

## Schedule C. List of Errata

Title	Insert	Remove	Note
Volume I, Chapter 2	Revision 1, page 2-82	Original, page 2-82	1
Volume I, Chapter 2	Revision 1, page 2-91	Original, page 2-91	2
Volume I, Chapter 4	Revision 1, page 4-17	Original, page 4-17	3
Volume II, Appendix F	Revision 1, page 5	Original, page 5	4
Volume II, Appendix F	Revision 1, page 9	Original, page 9	5
Volume II, Appendix F	Revision 1, page 13	Original, page 13	6
Volume II, Appendix F	Revision 1, page 33	Original, page 33	7
Volume I, Chapter 4	Revision 1, page 4-10	Original, page 4-10	8
Volume II, Appendix F	Revision 1, page 96	Original, page 96	9
Volume I, Chapter 8	Revision 1, page 8-23	Original, page 8-23	10
Volume I, Chapter 2	Revision 1, pages 2-44 to 2-46	Original, pages 2-44 to 2-46	11
Volume I, Chapter 2	Revision 1, page 2-80	Original, page 2-80	12
Volume I, Chapter 6	Revision 1, page 6-40	Original, page 6-40	13
Volume I, Chapter 11	Revision 1, page 11-2	Original, page 11-2	14
Volume I, Chapter 11	Revision 1, page 11-12	Original, page 11-12	15
Volume I, Chapter 5	Revision 1, page 5-51	Original, page 5-51	16
Volume I, Chapter 11	Revision 1, page 11-4	Original, page 11-4	17
Volume I, Chapter 5	Revision 1, page 5-39	Original, page 5-39	18
Volume I, Chapter 5	Revision 1, page 5-45	Original, page 5-45	19
Volume II, Appendix J	Revision 1, pages 4 to 5	Original, pages 4 to 5	20
Volume I, Chapter 5	Revision 1, page 5-40	Original, page 5-40	21

### Notes:

1. F2006 added to schedule D1-4 (as per BC Hydro's response to BCUC IR #1.2.37)
2. Headcount breakdown added on lines 31 – 33 to schedule D10 (as per BC Hydro's response to BCUC IR #1.82.1)
3. Note 1 referenced on line 12 corrected (as per BC Hydro's response to BCUC IR #1.4.11)
4. Table 2, residential growth rates corrected.
5. Table 6, Action 9 has been corrected to read "... with Power Smart."
6. Table 2.1, Action 9 has been corrected to read "... with Power Smart."
7. Section 6.2, third line has been corrected to read "... the 200<sub>3</sub> forecast is above the 200<sub>2</sub> forecast ..." (as per BC Hydro's response to BCUC IR #1.27.0)
8. Footnote 1, references to Table 4-12 has been corrected to Table 4-11 (as per BC Hydro's response to BCUC IR #1.2.18)
9. Table A4.1, title of table has been corrected to read "Actual and Weather-Adjusted Peak for BC Hydro Domestic System" (as per BC Hydro's response to BCUC IR #1.39.1)

10. Line 21, sentence has been corrected to read "... renewal of the forecasting function adds \$0.1 million in F2004 ..." (as per BC Hydro's response to BCUC IR #1.64.0)
11. Schedule A-5, numbers on lines 17 and 18 have been corrected; Schedule A-6, numbers on lines 16 and 17 have been corrected; and Schedule A-7, numbers on lines 15 and 16 have been corrected (as per BC Hydro's response to BCUC IR #1.43.1 – 1.43.2)
12. Line 2, heading replaced with "Market Electricity Purchases (Note 1)" and inclusion of Note 1 (as per BC Hydro's response to BCUC IR #1.2.33)
13. Numbers in Table 6-9 corrected (as per BC Hydro's response to BCUC IR #1.20.3)
14. Table 11-2, added row for BCTC. Simplified summary rows.
15. Table 11-4, project name "Mica Units 1 to 4 Stator Replacement" changed to "Mica Unit 4 Stator Replacement".
16. Table 5-30, O&M – Other changed to \$2.6m from \$1.5m; G&A – Other(net) changed to (\$0.1m) from \$1.0m.
17. Table 11-3, cost to project name "Burrard Generating Station Upgrade" spending to March 31, 2003 changed to \$182.8m from \$184.6m
18. Table 5-23, added program "Fire Risk Reduction" (as per BC Hydro's response to BCUC IR #1.5.43)
19. Table 5-28, Note 1 is deleted.
20. Tables 6 to 8, corrections to numbers (as per BC Hydro's response to BCUC IR #1.2.26)
21. Table 5-24, correction to numbers to "Fire Risk Reduction Program" (as per BC Hydro's response to BCUC IR #1.5.44)

## SCHEDULE D1-4

**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> Forecast	<u>F2005</u> Plan	<u>F2006</u> Plan	
1	Cost of Service - Generation (Heritage Contract)					
2	Cost of Energy component of Heritage Payment Obligation	D1-3	354.5	540.0	411.3	379.9
3	Displaced Hydro	D1-2	(5.4)	2.9	6.1	3.4
3	Electric Purchase Powerex	D1-2	<u>50.0</u>	<u>0.0</u>	<u>0.0</u>	<u>0.0</u>
4	Domestic cost of energy-Generation (Heritage Contract)	D1-2	399.1	542.9	417.4	383.3
5	Generation OMA	D1-1	\$ 147.4	\$ 161.7	\$ 168.3	\$ 169.8
6	GRTA charges from Transmission	C3	37.0	43.3	43.3	43.3
7	Taxes	B3	29.0	27.8	28.6	29.0
8	Depreciation and Amortization	B4	110.7	114.8	130.2	126.3
9	Finance Charges	B5	213.0	207.0	208.0	220.0
10	Allowed return on equity		<u>195.0</u>	<u>182.0</u>	<u>196.0</u>	<u>199.0</u>
11	Total Cost		<u>1,131.2</u>	<u>1,279.5</u>	<u>1,191.8</u>	<u>1,170.7</u>
12	Less: Trade Income	A-1	138.0	91.0	80.0	89.0
13	Other Utilities		21.9	19.5	20.1	20.7
14	Other miscellaneous Non-tariff revenues	A-8	<u>5.3</u>	<u>5.1</u>	<u>7.3</u>	<u>8.4</u>
15			<u>165.2</u>	<u>115.6</u>	<u>107.4</u>	<u>118.1</u>
16	Total Cost of Service - Generation	C1	<u>\$ 966.0</u>	<u>\$ 1,163.9</u>	<u>\$ 1,084.4</u>	<u>\$ 1,052.6</u>

