

BC Hydro
Deferral Account Report
March 31, 2006

June 2006

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SUMMARY OF DEFERRAL ACCOUNTS
For the Year Ended March 31, 2006

	Reference Schedule	Heritage Deferral Account (HDA)	Non Heritage Deferral Account (NHDA)	Trade Income Deferral Account (TIDA)	BCTC Transition Deferral Account (TIDA)	Total
1		076000	076100	076200	076400	
2		076001	076101	076201	076401	
3		137.8	131.3	(114.5)	-	154.6
4	A-2	92.4	64.6	(88.2)	24.0	92.8
5		10.5	8.6	(10.6)	0.9	9.4
6		<u>240.7</u>	<u>204.5</u>	<u>(213.3)</u>	<u>24.9</u>	<u>256.8</u>

- The transfers to the HDA and NHDA are related to variances in energy costs, not related to changes in load, from the forecast used in establishing rates (See Schedule C).
- The transfers to the HDA and NHDA are related to variances in energy costs, not related to changes in load, offset by the load variance (not deferred). The decision to import energy instead of utilizing hydro generation is based on many factors, such as the forecast market price of energy in future periods relative to the current period, current reservoir levels and future demand requirements.
- The NHDA energy costs variances are largely due to higher energy costs from IPP's and market energy purchases transferred from Heritage Energy. These are partially offset by the impact of lower IPP and long term purchase commitment volumes, and higher net sales to Powerex related to previous purchases made for future use by Powerex (offset in Powerex in the Trade Income Deferral Account transfer.)
- The transfer to the TIDA relates to the higher than Plan Trade Income. This includes the offsets for the amounts included in the NHDA transfer noted above.

Notes:

1. The interest charge/credit is shown as part of finance charges on the Consolidated Statement of Operations (Schedule A-3). Interest is calculated on the ending annual balance (excluding the interest portion) in each deferral account. The interest rate used is BC Hydro's weighted cost of debt.

1

Deferral Account Rules

2 The following “rules” are used by BC Hydro for providing clarity in determining the deferral
3 account transfers. These rules are derived from BC Hydro’s interpretation of the evidence and
4 testimony provided during the 2004 Revenue Requirement proceeding and in response to
5 Commission directive No. 19 of the October 29, 2004 Decision.

6 Heritage Payment Obligation Deferral Account (HDA)

7 ***Commission Directive October 29, 2004 Page 41:***

8 **Commission Findings**

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

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

- 13 1. Cost of energy, except those arising from changes in customer load*¹.
14 This item is expanded in greater detail below to provide clarification on the methodology used
15 to determine variances:
 - 16 • Market electricity purchases are treated as the dispatchable resource*³;
 - 17 • If no market purchases are planned or made, the next dispatchable resource is assumed
18 to be generation from the Burrard facility;
 - 19 • If total Heritage and non-Heritage energy volumes are lower than Plan, the Load
20 Variance is calculated using the Plan YTD average market purchase price of electricity *³;
 - 21 • If total Heritage and Non-Heritage energy volumes are higher than Plan the Load
22 variance is calculated using the Actual YTD average market purchase price of electricity
23 (netted for any gains/losses on energy derivatives and financial instruments used to
24 manage energy costs);*³ and
 - 25 • The total Heritage Energy (including Skagit / Seattle City Light commitments) is limited to
26 49000 GWh in terms of the Heritage contract. If the Heritage Energy including 100% of
27 market electricity purchases exceeds the Heritage Energy limit, the excess purchases are
28 transferred to Non-Heritage Energy in order to reduce the Heritage Energy volumes to
29 the Heritage Contract limit.
 - 30 • Cost of energy variances resulting from changes to compensation and mitigation costs,
31 water rental remissions, or Skagit energy transportation contracts are eligible for deferral.
32 These are price variances as they do not vary with volume.
- 33 2. Variable costs related to thermal generation*¹.
- 34 3. Significant unplanned major maintenance costs greater than \$1 million related to single event
35 equipment or infrastructure failure or caused by weather related events*¹.
- 36 4. Significant unplanned major capital expenditures having an incremental annual impact on the
37 Income Statement greater than \$1 million related to single event equipment or infrastructure
38 failure or caused by weather related events*¹.
- 39 5. Amortization of unplanned deferred capital costs pursuant to Commission Order No. G-53-
40 02*¹.
- 41 6. All net revenues from surplus hydro electricity sales*².
- 42 7. Skagit Valley Treaty revenues and ancillary services revenues*².

Schedule A-1

- 1 • An interest charge/credit^{*4} is to be calculated on the ending annual balance (excluding the
- 2 interest portion) in each deferral account. The interest rate used is BC Hydro's weighted cost
- 3 of debt during the period.

