

Richard Stout

Chief Regulatory Officer

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March 1, 2005

Mr. Robert J. Pellatt
Commission Secretary
British Columbia Utilities Commission
Sixth Floor – 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Mr. Pellatt:

**RE: British Columbia Hydro and Power Authority (“BC Hydro”)
Fiscal 2006 (“F2006”) Allowed Return on Equity (“ROE”)**

BC Hydro is writing to the British Columbia Utilities Commission (the “Commission”) regarding its allowed ROE for F2006, which commences on April 1, 2005. Based on its calculations as set out in Attachment No. 1, BC Hydro has determined that its allowed ROE for F2006 is 13.52%, a reduction of .39% from its allowed F2005 ROE of 13.91%. BC Hydro has also determined that the reduction in ROE will require a rate decrease of 0.15% in F2006.

The rate reduction of 0.15% for F2006 translates into a reduction in revenues of \$3 million. Due to the relatively minor reduction in revenue and considering the costs of implementing a rate reduction on April 1, 2005, BC Hydro is hereby proposing to reflect the reduced ROE for F2006 by way of a transfer of \$3 million to its deferral accounts, rather than by reducing its rates. At December 31, 2004 the net amount in BC Hydro’s deferral accounts was a debit of \$87 million, therefore, the balance in the deferral account as of December 31, 2004 will be reduced by \$3 million.

Discussion

As per Special Direction HC2 issued to the Commission, BC Hydro’s allowed ROE is to be equal to the pre-income tax annual rate of return allowed by the Commission to the most comparable investor-owned utility regulated under the Utilities Commission Act.

In its Decision of October 29, 2004 regarding BC Hydro’s F2005 and F2006 Revenue Requirements Application, the Commission stated that “for F2006 the allowed pre-income tax rate of return for BC Hydro will be determined based on the F2005 allowed rate of return on equity and the 2005 effective income tax rate for Terasen”.

On November 18, 2004 the Commission issued letter No. L-55-04 which set out the appropriate rate of return on common equity for a low-risk benchmark utility in 2005 at 9.03%. Terasen is considered to be the low-risk benchmark utility and therefore, BC Hydro has used this allowed ROE of 9.03% in its calculation. BC Hydro has also

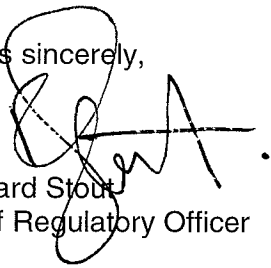


calculated that Terasen's income tax rate for 2005 is 33.20%, based on its approved 2005 rates after review by the Commission (see Attachments No. 1 and No. 2).

All relevant A to E Schedules, which were filed with the Commission in November and December 2004, have been updated to reflect the allowed F2006 ROE of 13.52% and the transfer of \$3 million to BC Hydro's deferral accounts (See Attachment No. 3 - Schedules).

BC Hydro therefore requests that the Commission approve BC Hydro's allowed ROE for F2006 at 13.52% and also to permit BC Hydro to forego a rate decrease of 0.15% on April 1, 2005 and instead, transfer an amount of \$3 million to its deferral accounts in order to reduce BC Hydro's allowed F2006 ROE to 13.52%.

Yours sincerely,



Richard Stout
Chief Regulatory Officer

Enclosure (3)

Attachment 1

BC Hydro calculates its allowed ROE using Terasen's 2005 allowed rate of return of 9.03% and Terasen's effective income tax rate.

Terasen's 2005 rates have now been approved by the Commission and Terasen's effective income tax rate can be calculated as follows (using Terasen's approved forecast income tax calculation – see Attachment No. 2)

(income tax expense – Large Corporation Tax) / (accounting income after tax + income tax expense – Large Corporation Tax)

$$(\$38,321 - \$3,049) / (\$70,975 + \$38,321 - \$3,049)$$

$$= \$35,272 / \$106,247$$

$$= \mathbf{33.20\%}$$

BC Hydro's allowed rate of return on a pre-income tax basis is therefore calculated as follows:

Terasen allowed after rate of return / (1 – Terasen effective income tax rate)

$$9.03 / (1 - .332)$$

$$9.03\% / .668 = \mathbf{13.52\%}$$
 allowed ROE on pre-income tax basis.