C

## SCHEDULE D10

### Resource Usage - MMBU (\$ millions)

<u>Line</u>		<u>F2003</u> Actual	<u>F2004</u> Forecast	<u>F2005</u> Plan	<u>F2006</u> Plan
<b>Operations, Maintenance and Administration Expenses by Resources</b>					
	Labour				
1	Direct	7.2	7.8	7.8	8.0
2	Indirect	0.2	0.4	-	-
3	Materials	0.4	0.7	0.7	0.7
	Internal Services				
4	Engineering	1.1	1.2	1.2	1.2
5	Field Services	2.8	1.2	1.2	1.2
6	BC Hydro Corporate Direct Charges	0.3	0.2	0.2	0.2
7	Other BCH Billings	1.8	2.1	2.1	2.1
	External Services				
8	ABS	2.0	5.7	5.9	5.9
9	Other	3.0	4.4	6.5	6.3
10	Buildings & Equipment	0.2	0.1	0.1	0.1
11	Vehicles	1.3	1.3	1.3	1.3
12	Corporate Allocation	-	-	-	-
13	Less: Capitalized Overhead	-	-	-	-
	Less: Recoveries				
14	Internal	(22.5)	(23.4)	(25.4)	(25.4)
15	External	(0.8)	(1.0)	(1.0)	(1.0)
16	Total OMA Expenses	<u>(3.0)</u>	<u>0.7</u>	<u>0.6</u>	<u>0.6</u>
<b>Operations, Maintenance and Administration Expenses by Category</b>					
17	Direct	17.7	21.4	23.5	23.6
18	Support	2.6	3.7	3.5	3.4
19	Corporate Allocations	-	-	-	-
20	Less: Capitalized Overhead	-	-	-	-
21	Less: Recoveries	(23.3)	(24.4)	(26.4)	(26.4)
22	Total OMA Expenses	<u>(3.0)</u>	<u>0.7</u>	<u>0.6</u>	<u>0.6</u>
<b>Capital Additions</b>					
23	Sustaining	-	2.1	0.8	0.5
24	Growth	0.0	-	-	-
25	Deferred Capital	-	-	-	-
26	Total Capital Gross of CIA	<u>0.0</u>	<u>2.1</u>	<u>0.8</u>	<u>0.5</u>
27	Sustaining CIA	-	-	-	-
28	Growth CIA	-	-	-	-
29	Total CIA	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>
30	Total Net Capital	<u>0.0</u>	<u>2.1</u>	<u>0.8</u>	<u>0.5</u>
<b>Headcount</b>					
31	M&P	4	6	6	6
32	IBEW	81	83	83	83
33	OPEIU	23	30	30	30
34	Total Headcount	<u>108</u>	<u>119</u>	<u>119</u>	<u>119</u>

C

## 5. Heritage Payment Obligation

The Heritage Payment Obligation for the test periods is forecast to be \$1,158.3 million and \$1,138.2 million for F2005 and F2006, respectively. A detailed description of the activities and costs associated with managing BC Hydro's Heritage Resources is provided in chapter 5. In the test periods, the capability of Heritage Resources (including economic market purchases to displace thermal capability) plus the resources under contract, are expected to be sufficient to meet the needs of domestic customers.

The calculation of the forecast Heritage Electricity to be supplied to BC Hydro Distribution is shown in Table 4-6.

**Table 4-6. Forecast Heritage Electricity Deliveries**

(GWh)	F2005 Forecast	F2006 Forecast
Reference Load Forecast with Power Smart and Fort Nelson <i>(Note 1)</i>	54,603	54,959
IPPs and other long-term purchases (existing and planned)	(6,598)	(7,003)
Total Forecast Heritage Electricity	48,005	47,956
Skagit Valley Treaty obligation	(340)	(340)
<b>Forecast Heritage Electricity to BC Hydro Distribution</b>	<b>47,665</b>	<b>47,616</b>

Notes:

1. See Appendix F, BC Hydro load forecast.

Approximately 340 GWh of Heritage Electricity is reserved to fulfill obligations under the Skagit Valley Treaty. Annual energy deliveries under the Skagit Valley Treaty are constant throughout the term of the Treaty, which is expected to end in 2066.

The forecast mix of resources used to supply Heritage Electricity takes into account the reservoir storage and the short term forecast cost of electricity purchases and gas prices.

Table 4-7 shows the expected Heritage Electricity supply sources as forecast in October 2003 based on September 30, 2003 system storage.

## Energy and Peak Forecast Before Power Smart

Table 2 provides a summary of historical and forecast sales and peak for selected years, before accounting for the effects of Power Smart, BC Hydro's demand-side management program.

- BC Hydro's total domestic gross sales include sales to residential, commercial and industrial customers, New Westminster and Aquila Networks Canada.
- BC Hydro's total domestic sales before Power Smart are expected to grow from 48,685 GWh in 2002/03 to 65,523 GWh in 2023/24.
- BC Hydro's total gross requirements include total domestic sales, firm exports, losses and BC Hydro's non-integrated areas.
- BC Hydro's total gross requirements before Power Smart are expected to grow from 53,339 GWh in 2002/03 to 73,191 GWh in 2023/24.
- BC Hydro's total integrated system peak (system coincident basis excluding Powerex and related losses) before Power Smart is expected to grow from 8,816 MW (9,405 MW weather normalized<sup>5</sup>) in 2002/03 to 13,083 MW in 2023/24.

**Table 2. Energy and Peak Forecast Before Power Smart for Selected Years**

	Residen- tial (GWh)	Commer- cial (GWh)	Industrial (GWh)	Total Domestic Sales (GWh)	Total Gross Require- ments (GWh)	Total Integrated System Peak * (MW)
1997/98	13802	12466	16339	43072	48342	8566 (8672)
2002/03	15287	13729	18596	48685	53339	8816 (9405)
2007/08	16857	15050	19139	52170	58265	10338
2012/13	18363	16578	20042	56241	62815	11175
2023/24	21743	20040	22283	65523	73191	13083
<b>Growth Rates<sup>6</sup></b>						
5 years: 97/98 to 02/03	2.1%	1.9%	2.6%	2.5%	2.0%	0.6% (1.6%)
5 years: 02/03 to 07/08	2.0%	1.9%	0.6%	1.4%	1.8%	3.2% (1.9%)
10 years: 02/03 to 12/13	1.9%	1.9%	0.8%	1.5%	1.6%	2.4% (1.7%)
last 11 years: 12/13 to 23/24	1.5%	1.7%	1.0%	1.4%	1.4%	1.4%

\* Values shown in brackets are based on weather normalized actuals

<sup>5</sup> Weather normalization reflects an adjustment of an actual metered load to reflect the difference between the temperature at which actual load occurred and the design temperature.