4 ^{*1} Per Commission Directive October 29, 2004 Page 30, Section 4.4 & Page 41 (Commission Findings)

5 ^{*2} Per Commission Directive October 29, 2004 Page 31, Section 4.4 & Page 41 (Commission Findings)

6 ^{*3} Per Commission Decision October 29, 2004, Page 38, Section 4.5.1.1

7 ^{*4} Per Commission Directive October 29, 2004 Page 45, Section 4.11

1 **Non-Heritage Deferral Account (NHDA)**

2 *Commission Directive October 29, 2004 Page 41:*

3 **Commission Findings**

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

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

- 13 1. Cost of energy - all non-HPO energy costs except those arising from changes in customer
 14 load*¹. This item is expanded in greater detail below to provide clarification on the
 15 methodology used to determine variances:
- 16 • If total Heritage and Non-Heritage energy volumes are lower than Plan, the Non –
 17 Heritage Load Variances (volume variances for IPP, Long term purchases and Market
 18 Purchases transferred from Heritage Energy) is calculated using the Plan YTD average
 19 market purchase price of electricity; ³ For Non – Integrated supply, the fuel costs are
 20 treated as the next dispatchable resource;
 - 21 • If total Heritage and Non-Heritage energy volumes are higher than Plan, the Non-
 22 Heritage Load Variance (volume variances for IPP, Long term purchases and Market
 23 Purchases transferred from Heritage Energy) is calculated using the Actual YTD average
 24 market purchase price of electricity (netted for any gains/losses on energy derivatives
 25 and financial instruments used to manage energy costs); ³ for Non-Integrated supply, the
 26 fuel costs are treated as the next dispatchable resource;
 - 27 • Any variances relating to fixed price gas transportation contracts would flow through the
 28 deferral accounts as they do not vary with volume;
 - 29 • Future Trade: when Powerex purchases energy for future trade the cost of the purchase
 30 from the external party and the sale to BC Hydro of this energy is recorded in Powerex
 31 and is included as part of Trade Income. The BC Hydro side of this entry is shown as part
 32 of domestic energy costs (on consolidation, the Powerex revenue from BC Hydro and the
 33 BCH energy costs from Powerex are eliminated). The difference between Actual and
 34 Plan on the BC Hydro side relating to energy for future trade will flow through the Non-
 35 Heritage Deferral Account. The Powerex side of the transaction is part of Trade Income
 36 and flows through the Trade Income Deferral Account. Similar treatment is made when
 37 the energy is returned to Powerex; and
 - 38 • Future Trade: when Powerex purchases energy for future trade, the Heritage Payment
 39 Obligation (HPO) is charged with a notional water rental charge for the use of this energy.
 40 The other side of this entry is shown as part of Non-Heritage energy. These entries are
 41 eliminated on consolidation. The difference between the Actual and Plan notional water
 42 rentals that is part of the HPO would flow through the Heritage Deferral Account. The
 43 opposite variance relating to the Non-Heritage side of the notional water rental
 44 transaction will flow through the Non-Heritage Deferral Account.
- 45 2. Significant unplanned major maintenance costs greater than \$1 million related to single event
 46 equipment or infrastructure failure or caused by weather related events*¹.

Schedule A-1

- 1 3. Significant unplanned major capital expenditures having an incremental annual impact on the
2 Income Statement greater than \$1 million related to single event equipment or infrastructure
3 failure or caused by weather related events*¹.
- 4 4. Founding Partner Benefits and any CIS Credits under the ABS Contract*¹.
- 5 • An interest charge/credit*² is to be calculated on the ending annual balance (excluding the
6 interest portion) in each deferral account. The interest rate used is BC Hydro's weighted cost
7 of debt during the period.

8 *¹ Per Commission Directive October 29, 2004 Page 37, Section 4.5 & Page 41 (Commission Findings)

9 *² Per Commission Directive October 29, 2004 Page 45, Section 4.11

1 **Trade Income Deferral Account (TIDA)**

2 ***Commission Directive October 29, 2004 Page 42, Section 4.6***

3 **Commission Findings**

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

- 6 • Any variance between the forecast Trade Income and the actual trade income*¹ will flow
7 through the TIDA except where Annual Trade Income is below \$Nil and above \$200 million.
- 8 • An interest charge/credit*² is to be calculated on the ending annual balance (excluding the
9 interest portion) in each deferral account. The interest rate used is BC Hydro's weighted cost
10 of debt during the period.

