup>		
1	Operations	171	129
2	Maintenance	243	139
3	Administration	163	139
4	A-1-A	<u>577</u>	<u>407</u>
	Operations, Maintenance, and Administration		
	Domestic Operations		
5	Generation (Heritage Contract)	168.3	169.8
6	Energy Supply Cost less Heritage Payment Obligation <sup>2</sup>	35.4	33.5
7	Transmission	182.9	19.7
8	Electricity Distribution and Non-Integrated Areas	133.3	133.4
9	Customer Care <sup>2</sup>	110.0	105.7
10	Corporate	(60.6)	(62.5)
11	Engineering Services	(0.6)	(0.6)
12	Field Services	(7.6)	(8.6)
13	MMBU	0.6	0.6
14	Powertech	13.1	13.6
15	Total OMA for Domestic Operations	<u>574.8</u>	<u>404.6</u>
16	Allocation of Corporate costs to Powerex	E1	2.3
17		<u>577.1</u>	<u>406.9</u>

**Notes:**

1. The figures from Schedule A-1-A have been rounded to the nearest \$ million.
2. Powersmart and energy management costs are discussed in Chapter 8, "Powersmart, Customer Care and Energy Management" but are included together with energy supply costs as discussed in Chapter 4.

## SCHEDULE B5-A

### Finance Charges (\$ millions)

<u>Line</u>	<u>Reference</u>	<u>F2005</u> Plan	<u>F2006</u> Plan
Finance Charges <sup>1</sup>			
	Interest on Debt Securities		
1	- bonds, notes and debentures	\$484	\$507
2	- revolving borrowings	16	25
3	Amortization of deferred debt costs and other expenses	<u>30</u>	<u>34</u>
4		\$530	\$566
Less:			
5	Sinking fund income	(55.0)	(50.0)
6	Other income	(20.0)	(14.0)
7	Finance charges capitalized to unfinished construction	<u>(25.0)</u>	<u>(41.0)</u>
8		<u>(100.0)</u>	<u>(105.0)</u>
9	Total	430.0	461.0
	A-1-A		
Allocation of Finance Charges by Functional Area			
10	Generation (Heritage Contract)	193.0	205.0
11	Energy Supply Cost less Heritage Payment Obligation <sup>2</sup>	4.2	4.6
12	Transmission	121.1	129.1
13	Electricity Distribution and Non-Integrated Areas	102.2	114.2
14	Corporate	<u>9.5</u>	<u>8.1</u>
15	Total	<u>430.0</u>	<u>461.0</u>

Notes:

1. The figures from Schedule A-1 have been rounded to the nearest \$ million.
2. Powersmart and energy management costs are discussed in Chapter 8, "Powersmart, Customer Care and Energy Management" but are included together with energy supply costs as discussed in Chapter 4.

Total finance charges less the portion attributable to Corporate are allocated based on the percentages shown in Schedule B7 in Chapter 2 of the Application.

The Corporate portion relates to the deemed interest charges on assets held in BCH Service Asset Corporation (see section 6.2.2, chapter 2).