Attachment 2

INCOME TAXES / REVENUE DEFICIENCY
FOR THE YEAR ENDING DECEMBER 31, 2005
(\$000)

Line No.	Particulars (1)	2005				November 19, 2004 Annual Change (5)	Reference (7)
		2005 Advance Payments (2)	Existing Rates (3)	Revised Revenue (4)	Total (5)		
CALCULATION OF INCOME TAXES							
1	Earned Return	\$183,587	\$184,067	(\$1,439)	\$182,628	(\$959)	Current Applical
2	Deduct - Interest on Debt	(111,230)	(111,230)	1	(11,229)	1	
3	Add - Non-Tax Ded. Expense (Net)	(357)	(424)	0	(424)	(57)	Tab A-6, Page
4	Accounting Income After Tax	71,990	72,413	(1,438)	70,976	(1,015)	
5	Add (Deduct) - Timing Differences	(10,273)	(10,273)	0	(10,273)	0	Tab A-6, Page
6	Add - Large Corporation Tax	3,032	3,024	25	3,049	17	
7	Taxable Income After Tax	\$54,749	\$65,164	(\$1,413)	\$63,751	(\$986)	
8	Income Tax Rate (Current Tax)	35.620%	35.620%	35.620%	35.620%	0.000%	
9	1 - Current Income Tax Rate	64.380%	64.380%	64.380%	64.380%	0.000%	
10	Taxable Income (L10 - L13)	\$100,573	\$101,218	(\$2,195)	\$99,023	(\$1,950)	
11	Income Tax - Current (L12 x L15)	\$35,824	\$36,054	(\$782)	\$35,272	(\$552)	
12	Large Corporation Tax	3,032	3,024	25	3,049	17	
13	Total	\$36,856	\$39,078	(\$757)	\$38,321	(\$335)	Current Applical
REVENUE DEFICIENCY							
14	Earned Return	\$183,587		(\$1,439)	\$182,628	(\$959)	Current Applical
15	Add - Income Taxes	38,856		(757)	38,321	(535)	Current Applical
16	Deduct - Utility Income Before Taxes,	(223,494)		0	(223,145)	349	Current Applical
17	Existing Rates	0		0	0	0	
18	Corporate Capital Tax						
19	Deficiency After Corporate Capital Tax	(\$1,651)		(12,196)	\$2,198	(\$1,145)	

Attachment 3

Consolidated Statement of Operations with Proposed Rate Increases
For the Years Ended March 31
(\$ millions)

	A	B	C	D
	F2003	F2004	F2005	F2006
	Actual	Actual	Forecast	Forecast
REVENUES				
Domestic				
Residential	\$ 923	\$ 960	\$ 1,018	\$ 1,032
Light industrial and commercial	893	912	948	958
Large industrial	516	525	526	521
Other energy sales	88	89	89	90
Miscellaneous	55	67	61	55
	<u>2,475</u>	<u>2,553</u>	<u>2,642</u>	<u>2,656</u>
Intersegment revenues	6	62	125	116
	<u>2,481</u>	<u>2,615</u>	<u>2,767</u>	<u>2,772</u>
EXPENSES				
Domestic energy costs	708	995	903	855
BCTC wholesale transmission service	-	-	-	61
BCTC asset management fee	-	-	-	117
Operations expense	143	168	171	129
Maintenance expense	196	240	244	138
Administration expense	167	168	156	134
Depreciation and amortization	414	536	416	420
Taxes	145	146	145	147
	<u>1,773</u>	<u>2,253</u>	<u>2,035</u>	<u>2,001</u>
INCOME BEFORE FINANCE CHARGES, RESTRUCTURING COSTS, TRANSFER FROM RSA AND TRADE INCOME	708	362	732	771
Finance charges	457	435	428	463
INCOME BEFORE RESTRUCTURING COSTS, TRANSFER FROM RSA AND TRADE INCOME	251	(73)	304	308
Restructuring Costs	37	8	-	-
INCOME BEFORE TRANSFER FROM RSA AND TRADE INCOME	214	(81)	304	308
Transfer from RSA	66	21	-	-
DOMESTIC NET INCOME	<u>280</u>	<u>(60)</u>	<u>304</u>	<u>308</u>
TRADE NET INCOME	<u>138</u>	<u>158</u>	<u>89</u>	<u>91</u>
TOTAL NET INCOME BEFORE DEFERRAL ACCOUNTS	<u>418</u>	<u>98</u>	<u>393</u>	<u>399</u>
DEFERRAL ACCOUNT TRANSFERS	-	-	-	(3)
TOTAL NET INCOME	<u>\$ 418</u>	<u>\$ 98</u>	<u>\$ 393</u>	<u>\$ 396</u>
PAYMENT TO THE PROVINCE	<u>\$ 338</u>	<u>\$ 73</u>	<u>\$ 318</u>	<u>\$ 307</u>
ACTUAL/FORECAST RETURN ON EQUITY	15.47%	3.60%	13.91%	13.52%
ALLOWED RETURN ON EQUITY	15.47%	14.33%	13.91%	13.52%
BALANCE IN RSA	<u>\$ 21</u>	<u>\$ -</u>	<u>\$ -</u>	<u>\$ -</u>
RATE INCREASE	0.00%	0.00%	4.85%	0.00%
CUMULATIVE RATE INCREASE	<u>0.00%</u>	<u>0.00%</u>	<u>4.85%</u>	<u>4.85%</u>

Shaded amounts indicate changes from the November 2004 submission.