<sup>6</sup> Unless otherwise noted, growth rates are calculated as annual compound growth rates.

**Table 6. Decisions and Summary Responses**

Decision	Action
1. More appropriate to use load forecast before Power Smart rather than with Power Smart in comparing historical growth rates.	1. Both before Power Smart and with Power Smart forecasts are shown to increase transparency of the forecast in Sec. 5.
2. Provide an understanding of the methodology, input data and impacts of drivers.	2. Methodology is presented in Sec. 3, input data in Sec. 4 and impacts of drivers in Sec. 7.
3. Transparency of weather normalization, back-casting and assumptions need improvement.	3. Weather normalization is reviewed in App. 3 and App. 4, alternative forecasts in App. 5, back-casting for peak in Sec. 11 and App. 6, and assumptions in Sec. 4.
4. Include the following in future applications for major project additions: •Explanation of the selected methodology and alternatives considered; •Listing of data sources and assumptions; •Validation of the modelled outputs; •Comment on growth trends.	4. Incorporated in current forecast: •Algorithms used are explicitly stated in Sec. 3 as are a variety of regression-based alternatives in App. 5 and App. 6; •Data sources and key growth assumptions are provided in Sec. 4; •Regression modelling is used to validate the modelled outputs in App. 5 and App. 6; •Growth trends are summarized in Sec. 5.
5. Use updated numbers for Power Smart when calculating peak demand for Vancouver Island.	5. Most recent 10-Year Power Smart plan as summarized in Sec. 12 has been used for the forecast with Power Smart.
6. Adjust BC Hydro peak forecasts between 2003/04 and 2011/12 to reflect lower population growth on Vancouver Island.	6. Forecasts of numbers of accounts for all regions, including Vancouver Island, have been adjusted to reflect most recent population forecasts and peak is lower than last year's estimates for all years of the forecast period.
7. Use of -3.7 degrees Celsius based on 30-year rolling average is appropriate for Vancouver Island.	7. For this forecast, design-day temperatures of minus 6.8 degrees Celsius for the system and minus 4.4 degrees Celsius for Vancouver Island are being used. A review is underway to determine the most appropriate design-day temperatures.
8. Adjust the peak for Vancouver Island downward to adjust for anticipated rate changes.	8. Scenarios have been developed using a range of relevant elasticities from recent third party studies in high cost jurisdictions and from internal econometric estimates to provide indicative information.
9. Adjust peak for 2007/08 and 2011/12 downwards in order to account for negative variances.	9. Compared to last year's forecast, the peak for Vancouver Island has been adjusted downward by 26 MW for 2007/08 and 35 MW for 2011/12 with Power Smart.

c

**Table 2.1. B.C. Utilities Commission Decision and Actions**

Decision	Action
1. More appropriate to use load forecast before Power Smart rather than with Power Smart in comparing historical growth rates.	1. Both before Power Smart and with Power Smart forecasts are shown to increase transparency of the forecast in Sec. 5.
2. Provide an understanding of the methodology, input data and impacts of drivers.	2. Methodology is presented in Sec. 3, input data in Sec. 4 and impacts of drivers in Sec. 7.
3. Transparency of weather normalization, back-casting and assumptions need improvement.	3. Weather normalization is reviewed in App. 3 and App. 4, alternative forecasts in App. 5, back-casting for peak in Sec. 11 and App. 6, and assumptions in Sec. 4.
4. Include the following in future applications for major project additions: <ul style="list-style-type: none"> <li>• Explanation of the selected methodology and alternatives considered;</li> <li>• Listing of data sources and assumptions;</li> <li>• Validation of the modelled outputs;</li> <li>• Comment on growth trends.</li> </ul>	4. Incorporated in current forecast: <ul style="list-style-type: none"> <li>• Algorithms used are explicitly stated in Sec. 3 as are a variety of regression-based alternatives in App. 5 and App. 6;</li> <li>• Data sources and key growth assumptions are provided in Sec. 4;</li> <li>• Regression modelling is used to validate the modelled outputs in App. 5 and App. 6;</li> <li>• Growth trends are summarized in Sec. 5.</li> </ul>
5. Use updated numbers for Power Smart when calculating peak demand for Vancouver Island.	5. Most recent 10-Year Power Smart plan as summarized in Sec. 12 has been used for the forecast with Power Smart.
6. Adjust BC Hydro peak forecasts between 2003/04 and 2011/12 to reflect lower population growth on Vancouver Island.	6. Forecasts of numbers of accounts for all regions, including Vancouver Island, have been adjusted to reflect most recent population forecasts and peak is lower than last year's estimates for all years of the forecast period.
7. Use of -3.7 degrees Celsius based on 30-year rolling average is appropriate for Vancouver Island.	7. For this forecast, design-day temperatures of minus 6.8 degrees Celsius for the system and minus 4.4 degrees Celsius for Vancouver Island are being used. A review is underway to determine the most appropriate design-day temperatures.
8. Adjust the peak for Vancouver Island downward to adjust for anticipated rate changes.	8. Scenarios have been developed using a range of relevant elasticities from recent third party studies in high cost jurisdictions and from internal econometric estimates to provide indicative information.
9. Adjust peak for 2007/08 and 2011/12 downwards in order to account for negative variances.	9. Compared to last year's forecast, the peak for Vancouver Island has been adjusted downward by 26 MW for 2007/08 and 35 MW for 2011/12 with Power Smart.

c

**Table 6.1. Comparison of Reference Energy Forecasts With Power Smart: Gross System Requirements**

	October 2003 Forecast (GWh)	December 2002 Forecast (GWh)	October 2003 minus December 2002 (GWh)
1998/99	50897	50897	-
1999/00	51534	51354	-
2000/01	52978	52978	-
2001/02	52567	52582	-15
2002/03	53339	53804	-465
2003/04	54563	54096	467
2004/05	54728	54916	-188
2005/06	55086	55269	-183
2006/07	55454	55872	-418
2007/08	56075	56678	-603
2008/09	56641	57600	-959
2009/10	57207	58685	-1478
2010/11	57810	59376	-1566
2011/12	58410	59852	-1442
2012/13	59298	60151	-853
2013/14	60169	60609	-440
2014/15	61088	61635	-547
2015/16	62018	62685	-667
2016/17	62910	63714	-804
2017/18	63832	64776	-944
2018/19	64758	65802	-1044
2019/20	65709	66892	-1183
2020/21	66699	67958	-1259
2021/22	67657	69009	-1352
2022/23	68656	70049	-1393
2023/24	69675	-	-

## 6.2. Residential Sales

Table 6.2 compares the October 2003 residential reference forecast including Power Smart with the December 2002 forecast including Power Smart. For residential sales, the 2003 forecast is above the 2002 forecast by 227 GWh for 2003/04, above the 2002 forecast by 266 GWh in 2012/13 and below the 2002 forecast by 155 GWh in 2022/23. The main reason for the increase in forecast residential sales for most of the forecast period is that the residential use rate has been increasing due to the increased saturation of secondary appliances, as demonstrated by billing data analysis. A second reason driving growth is the increase in the forecast number of residential accounts due to forecasts of strong housing starts for the first four years. Beyond this period, account growth levels off and is less strong than was assumed last year as a result of lower population forecast growth, bringing down forecast residential sales.