## SCHEDULE C-A

### Functional Revenue Requirements Summary (\$ millions)

<u>Line</u>	<u>Reference</u>	<u>F2005</u> Plan	<u>F2006</u> Plan	
1	Cost of Service - Generation (Heritage Contract)	C1-A	1,140.7	1,095.2
2	Cost of Service - Energy Supply Cost less Heritage Payment Obligation <sup>1</sup>	C2-A	464.8	483.7
3	Cost of Service - Transmission BC Hydro portion	C3-A	550.4	390.0
4	Cost of Service - Electricity Distribution and Non-Integrated Areas	C4-A	525.8	551.9
5	Cost of Service - Customer Care <sup>1</sup>	C5	105.8	101.5
6	Cost of Service - Corporate	C6	-	-
7	Cost of Service - Service Organizations and Subsidiaries	C7	3.3	3.0
8			<u>2,790.8</u>	<u>2,625.3</u>
9	Asset Management Fee from BCTC	BCTC	-	116.7
10	Wholesale Transmission Service Charges from BCTC	BCTC	-	61.0
11			<u>2,790.8</u>	<u>2,803.0</u>
12	Less: Transmission Point-to-Point Wheeling in Miscellaneous Revenues <sup>2</sup>	A-8	5.5	-
13	Inter-Segment Revenues	A-1	125.0	116.0
14			<u>130.5</u>	<u>116.0</u>
15	Total Cost of Service		<u>2,660.3</u>	<u>2,687.0</u>
Contributions by Customer Segment				
16	Residential		1,050	1,073
17	Light Industrial and Commercial		976	996
18	Large Industrial		542	540
19	Other Energy Sales		91	92
20			<u>2,659</u>	<u>2,701</u>
21	Less: Other Utilities revenues included in Other Energy Sales		19	20
22			<u>2,640</u>	<u>2,681</u>
23	Net Income Shortfall		21	7
23	Rounding		(0.7)	(1)
23			<u>2,660.3</u>	<u>2,687.0</u>

Notes:

1. Powersmart and energy management costs are discussed in Chapter 8, "Powersmart, Customer Care and Energy Management" but are included together with energy supply costs as discussed in Chapter 4.
2. These relate to Wheeling tariff revenues and are therefore not deducted in calculating the Transmission Cost of Service. They are deducted in calculating BC Hydro's total cost of service.

## SCHEDULE C1 -A

### Cost of Service - Generation (Heritage Contract) (\$ millions)

<u>Line</u>	<u>Reference</u>	<u>F2005</u> <u>Plan</u>	<u>F2006</u> <u>Plan</u>
	Cost of Service - Generation (Heritage Contract)		
1	Generation OMA	\$ 168.3	\$ 169.8
2	Domestic Cost of Energy-Generation	496.5	441.6
3	GRTA charges from Transmission	43.3	43.3
4	Taxes	28.6	29.0
5	Depreciation and Amortization	130.2	126.3
6	Finance Charges	193.0	205.0
7	Allowed return on equity	<u>196.0</u>	<u>199.0</u>
8	Total Cost	<u>1,255.9</u>	<u>1,214.0</u>
9	Less: Trade Income	89.0	91.0
10	Other Utilities	18.9	19.4
11	Other miscellaneous Non-tariff revenues	<u>7.3</u>	<u>8.4</u>
12		<u>115.2</u>	<u>118.8</u>
13	Total Cost of Service - Generation <sup>1</sup>	<u>\$ 1,140.7</u>	<u>\$ 1,095.2</u>

**Note:**

1. This is not the same as the Heritage Payment Obligation. The reconciliation is shown in Schedules D1-2-A and D1-3-A.

**SCHEDULE C2-A**

**Cost of Service - Energy Supply Cost less Heritage Payment Obligation**  
(\$ millions)

<u>Line</u>		<u>Reference</u>	<u>F2005</u> <u>Plan</u>	<u>F2006</u> <u>Plan</u>
	Cost of Service - Energy Supply Cost less Heritage Payment Obligation			
1	Depreciation and Amortization <sup>1</sup>	B4	27.9	32.9
2	Finance Charges	B5-A	4.2	4.6
3	Allowed ROE <sup>2</sup>	B6	<u>4.3</u>	<u>4.7</u>
4			36.4	42.2
5	Power Smart OMA	D3	<u>22.6</u>	<u>22.4</u>
6			<u>59.0</u>	<u>64.6</u>
7	IPP Cost of Energy and long-term purchase commitments	A-9-A	380.0	395.0
8	Gas transportation & domestic transmission	A-9-A	<u>13.0</u>	<u>13.0</u>
9	Domestic cost of energy-Energy Supply Cost		<u>393.0</u>	<u>408.0</u>
10	Energy Management OMA	D2	12.8	11.1
11	Cost of Service-Energy Supply Cost less Heritage Payment Obligation		<u>464.8</u>	<u>483.7</u>

Notes:

- 90% of DSM amortization is shown as part of Energy Supply Cost and 10% is shown as part of Transmission (Schedule C3-A).
- Includes purchase commitments entered into before F2001 and agreements from F2001. See Chapter 4 Table 4-1.