Schedule A-2 (February 2005)

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

	A	B	C	D
	F2003	F2004	F2005	F2006
	Actual	Actual	Forecast	Forecast
Capital Assets				
Capital assets in service	\$ 14,940	\$ 15,293	\$ 15,861	\$ 16,262
Less accumulated depreciation	5,816	5,964	6,252	6,540
	9,124	9,329	9,609	9,722
Unfinished construction	669	515	562	827
	9,793	9,844	10,171	10,549
Current Assets				
Temporary investments	4	47	4	4
Accounts receivable and accrued revenue	362	323	435	437
Materials and supplies	88	86	88	88
Prepaid expenses	86	108	87	68
Unrealized gains on mark-to-market transactions	10	104	-	-
	550	668	614	597
Other Assets and Deferred Charges				
Loan receivable	23	2	2	2
Sinking funds	1,037	981	984	844
Demand-Side Management programs	123	161	237	299
Deferred debt costs	385	150	84	51
Regulatory asset - VIGP/GSX (net) ¹	-	-	18	18
	1,568	1,294	1,325	1,214
	\$ 11,911	\$ 11,806	\$ 12,110	\$ 12,360
Long-Term Debt	7,890	7,881	7,992	8,245
Foreign Currency Contracts	2	63	65	60
Current Liabilities				
Accounts payable and accrued liabilities	689	672	536	462
Accrued interest	108	115	117	121
Accrued Payment to the Province	338	73	318	307
Unrealized losses on mark-to-market transactions	10	78	-	-
	1,145	938	971	890
Deferred Credits and Other Liabilities				
Deferral accounts	-	-	-	3
Provision for future removal and site restoration costs	174	202	-	-
Asset Retirement Obligation	-	-	19	20
Regulatory liability for FRSR provision ²	-	-	233	214
Deferred revenue	258	276	293	313
Rate stabilization account	21	-	-	-
Contributions arising from the Columbia River Treaty	203	193	184	175
Contributions in aid of construction	609	619	635	653
	1,265	1,290	1,364	1,378
Retained Earnings	1,609	1,634	1,718	1,787
	\$ 11,911	\$ 11,806	\$ 12,110	\$ 12,360
Debt to Equity Ratio	71.7:28.3	71.6:28.4	71.2:28.8	71.6:28.4

Notes:

1. As per Commission directive No. 59 of the October 29, 2004 decision.
2. As per Commission directive No. 50 of the October 29, 2004 decision.

Shaded amounts indicate changes from the November 2004 submission.

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

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	A	B	C	D
	F2003	F2004	F2005	F2006
	Actual	Actual	Forecast	Forecast
Retained earnings at beginning of year	\$ 1,529	\$ 1,609	\$ 1,634	\$ 1,700
Net income	418	98	393	396
Payment to the Province	(338)	(73)	(318)	(307)
Asset Retirement Obligation Adjustment ¹	-	-	(9)	-
Special Dividend to the Province for BCTC ²	-	-	-	(20)
Retained earnings at end of year	<u>\$ 1,609</u>	<u>\$ 1,634</u>	<u>\$ 1,700</u>	<u>\$ 1,769</u>
Regulatory Adjustment for VIGP/GSX ³	-	-	18	18
Regulatory Retained Earnings	<u>\$ 1,609</u>	<u>\$ 1,634</u>	<u>\$ 1,718</u>	<u>\$ 1,787</u>

Notes:

1. Relates to prior period adjustments to set up the ARO.
 2. The Special Dividend to the Province for BCTC was paid in fiscal 2004. It is shown in fiscal 2006, because BCTC is consolidated with BC Hydro in fiscal 2004 and fiscal 2005.
 3. Relates to Commission directive of October 29, 2004 decision.
- A regulatory asset is also shown on the balance sheet for this amount.

Shaded amounts indicate changes from the November 2004 submission.

SCHEDULE A-4 (February 2005)

Consolidated Statement of Cash Flows
For the Years ended March 31
(\$ millions)