1 **Table 4-4. Energy Purchases from Pre-F2001 Commitments**

Project	Energy Purchases (GWh/Year)			
	F2003	F2004	F2005	F2006
<b>Pre-1994</b>				
McMahon Co-Generating Project	839	824	840	840
NWE Williams Lake	528	499	545	545
Mamquam River Hydro	200	227	250	250
Salmon Inlet (Sechelt Creek)	80	73	80	80
Soo River	73	72	65	65
Brown Lake Hydro	59	53	57	57
Akolkolex	42	50	50	50
Walden North	29	29	45	45
Scuzzy Creek	33	36	38	38
Ptarmigan Creek (Robson Valley)	19	18	20	20
Doran Taylor	23	20	23	23
East Twin Creek Hydro	5	5	6	6
Seaton Creek Hydro	1.00	0.87	0.50	0.50
Clyde Coats	0.31	0.50	0.48	0.48
Morehead Creek	0.36	0.47	0.55	0.55
McDonald Ranch	0.38	0.43	0.49	0.49
<b>1994 to 2000</b>				
Island Cogeneration Project (ICP)	1,338	1,811	1,519	1,802
Purcell Woodwaste Power Project	91	91	89	89
<b>1997 BC/Alcan Agreement (LTEPA)</b>				
Alcan	1,518	1,230	1,230	1,230
Arrow Lakes Hydro (Keenleyside)	88	743	772	772
<b>Total Purchases<sup>1</sup></b>	<b>4,967</b>	<b>5,783</b>	<b>5,631</b>	<b>5,914</b>

2 The history of these commitments is set out below.

3 **3.1.1. Pre-1994 Energy Acquisition Commitments**

4 In F2005 and F2006, BC Hydro will be acquiring energy under contracts resulting from two  
 5 pre-1994 requests for proposals (RFPs). As a result of its first RFP issued in 1988,  
 6 BC Hydro entered into electricity purchase agreements relating to the NWE Williams Lake,  
 7 McMahon Co-Generating Project and Lower Mamquam River Hydro facilities. These  
 8 projects total 220 MW of capacity and 1,635 GWh/year of expected energy capability.

9 In 1989, BC Hydro issued its second RFP. This RFP was restricted to projects under 5 MW  
 10 of installed capacity and used a standardized EPA with standard pricing. A total of 13 small

<sup>1</sup> The volumes in Table 4-4 are slightly less than shown in Table 4-11 because BC Hydro purchases small amounts of energy (approximately 20-25 GWh/year) from neighbouring utilities to serve BC Hydro customers in areas lacking direct connections to BC Hydro facilities. These amounts are reflected in Table 4-11, but not in Table 4-4.

**Table A4.1. Actual and Weather-Adjusted Peak for BC Hydro Domestic System**

c

Year	Actual (MW)	Bottom-up Approach Substation Weather-Normalized <sup>1</sup> (MW)	Top-Down Procedure Weather-Normalized (MW)	Weather-Adjusted Base Year for Forecast
1993/94	8059	8209		8209
1994/95	8168	8253		8253
1995/96	8451	8301		8301
1996/97	8267	8271		8271
1997/98	8243	8385		8385
1998/99	8777	8772	9076	8772
1999/00	8423	8835	9053	8835
2000/01	8995	8986	9154	8986
2001/02	8692	9016	9339	9016
2002/03	8481	8972	9127	9082

Note 1. As released in VIGP hearing.

1 **3 Energy Management**

2 **3.1 Introduction**

3 BC Hydro's approach to energy acquisition is described in Chapter 4. In F2004, BC Hydro  
4 consolidated the energy management function within a group in BC Hydro Distribution called  
5 Power Planning & Portfolio Management. This section describes the activities and the  
6 operations, maintenance and administration costs associated with energy planning,  
7 acquisition and energy supply management.

8 **3.2 Scope of Services**

9 BC Hydro's Power Planning & Portfolio Management group performs the following functions:

- 10 • produces the Load Forecast,  
11 • produces the Integrated Electricity Plan,  
12 • manages BC Hydro's portfolio of long-term supply contracts, and  
13 • manages BC Hydro's acquisition of new supply.

14 **3.2.1 Load Forecast**

15 BC Hydro's system is operating closer to capacity, which demands a more regional, short-  
16 term and risk-focused forecast. Load forecasting requires sophisticated methods and tools  
17 to illustrate risks and sensitivity analyses. Furthermore, the forecast information must be  
18 transparent, consistent, relevant and accessible for both internal and external users.

19 In light of these considerations, BC Hydro has changed its traditional load forecasting  
20 methodologies and approaches to better meet user expectations. The Load Forecast is  
21 attached in appendix F. The renewal of the forecasting function adds \$0.1 million in F2004 | c  
22 and \$0.3 million in F2005.

23 **3.2.2 Integrated Electricity Plan (IEP)**

24 BC Hydro has not developed a comprehensive IEP since 1995, though it published an  
25 update in 2000. BC Hydro expects to complete the 2004 IEP in March 2004, after  
26 stakeholder input. The IEP will reflect the current provincial electricity market, primarily

## SCHEDULE A-5

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

	A		B		C		D	
	F2003	F2004	%	F2005	%	F2006	%	
	Actual	Forecast		Plan		Plan		
<b>Revenue</b>								
Residential revenue	\$923	\$959	4%	\$1,041	9%	\$1,077	3%	
Revenue variance	n/a	\$36		\$82		\$36		
<b>Variance</b>								
Rate increase:	n/a	n/a		70		22		
Volume:								
Number of customers	n/a	16		16		17		
Usage per customer	n/a	23		1		1		
Power Smart savings	n/a	(3)		(5)		(4)		
Total Variance	n/a	\$36		\$82		\$36		
<b>Sales Volume (in GW·h)</b>	15,024	15,654	4%	15,836	1%	16,063	1%	
<b>Number of Customers</b>	1,442,597	1,465,057	2%	1,489,254	2%	1,515,170	2%	

( ) represents an unfavourable variance.

