



FOR GENERATIONS

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July 7, 2010

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

Dear Ms. Hamilton:

**RE: British Columbia Utilities Commission (BCUC)
British Columbia Hydro and Power Authority (BC Hydro)
F2005/F2006 Revenue Requirements Application
BCUC Order No. G-96-04
Decision, October 29, 2004, Page 45, Directive No. 17, Page 218**

Pursuant to BCUC Directive No. 17 of the October 29, 2004 Decision concerning BC Hydro's F2005/F2006 Revenue Requirements Application, BC Hydro attaches its Fiscal 2010 Fourth Quarter Deferral Account report for the twelve-month period ending March 31, 2010. This report contains information on the Heritage Deferral Account (**HDA**), the Non-Heritage Deferral Account (**NHDA**), the Trade Income Deferral Account (**TIDA**), and the BCTC Deferral Account (**BCTCDA**).

For further information, please contact Guy Leroux at 604 623-3696.

Yours sincerely,

A handwritten signature in black ink, appearing to read "J. Sofield".

Joanna Sofield
Chief Regulatory Officer

Enclosure (1)



Deferral Account Report

For the Twelve Months Ended

March 31, 2010

(F2010 Q4)

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British Columbia Hydro and Power Authority
 Summary of Deferral Accounts
 For Twelve Months Ended March 31, 2010
 (\$ million)

Schedule A

Line No.	Particulars (1)	Opening Balance at April 1, 2009 (2)	Changes (Schedule B) (3)	Amortization (4)	Interest (5)	Ending Balance at March 31, 2010 (6)
1	Heritage Deferral Account (HDA)	\$328.9	\$3.1	(\$29.3)	\$22.2	\$324.9
2	Non-Heritage Deferral Account (NHDA)	74.4	44.9	(6.6)	6.8	119.5
3	Trade Income Deferral Account (TIDA)	(79.9)	191.5	7.1	3.0	121.7
4	BCTC Deferral Account	9.7	9.6	(0.9)	0.2	18.7
5	Total	\$333.1	\$249.1	(\$29.7)	\$32.2	\$584.8

6
7

8 In the October 29, 2004 BCUC Decision, the Commission approved the creation of four deferral accounts to capture
 9 the differences between forecasts used in setting rates and actuals. The forecast used in this deferral account report is the
 10 F2010 test year forecast as approved by the BCUC F09/F10 RRA Decision dated March 13, 2009.

11

12 The transfers into the HDA of \$3.1 million are due to a variety of reasons (Schedule B).

13

14 The transfers into the NHDA of \$44.9 million are largely due to the impact of lower customer load. This was partly offset by
 15 lower deliveries from IPPs.

16

17 The transfers into the TIDA are as a result of trade income being below forecast for the twelve months ended March 31, 2010.
 18 The shortfall in trade income is largely attributable to the impact of lower spreads in the market and the impact
 19 of the U.S. to Canadian dollar exchange rate.

20

21 Revenues collected via the Deferral Account Rate Rider (DARR) are used to amortize (reduce) the deferral account balances.
 22 The reduction is allocated to each deferral account based on the proportion of the ending F2009 deferral account balances.

23

24 Interest is calculated on the ending monthly balance (before interest) in each deferral account. The interest rate used is
 25 6.55 per cent, which is BC Hydro's weighted cost of debt for the prior fiscal year-end as agreed to in the F07/F08 RRA NSA.

26

27 Due to minor rounding some totals may not add.

British Columbia Hydro and Power Authority
 Summary of Deferral Account Changes
 For Twelve Months Ended March 31, 2010
 (\$ in millions)