	A	B	C	D
	F2003	F2004	F2005	F2006
	Actual	Actual	Forecast	Forecast
Operating Activities				
Net income	\$ 418	\$ 98	\$ 393	\$ 396
Adjustments for:				
Depreciation and amortization	417	539	421	424
Rate stabilization account transfers	(66)	(21)	-	-
Deferral account transfers	-	-	-	3
Other non-cash items	24	(4)	2	(18)
	793	612	816	805
Working capital changes	1	1	(227)	(53)
Cash provided by operating activities	794	613	589	752
Investing Activities				
Capital asset expenditures	(680)	(606)	(716)	(894)
Contributions in aid of construction	62	56	51	54
Demand side management programs	(45)	(63)	(101)	(93)
Future removal and site restoration costs	(12)	(15)	-	-
Net asset dismantling costs	-	-	(17)	(17)
Loan receivable	(8)	(1)	-	-
Proceeds from property and asset sales	1	10	4	79
Cash used for investing activities	(682)	(619)	(779)	(871)
Financing Activities				
Bonds, notes and debentures				
Issued	1,007	790	600	700
Retired	(1,019)	(450)	(598)	(607)
Revolving borrowings changes	147	(47)	184	179
Sinking funds	48	53	34	185
Deferred debt costs	3	7	-	-
Settlement of financial instruments	22	34	-	-
Cash provided by financing activities	208	387	220	457
Payment to the Province	(333)	(338)	(73)	(318)
Special Dividend to the Province for BCTC	-	-	-	(20)
Increase (decrease) in cash	(13)	43	(43)	-
Cash at beginning of year	17	4	47	4
Cash at end of year	\$ 4	\$ 47	\$ 4	\$ 4

Shaded amounts indicate changes from the November 2004 submission.

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

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	A		B		C		D	
	F2003	F2004	F2005	F2006	F2005	F2006	F2005	F2006
	Actual	Actual	% Forecast	% Forecast	% Forecast	% Forecast	% Forecast	% Forecast
Revenue								
Residential revenue	\$ 923	\$ 960	4%	\$ 1,018	6%	\$ 1,032	1%	
Revenue variance	n/a	\$ 37		\$ 58		\$ 14		
Variance								
Rate increase:		n/a		47		-		
Volume:								
Number of customers	n/a	15		15		17		
Usage per customer	n/a	28		(1)		1		
Power Smart savings	n/a	(6)		(3)		(4)		
Total Variance	n/a	\$ 37		\$ 58		\$ 14		
Sales Volume (in GW·h)	15,024	15,646	4%	15,836	1%	16,063	1%	

() represents a negative variance.

Residential revenues are expected to increase largely due to customer growth which is expected to be an average of 1.70% over the period from 2004 to 2006, and to the rate increase in F2005.

The usage variance in fiscal year 2004 is high due to Fiscal 2003 having a warmer than normal year. Forecast 2005 and 2006 assumes normal weather.

Shaded amounts indicate changes from the November 2004 submission.

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	Actual	%	Forecast	%	Forecast	%	
Revenue								
Light industrial & commercial	\$ 893	\$ 912	2%	\$ 948	4%	\$ 958	1%	
Revenue variance	n/a	\$ 19		\$ 36		\$ 10		
Variance								
Rate increase:		n/a		44		-		
Volume:								
GDP & Employment*	n/a	21		6		20		
Power Smart savings	n/a	(2)		(14)		(10)		
Total Variance	n/a	\$ 19		\$ 36		\$ 10		
Sales Volume (in GW·h)	16,757	17,175	0%	17,003	-1%	17,202	1%	

() represents a negative variance.

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

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

Shaded amounts indicate changes from the November 2004 submission.

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

	A		B		C		D	
	F2003	F2004	F2005	F2006	F2003	F2004	F2005	F2006
	Actual	Actual	%	Forecast	%	Forecast	%	Forecast
Revenue (in millions)								
Large industrial	\$ 516	\$ 525	2%	\$ 526	0%	\$ 521	-1%	
Revenue variance	n/a	\$ 9		\$ 1		\$ (5)		
Variance								
Rate increase:		n/a		24		-		
Volume:								
Usage per customer	n/a	14		(15)		1		
Power Smart savings	n/a	(5)		(8)		(6)		
Total Variance	n/a	\$ 9		\$ 1		\$ (5)		
Sales Volume (in GW·h)	15,179	15,505	2%	14,733	-5%	14,604	-1%	

() represents a negative variance.

Large industrial revenues are expected to increase largely due to the impact of the proposed rate increases. The increase in 2004 is due primarily to increased 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 positively impacted by the improvement in the Global economy. The pulp chemical sales are dependent on the pulp and paper sector and therefore have also been positively impacted.

Fiscal 2005 revenues are expected to increase largely due to the impact of the rate increase.

Shaded amounts indicate changes from the November 2004 submission.