**SCHEDULE C3-A - Cost of Service - Transmission**  
(\$ millions)

Line	Reference	F2005	F2006		
		Plan	BC Hydro	BCTC	
1	Operating, Maintenance & Administration (Note 1)	D4-A	182.9	19.7	166.1
2	Cost of Market (Note 2)	B1	1.0	-	5.8
Asset Related Expense					
3	Finance Charge	B5-A	121.1	129.1	1.7
4	Depreciation & Amortization (Note 3)	B4	151.9	142.7	16.7
5	Grants & Taxes	B3	89.5	90.5	0.3
6	Allowed Return	B6	123.0	126.0	3.9
7	<b>Total Cost</b>		<b>669.4</b>	<b>508.0</b>	<b>194.5</b>
Less Non-WTS Revenues and Recoveries					
8	Generation Related Transmission Assets	C1-A	(43.3)	(43.3)	
9	Substation Distribution Asset Management	C4-A	(67.7)	(69.0)	
10	Aquila General Wheeling Agreement	A8	(3.8)		(3.8)
11	Secondary Revenues	A8	(4.2)	(5.7)	
12	<b>Total Non-WTS Revenues and Recoveries</b>		<b>(119.0)</b>	<b>(118.0)</b>	<b>(3.8)</b>
13	<b>Total Transmission Revenue Requirement</b>		<b>550.4</b>	<b>390.0</b>	<b>190.7</b>

Notes:

- (1) F2004 includes \$11.1 million in restructuring costs.
- (2) F2003 through F2005 reflects Congestion Mgmt cost only, F2006 reflects Ancillary Services cost plus Congestion Mgmt.
- (3) Includes 10% of amortization relating to DSM. Remaining 90% is shown in Energy Supply Cost - Cost of Service (Schedule C2-A). 10% of DSM amortization equates to \$2.5M, \$3.1M, and \$3.6M respectively for F2003 to F2006.

**SCHEDULE C4-A**

**Cost of Service - Electricity Distribution and Non-Integrated Areas**  
(\$ millions)

<u>Line</u>		<u>Reference</u>	<u>F2005</u> Plan	<u>F2006</u> Plan
	Cost of Service - Electricity Distribution and Non-integrated Areas			
1	Domestic Cost of Energy - Non-Integrated Areas	A9-A	15.0	15.0
2	Electricity Distribution and Non-Integrated Areas OMA	D5	133.3	133.4
3	Taxes	B3	18.8	19.1
4	Depreciation and Amortization	B4	89.6	93.4
5	Finance Charges	B5	102.2	114.2
6	Allowed Net Income	B6	103.7	112.3
7	Sub-Total		<u>462.6</u>	<u>487.4</u>
8	Distribution Substations (from Transmission)	C3-A	67.7	69.0
9	Cost of Service - Electricity Distribution and Non-Integrated Areas		<u>530.3</u>	<u>556.4</u>
10	Less: Miscellaneous non-tariff revenues	A-8	4.5	4.5
11	Total Cost of Service - Electricity Distribution and Non-integrated areas		<u>525.8</u>	<u>551.9</u>

SCHEDULE D1-2-A (Revised)

	A	B	
	F2005	F2006	
	Plan	Plan	Reference
1	<b>Domestic Cost of Energy - Generation (Heritage Contract)</b>		
2	<b>For the Years Ended March 31</b>		
3	<b>(\$ millions)</b>		
4			
5			
6			
7			
8			
9	Domestic Cost of Energy - Generation (Heritage Contract)		
10	258.3	280.6	A-9-A
11	183.1	112.1	A-9-A
12	Natural gas for thermal generation		
13	24.4	16.1	A-9-A
14	11.6	10.2	A-9-A
15	Other		
16	(3.5)	-	A-9-A
17	7.2	7.3	A-9-A
18	<u>481.1</u>	<u>426.3</u>	
19			
20			
21	3.6	3.5	
22	11.8	11.8	
23	<u>15.4</u>	<u>15.3</u>	A-9-A
24	<u>496.5</u>	<u>441.6</u>	
25			
26			
27			
28	<b>Reconciliation of Domestic Cost of Energy - Generation (Heritage Contract)</b>		
29	<b>to the cost of energy component of the Heritage Payment Obligation</b>		
30	496.5	441.6	
31	(7.5)	(5.8)	
32			
33			
34	Cost of energy component		
35	<u>\$489.0</u>	<u>\$435.8</u>	
36			