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

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

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

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

SCHEDULE A-6

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

1  
2  
3  
4  
5  
6  
7  
8  
9  
10  
11  
12  
13  
14  
15  
16  
17  
18  
19  
20  
21  
22  
23  
24  
25  
26  
27  
28  
29  
30  
31  
32  
33  
34  
35  
36  
37  
38  
39  
40  
41

	A		B		C		D	
	F2003	F2004		F2005		F2006		
	Actual	Forecast	%	Plan	%	Plan	%	
<b>Revenue</b>								
Light industrial & commercial	\$893	\$901	1%	\$970	8%	\$1,000	3%	
Revenue variance	n/a	\$8		\$69		\$30		
<b>Variance</b>								
Rate increase:	n/a	n/a		66		20		
Volume:								
GDP & Employment*	n/a	12		15		19		
Power Smart savings	n/a	(4)		(12)		(9)		
Total Variance	n/a	\$8		\$69		\$30		
<b>Sales Volume (in GW-h)</b>	16,757	16,947	1%	17,003	0%	17,202	1%	
<b>Number of Customers</b>	183,188	184,233	1%	185,231	1%	186,214	1%	

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

( ) represents an unfavourable variance

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

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

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

c  
c  
n  
c

SCHEDULE A-7

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

	A		B		C		D	
	F2003	F2004		F2005		F2006		
	Actual	Forecast	%	Plan	%	Plan	%	
<b>Revenue (in millions)</b>								
Large industrial	\$516	\$503	-3%	\$539	7%	\$543	1%	
Revenue variance	n/a	\$(13)		\$36		\$4		
<b>Variance</b>								
Rate increase:	n/a	n/a		37		10		
Volume:								
Power Smart savings	n/a	(9)		8		0		
Usage per customer	n/a	(4)		(9)		(6)		
Total Variance	n/a	\$(13)		\$36		\$4		
<b>Sales Volume (in GW-h)</b>	15,179	14,801	-2%	14,734	0%	14,601	-1%	
<b>Number of Customers</b>	133	135	2%	136	1%	136	0%	

( ) represents an unfavourable variance

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

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

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

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

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

## SCHEDULE D1-2

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

Line	F2003 Actual	F2004 Forecast	F2005 Plan	F2006 Plan
Domestic Cost of Energy - Generation (Heritage Contract)				
1				
2	258.2	246.6	264.5	281.2
3	104.4	249.2	105.2	55.4
4				
5	17.4	16.8	17.9	13.8
6	10.7	11.2	10.5	10.0
7	0.1	-	-	-
8				
9	(3.4)	(3.7)	(3.5)	-
10	6.8	7.0	7.2	7.3
11	<u>394.2</u>	<u>527.1</u>	<u>401.8</u>	<u>367.7</u>
12	4.9	4.0	3.8	3.8
13	-	11.8	11.8	11.8
14	<u>4.9</u>	<u>15.8</u>	<u>15.6</u>	<u>15.6</u>
15	<u>399.1</u>	<u>542.9</u>	<u>417.4</u>	<u>383.3</u>
<b>Reconciliation of Domestic Cost of Energy - Generation (Heritage Contract) to the cost of energy component of the Heritage Payment Obligation</b>				
16	399.1	542.9	417.4	383.3
17	5.4	(2.9)	(6.1)	(3.4)
18	(50.0)	-	-	-
19	<u>\$354.5</u>	<u>\$540.0</u>	<u>\$411.3</u>	<u>\$379.9</u>

Notes:

1. F2003 includes electricity purchases from Powerex. See Note 3.
2. Displaced Hydro relates to water rentals associated with the trade account.
3. This relates to energy purchases made by Powerex for future trade. This energy is sold to BC Hydro when it enters the system. BC Hydro records a sale to Powerex when this energy is returned. These are part of the Generation function but are not included in the Heritage Payment Obligation.

1 **Table 6-9. General and Administration Costs**

(\$ millions)	F2004 Forecast	F2005 Plan	F2006 Plan
<b>BCTC Costs</b>			
President & CEO	\$3.1	\$0.8	\$0.8
Communications	0.6	1.0	1.0
Strategy and Planning	2.4	3.0	3.1
Stakeholder Relations	0.8	1.0	1.1
Corporate Services & CFO	3.7	4.5	4.4
Regulatory	2.1	2.4	2.4
Finance	13.5	3.7	2.7
Legal & General Counsel	3.9	4.8	4.7
Human Resources	2.7	2.5	2.4
Capital Overhead	(5.2)	(5.2)	(5.2)
<b>Total BCTC Costs</b>	<b>\$27.5</b>	<b>\$18.6</b>	<b>\$17.5</b>
<b>BC Hydro Transmission Costs</b>			
Aboriginal Relations	\$0.5	\$0.5	\$0.5
Rights Management and Issues	0.4	0.3	0.3
Property Services	0.5	0.4	0.4
<b>Total BC Hydro Transmission Costs</b>	<b>\$1.5</b>	<b>\$1.3</b>	<b>\$1.3</b>
<b>Total General &amp; Administration Cost</b>	<b>\$29.0</b>	<b>\$19.9</b>	<b>\$18.8</b>

2 Notes:

3 1. F2003 is not provided. Refer to Table 6-3 for a year over year reconciliation for total transmission.

4 The BCTC organization is built upon BC Hydro's former Transmission line of business. This  
 5 structure was supplemented by functions required for an independent transmission business  
 6 entity charged with carrying out the policy direction of the Energy Plan and the roles and  
 7 responsibilities under the Designated Agreements. BCTC's organizational structure and  
 8 staffing levels are designed to ensure that BCTC has full organizational capability for  
 9 conducting transmission system operations and planning, maintaining system reliability, and  
 10 asset management and maintenance. BCTC continues to use services provided by  
 11 BC Hydro, (principally Field Services and Engineering Services) and ABS, in carrying out  
 12 transmission capital, maintenance, and business programs. F2004 and F2005 include costs  
 13 for the establishment costs of BCTC, the majority of the establishment costs will be expended  
 14 in F2004.