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

	A	B	C	D
	F2003	F2004	F2005	F2006
	Actual	Actual	Forecast	Forecast
9 Actual/forecast return on equity	15.47%	3.60%	13.91%	13.52%
11 Allowed return on equity ¹	15.47%	14.33%	13.91%	13.52%
13 Numerator				
14 Consolidated net income after rate				
15 stabilization account transfer	\$ 418	\$ 98	\$ 393	\$ 396
17 Denominator				
18 Retained earnings - end of year	\$ 1,609	\$ 1,634	\$ 1,718	\$ 1,787
19 Deferred credits - end of year	1,091	1,088	1,112	1,141
20 Equity - end of year	\$ 2,700	\$ 2,722	\$ 2,830	\$ 2,928

22 Note:

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

26 **Definition of Return on Equity**

28 Return on equity = Consolidated Net Income / Ending Equity

29 Where Equity = Retained earnings + Deferred credits

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

31 Treaty and Contributions in aid of construction + RSA balance

	F2003	F2004	F2005	F2006
	Actual	Actual	Forecast	Forecast
35 Deferred Credits				
36 Deferred revenue	\$ 258	\$ 276	\$ 293	\$ 313
37 Contributions arising from the				
37 Columbia River Treaty	203	193	184	175
38 Contributions in aid of construction	609	619	635	653
39 Rate stabilization account	21	-	-	-
40	\$ 1,091	\$ 1,088	\$ 1,112	\$ 1,141

Shaded amounts indicate changes from the November 2004 submission.

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

	A	B	C	D
	F2003	F2004	F2005	F2006
	Actual	Actual	Forecast	Forecast
Debt to equity	72:28	72:28	71:29	72:28
Debt				
Long term debt net of sinking funds	\$ 6,853	\$ 6,900	\$ 7,008	\$ 7,401
Temporary investments	(4)	(47)	(4)	(4)
	<u>\$ 6,849</u>	<u>\$ 6,853</u>	<u>\$ 7,004</u>	<u>\$ 7,397</u>
Equity				
Deferred credits	\$ 1,091	\$ 1,088	\$ 1,112	\$ 1,141
Retained earnings	1,609	1,634	1,718	1,787
	<u>\$ 2,700</u>	<u>\$ 2,722</u>	<u>\$ 2,830</u>	<u>\$ 2,928</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

Shaded amounts indicate changes from the November 2004 submission.

Schedule A-18 (February 2005)

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Revenue Requirements
For the Years Ended March 31
(\$ millions)

	A	B
	F2005	F2006
	Forecast	Forecast
Domestic energy costs	\$ 903	\$ 855
BCTC wholesale transmission service		61
BCTC asset management fee		117
Operations expense	171	129
Maintenance expense	244	138
Administration expense	156	134
Amortization	416	420
Taxes	145	147
Finance charges	428	463
Total expenditures	2,463	2,464
Plus: Allowed return	393	396
Less:		
Trade Income	(89)	(91)
Intersegment revenues	(125)	(116)
Miscellaneous revenues	(61)	(55)
Revenues from Other Utilities	(19)	(20)
Total Revenue Requirement	2,562	2,578
Less:		
Light Fixture charges on		
Street Lighting (Non-tariff revenue)	(10)	(10)
Transfers to Deferral Accounts	-	3
Rounding	-	1
Total Tariff Revenues from Schedule A-19	\$ 2,552	\$ 2,572

Schedule A-19 (February 2005)

Domestic revenues
For the Years Ended March 31
(\$ millions)

	A	B
	F2005	F2006
	Forecast	Forecast
Domestic revenues before rate increase ¹	\$ 2,649	\$ 2,653
Less: Non-tariff revenues ² :		
Miscellaneous	(61)	(55)
Skagit River Treaty	(19)	(19)
Light fixture charges on Street Lighting	(10)	(10)
Intersegment revenues	(125)	(116)
Tariff revenues before rate increase	2,434	2,453
Cumulative Rate increase % ³	4.85%	4.85%
Tariff revenues after rate increase	<u>\$ 2,552</u>	<u>\$ 2,572</u>
Domestic revenues after rate increase ⁴	\$ 2,767	\$ 2,772
Less: Non-tariff revenues:		
Miscellaneous	(61)	(55)
Skagit River Treaty	(19)	(19)
Light fixture charges on Street Lighting	(10)	(10)
Intersegment revenues	(125)	(116)
Tariff revenues after rate increase	<u>\$ 2,552</u>	<u>\$ 2,572</u>

Notes:

1. From Table 2-2 in the December 2003 Application adjusted for changes in intersegment and Skagit revenues as documented in the Revised Evidentiary Update.
2. As per the Revised Evidentiary Update
3. Includes rate increase of 4.85% in F2005.
4. From Schedule A-1 (November 2004)

SCHEDULE B-3 (February 2005)