Schedule B

Line No.	Particulars (1)	Actual (2)	RRA (3)	Variance (4)	Ref. (5)
1	Heritage Deferral Account				
2	Cost of Energy - Total Heritage	\$ 454.8	\$ 446.6	\$ 8.2	Sch C - Line 8
3	Notional Water Rental (Displaced Hydro)	10.8	1.5	9.3	Sch F - Note 1
4	Mark to market (gains)/losses on derivatives	(10.6)	-	(10.6)	Sch F - Note 2 Line 33
5	Significant unplanned major maintenance costs	2.1	-	2.1	Note 1
6	Skagit Valley Treaty & Ancillary revenue	(19.4)	(22.6)	3.2	
7	Amortization of unplanned deferred capital cost per				
8	BCUC Order No. G-53-02	5.7	6.7	(1.0)	
9	Transfer of GMS3 related cost of energy opportunity costs	(8.3)	-	(8.3)	Note 2
10	Variable cost related to thermal generation	0.2	-	0.2	Sch. F - Note 6
11	Total	<u>\$ 435.3</u>	<u>\$ 432.2</u>	<u>\$ 3.1</u>	
12					
13	Non-Heritage Deferral Account				
14	Cost of Energy - Total Non-Heritage	\$ 667.2	\$ 690.0	\$ (22.8)	Sch C - Line 20
15	Notional Water Rental (Displaced Hydro)	(10.8)	(1.5)	(9.3)	Sch F - Note 1
16	Unrealized value of monthly gas requirements	(0.4)	-	(0.4)	Sch E - Line 9
17	FX (gain) / loss on Powerex trade account	(4.5)	-	(4.5)	Sch F - Note 3
18	Subtotal	<u>\$ 651.5</u>	<u>\$ 688.5</u>	<u>(37.0)</u>	
19	Domestic revenue variance			82.5	Sch F - Note 4
20	Founding Partner Benefits - ABS Contract			(0.6)	
21	Total			<u>\$ 44.9</u>	
22					
23	Trade Income Deferral Account				
24	Powerex Net Income (Loss)			\$ 7.5	Note 3
25	Excess below threshold for deferral account transfer			-	
26				7.5	
27	Less: Trade Income from RRA Decision			199.0	
28	Total			<u>\$ 191.5</u>	
29					
30	BCTC Deferral Account				
31	BCTC Asset Management Fee:				
32	Transmission Assets	\$ 92.4	\$ 92.4	\$ -	
33	Generation Related Transmission Assets	8.2	8.2	-	
34	Substation Distribution Assets	16.8	14.7	2.1	
35	Net NITS and PTP Charges:				
36	Total NITS and PTP Charges	573.7	591.9	(18.2)	
37	Less: Intersegment Revenues - NITS	(442.8)	(456.6)	13.8	
38	Less: Intersegment Revenues - PTP	(60.0)	(60.5)	0.5	
39	Less: Charges Included in HDA and TIDA	(42.9)	(46.4)	3.5	
40	External PTP Revenues	(8.2)	(8.3)	0.1	
41	Subtotal	<u>\$ 137.2</u>	<u>\$ 135.4</u>	<u>1.8</u>	
42	Reconciling Difference from F2009			(0.5)	Note 4
43	Adjustment of F09 deferral baseline to the approved RRA			8.3	Note 5
44	Total			<u>\$ 9.6</u>	
45					
46					
47	1) Significant unplanned major maintenance costs for F2010 consists of \$1.8 million related to the Revelstoke Stator Lamination repairs and \$0.3 million related to the Kootenay Canal concrete lining repairs. The total to-date cost to repair the Kootenay Canal concrete amounted to \$1.8 million, of which \$1.5 million was deferred in F2009.				
48	2) Per the March 13, 2009 F09/F10 RRA Decision, BC Hydro was directed to transfer out of the HDA any unplanned maintenance costs as well as opportunity cost of energy associated with the GMS3 repairs into the GMS3 Regulatory Account. For the twelve months ended March 31, 2010, \$8.3 million related to the cost of energy opportunity cost was transferred from the HDA into the GMS3 Regulatory Account.				
49	3) Powerex net income reported for regulatory purposes is net of the \$4.3 million corporate overhead allocation from BC Hydro to Powerex in accordance with Directive 9 of the F09/F10 RRA Decision.				
50	4) As noted on Schedule B, Line 44 of the F2009 Fourth Quarter Deferral Account report, the difference between the reported F2009 BCTC deferral addition of \$6.7 million and the \$6.2 million reported in BC Hydro's Annual Report is to be reflected in F2010 results.				
51	5) Adjustment is the result of a change in the F2009 baseline to comply with the approved RRA.				