15 1.1.1 Business Organization

16 In establishing BCTC, careful consideration was given to ensure that all existing BC Hydro  
 17 staff involved in transmission operations and asset management activities were fully  
 18 deployed into the new organization. This furthers the goal of continuity of business  
 19 knowledge and retention of critical skills required for the transmission business. New BCTC  
 20 positions were created for corporate and other functions only after concluding that no

1 Future capital spending requirements are identified within the operating plans presented in  
 2 chapters 3 to 9. Table 11-2 identifies the forecast capital additions by expenditure category  
 3 for F2004 to F2006.

4 **Table 11-2. Capital Expenditure Forecast, F2004 to F2006**

Expenditure Category (\$ millions)	F2004			F2005			F2006		
	S	G	Total	S	G	Total	S	G	Total
Generation Hydro	\$95	\$22	\$117	\$96	\$13	\$109	\$123	\$12	\$135
Generation Thermal	6	33	39	3	58	61	3	193	196
Transmission - Lines	71	16	87	41	9	50	44	12	56
Substations	34	37	71	45	80	125	53	150	203
Distribution	75	118	193	84	123	207	86	130	216
Computers	65	2	67	60	4	64	50	4	54
Land & Buildings	10	0	10	8	0	8	6	0	6
Surveys & Investigations (incl Aboriginal Negotiations)	14	0	14	10	0	10	5	0	5
Vehicles	21	0	21	17	0	17	19	0	19
Power Smart	0	116	116	0	105	105	0	94	94
Other	22	0	22	18	0	18	5	0	5
BCTC (Note 2)	12	0	12	47	0	47	0	0	0
<b>Gross Expenditures</b>	<b>\$425</b>	<b>\$344</b>	<b>\$769</b>	<b>\$429</b>	<b>\$392</b>	<b>\$821</b>	<b>\$394</b>	<b>\$595</b>	<b>\$989</b>
CIA - Specific	0	-8	-8	0	-8	-8	0	-9	-9
CIA - Recurring	-3	-37	-39	-4	-38	-42	-4	-41	-45
<b>Net Expenditures incl BCTC (Note 3)</b>	<b>\$422</b>	<b>\$299</b>	<b>\$722</b>	<b>\$425</b>	<b>\$346</b>	<b>\$771</b>	<b>\$390</b>	<b>\$545</b>	<b>\$935</b>

5 Notes:

- 6 1. S = Sustaining Capital Expenditures; G = Growth Capital Expenditures
- 7 2. Includes expenditures on BCTC-owned assets only.
- 8 3. BCTC Capital Expenditures are consolidated for F2004 and F2005 only (see section 3.10, page  
9 2-21).
- 10 4. Some columns do not total due to rounding.

11 This remainder of this chapter includes lists of historical (since F1994), in-progress, or  
 12 planned capital projects, by line of business or service organization, with capital cost greater  
 13 than \$2 million. Descriptions are provided for projects with capital cost greater than  
 14 \$5 million.

15 As discussed in chapter 6, BCTC has responsibility for planning and justifying capital  
 16 projects relating to BC Hydro's transmission assets. As a result, historical, in-progress, and  
 17 planned capital expenditures relating to transmission assets are identified in chapter 6.

Project Name (\$ millions)	Est. Project Completion Date	Sustain/ Growth	Primary Business Driver	To March 31, 2003 (Note 1)	F2004 Forecast (Note 2)	F2005 Plan (Note 3)	F2006 Plan (Note 3)	Total Cost (Note 4)	Section Ref. (Note 5)
PRV									
GM Shrum Unit Transformers and Generators Protection	F2007	Sustaining	Reliability	0.0	0.2	1.1	2.3	8.9	2.2.14
Strathcona Embankment Dam Improvements	F2007	Sustaining	Risk Mgmt	0.0	0.0	0.2	3.0	7.2	2.2.15
LaJoie Dam Safety Improvements	F2007	Sustaining	Risk Mgmt	0.0	0.0	1.8	4.0	6.3	2.2.16
GM Shrum Unit 8 Capacity Increase	F2007	Sustaining	Reliability	0.0	0.0	0.4	2.1	4.3	
Aberfeldie Redevelopment	F2008	Growth	Reliability	0.0	0.1	1.0	1.5	51.6	2.2.17
Mica Unit 4 Stator Replacement	F2008	Sustaining	Reliability	0.0	0.0	0.4	2.7	12.8	2.2.18
Peace Canyon Generator Deficiency Project	F2009	Sustaining	Cost Efficiency	0.0	0.3	0.8	10.6	46.0	2.2.19
First Nations Negotiations	Ongoing	Sustaining	Consent to Operate	23.2	7.2	6.8	3.6	40.8	2.2.20
Burrard Asbestos Program	Ongoing	Sustaining	Safety	3.9	1.1	1.3	1.2	7.5	2.2.21
Fire Risk Reduction Program (F1995 - F2009)	Ongoing	Sustaining	Risk Mgmt	10.3	5.2	4.1	2.6	31.3	2.2.22
Security Measures	Ongoing	Sustaining	Risk Mgmt	0.0	0.0	2.6	1.7	6.1	

1 Notes for all tables identifying Planned and In-Progress Projects:

- 2 1. To March 31, 2003 = Project spending to the end of F2003, for projects that are underway but will not be completed during F2004.
- 3 2. F2004 Forecast = Forecast spending during F2004.
- 4 3. F2005 Plan and F2006 Plan = Planned spending during each of F2005 and F2006.
- 5 4. Total Cost = Estimated total cost at project completion. Total Cost will be equal to the sum of the previous columns for projects completed
- 6 prior to the end of F2006. Total Cost is greater than the sum of the previous columns for projects with completion dates after F2006 and
- 7 includes expenditures after F2006 to completion.
- 8 5. Section Ref. = Section number of descriptions of projects with capital cost greater than \$5 million.

## 1 **10 Line of Business Support**

2 Line of Business Support includes Human Resources, Controller's Office, The Executive  
3 Vice-President's Office, and other line of business expenses.

4 **Table 5-30. Line of Business Support, F2004 to F2006**

	F2004 Forecast		F2005 Plan		F2006 Plan	
	\$ Millions	Headcount	\$ Millions	Headcount	\$ Millions	Headcount
Operations and Maintenance						
Other	\$1.2		\$2.6		\$2.6	
General and Administration						
Business Information Management	3.6	16	3.5	15	3.4	14
Financial Services	3.3	29	3.8	27	3.6	26
Records Support	0.7	10	0.6	10	0.6	10
Human Resources	1.1	7	1.3	7	1.3	7
ABS	9.0		9.4		8.7	
Other (net)	4.9		(0.1)		0.4	
<b>Total Operating costs</b>	<b>\$23.8</b>	<b>62</b>	<b>\$21.1</b>	<b>59</b>	<b>\$20.6</b>	<b>57</b>

5 Headcount for "Other," which includes replacement employees hired under training  
6 programs and employees on paid leave, is excluded from Table 5-30.