**Functionalized Costs
F2006**

(\$ millions)	Corporate	Energy Supply less Heritage Payment Obligation ¹	Generation (Heritage Contract) ²	Transmission	Electricity Distribution &NIA ⁷	Customer Care ¹	Service Orgs and Subsidiaries Chapter 9	Consolidated
	Chapter 3	Chapter 4	Chapter 5	Chapter 6	Chapter 7	Chapter 8	Chapter 9	
B1		408.0	431.6		15.0			854.6
	Domestic cost of energy							
	OMA Expenses							
	Operations, maintenance, and administration (net)	63.8	126.0	3.5	107.6	97.3	(18.2)	400.9
	Corporate Allocations	(121.3)	39.3	14.7	23.0	7.5	25.5	
	Adjusted OMA including Corporate Allocations	(57.5)	165.3	18.2	130.6	104.8	7.3	400.9
B4	Depreciation	52.0	113.4	138.0	71.1		17.2	419.6
B3	Taxes	7.5	29.0	90.5	19.1		1.0	147.1
B5	Finance charges	8.1	4.7	203.4	133.3			463.0
B6	Allowed net income (return on equity)		4.1	177.0	116.0			396.0
C3	Other ³				98.9			
A-1	Restructuring Costs		43.3		66.7			110.0
A-8	Miscellaneous external revenues							
	Cost of Service by Function	(10.1)	(118.8)	(115.7)	(4.5)	(4.2)	(22.5)	(275.8)
BCTC	Asset Management Fee to BCTC ⁴			380.3	510.4	100.6	3.0	2,515.4
BCTC	WTS Charges from BCTC ⁴							116.7
A-1	Intersegment revenues ⁵							61.0
	Total Revenue Requirement ⁶							(116.0)
								2,577.1

Schedule
to cross
reference

C6 C2 C1 C3 C4 C5 C7

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.
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)

Shaded amounts indicate changes from the November 2004 submission.

SCHEDULE B6 (February 2005)

Allowed Net Income (Return on Equity)
(\$ millions)

<u>Line</u>	<u>Reference</u>	<u>F2003</u> Actual	<u>F2004</u> Actual	<u>F2005</u> Forecast	<u>F2006</u> Forecast	
Allowed Net Income (Return on Equity)						
1	Allowed ROE%	Chapter 10	15.47%	14.33%	13.91%	13.52%
2	Ending Equity Balance	A-15	\$ 2,700	\$ 2,722	\$ 2,830	\$ 2,928
3	Allowed Net Income		\$ 418	\$ 396	\$ 393	\$ 396
Allocation of Allowed Net Income (Return on Equity)						
4	Generation (Heritage Contract)	C1	195.0	183.4	178.9	177.0
5	Energy Supply Cost less Heritage Payment Obligation	C2	4.0	4.0	3.9	4.1
6	Transmission	C3	123.0	119.1	117.4	116.0
7	Electricity Distribution and Non-Integrated Areas	C4	96.0	89.5	92.8	98.9
8	Total		<u>418.0</u>	<u>396.0</u>	<u>393.0</u>	<u>396.0</u>

Shaded amounts indicate changes from the November 2004 submission.

The Allowed ROE% for F2006 is shown in Appendix 1.

The Allowed Net Income is allocated based on the rate base % shown in Schedule B7.

SCHEDULE C (February 2005)

Functional Revenue Requirements Summary
(\$ millions)

<u>Line</u>	<u>Reference</u>	<u>F2003</u>	<u>F2004</u>	<u>F2005</u>	<u>F2006</u>	
		<u>Actual</u>	<u>Actual</u>	<u>Forecast</u>	<u>Forecast</u>	
1	Cost of Service - Generation (Heritage Contract)	C1	966.0	1,268.6	1,098.7	1,044.2
2	Cost of Service - Energy Supply Cost less Heritage Payment Obligation ¹	C2	346.1	446.2	458.0	476.9
3	Cost of Service - Transmission BC Hydro portion	C3	539.6	560.2	543.1	380.3
4	Cost of Service - Electricity Distribution and Non-Integrated Areas	C4	467.3	476.0	484.3	510.4
5	Cost of Service - Customer Care ¹	C5	92.7	111.1	104.9	100.6
6	Cost of Service - Corporate	C6	65.0	(8.7)	-	-
7	Cost of Service - Service Organizations and Subsidiaries	C7	(6.4)	0.9	3.3	3.0
8			<u>2,470.3</u>	<u>2,854.3</u>	<u>2,692.3</u>	<u>2,515.4</u>
9	Asset Management Fee from BCTC	BCTC	-	-	-	116.7
10	Wholesale Transmission Service Charges from BCTC	BCTC	-	-	-	61.0
11			<u>2,470.3</u>	<u>2,854.3</u>	<u>2,692.3</u>	<u>2,693.1</u>
12	Less: Transmission Point-to-Point Wheeling in Miscellaneous Revenues ²	A-8	0.8	4.9	5.5	-
13	Inter-Segment Revenues	A-1	6.0	62.0	125.0	116.0
14			<u>6.8</u>	<u>66.9</u>	<u>130.5</u>	<u>116.0</u>
15	Total Cost of Service		<u>2,463.5</u>	<u>2,787.4</u>	<u>2,561.8</u>	<u>2,577.1</u>
Contributions by Customer Segment						
16	Residential		923	960	1,018	1,032
17	Light Industrial and Commercial		893	912	948	958
18	Large Industrial		516	525	526	521
19	Other Energy Sales		88	89	89	90
	Transfer to Deferral Accounts		66	21	-	(3)
20			<u>2,486</u>	<u>2,507</u>	<u>2,581</u>	<u>2,598</u>
21	Less: Other Utilities revenues included in Other Energy Sales		22	18	19	20
22			<u>2,464</u>	<u>2,489</u>	<u>2,562</u>	<u>2,578</u>
23	Net Income Shortfall		-	298.4	-	-
24	Rounding adjustment		(0.5)	-	(0.2)	(0.9)
25			<u>2,463.5</u>	<u>2,787.4</u>	<u>2,561.8</u>	<u>2,577.1</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.