British Columbia Hydro and Power Authority
Domestic Cost of Energy
For Twelve Months Ended March 31, 2010
(\$ in millions)

Schedule C

Line No.	Particulars (1)	Actual (2)	RRA (3)	Variance (4)	Ref. (5)
1	Heritage Energy:				
2	Water rentals	\$ 311.1	\$ 339.1	\$ (28.0)	
3	Market electricity purchases	80.5	59.6	20.9	
4	Natural gas for thermal generation	38.9	39.2	(0.3)	
5	Domestic Transmission	15.9	15.5	0.4	
6	Surplus Sales	-	(6.8)	6.8	
7	Other	8.4	0.0	8.4	
8		<u>454.8</u>	<u>446.6</u>	<u>8.2</u>	Sch B - Line 2
9					
10	Non-Heritage Energy:				
11	Waneta (water rentals)	0.5	-	0.5	
12	IPP's and long-term purchase commitments	567.4	627.6	(60.2)	
13	Market electricity purchases (transfer from Heritage)	-	-	-	
14	Non-Integrated Areas (NIA):				
15	NIA Fuel	12.1	18.3	(6.2)	
16	NIA IPP's	8.6	8.2	0.4	
17	Gas and Other Transportation	11.4	16.0	(4.6)	
18		<u>600.0</u>	<u>670.1</u>	<u>(70.1)</u>	
19	Net purchases / (sales) from / to Powerex (Trade Account)	67.2	19.9	47.3	Sch F - Note 5
20		<u>667.2</u>	<u>690.0</u>	<u>(22.8)</u>	Sch B - Line 14
21					
22	BCTC PTP & External NITS	87.9	88.9	(1.0)	
23	Total Domestic Cost of Energy	\$ 1,209.9	\$ 1,225.5	\$ (15.6)	Sch D - Line 12
24					
25	Heritage Energy (GWh):				
26	Water rentals	43,137	46,817	(3,680)	
27	Net purchases from Powerex (Displaced Hydro)	1,525	213	1,312	
28	Market electricity purchases	2,161	1,091	1,070	
29	Natural gas for thermal generation	400	260	141	
30	Exchange net	(1,092)	224	(1,316)	
31	Surplus Sales	-	(99)	99	
32		<u>46,131</u>	<u>48,505</u>	<u>(2,374)</u>	
33					
34	Non-Heritage Energy (GWh):				
35	Waneta (water rentals)	71	-	71	
36	IPP's and long-term purchase commitments	8,893	9,277	(384)	
37	Market electricity purchases (transfer from Heritage)	-	-	-	
38	Non-Integrated Areas (NIA):				
39	NIA Fuel	71	74	(3)	
40	NIA IPP's	42	41	1	
41		<u>9,077</u>	<u>9,392</u>	<u>(315)</u>	
42					
43	Total sources of supply	55,208	57,898	(2,690)	
44	Less : Line loss and system use	(4,975)	(5,276)	301	
45					
46	Total Domestic Sales Volumes	<u>50,233</u>	<u>52,622</u>	<u>(2,389)</u>	

British Columbia Hydro and Power Authority
Consolidated Statement of Operations
For Twelve Months Ended March 31, 2010
(\$ in millions)

Schedule D

Line No.	Particulars	Actual	RRA	Variance	Ref.
	(1)	(2)	(3)	(4)	(5)
1	REVENUES				
2	Domestic				
3	Residential	\$ 1,299.9	\$ 1,241.1	\$ 58.8	
4	Light industrial and commercial	1,132.5	1,165.1	(32.5)	
5	Large industrial	485.2	579.4	(94.1)	
6	Other energy sales	99.9	100.5	(0.6)	
7	Miscellaneous	55.2	39.9	15.3	
8		3,072.8	3,125.9	(53.1)	
9	Intersegment revenues	60.9	64.8	(3.9)	Sch E - Line 13
10		3,133.7	3,190.7	(57.0)	
11	EXPENSES				
12	Domestic energy costs	1,209.9	1,225.5	(15.6)	Sch C - Line 23
13	Operating costs	692.4	628.6	63.8	
14	Deferred Costs	494.1	186.1	308.0	
15	Depreciation and amortization	437.40	422.5	14.9	
16	Taxes	172.6	178.1	(5.5)	
17	Finance charges	384.0	498.5	(114.5)	
18		3,390.4	3,139.3	251.1	
19	DOMESTIC INCOME (LOSS) BEFORE TRANSFER				
20	(TO)/FROM DEFERRAL ACCTS	(256.7)	51.3	(308.1)	
21					
22	POWEREX NET INCOME (LOSS)	7.5	199.0	(191.5)	Sch B - Line 26 & 27; Note 1
23	POWERTECH NET INCOME (LOSS)	0.7	1.9	(1.2)	
24					
25	TOTAL INCOME BEFORE TRANSFER (TO)/FROM				
26	DEFERRAL ACCOUNTS	(248.5)	252.2	(500.8)	
27					
28	Heritage Deferral Account transfers	(4.0)	(9.0)	5.0	
29	Non-Heritage Deferral Account transfers	45.1	(10.9)	56.0	
30	Trade Income Deferral Account transfers	201.6	11.8	189.8	
31	BCTC Deferral Account transfers	8.9	(2.5)	11.4	
32	Future Removal and Site Restoration Regulatory Account	12.8	21.0	(8.2)	
33	First Nation Costs Regulatory Account	10.6	14.2	(3.6)	
34	Procurement Enhancement Initiative Regulatory Account	11.1	6.9	4.2	
35	Demand Side Management Regulatory Account	78.5	85.7	(7.2)	
36	Site C Regulatory Account	24.8	16.8	8.0	
37	GMS3 Regulatory Account	(1.0)	(3.7)	2.7	
38	Net Employment Cost Regulatory Account	(32.5)	-	(32.5)	
39	Non-Current Pension Cost Regulatory Account	85.6	-	85.6	
40	ROE Adjustment Regulatory Account	56.4	56.4	-	
41	Foreign Exchange Gains/Losses Regulatory Account	(43.8)	(2.3)	(41.5)	
42	Finance Charge Regulatory Account	(104.8)	-	(104.8)	
43	Environmental Compliance & Remediation Liability Provision	320.5	-	320.5	
44	Other Regulatory Accounts	25.8	14.9	10.9	Note 2
45	TOTAL NET INCOME	447.1	\$ 451.5	\$ (4.4)	
46					
47					