11 *¹ Per Commission Directive October 29, 2004 Page 42, Section 4.6

12 *² Per Commission Directive October 29, 2004 Page 45, Section 4.11

1 **BCTC Transition Deferral Account (BCTC TDA)**

2 *Commission Directive October 29, 2004 Page 42 & 43, Section 4.7*

3 **Commission Findings**

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

- 8 • The BCTC Transition Deferral Account*¹ relates to two variances:
- 9 • a) variances between BC Hydro's Asset Management/Maintenance Revenue
10 Requirement forecast at \$116.7 million*² in BC Hydro's Revenue Requirement and BC
11 Hydro's actual Asset Management/Maintenance charges from BCTC, and
- 12 • b) variances between BCTC's Revenue Requirement forecast charges to BC Hydro of
13 \$61.0 million*² in BC Hydro's Revenue Requirement and the BCTC charges to BC Hydro.
- 14 • An interest charge/credit*³ is to be calculated on the ending annual balance (excluding the
15 interest portion) in each deferral account. The interest rate used is BC Hydro's weighted cost
16 of debt during the period.

17 *¹ Per Commission Directive October 29, 2004 Pages 42-43, Section 4.7

18 *² Per BC Hydro 2004/05 and 2005/06 Revenue Requirement Application (November 15, 2004 Compliance
19 Filing), Chapter 2, Schedule B-3

20 *³ Per Commission Directive October 29, 2004 Page 45, Section 4.11

**Summary of Deferral Account Transfers
For the Year Ended March 31, 2006
(\$ in millions)**

	F2006 Actual YTD	Reference Schedule
<u>Heritage Deferral Account</u>		
1) Cost of energy (except those arising from changes to customer load)	92.4	C (line 7)
2) Variable costs related to thermal generation.	0.0	C (line 9)
3) Significant unplanned major maintenance costs greater than \$1 million related to single event equipment or infrastructure failure or caused by weather related events	-	
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	-	
5) Amortization of unplanned deferred capital costs pursuant to Commission Order No. G-53-02.	-	
6) All net revenues from surplus hydro electricity sales.	-	
7) Skagit Valley Treaty revenues and ancillary services revenues.	0.0	C (line 10)
Transfer to Heritage Deferral Account for the twelve months ended March 31, 2006	<u>92.4</u>	A;A-3
<u>Non-Heritage Deferral Account</u>		
1) Cost of energy - all non-HPO energy costs except those arising from changes in customer load	60.8	C (line 15-18)
2) Significant unplanned major maintenance costs greater than \$1 million related to single event equipment or infrastructure failure or caused by weather related events	7.3	C (line 20)
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.	-	
4) Founding Partner Benefits and any CIS Credits under the ABS Contract	(0.6)	C (line 22)
5) F2006 Return on Equity Deferral (BCUC Order G-48-05)	(2.9)	C (line 21)
Transfer to Non Heritage Deferral Account for the twelve months ended March 31, 2006	<u>64.6</u>	A; A-3
<u>Trade Income Deferral Account</u>		
Transfer to Trade Income Deferral Account for the twelve months ended March 31, 2006	<u>(88.2)</u>	C-4; A; A-3
<u>BCTC Transition Deferral Account</u>		
1) BCTC Asset Management / Maintenance Fee	(3.9)	C-5
2) BCTC Wholesale Transmission Service / BCTC Revenue Forecast	27.9	C-5
Transfer to Trade Income Deferral Account for the twelve months ended March 31, 2006	<u>24.0</u>	A; A-3
<u>First Nations Regulatory Asset Account Transfer</u>		
Transfer for the year ending March 31, 2006	<u>87.7</u>	C-6; A-3

Consolidated Statement of Operations
For the Year Ended March 31, 2006
(\$ Millions)

	A	B	C	
	Actual	Plan	Variance	Reference Schedule
REVENUES				
Domestic				
Residential	1,046	1,032	14	
Light industrial and commercial	989	958	31	
Large industrial	584	521	63	
Other energy sales	91	90	1	
Miscellaneous	55	55	(1)	
	<u>2,765</u>	<u>2,656</u>	<u>109</u>	
Intersegment revenues	65	116	(51)	D
	<u>2,830</u>	<u>2,772</u>	<u>58</u>	
EXPENSES				
Domestic energy costs	1,165	855	(310)	B
BCTC wholesale transmission service	77	61	(16)	
BCTC asset management fee	113	117	4	
Operations expense	230	129	(101)	
Maintenance expense	155	138	(17)	
Administration expense	162	134	(29)	
Depreciation and amortization	467	420	(46)	
Taxes	144	147	3	
Finance charges	424	463	38	
	<u>2,936</u>	<u>2,463</u>	<u>(473)</u>	
DOMESTIC INCOME (LOSS) BEFORE TRANSFER (TO)/FROM DEFERRAL ACCTS	(105)	309	(415)	
TRADE INCOME	179	91	89	C-4
TOTAL INCOME BEFORE TRANSFER (TO)/FROM DEFERRAL ACCOUNTS	74	400	(326)	
Heritage Deferral Account transfers	92	-	92	C
Non- Heritage Deferral Account transfers	65	(3)	68	C
Trade Income Deferral Account transfers	(88)	-	(88)	C-4
BCTC Transition Deferral Account transfers	24	-	24	C-5
Regulatory provision for future removal and site restoration costs	11	-	11	
First nations Regulatory Asset Account Transfer	88	-	88	C-6
	<u>192</u>	<u>(3)</u>	<u>195</u>	
TOTAL NET INCOME	266	397	(132)	