Notes:

1. Displaced Hydro relates to water rentals associated with trade income.

This schedule corresponds to Schedule D1-2 on page 2-80 of the Application. As in the Application, the costs shown on the Domestic Cost of Energy Schedule A-9-A, relating to IPP and long-term purchase commitments, net purchases from Powerex, non-integrated energy, gas transportation and congestion management are not Heritage energy. The remainder of the energy costs shown on Schedule A-9-A relate to Heritage energy and tie into the schedule above.

SCHEDULE D1-3-A (Revised)

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## Forecast Heritage Payment Obligation For the Years Ended March 31 (\$ millions)

	A	B	
	F2005	F2006	
	Plan	Plan	Reference
Cost Components of Heritage Payment Obligation			
Cost of Energy component of Heritage Payment Obligation	\$ 489.0	\$ 435.8	D1-2-A
Operating Costs	168.3	169.8	
Depreciation and Amortization	130.2	126.3	
Taxes and Grants	28.6	29.0	
Finance Charges	193.0	205.0	
GRTA Expenses	43.3	43.3	
Gross Heritage Payment Obligation	1,052.4	1,009.2	
Less Other Revenues			
Skagit Valley Treaty	18.9	19.4	
Ancillary Services and Other Miscellaneous Revenue	7.3	8.4	
Total Other Revenues	26.2	27.8	
Net Costs	1,026.2	981.4	
Add: Return on Equity	196.0	199.0	
Forecast Heritage Payment Obligation	\$ 1,222.2	\$ 1,180.4	

The shaded numbers represent the figures that have changed from the forecasts in the Application. The differences from the Application are as follows:

	F2005	F2006
Increase in cost of energy <i>(Note 1)</i>	\$ 77.7	\$ 55.9
Decrease in finance charges <i>(Note 2)</i>	(15.0)	(15.0)
Decrease in Skagit Valley Treaty <i>(Note 3)</i>	1.2	1.3
	\$ 63.9	\$ 42.2

**Notes:**

1. This increase primarily relates to the impact of lower expected water inflows. This is discussed further in Section 3.4. The increase in the cost of energy component is also partly caused by a small increase in the Heritage Supply volume of 83 GWh in F2005 and 78 GWh in F2006 (Refer to BCUC IR # 1.16.1). This increase in volumes results in an increase in the cost of energy component of \$0.7 million and \$0.6 million for F2005 and F2006 respectively. The increase in the water rental fees as explained on page 2A-9 also contributes to the increase in energy costs.

	F2005	F2006
Cost of Energy component of HPO - Revised Evidentiary Update	\$ 489.0	\$ 435.8
Cost of Energy component of HPO - Application	411.3	379.9
Increase in cost of energy	\$ 77.7	\$ 55.9

2. This decrease relates to the decrease in finance charges attributable to the Heritage Contract. The portion attributable to the Heritage Contract is determined by its proportion of rate base. This methodology is detailed on Schedule B5, page 2-67 and Schedule B7, page 2-69 of the Application. The decrease in total finance charges is explained in Section 3.6.

	F2005	F2006
Finance Charges - Revised Evidentiary Update	\$ 193.0	\$ 205.0
Finance Charges - Application	208.0	220.0
Decrease in finance charges	\$ (15.0)	\$ (15.0)

3. This decrease is due to the stronger Canadian dollar assumptions. These revenues are in US dollars. As a result, a stronger Canadian dollar reduces the Canadian dollar equivalent of these revenues.