48 1) Powerex net income reported for regulatory purposes is net of the \$4.3 million YTD corporate overhead costs allocated from
49 BC Hydro to Powerex in accordance with Directive 9 of the F09/F10 RRA Decision.

50
51 2) Included in Other Regulatory Accounts are the following regulatory assets and liabilities: F07/F08 RRA Depreciation Study,
52 Pre-1996 Contributions in Aid of Construction, Storm Damage, Smart Metering and Infrastructure, Capital Project Investigation
53 Costs, Taxes, Amortization Variance on Capital Additions, and the Home Purchase Offer Program.

British Columbia Hydro and Power Authority
Intersegment Revenues
For Twelve Months Ended March 31, 2010
(\$ in millions)

Schedule E

Line No.	Particulars (1)	Actual (2)	RRA (3)	Variance (4)	Ref. (5)
1	Point-to-Point wheeling charge to Powerex	\$ 35.2	\$ 29.5	\$ 5.7	1)
2					
3	Point-to-Point wheeling charge to BCH	24.8	31.0	(6.2)	2)
4					
5	Allocation of BCH Corporate costs to Powerex	4.3	4.3	-	3)
6					
7	Mark to Market gains/(losses) on energy derivatives with Powerex	0.4	-	0.4	4)
8					
9	Unrealized value of monthly gas requirement with Powerex	0.4	-	0.4	5) and Sch B L16
10					
11	Gains (losses) on cash flow hedges with Powerex	(4.3)	-	(4.3)	6)
12					
13	Total	<u>\$ 60.9</u>	<u>\$ 64.8</u>	<u>\$ (3.9)</u>	

- 16 1) These transmission revenues relate to an allocation of BC Hydro's cost of purchases of point-to-point
17 transmission within B.C. for export and some import transactions. These revenues are eliminated
18 against trade cost of energy on consolidation.
19
- 20 2) These transmission revenues relate to an allocation of BC Hydro's cost of purchases of point-to-point
21 transmission relating to BC Hydro's Skagit Valley Treaty commitment, Canadian Entitlement Agreement
22 (BCTC OATT Schedule 02) and Scheduling, System Control & Dispatch services (BCTC OATT Schedule 03).
23 These revenues are eliminated against domestic cost of energy on consolidation.
24
- 25 3) These revenues relate to an allocation of corporate overhead costs to Powerex and are eliminated against trade
26 income on consolidation.
27
- 28 4) This relates to mark-to-market gains on energy derivatives with Powerex. This revenue is eliminated
29 against trade income on consolidation. See Sch F, Note 2, Line 29.
30
- 31 5) Under the BC Hydro Transfer Pricing Agreement with Powerex, BC Hydro is required to notify Powerex on the
32 15th business day of each month the quantity of gas required for the next following month for its Thermal
33 Generation Plants to serve Domestic Load and to satisfy its obligations under the Gas Utility Contracts.
34 During the time when BC Hydro has submitted the monthly gas requirement to Powerex and the delivery of gas
35 in the next following month, the cost of the gas changes due to the fluctuation of the commodity prices.
36 BC Hydro and Powerex recognize the mark-to-market of the monthly gas requirement until the commodity
37 has been delivered. The offset to this amount is included as part of Trade Income.
38
- 39 6) See Schedule F Note 3.