1. The Statement of Operations is presented in a consistent format to the Statement of Operations presented in the 2004 Revenue Requirement Application.
2. The 'Plan' is the 2006 Plan per the Revenue Requirement in terms of the BCUC February 2005 Decision.

DOMESTIC COST OF ENERGY
For the Year Ended March 31, 2006

(\$ millions)	Actual	Plan	Variance	Reference Schedule
Heritage Energy:				
Water rentals	272	270	(1)	
Market electricity purchases	234	112	(122)	C-2
Natural gas for thermal generation	32	26	(5)	
Domestic Transmission	16	16	(1)	
Other	6	8	1	
	560	432	(128)	C-1
Non-Heritage Energy:				
IPP's and long-term purchase commitments	456	395	(61)	
Market electricity purchases	117	-	(117)	C-3
Non-Integrated Areas:				
NIA Fuel	12	4	(7)	
NIA IPP's	7	11	3	C-3
Gas and Other Transportation	13	13	(0)	
Net purchases from Powerex (Trade Account)	-	-	-	
	605	423	(182)	C-1
Total Domestic Cost of Energy	1,165	855	(310)	A - 3
(GW.h)				
Heritage Energy:				
Water rentals	46,850	46,045	(805)	
Net sales to Powerex (Displaced Hydro)	(1,327)	(1,200)	127	
Market electricity purchases	3,903	2,757	(1,146)	C-2
Natural gas for thermal generation	204	233	29	
Exchange net	(630)	199	829	
	49,000	48,034	(966)	C-3
Non-Heritage Energy:				
IPP's and long-term purchase commitments	6,741	6,950	209	C-3
Market electricity purchases	1,950	-	(1,950)	C-3
Non-Integrated Areas:				
NIA Fuel	71	42	(29)	
NIA IPP's	38	63	25	
	8,800	7,056	(1,744)	
Total sources of supply	57,800	55,090	(2,710)	
Less : Line loss and system use	(5,360)	(5,483)	(123)	C-3
	52,440	49,607	(2,833)	C-3
(\$/MW.h)				
Water rentals	5.8	5.9	0.1	
Market electricity purchases	60.0	40.7	(19.3)	
Natural gas for thermal generation	155.4	112.8	(42.6)	
IPP's and long-term purchase commitments	67.6	56.8	(10.8)	C-2
Non-Integrated Areas:				
NIA Fuel	165.9	104.2	(61.7)	
NIA IPP's	194.8	168.2	(26.7)	
Total weighted average cost	20.2	15.5	(4.6)	

The Cost of Energy Schedule is presented in a similar format to the Cost of Energy Schedule (Schedule A-9) presented as part of the 2004 Revenue Requirement Application. The only exception is that this schedule further breaks down energy costs between Heritage and Non-Heritage cost of energy.

TRANSFERS TO HERITAGE (HDA) AND NON-HERITAGE (NHDA) DEFERRAL ACCOUNTS
For the Year Ended March 31, 2006

1				
2				
3	(\$millions)			
4	Transfer to HDA:			
5	Total Heritage energy variance	(a)	157.6	C-1
6	Less: Load Variance (Note 5)		65.3	C-2
7	Heritage Energy Deferral		<u>92.4</u>	A-2
8				
9	Add: Variable Costs related to Thermal Generation		0.0	A-2
10	Add: Skagit Valley Treaty Revenues and		0.0	A-2
11	Ancillary Services Revenues		<u>0.0</u>	
12	Transfer to HDA		<u><u>92.4</u></u>	A; A-2; A-3
13				
14	Transfer to NHDA:			
15	Total Non-Heritage energy variance	(b)	\$ 179.1	C-1
16	Add: Load Variance - IPP's (Note 6)		(117.7)	C-3
17	Add: Load Variance - Non-Integrated areas (Note 6)		<u>(0.5)</u>	C-3
18	Non - Heritage Energy Deferral		\$ 60.8	A-2
19				
20	Add: Mountain Pine Beetle Costs		7.3	A-2
21	Less: F2006 Return on Equity Deferral (BCUC Order G-48-05)		(2.9)	A-2
22	Less: Founding Partner Benefits and any CIS Credits under the ABS Contract		<u>(0.6)</u>	A-2
23	Transfer to NHDA		<u><u>\$ 64.6</u></u>	A;A-2;A-3