Shaded amounts indicate changes from the November 2004 submission.

SCHEDULE C1 (February 2005)

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

<u>Line</u>	<u>Reference</u>	<u>F2003</u> Actual	<u>F2004</u> Actual	<u>F2005</u> Forecast	<u>F2006</u> Forecast
	Cost of Service - Generation (Heritage Contract)				
1	Generation OMA	\$ 147.4	\$ 184.1	\$ 163.7	\$ 165.3
2	Domestic Cost of Energy-Generation	399.1	597.7	493.5	431.6
3	GRTA charges from Transmission	37.0	43.3	43.3	43.3
4	Taxes	29.0	28.2	28.6	29.0
5	Depreciation and Amortization	110.7	216.3	115.4	113.4
6	Finance Charges	213.0	197.0	190.5	203.4
7	Allowed return on equity	195.0	183.4	178.9	177.0
8	Total Cost	<u>1,131.2</u>	<u>1,450.0</u>	<u>1,213.9</u>	<u>1,163.0</u>
9	Less: Trade Income	138.0	158.0	89.0	91.0
10	Other Utilities	21.9	18.0	18.9	19.4
11	Other miscellaneous Non-tariff revenues	5.3	5.4	7.3	8.4
12		<u>165.2</u>	<u>181.4</u>	<u>115.2</u>	<u>118.8</u>
13	Total Cost of Service - Generation ¹	<u>\$ 966.0</u>	<u>\$ 1,268.6</u>	<u>\$ 1,098.7</u>	<u>\$ 1,044.2</u>

Note:

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

Shaded amounts indicate changes from the November 2004 submission.

SCHEDULE C2 (February 2005)

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

<u>Line</u>		<u>Reference</u>	<u>F2003</u>	<u>F2004</u>	<u>F2005</u>	<u>F2006</u>
			Actual	Actual	Forecast	Forecast
Cost of Service - Energy Supply Cost less Heritage Payment Obligation						
1	Depreciation and Amortization ¹	B4	22.4	21.6	22.9	27.9
2	Finance Charges ¹	B5	5.0	4.0	4.2	4.7
3	Allowed ROE ¹	B6	4.0	4.0	3.9	4.1
4			31.4	29.6	31.0	36.7
5	Power Smart OMA	D3	12.8	20.2	21.3	21.2
6			44.2	49.8	52.3	57.9
7	IPP Cost of Energy and long-term purchase commitments ²	A-9	289.4	372.2	380.0	395.0
8	Gas transportation & domestic transmission	A-9	5.2	9.9	13.0	13.0
9	Domestic cost of energy-Energy Supply Cost		294.6	382.1	393.0	408.0
10	Energy Management OMA	D2	7.3	14.3	12.7	11.0
11	Cost of Service-Energy Supply Cost less Heritage Payment Obligation		346.1	446.2	458.0	476.9

Notes:

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

Shaded amounts indicate changes from the November 2004 submission.

SCHEDULE C3 - Cost of Service - Transmission (February 2005)
(\$ millions)

Line	Reference	F2003	F2004	F2005	F2006 Forecast		
		Actual	Actual	Forecast	BC Hydro	BCTC	
1	Operating, Maintenance & Administration (Note 1)	D4	158.2	182.1	181.4	18.2	166.1
2	Cost of Market (Note 2)	B1	0.8	1.0	1.0	-	5.8
Asset Related Expense							
3	Finance Charge	B5	135.0	127.8	125.0	133.3	1.7
4	Depreciation & Amortization (Note 3)	B4	129.9	145.5	147.3	138.0	16.7
5	Grants & Taxes	B3	89.4	88.4	89.5	90.5	0.3
6	Allowed Return	B6	123.0	119.1	117.4	116.0	3.9
7	Total Cost		636.3	663.9	661.6	496.0	194.5
Less Non-WTS Revenues and Recoveries							
8	Generation Related Transmission Assets	C1	(37.0)	(43.3)	(43.3)	(43.3)	
9	Substation Distribution Asset Management	C4	(52.0)	(52.0)	(67.2)	(66.7)	
10	Aquila General Wheeling Agreement	A8	(3.8)	(3.7)	(3.8)		(3.8)
11	Secondary Revenues	A8	(3.8)	(4.7)	(4.2)	(5.7)	
12	Other Recoveries		(0.1)	-			
13	Total Non-WTS Revenues and Recoveries		(96.7)	(103.7)	(118.5)	(115.7)	(3.8)
14	Total Transmission Revenue Requirement		539.6	560.2	543.1	380.3	190.7

Notes:

- (1) F2004 includes \$8.3 million in restructuring costs.
- (2) F2003 through F2005 reflects Congestion Mgmt cost only, F206 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).