Line No.	Particulars			
	(1)			
1	1 Notional water rentals (Displaced Hydro) relates to water rentals associated with trade income. The			
2	notional water rental mechanism is described in the response to BCUC IR No. 1.2.36 dated January 23,			
3	2004. The transactions relating to the notional water rental are eliminated on consolidation and there is no			
4	net impact on the combined HDA and NHDA as the transactions are mirrored within each account.			
5				
6	2 In order to mitigate some of the commodity risk on domestic energy costs, BC Hydro enters into various			
7	forward contracts with Powerex for the purchase of electricity and natural gas. Powerex can then choose			
8	to match these forward contracts with a third party or can take on the risk/benefits on their own. The			
9	transactions between BC Hydro and Powerex are eliminated on consolidation. With respect to the deferral			
10	accounts, any gain or loss on the derivative instruments on the Powerex side would flow through the			
11	TIDA and the corresponding gain/loss on the BC Hydro side would flow through the HDA and			
12	NHDA. While the gain/loss on these derivative instruments are not shown as part of energy costs			
13	on the financial statements due to GAAP reporting requirements, these gains/losses are reclassified			
14	for the calculation of deferral account transfers as they are part of managing the energy purchase costs.			
15				
16	The gain on energy derivatives related to Heritage energy totalled \$9.9 million for the twelve months ended March 31, 2010			
17	with the corresponding loss shown as part of Trade Income. There was no gain / loss on energy derivatives related to			
18	Non-Heritage energy for the twelve months ended March 31, 2010. The gain/loss on BC Hydro's side related			
19	to energy derivatives, excluding foreign exchange gains or losses, is shown as part of intersegment revenues.			
20				
21	The Liquidity Reserve represents adjustments to estimates of value based on illiquidity in order to arrive at fair market			
22	value. As positions are marked to the mid-point of the bid/ask spread to determine market value, appropriate			
23	adjustments to total mark-to-market estimates for open positions are made to reflect the liquidity of the market.			
24				
25	In accordance with the terms of the F07/F08 RRA Negotiated Settlement, BC Hydro no longer enters into any new			
26	hedging contracts in regard to natural gas purchases.			
27				
28			Non-	
		Heritage	Heritage	Total
29	Gain / (Loss) on energy derivatives (Sch. E Line 7)	\$ 0.4	\$ -	\$ 0.4
30	Foreign Exchange Gain / (Loss) on energy derivatives	9.5	-	9.5
31	Gain/(Loss) on energy derivatives	9.9	-	9.9
32	Liquidity Reserve	0.7	-	0.7
33	Total Gain / (Loss) on derivatives (Sch. B Line 4)	\$ 10.6	\$ -	\$ 10.6
34				
35	Gain/(Loss) on Electricity	\$ 10.6	\$ -	\$ 10.6
36	Gain/(Loss) on Gas	-	-	-
37	Gain/(Loss) on derivatives (Sch. B Line 4)	\$ 10.6	\$ -	\$ 10.6
38				
39	3 This relates to the foreign exchange gain/loss on the Trade Account payable to Powerex. Powerex has			
40	a corresponding loss/gain on their receivable and this loss/gain would be part of Trade Income. Foreign exchange			
41	gains/losses arise as the Trade Account is recorded in \$US. The gain/loss on the BC Hydro side is eliminated			
42	against the loss/gain on the Powerex side of consolidation within the finance charge component. As the mirror			
43	entry for Trade Income relating to F/X on the Trade Account is recorded on the Non-Heritage energy side,			
44	there is no net impact on the combined NHDA and TIDA due to these transactions. Net FX gains include losses			
45	related to internal cashflow hedges with Powerex.			
46				
47	4 Load Variance: as per Directive 31 in the F09/F10 RRA Decision, BC Hydro is allowed to defer the net load variance.			
48	The net cost of load variance is calculated by adding the domestic revenue variance into the NHDA deferral account,			
49	which nets against the cost of energy variance due to load as included in Schedule B Line 14.			
50				
51	Domestic Revenue Variance	Actual	RRA Decision	Variance
52	Domestic Revenue (excluding Seattle City Light revenue and Rate Rider Revenue)	\$ 2,971.6	\$ 3,054.1	\$ 82.5
53				
54	5 These sales / purchases relate to the return of energy bought by Powerex in prior periods to enable future sales.			
55	These revenues are eliminated against trade cost of energy on consolidation. The transactions between			
56	BC Hydro and Powerex have no net impact on the combined NHDA and the TIDA.			
57				
58	6 Variance from plan related to natural gas for thermal generation - GWh (Schedule C - L28)	GWh		141.0
59	Average cost per MWh of additional production	\$/ MWh	\$	1.0
60	Total variable cost related to thermal generation	million	\$	0.2