TRANSFERS TO HERITAGE (HDA) AND NON-HERITAGE (NHDA) DEFERRAL ACCOUNTS
For the Year Ended March 31, 2006

Reconciliation of Energy costs for Deferral Account Treatment

(\$ millions)	Actual	Plan	Variance	Reference Schedule
Heritage Energy:				
Heritage Energy costs	\$ 559.9	\$ 431.7	\$ (128.2)	B
Notional Water rental (Displaced Hydro) (Note 1)	(6.0)	(5.8)	0.2	
Mark to market (gain)/loss on energy derivatives and financial settlements (Note 2)	29.7		(29.7)	C-2
Cost of energy portion of Heritage Payment Obligation	\$ 583.6	\$ 425.9	\$ (157.6)	(a) C
Non-Heritage Energy:				
Non-Heritage Energy costs	\$ 604.9	\$ 423.0	\$ (182.1)	B
Net sales to Powerex - Future Use (Note 3)	(68.1)	(49.0)	19.1	D
Notional water rentals (Displaced Hydro) (Note 1)	6.0	5.8	(0.2)	
F/X loss(gain) on Pwx trade account (Note 4)	(3.9)	-	3.9	
Mark to market (gain)/loss on energy derivatives and financial settlements (Note 2)	19.8	-	(19.8)	C-2
Cost of energy portion of Non-Heritage Payment Obligation	\$ 558.7	\$ 379.8	\$ (179.1)	(b) C

(GW.h)

Notes:

1. Notional water rentals (Displaced Hydro) relates to water rentals associated with trade income. The notional water rental mechanism is described in the response to BCUC IR No. 1.2.36 dated January 23, 2004. The transactions relating to the notional water rental are eliminated on consolidation and there is no net impact on the combined HDA and NHDA as the transactions are mirrored within each account.

2. In order to mitigate some of the commodity risk on domestic energy costs, BC Hydro enters into various forward contracts with Powerex for the purchase of electricity and natural gas. Powerex can then choose to match these forward contracts with a third party or can take on the risk/benefits on their own. The transactions between BC Hydro and Powerex are eliminated on consolidation. With respect to the deferral accounts, any gain or loss on the derivative instruments on the Powerex side would flow through the Trade Income Deferral Account (TIDA) and the corresponding gain/loss on the BC Hydro side would flow through through the HDA and NHDA. While the gain/loss on these derivative instruments are not shown as part of energy costs on the financial statements due to GAAP reporting requirements, these gains/losses are reclassified for the calculation of deferral account transfers as they are part of managing the energy purchase costs.

Transfer to HDA and NHDA continued

Schedule C-2

1 The loss on energy derivatives related to Heritage energy totalled \$28.8 million for the year ended
 2 March 31, 2006 with the corresponding gain shown as part of Trade Income. The loss on energy derivatives
 3 related to Non-Heritage energy totalled \$13 million with the corresponding gain shown as part of Trade income.
 4 The gain/loss on BC Hydro's side related to these energy derivatives is shown as part of intersegment revenues.
 5
 6
 7 BC Hydro also enters into derivatives with third parties to manage foreign exchange exposure on the corresponding
 8 energy derivatives. These foreign exchange derivative transactions are made on a cash flow basis of the underlying
 9 or gas electricity derivatives which, by market convention, settle on the 20th or 25th of the following month.
 10 Gains and losses on these transactions are netted against Heritage and Non-Heritage Energy purchase costs
 11 as they are used to manage these energy costs and mitigate risk. On the consolidated income statement these
 12 gains/losses are recorded as part of other miscellaneous income to comply with GAAP reporting requirements.
 13 The loss for the twelve months ended March 31, 2006 was \$0.8 million related to Heritage Energy and a loss of \$6.8 million
 14 related to Non-Heritage Energy.

15
 16 (\$millions)
 17 **Summary:**

**Reference
 Schedule**

	Heritage	Non- Heritage	Total
18			
19	(27.8)	(12.8)	(40.6)
20	(1.0)	(0.2)	(1.2)
21	(28.8)	(13.0)	(41.8)
22			
23	(0.8)	(6.8)	(7.6)
24			
25	\$ (29.7)	\$ (19.8)	\$ (49.5)
26	C-1	C-1	

27
 28
 29 3. These sales relate to the return of energy bought by Powerex in prior periods to enable future sale. These revenues are eliminated
 30 against trade cost of energy on consolidation. The transactions between BC Hydro and Powerex has no net impact on the com
 31

32 4. This relates to the foreign exchange gain on the Trade Account payable to Powerex. Powerex would have a corresponding loss on
 33 their receivable and this loss would be part of Trade Income. Foreign exchange gains/losses arise as the Trade Account is reco
 34
 35
 36
 37
 38
 39