Shaded amounts indicate changes from the November 2004 submission.

SCHEDULE C4 (February 2005)

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

Line	Reference	F2003	F2004	F2005	F2006
		Actual	Actual	Forecast	Forecast
Cost of Service - Electricity Distribution and Non-integrated Areas					
1	A9	14.1	14.2	15.0	15.0
2	D5	102.0	128.0	130.6	130.6
3	B3	18.3	18.9	18.8	19.1
4	B4	87.6	83.7	65.6	71.1
5	B5	104.0	96.1	98.8	113.5
6	B6	96.0	89.5	92.8	98.9
7		422.0	430.4	421.6	448.2
8	C3	52.0	52.0	67.2	66.7
9		474.0	482.4	488.8	514.9
10	A-8	6.7	6.4	4.5	4.5
11		467.3	476.0	484.3	510.4

Shaded amounts indicate changes from the November 2004 submission.

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

	F2003	F2004	F2005	F2006	Reference
	Actual	Actual	Forecast	Forecast	
9 Cost Components of Heritage Payment Obligation					
10 Cost of Energy component of Heritage Payment Obligation	\$ 354.5	\$ 567.5	\$ 486.0	\$ 425.8	D1-2
11 Operating Costs	147.4	162.1	163.7	165.3	
12 Depreciation and Amortization	110.7	118.3	115.4	113.4	
13 Taxes and Grants	29.0	28.2	28.6	29.0	
14 Finance Charges	213.0	197.0	190.5	203.4	
15 GRTA Expenses	37.0	43.3	43.3	43.3	
16 Gross Heritage Payment Obligation	<u>891.6</u>	<u>1,116.4</u>	<u>1,027.5</u>	<u>980.2</u>	
17 Less Other Revenues					
18 Skagit Valley Treaty	21.9	18.0	18.9	19.4	
19 Ancillary Services and Other Miscellaneous Revenue	5.3	5.4	7.3	8.4	
20 Total Other Revenues	<u>27.2</u>	<u>23.4</u>	<u>26.2</u>	<u>27.8</u>	
21 Net Costs	864.4	1,093.0	1,001.3	952.4	
22 Add: Return on Equity	195.0	183.4	178.9	177.0	
23 Forecast Heritage Payment Obligation	<u>\$ 1,059.4</u>	<u>\$ 1,276.4</u>	<u>\$ 1,180.2</u>	<u>\$ 1,129.4</u>	

Shaded amounts indicate changes from the November 2004 submission.

SCHEDULE D1-4 (February 2005)

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

<u>Line</u>	<u>Reference</u>	<u>F2003</u> Actual	<u>F2004</u> Actual	<u>F2005</u> Forecast	<u>F2006</u> Forecast	
Cost of Service - Generation (Heritage Contract)						
1	Cost of Energy component of Heritage Payment Obligation	D1-3	\$ 354.5	\$ 567.5	\$ 486.0	\$ 425.8
2	Displaced Hydro	D1-2	(5.4)	0.2	7.5	5.8
	Electricity purchases Powerex	D1-2	50.0	30.0		
3	Domestic cost of energy-Generation (Heritage Contract)	D1-2	399.1	597.7	493.5	431.6
4	Generation OMA	D1-1	147.4	184.1	163.7	165.3
5	GRTA charges from Transmission	C3	37.0	43.3	43.3	43.3
6	Taxes	B3	29.0	28.2	28.6	29.0
7	Depreciation and Amortization	B4	110.7	216.3	115.4	113.4
8	Finance Charges	B5	213.0	197.0	190.5	203.4
9	Allowed return on equity	B6	195.0	183.4	178.9	177.0
10	Total Cost		1,131.2	1,450.0	1,213.9	1,163.0
11	Less: Trade Income	A-1	138.0	158.0	89.0	91.0
12	Other Utilities		21.9	18.0	18.9	19.4
13	Other miscellaneous Non-tariff revenues	A-8	5.3	5.4	7.3	8.4
14			165.2	181.4	115.2	118.8
15	Total Cost of Service - Generation	C1	\$ 966.0	\$ 1,268.6	\$ 1,098.7	\$ 1,044.2

Shaded amounts indicate changes from the November 2004 submission.