Schedule G
Deferral Account Rules

The following “rules” are used by BC Hydro for providing clarity in determining the Deferral Account transfers. These rules are derived from BC Hydro’s interpretation of the evidence and testimony provided during the F2005/F2006 Revenue Requirement Application proceeding and in response to BCUC Directive No. 19 of the October 29, 2004 Decision, and updated for the F07/F08 RRA NSA and Directives included in the F09/F10 RRA Decision.

Heritage Deferral Account (HDA)

Commission Decision, October 29, 2004, Page 41:

Commission Findings

The Commission Panel approves the HDA as proposed by BC Hydro, and approves BC Hydro's forecast of the cost components of the HPO for F2005 and F2006.

Variations between the forecast and the actual cost for the following components of the Heritage Payment Obligation will flow through the HDA:

1. Cost of energy.¹

This item is expanded in greater detail below to provide clarification on the methodology used to determine variances:

- Gains/losses on energy derivatives and financial instruments used to minimize energy costs are included as part of total energy costs.
- The total Heritage Energy (including Skagit/Seattle City Light commitments) is limited to 49,000 GWh in terms of the Heritage contract. If the Heritage Energy including 100 per cent of market electricity purchases exceeds the Heritage Energy limit, the excess purchases are transferred to Non-Heritage Energy in order to reduce the Heritage Energy volumes to the Heritage Contract limit.
- Cost of energy variances resulting from changes to compensation and mitigation costs, water rental remissions, or Skagit energy transportation contracts are eligible for deferral. These are price variances as they do not vary with volume.
- All load curtailment costs are to be included as part of the Heritage Payment Obligation and variance between Actual and Plan is to be included in the HDA.²

2. Variable costs related to thermal generation.¹

3. Significant unplanned major maintenance costs greater than \$1 million related to single event equipment or infrastructure failure or caused by weather related events.¹

4. Significant unplanned major capital expenditures having an incremental annual impact on the Income Statement greater than \$1 million related to single event equipment or infrastructure failure or caused by weather related events.¹

5. Amortization of unplanned deferred capital costs pursuant to Commission Order No. G-53-02.¹

6. All net revenues from surplus hydro electricity sales.³

7. Skagit Valley Treaty revenues and ancillary services revenues.³

8. An interest charge/credit⁴ is to be calculated on the ending monthly balance in each deferral account. The interest rate used is BC Hydro's weighted cost of debt for the prior fiscal year-end.

¹ Per F05/F06 RRA Decision Directive 11, amended by the F09F/10 RRA Decision, Directive 31.

² Per F09/F10 RRA Decision, Directive 30.

³ Per F05/F06 RRA Decision, Directive 11.

⁴ Per F05/F06 RRA Decision Directive 18, amended by the F07/F08 RRA Negotiated Settlement Agreement.

Non-Heritage Deferral Account (NHDA)

Commission Decision, October 29, 2004, Page 41:

Commission Findings

The Commission Panel approves all elements of the NHDA, except the distribution emergency restoration costs elements, item 4, because it can be forecast with some confidence, unlike unplanned major capital expenditures and unplanned major maintenance expenditures, and because of risk/reward considerations. Given the denial of item 4 of the NHDA, item 3 of the NHDA is to be as set forth in Final Argument. The Commission Panel approves BC Hydro's forecast of the NHDA non-HPO cost of energy for F2005 and F2006.