40 5. Load Variance for HDA is calculated as the Load Volume variance multiplied by the actual average price of market
 41 purchases net of the gain/losses on mark to market energy transactions. (966 GW.h * \$67.58/MW.h) = \$65.3 million.
 42
 43

44 (\$millions)

**Reference
 Schedule**

45			
46	\$ 234.1		B
47	29.7		C-1
48	\$ 263.8	(1)	
49			
50	3,903	(2)	B
51			
52	67.58		
53			
54	966		B

- 1 6. Load Variance for NHDA calculated as sum of:
 2 a) sum of the IPP, Long Term Purchase Commitments and Electricity Purchases Transfer from Heritage Energy (note 7)
 3 volume variances multiplied by the actual average price of market electricity purchases
 4 (1741 Gw.h * \$67.58/MW.h) = \$117.7 million. C
 5 b) Non-Integrated Areas Load Volume Variance multiplied by the actual Non-Integrated Areas average price
 6 (3.27 GW.h * 165.89) = \$0.5 million. C

Reconciliation of Energy Volumes (GW.h)		
Increase in domestic sales volumes from Plan		2,833
Decrease in line loss and system use		(123)
Net change in volumes		<u>2,710</u>
Change in HPO energy volumes		966
Change in Non-Heritage energy:		
IPP's and long-term purchase commitments	(209)	
Market Purchases (Note 7)	1,950	
	<u>1,741</u>	<u>1,741</u>
Non-Integrated areas		<u>3</u>
		<u>2,710</u>

24 7. Total Heritage energy (including Skagit commitments) is limited to 49000 Gwh in terms of the Heritage Contract.
 25 This Heritage Contract limit would be exceeded if all market energy purchases were allocated to Heritage Energy
 26 supply. Therefore, a portion of the market purchases are allocated to Non-Heritage Energy in order to reduce the
 27 Heritage Energy volumes to the Heritage Contract limits as follows:

	GW.h	
30 Total Heritage Energy excluding Market Purchases	46,424	
31 Less: Net Sales to Powerex (Displaced Hydro Generation)	(1,327)	
32 100% of Market Energy Purchases	<u>5,853</u>	
33 Total Heritage Energy including 100% of Market Energy Purchases	<u>50,950</u>	(1)
34		
35 Heritage Contract Limit of 49000 GW.h	49,000	(2)
36		
37 Excess Market Purchases ((1) - (2))	1,950	

39 The cost of market energy purchases and related energy and foreign exchange derivatives are allocated between
 40 Heritage Energy and Non-Heritage Energy based on allocation of market purchases

	Heritage	Non - Heritage	Total
43 Market Energy Purchase volumes (GWh)	<u>3,903</u>	<u>1,950</u>	<u>5,853</u>
45 Total Market Energy Purchases costs (\$millions)	\$ 234.1	\$ 117.0	\$ 351.1

47 8. F2006 Return on Equity Deferral is included in existing deferral accounts as per BCUC Order G-48-05,
 48 dated May 20, 2005.

Schedule C-4

			Reference Schedule
1	Transfer to Trade Income Deferral Account		
2	For the Year Ended March 31, 2006		
3	(\$ in millions)		
4			
5			
6			
7			
8	Actual Trade Income	179	A-3
9	Excess over Cap for deferral account transfer	-	
10		<u>179</u>	
11	Less: Plan Trade Income	91	A-3
12	Transfer to Trade Income Deferral Account	<u><u>88</u></u>	A; A-2; A-3

Transfer to BCTC Transition Deferral Account
For the Year Ended March 31, 2006
(\$ in millions)

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	F2006 Actual	F2006 Plan	Variance	Reference Schedule
<u>BCTC Asset Management Fee</u>				
Transmission Assets	91.0	94.6	(3.6)	
Generation Related Transmission Assets	10.2	10.3	(0.1)	
Substation Distribution Assets	11.6	11.8	(0.2)	
	112.8	116.7	(3.9)	
<u>BCTC Wholesale Transmission Service / BCTC Revenue Forecast (Note 2)</u>				
BCTC Network Integrated Transmission Service (NITS)	57.5	61.0	(3.5)	
BCTC Point to Point (PTP) Expenses	24.8	-	24.8	
Ancillary Services Expenses and other	6.7	-	6.7	
	88.9	61.0	27.9	
Total	201.7	177.7	24.0	A; A-2; A-3

Notes:

1. The transfer to the BCTC Transition Deferral Account*¹ relates to two variances:

- a) variances between BC Hydro's Asset Management/Maintenance Revenue Requirement forecast at \$116.7 million*² 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 of \$61.0 million*² in BC Hydro's Revenue Requirement and the BCTC charges to BC Hydro.