### 7 **10.1 Human Resources**

8 The BC Hydro Generation Human Resources Department provides support to management  
9 on issues impacting people, other than where services are provided by Corporate Human  
10 Resources as discussed in chapter 3. The support includes developing strategies for  
11 staffing, and attraction/retention, compensation issues, competency and employee  
12 development, change management consultation, and advice on process changes.

### 13 **10.2 BC Hydro Generation Controllers Office**

14 The Controllers Office provides information technology, finance, and record management  
15 support to the BC Hydro Generation business. Information Technology supports  
16 applications such as PassPort, Operational Information/Plant Information, Commercial  
17 Management, PeopleSoft, and Data Warehouse reporting. Finance is responsible for the  
18 overall financial integrity of BC Hydro Generation. Records Management provides record  
19 management standards and their application for BC Hydro Generation.

Project Name (\$ millions)	Project Completion Date (Note 1)	Primary Business Driver (Note 2)	Spending to March 31, 2003 (Note 3)	Est. Cost at Completion (Note 4)	Section Ref. (Note 5)
WAC Bennett Dam Drainage Improvements	2000	Risk Mgmt	4.3		
Aberfeldie Dam Stability Improvements	2000	Risk Mgmt	2.7		
Business Transition Program	2002	Cost Efficiency	40.5		2.1.6
Burrard Generating Station Unit 1 Generator Rehabilitation	2002	Reliability	14.8		2.1.7
Stave Falls Visitor Centre	2002	Consent to Operate	7.7		2.1.8
Stave Falls Rockfill Alternative	2002	Risk Mgmt	4.6		
Kootenay Canal 230KV & 60KV Interconnection with WKP	2002	Cost Efficiency	4.0		
HLK U/S Navigation Lock Gate Crane PLC	2002	Reliability	2.1		
Burrard Generating Station Unit 2 Emergency Rehabilitation	2003	Reliability	3.0		
ESSO Steam Project	2003	Profitable Growth	2.5		
Peace Canyon GS Tailrace Improvements	2003	Externally Driven Growth	2.3		
Burrard Generating Station Upgrade	2004	Reliability/ Consent to Operate	182.8	199.3	2.1.9
Seven Mile Generating Station Unit 4	2004	Externally Driven Growth	80.6	88.9	2.1.10
Bridge River Turbine Runner Upgrade Units 1 to 6	2004	Externally Driven Growth	13.1	15.1	2.1.11
WAC Bennett Dam Deficiency Investigation	2004	Risk Mgmt	9.9	9.9	2.1.12
Coquitlam Dam Deficiency Investigation	2004	Risk Mgmt	4.5	5.5	
Fort Nelson GS Integration into Thermal Generation	2004	Cost Efficiency	2.7	3.9	
Ruskin Dam Deficiency Investigation	2004	Risk Mgmt	2.5	3.1	
Hugh Keenleyside Dam Deficiency Investigation	2004	Risk Mgmt	4.0	4.1	
Fall Protection Program	2004	Employee Safety	9.2	10.6	2.1.13

c

1 Aberfeldie Generating station is at end of life. Replacing the wood stave penstock is  
 2 scheduled for F2005 and this will be followed by redevelopment of the station.

3 Table 5-23 provides a summary of major capital projects in the Columbia Region during the  
 4 test periods.

5 **Table 5-23. Capital Projects > \$2 million, Columbia Region, F2004 to F2006**

(\$ millions)	F2004 Forecast	F2005 Plan	F2006 Plan
Aberfeldie Redevelopment	\$ -	\$1.0	\$1.5
Aberfeldie Woodstave Pipeline Replacement	-	0.1	6.2
Fire Risk Reduction	1.1	2.0	0.1
Mica Replace Unit 4 Stator	-	0.4	2.7
Revelstoke Slope Stability Improvements	0.7	1.3	-
Kootenay Canal T4 Unit Transformer Replacement	2.1	-	-
Seven Mile Dam Safety Improvements	23.9	24.0	2.3

| c

6 **7.2.3 Coastal Region**

7 Over the next 5 years, the Coastal Region plans to:

- 8 • direct capital investment to improve reliability and Commercial Performance, reduce  
 9 equipment and environmental risks, and reduce operating and maintenance costs;
- 10 • ensure that Burrard Generating Station is operated and maintained to provide reliable  
 11 transmission support and 450 MW of capacity for the Lower Mainland;
- 12 • upgrade John Hart Generating Station to ensure reliable equipment and environmental  
 13 performance;
- 14 • complete high priority risk reduction programs for fire, seismic, and asbestos; and
- 15 • initiate a generator rewind program based on asset health and commercial risk.

16 Table 5-24 provides a summary of major capital projects in the Coastal Region during the  
 17 test periods.

**9 Sustainability and Aboriginal Relations**

**9.1 Financial Summary**

Table 5-27 and Table 5-28 summarize Sustainability and Aboriginal Relations operating costs, headcount, and major capital projects during the test periods.

**Table 5-27. Sustainability and Aboriginal Relations Operating Costs, F2004 to F2006**

	F2004 Forecast		F2005 Plan		F2006 Plan	
	\$ Millions	Headcount	\$ Millions	Headcount	\$ Millions	Headcount
General and Administration						
First Nations	\$1.5	22	\$1.4	21	\$1.3	21
Public Use Areas	1.4	3	1.4	3	1.4	3
Environmental Impact Management	2.2	7	1.7	8	1.7	8
Regulatory Relations & Strategic Issues	2.8	20	2.3	20	2.2	20
Water Use Planning Project	-	5	-	1	-	-
<b>Total Operating Costs</b>	<b>\$7.9</b>	<b>57</b>	<b>\$6.8</b>	<b>53</b>	<b>\$6.6</b>	<b>52</b>

**Table 5-28. Capital Projects > \$2 Million, Sustainability & Aboriginal Relations**

(\$ millions)	F2004 Forecast	F2005 Plan	F2006 Plan
First Nations Negotiations	\$7.2	\$6.8	\$3.6
Water Use Programs	4.2	1.3	0.3

**9.2 Background**

BC Hydro Generation is challenged with managing its business in one of the most demanding operating environments in North America. The river systems that provide water used to fuel up to 90% of the energy produced by BC Hydro Generation are indicative of some of the most environmentally sensitive watersheds in communities today. Most of BC Hydro Generation’s watersheds provide habitat to species with high public value, such as salmon and sturgeon, which have been identified as “at risk”. Public usage of these resources has increased dramatically over the past ten years. In addition, questions regarding aboriginal rights and ownership over land and water in the province have been brought sharply into focus over the past decade. Together these issues combine to

## 1 3 Cost of Energy

2 Peak demand during in F1994 and F2003 is shown in Table 5.

3 **Table 5. Comparison of Peak Demand**

(MW)	F1994	F2003
Peak one-hour demand	8,059	8,481

4 Although load has continued to grow, BC Hydro did not add significant sources of new  
 5 generating capacity that entered service during the period F1994 to F2003<sup>1</sup>. Instead,  
 6 greater dependence was placed on electricity purchases from IPPs and market purchases.