Variances between the forecast and the actual cost for the following components of the Non-Heritage Cost of Energy will flow through the NHDA:

1. Cost of energy - all non-HPO energy costs.¹ This item is expanded in greater detail below to provide clarification on the methodology used to determine variances:
 - Any variances relating to fixed price gas transportation contracts would flow through the deferral accounts as they do not vary with volume;
 - Future Trade: when Powerex purchases energy for future trade the cost of the purchase from the external party and the sale to BC Hydro of this energy is recorded in Powerex and is included as part of Trade Income. The BC Hydro side of the entry is shown as part of domestic energy costs (on consolidation, the Powerex revenue from BC Hydro and the BC Hydro energy costs from Powerex are eliminated). The difference between Actual and Plan on the BC Hydro side relating to energy for future trade flows through the Non-Heritage Deferral Account. The Powerex side of the transaction, which is part of Trade Income, flows through the Trade Income Deferral Account. Similar treatment is made when the energy is returned to Powerex; and
 - Future Trade: when Powerex purchases energy for future trade, the Heritage Payment Obligation (HPO) is charged with a notional water rental charge for the use of this energy. The other side of this entry is shown as part of Non-Heritage energy. These entries are eliminated on consolidation. The difference between the Actual and Plan notional water rentals that is part of the HPO flows through the Heritage Deferral Account. The opposite variance relating to the Non-Heritage side of the notional water rental transaction flows through the Non-Heritage Deferral Account.
 - Gains/losses on energy derivatives and financial instruments used to minimize energy costs are included as part of total energy costs.
2. Significant unplanned major maintenance costs greater than \$1 million related to single event equipment or infrastructure failure.¹
3. Significant unplanned major capital expenditures having an incremental annual impact on the Income Statement greater than \$1 million related to single event equipment or infrastructure failure or caused by weather related events.¹
4. Founding Partner Benefits and any CIS Credits under the ABS Contract.¹
5. Impact of load variance.²
 - The Net Cost of Energy deferral amount is calculated by subtracting the Gross Load Variance and adding the Net Load Variance to the Gross Cost of Energy deferral amount. In practice, because Net Load Variance equals Gross Load Variance less Domestic Revenue Variance, the Net Cost of Energy Deferral simplifies to the Gross Cost of Energy Deferral minus the Domestic Revenue Variance.
6. An interest charge/credit³ is to be calculated on the ending monthly balance in each deferral account. The interest rate used is BC Hydro's weighted cost of debt for the prior fiscal year-end.

¹ Per F05/F06 RRA Decision, Directive 12, amended by F09F/10 RRA Decision, Directive 31.

² F09/F10 RRA Decision, Directive 31.

³ Per F05/F06 RRA Decision Directive 18, amended by the F07/F08 RRA Negotiated Settlement Agreement.

Trade Income Deferral Account (TIDA)

Commission Decision, October 29, 2004, Page 42, Section 4.6:

Commission Findings

The Commission Panel approves the TIDA as proposed by BC Hydro, and approves BC Hydro's forecast of Trade Income for F2005 and F2006.

- Any variance between the forecast Trade Income and the actual trade income¹ will flow through the TIDA except where Annual Trade Income is below \$Nil and above \$200 million.
- An interest charge/credit² is to be calculated on the ending monthly balance in each deferral account. The interest rate used is BC Hydro's weighted cost of debt for the prior fiscal year-end.

BCTC Deferral Account (BCTC DA)

Commission Decision, October 29, 2004, Pages 42 and 43, Section 4.7:

Commission Findings

The Commission Panel approves the BCTC DA as proposed by BC Hydro, and approves BC Hydro's F2005 and F2006 forecast, subject to the adjustments required by this Decision, of the Asset Management/Maintenance Revenue Requirement and the BCTC Revenue Requirement for the purpose of the BCTC TDA.

- The BCTC Deferral Account relates to two variances:
 - a) variances between BC Hydro's Asset Management/Maintenance Revenue Requirement forecast in BC Hydro's Revenue Requirement and BC Hydro's actual Asset Management/Maintenance charges from BCTC, and
 - b) variances between BCTC's Revenue Requirement forecast charges to BC Hydro in BC Hydro's Revenue Requirement and the BCTC charges to BC Hydro for transmission services.
- An interest charge/credit³ is to be calculated on the ending annual balance in each deferral account. The interest rate used is BC Hydro's weighted cost of debt for the prior fiscal year-end.

¹ Per F05/F06 RRA Decision, Directive 13.

² Per F05/F06 RRA Decision Directive 18, amended by the F07/F08 RRA Negotiated Settlement Agreement.

³ Per F05/F06 RRA Decision Directive 18, amended by the F07/F08 RRA Negotiated Settlement Agreement.