2. At the time of preparing the BC Hydro Revenue Requirement, it was not anticipated that BCTC would be sharing in the Point to Point (PTP) revenues collected and any PTP revenues collected by BCTC were credited back to BC Hydro. Therefore, BC Hydro's Revenue Requirement did not include any net costs for collection from BC Hydro customers for any net external PTP expenses on consolidation.

In terms of the BCUC Decision on BCTC's Revenue Requirement, BC Hydro is now sharing both the Network Integrated Transmission Service (NITS) and PTP revenues with BCTC. Therefore, on consolidation BC Hydro now has net external PTP expenses that were not included in its approved revenue requirement.

*¹ Per Commission Directive October 29, 2004 Page 43, Section 4.7

*² Per BC Hydro 2004/05 and 2005/06 Revenue Requirement Application, Chapter 2, Schedule B-3 (November 15, 2004 Compliance Filing)

First Nations Regulatory Account
For the Year Ended March 31, 2006
(\$ in millions)

	F2006 Actual	F2006 Plan	Variance	Reference Schedule
First Nations Obligation Provision	87.7	-	87.7	A-2 ; A-3

In F2006 negotiations with two First Nations groups that have brought actions against BC Hydro have progressed to the point where, according to GAAP, a provision for potential settlements must be recorded. Consequently, BC Hydro has booked the required provision in F2006, although at this time, BC Hydro does not forecast any settlement payment in the test period.

In order that BC Hydro may in future years recover any actual payments arising from a settlement of these claims, BC Hydro has, by Commission Order G-56-06 received May 18, 2006, established a regulatory asset in respect of the provision.

INTERSEGMENT REVENUES
For the Year Ended March 31, 2006

	<u>Actual</u>	<u>Plan</u>	<u>Variance</u>	<u>Reference Schedule</u>
Net sales to Powerex - Future Trade <i>(Note 1)</i>	68	49	19	C-1
Point-to-Point wheeling charge to Powerex <i>(Note 2)</i>	21	53	(32)	
Point-to-Point wheeling charge to BCH <i>(Note 3)</i>	17	12	5	
Allocation of BCH Corporate costs to Powerex <i>(Note 4)</i>	2	2	(0)	
Mark to Market gains on energy derivatives with Powerex <i>(Note 5)</i>	(43)	-	(43)	
Total	65	116	(51)	A - 3

Notes:

1. These sales in the Plan relate to a return of energy bought by Powerex in prior periods to enable future sale. These revenues are eliminated against trade cost of energy on consolidation.
2. These transmission revenues relate to an allocation of BC Hydro's cost of purchases of point-to-point transmission within BC for export and some import transactions. These revenues are eliminated against trade cost of energy on consolidation.
3. These transmission revenues relate to an allocation of BC Hydro's cost of purchases of point-to-point transmission relating to BC Hydro's Skagit Valley Treaty commitment, Canadian Entitlement Agreement (BCTC OATT Schedule 02) and Scheduling, System Con
4. These revenues relate to an allocation of corporate costs to Powerex and are eliminated against trade income on consolidation.
5. This relates to a mark to market gains on energy derivatives with Powerex. This revenue is eliminated against trade income on consolidation.

References to Commission Directives and Revenue Requirement Application

Reference:	Wording in Document:
<p>Commission Directive October 29, 2004 Page 30-31, Section 4.4</p>	<p>4.4 Heritage Payment Obligation Deferral Account</p> <p>The cost elements for the HPO set forth in BC Hydro’s Final Argument are itemized as follows:</p> <ol style="list-style-type: none"> 1. cost of energy – all variances except those arising from changes in customer load (part of (a)(i)); 2. cost of energy – variable costs related to thermal generation. (part of (a)(ii)); 3. significant unplanned major maintenance costs greater than \$1 million related to single event equipment or infrastructure failure or caused by weather related events (part of (a)(ii)); 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 (part of (a)(iii)); 5. amortization of unplanned deferred capital costs pursuant to Commission Order No. G-53-02 (part of (a)(iv)); 6. all net revenues from surplus hydro electricity sales (all revenues in (b)(iii)); and 7. Skagit Valley Treaty revenues (all revenues in (b)(i)) and ancillary services revenues (all revenues in (b)(ii)).
<p>Commission Directive October 29, 2004 Page 37, Section 4.5</p>	<p>4.5 Non-Heritage Deferral Account</p> <p>BC Hydro’s Non-Heritage Deferral Account proposal, as set forth in BC Hydro Argument and amended during the oral phase of argument (T22: 4161), is set forth below:</p> <ol style="list-style-type: none"> 1. cost of energy – all variances in non-HPO energy costs except those arising from changes in customer load; 2. significant unplanned major maintenance costs greater than \$1 million related to single event equipment or infrastructure failure or caused by weather related events; 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; 4. distribution emergency restoration costs – all variances in emergency restoration expenditures; and 5. all Founding Partner Benefits and CIS Credits under the ABS Contract.
<p>Per Commission Decision October 29, 2004, Page 38, Section 4.5.1.1</p>	<p>BC Hydro proposes that load variances be valued at the actual average cost of the highest priced resource option used to serve the load when the load variance is positive, that is, when actuals are higher than forecast. When actuals are lower than forecast, BC Hydro proposes that load variances be valued at forecast costs.</p> <p>When actuals are less than forecast, BC Hydro will not be purchasing power so BC Hydro proposes to use the average of the forecast of the highest resource option. When actuals are greater than forecast, BC Hydro will be purchasing power to meet the variance so BC Hydro proposes to use the average of the actual highest resource option purchases.</p>