7 Table 6 shows the change in sources of energy over the past decade and Table 7 shows  
 8 the change in costs of energy.

9 **Table 6. Comparison of Energy Sources**

(GWh)	F1994	F2003	Change
Hydro generation	39,935	47,665	7,730
Independent Power Producers (IPP) and other long-term purchase contracts	2,191	4,950	2,759
Other Energy Purchases	766	896	130
Thermal Resources	3,248	251	(2,997)
Non-integrated Energy	62	96	34
Net Purchase from Powerex		1,113	1,113
Net Storage Returns (Exchange Net)	131	(1,605)	(1,736)
	46,333	53,366	7,033
Line Loss and System Use	(4,315)	(4,689)	(374)
<b>Domestic Sales Volume</b>	<b>42,018</b>	<b>48,677</b>	<b>6,659</b>

<sup>1</sup> Projects at Stave Falls and Fort Nelson replaced older generating assets. Seven Mile Unit 4 entered service in F2004.

1 **Table 7. Comparison of Energy Costs**

(\$ millions)	F1994 <i>(Note 1)</i>	F2003	Change
Hydro	\$216	\$259	\$43
IPPs and other long-term purchase contracts	74	290	216
Other Energy Purchases	18	54	36
Natural Gas for Thermal Generation <i>(Note 2)</i>	48	28	(20)
Non-integrated	11	14	3
Transmission charges and other expenses	2	13	11
Net Purchases from Powerex	0	50	50
<b>Domestic Energy Costs</b>	<b>\$369</b>	<b>\$708</b>	<b>\$339</b>

2 Notes:

- 3 1. Reclassified to conform to presentation in F2003, as described in schedule 1.  
 4 2. Natural gas costs in F2003 also include fixed transportation costs of approximately \$10 million  
 5 related to the Bypass Transportation Agreement between Terasen and BC Hydro.

6 Table 8 shows the average energy price by source.

7 **Table 8. Average Energy Price**

(\$/MWh)	F1994	F2003	Change
Hydro	\$5.41	\$5.43	\$0.02
IPPs and other long-term contracts	33.78	58.59	24.81
Other Energy Purchases	23.50	60.27	36.77
Natural Gas for Thermal Generation	14.78	111.55	96.77
Non-integrated	177.42	145.83	(31.59)
Net Purchases from Powerex	0	44.92	44.92
<b>Weighted average cost <i>(Note 1)</i></b>	<b>\$8.78</b>	<b>\$14.54</b>	<b>\$5.76</b>

8 Notes:

- 9 1. Relates to total domestic energy costs divided by domestic sales volumes.

10 The increase in domestic energy costs has been primarily caused by increases in the price  
 11 of energy sources needed to meet demand. While revenues from domestic sales increased  
 12 by 17% from F1994, the average energy price has increased by 66% over this period as  
 13 shown in Table 8. The increase in the market price of energy has been caused by several  
 14 factors including the increase in demand due to the growth in the North American economy  
 15 over this period, and tightness in supply as new generation facilities have not kept pace with  
 16 the growth in demand. The unusually large increase in the unit cost of thermal generation is  
 17 largely caused by the low volume of generation in F2003 together with the inclusion of a  
 18 fixed cost component related to the Bypass Transportation Agreement mentioned above.

19 Table 9 shows the change in domestic energy costs by volumes.

1 **Table 5-24. Capital Projects > \$2 million, Coastal Region, F2004 to F2006**

(\$ millions)	F2004 Forecast	F2005 Plan	F2006 Plan
Bridge River 2 T5, T6, and T7 Transformer Replacement	\$2.8	\$0.4	\$0.2
John Hart Penstock 1 Replacement	-	0.5	13.7
Cheakamus Turbine Upgrade	3.2	3.4	0.6
Burrard Asbestos Replacement Program	1.1	1.3	1.2
John Hart T2, T4, and T6 Replacement	2.4	-	-
Strathcona T1 Replacement	1.0	0.4	0.6
Fire Risk Reduction Program	1.4	1.7	2.5
Coquitlam Dam Seismic Improvements	1.3	3.0	8.8
Elsie Lake Dam Seismic Improvements	1.3	5.8	-
Ruskin Dam Strengthening of Concrete Dam	0.2	0.7	15.0
Stave Falls (Blind Slough Dam) Seismic Strengthening	0.5	2.0	5.0
La Joie Dam Safety Improvements	-	1.8	4.0
Strathcona Embankment Dam Improvements	-	0.2	3.0

2 A particular issue for the Coastal Region is the Burrard Generating Station, which is the  
 3 largest thermal generating facility in the BC Hydro system. It comprises six conventional  
 4 natural gas-fired, steam units with a nominal capacity of 913 MW.

5 BC Hydro's current short term plan for Burrard Generating Station is to maintain three units  
 6 in standby generation mode (4, 5 and 6), and three units in VAR support mode (1, 2 and 3).  
 7 The three units available in standby generation mode will be exercised on a regular basis to  
 8 ensure availability and will be dispatched as needed to provide capacity and energy to the  
 9 BC Hydro system. The steam turbines and boilers for the units in VAR support mode will be  
 10 preserved in storage, and will be recallable to generation mode on approximately 6 month's  
 11 notice. This configuration will ensure that approximately 450 MW of capacity and  
 12 3,300 GWh/year of energy capability will be available from Burrard Generating Station for  
 13 the next several years, full capability is preserved for resource planning purposes. In  
 14 addition, the VAR support from units 1, 2 and 3 will be sufficient to meet voltage support  
 15 requirements on the BC Hydro transmission system.

16 In late 2002 the Provincial Government established a MLA committee to review the future of  
 17 Burrard Generating Station.