	F2005	F2006
Skagit Valley Treaty - Revised Evidentiary Update	\$ 18.9	\$ 19.4
Skagit Valley Treaty - Application	20.1	20.7
Decrease in Skagit Valley Treaty	\$ 1.2	\$ 1.3

**SCHEDULE D1-4-A**

**Cost of Service - Generation (Heritage Contract) (reconciled with cost of energy component from Heritage Payment Obligation)**  
(\$ millions)

<u>Line</u>	<u>Reference</u>	<u>F2005</u> Plan	<u>F2006</u> Plan	
Cost of Service - Generation (Heritage Contract)				
1	Cost of Energy component of Heritage Payment Obligation	D1-3-A	\$ 489.0	\$ 435.8
2	Displaced Hydro	D1-2-A	7.5	5.8
3	Domestic cost of energy-Generation (Heritage Contract)	D1-2-A	496.5	441.6
4	Generation OMA	D1-1	168.3	169.8
5	GRTA charges from Transmission	C3-A	43.3	43.3
6	Taxes	B3	28.6	29.0
7	Depreciation and Amortization	B4	130.2	126.3
8	Finance Charges	B5-A	193.0	205.0
9	Allowed return on equity	B6	196.0	199.0
10	Total Cost		<u>1,255.9</u>	<u>1,214.0</u>
11	Less: Trade Income	A-1-A	89.0	91.0
12	Other Utilities		18.9	19.4
13	Other miscellaneous Non-tariff revenues	A-8	7.3	8.4
14			<u>115.2</u>	<u>118.8</u>
15	Total Cost of Service - Generation	C1-A	<u>\$ 1,140.7</u>	<u>\$ 1,095.2</u>

**SCHEDULE D4-A Resource Usage - Transmission**  
(\$ millions)

Line		F2006		
		F2005	Plan	
		Plan	BC Hydro	BCTC
Operating, Maintenance, and Administration Expenses by Resource				
	Labour			
1	Direct	28.1		28.6
2	Indirect	11.2		11.4
3	Materials	4.4		4.4
	BC Hydro Services			
4	Engineering	14.2		14.2
5	Field Services	69.2		69.2
6	BC Hydro Corporate Direct Charges	5.7	4.8	0.9
7	Other BC Hydro Billings	3.8		4.9
	External Services			
8	ABS*	10.0		10.6
9	Other	29.5		28.0
10	Buildings & Equipment	2.9		2.8
11	Vehicles	0.1		0.1
12	Corporate Allocation	15.4	16.2	
13	Less: Capitalized Overhead	(5.2)		(5.2)
	Less: Recoveries			
14	Internal	(6.3)	(1.3)	(3.7)
15	External	(0.1)		(0.1)
16	<b>Total OMA Expenses</b>	<b>182.9</b>	<b>19.7</b>	<b>166.1</b>
Operating, Maintenance, and Administration Expenses by Category				
17	Direct	154.0	4.8	151.1
18	Support	25.1		24.0
19	Corporate Allocations	15.4	16.2	
20	Less: Capitalized Overhead	(5.2)		(5.2)
21	Less: Recoveries	(6.4)	(1.3)	(3.8)
22	<b>Total OMA Expenses</b>	<b>182.9</b>	<b>19.7</b>	<b>166.1</b>
Capital Expenditures				
23	Sustaining	155.0	104.0	43.0
24	Growth	89.0	162.0	
25	CIA	(8.0)	(9.0)	
26	<b>Total Capital Expenditures</b>	<b>236.0</b>	<b>257.0</b>	<b>43.0</b>
Headcount				
27	M&P	181	-	181
28	IBEW	98	-	98
29	OPEIU	47	-	47
30	<b>Total Headcount</b>	<b>326</b>	<b>-</b>	<b>326</b>

\* Internal charges from the Shared Service organization that was outsourced to ABS in F2004 have been classified as ABS costs for F2003 even though the outsourcing did not occur until F2004.

F2004 includes \$11.1 million relating to restructuring costs.