Appendix 1

References to Commission Directives and Revenue Requirement Application

<p>Commission Directive October 29, 2004 Page 41</p>	<p>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.</p> <p>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.</p>
<p>Commission Directive October 29, 2004 Page 42, Section 4.6</p>	<p>BC Hydro proposes to record variances between BC Hydro's forecast Trade Income and actual Trade Income, as defined in HC2, in the TIDA and submits that its TIDA proposal is consistent with the requirements of subsection 7(a)(ii) of HC2 (BC Hydro Argument p. 76).</p> <p>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.</p>
<p>Commission Directive October 29, 2004 Page 42 & 43, Section 4.7</p>	<p>BC Hydro applies under section 7(b) of HC2 for a deferral account for two elements of the F2006 Transmission Revenue Requirement as set out in Exhibit B1-108. The two elements are: (1) BC Hydro Asset Management/ Maintenance Revenue Requirement forecast at \$116.7 million, and (2) BCTC Revenue Requirement forecast at \$74 million. The Commission Panel accepts that any variances from such amounts would only arise as a result of the Commission's decision on BCTC's F2006 revenue requirement application, and would be beyond BC Hydro's control (BC Hydro Argument, p. 78).</p> <p>Commission Findings The Commission Panel approves the BCTC TDA 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.</p>
<p>Commission Directive October 29, 2004 Page 45, Section 4.11</p>	<p>The Commission Panel approves BC Hydro's proposal that annually the average balance in each deferral account attract an interest charge or credit equivalent to BC Hydro's weighted cost of debt during the same period.</p>
<p>BC Hydro 2004/05 and 2005/06 Revenue Requirement Application (November 15, 2004 Compliance Filing), Chapter 2, Schedule B-3</p>	<p>Refer to Schedule B-3 below table.</p>

References to Commission Directives and Revenue Requirement Application

SCHEDULE B-3 (November 2004)									
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	Consolidated
		Chapter 3	Chapter 4	Chapter 5	Chapter 6	Chapter 7	Chapter 8	Chapter 9	
B1	Domestic cost of energy		408.0	431.6		15.0			854.6
	OMA Expenses								-
	Operations, maintenance, and administration (net)	63.8	20.9	126.0	3.5	107.6	97.3	(18.2)	400.9
	Corporate Allocations	(121.3)	11.3	39.3	14.7	23.0	7.5	25.5	-
B2	Adjusted OMA including Corporate Allocations	(57.5)	32.2	165.3	18.2	130.6	104.8	7.3	400.9
B4	Depreciation	52.0	27.9	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	113.5		-	463.0
B6	Allowed net income (return on equity)		4.2	181.9	119.3	101.6		-	407.0
C3	Other ³			43.3		66.7			110.0
A-1	Restructuring Costs	-	-	-	-	-	-	-	-
A-8	Miscellaneous external revenues	(10.1)		(118.8)	(115.7)	(4.5)	(4.2)	(22.5)	(275.8)
	Cost of Service by Function	-	477.0	1,049.1	383.6	513.1	100.6	3.0	2,526.4
BCTC	Asset Management Fee to BCTC ⁴								116.7
BCTC	WTS Charges from BCTC ⁴								61.0
A-1	Intersegment revenues ⁵								(116.0)
	Total Revenue Requirement ⁶								2,588.1
Schedule to cross reference		C6	C2	C1	C3	C4	C5	C7	
Notes:	<p>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.</p> <p>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.</p> <p>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.</p> <p>4. Relates to charges from BCTC</p> <p>5. See Chapter 2 Section 3.3 for details.</p> <p>6. Small differences from Chapter 1 Table 3 relate to rounding differences.</p> <p>7. Domestic cost of energy for Electricity Distribution & NIA is from Domestic Cost of Energy - Non-Integrated Areas (see line 1, schedule C4)</p>								
	Shaded amounts indicate changes to the test years from the Revised Evidentiary Update.								