
Revenue Requirement Application
2004/05 and 2005/06



Volume 2

Appendix J.

Consolidated Historical Financials

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1 **1 Consolidated Financial History**

2 This appendix compares BC Hydro's financial position in F2003 to its financial position in
 3 F1994. Table 1 provides BC Hydro's income statements in those years.

4 **Table 1. Summary of Changes to Income Statement**

(\$ millions)	F1994 (Note 1)	F2003
Revenues		
Domestic	\$2,103	\$2,475
Intersegment Revenue (Note 2)	-	6
	2,103	2,481
Expenses		
Energy Costs	369	708
Operations, Maintenance, and Administration	433	506
Depreciation and Amortization	300	414
Taxes	170	145
	1,272	1,773
Income before Finance Charges, Restructuring Costs, Trade Income and Transfer from Rate Stabilization Account	831	708
Finance Charges	679	457
Income before Restructuring Costs, Trade Income and Transfer from Rate Stabilization Account	152	251
Restructuring Costs	0	37
Income before Trade Income and Transfer from Rate Stabilization Account	152	214
Trade Income	38	138
Transfer from Rate Stabilization Account	0	66
Net Income	\$190	\$418

5 Notes:

- 6 1. F1994 has been reclassified to conform to the presentation for F2003. See schedule 1 for details
 7 on the restatements.
 8 2. See chapter 2, section 3.3.

1 **2 Customer Profile and Domestic Sales**

2 BC Hydro added more than 230,000 customers to the system between F1994 and F2003,
 3 representing a 17% increase as shown in Table 2. Correspondingly, domestic revenues
 4 increased by \$372 million from F1994 to F2003.

5 **Table 2. Comparison of Customer Profile**

Number of Customers	F1994	F2003	% Increase
Residential	1,235,705	1,442,597	17%
Light Industrial & Commercial	158,570	183,188	16%
Large Industrial	82	133	62%
Other	2,781	3,092	11%
Total	1,397,138	1,629,010	17%

(Note 1)

6 Notes:

7 1. Total customers shown in the F2003 Annual Report is 1,629,186. The difference is 176 electricity
 8 trade customers.

9 The large industrial category includes approximately 35 distribution rate transmission
 10 voltage customers that were included in the light industrial and commercial category in
 11 F1994.

12 Table 3 and Table 4 compare customer sales volumes and revenues.

13 **Table 3. Comparison of Customer Sales**

Sales Volume (GWh)	F1994	F2003	% Increase
Residential	12,442	15,024	21%
Light Industrial & Commercial	14,086	16,757	19%
Large Industrial	14,178	15,179	7%
Other <i>(Note 1)</i>	1,312	1,717	31%
Total	42,018	48,677	16%

14 Notes:

15 1. Includes sales to other utilities under long-term contracts.

1 **Table 4. Comparison of Customer Revenues**

(\$ millions)	F1994	F2003	% Increase
Residential	\$762	\$923	21%
Light Industrial & Commercial	751	893	19%
Large Industrial	475	516	9%
Other	73	88	21%
Total Electricity Revenues	\$2,061	\$2,420	17%
Miscellaneous Revenues <i>(Note 1)</i>	42	55	
Total Domestic Revenue	\$2,103	\$2,475	

2 Notes:

- 3 1. These revenues consist of 3rd party revenues of BC Hydro's subsidiaries (Powertech and
 4 Westech), together with transmission wheeling revenues and other miscellaneous items. F1994
 5 revenues have been reclassified to conform to the presentation for F2003. See schedule 1 for
 6 details.

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 F2003¹. 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)
Domestic Sales Volume	42,018	48,677	6,659

¹ 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
Domestic Energy Costs	\$369	\$708	\$339

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
Weighted average cost <i>(Note 1)</i>	\$8.78	\$14.54	\$5.76

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 9. Changes in Domestic Energy Costs and Volumes**

	F1994	F2003	Change
Domestic cost of energy (\$ millions)	\$369	\$708	\$339
Domestic sales volumes (GWh)	42,018	48,677	6,659
Domestic energy unit cost (\$/MWh)	\$8.8	\$14.5	\$5.7
Variance (\$ millions):			
Increase in Unit Cost			\$280
Increase in Volume			59
			\$339

2 The variance would have been larger if it were not for the difference in water inflows in these
 3 years and their associated impact on low-cost hydro generation capability. F1994 was a low
 4 water year with inflows at 85% of normal whereas F2003 was an above average water year
 5 with inflows at 109% of normal. As a result, hydro generation was higher in F2003 thereby
 6 reducing costs as less reliance was placed on more expensive sources of supply such as
 7 thermal generation and market purchases.

1 **3.1 Summary of Changes to BC Hydro's Generation Capabilities**

2 Table 10 summarizes changes to BC Hydro's generation capabilities.

3 **Table 10. Comparison of BC Hydro's Generation Installed Capacity**

(MW)	F1994	F2003	Comment
Hydroelectric Generation			
GM Shrum	2,730	2,730	
Revelstoke	1,843	1,980	Resource Smart capacity upgrade
Mica	1,736	1,805	Resource Smart capacity upgrade
Peace Canyon	700	694	Change in water license limit
Seven Mile	594	594	Seven Mile increased to 804 MW in early F2004.
Kootenay Canal	528	580	Resource Smart capacity and efficiency upgrade
Bridge River	480	466	Change in water license limit
Other Hydro	1,095	1,160	Stave Falls redevelopment, decommissioning of Coursier Lake
Total Hydroelectric	9,706	10,009	
Thermal Generation			
Burrard Generating Station	912	912	
Other	220	182	Decommissioning of Keogh Gas Turbine, construction of Fort Nelson
Total Thermal	1,132	1,094	
Total Generation Capacity	10,838	11,103	

1 **4 Trade Income**

2 Trade income has increased primarily as a result of increased trading activity. Sales volume
3 increased by 28,537 MWh from F1994 to F2003, as shown in Table 11.

4 **Table 11. Change in Trade Income and Sales Volumes**

	F1994	F2003	Change
Trade Income (\$ millions)	\$38	\$138	\$100
Sales volumes (GWh)	2,645	31,182	28,537

5 The allocation of energy costs for F1994 assigned the highest unit cost of non-firm energy
6 supply to electricity trade revenues. The allocation method for F2003 is defined in the
7 Transfer Price Agreement now defines the transaction between BC Hydro and Powerex
8 (see appendix K). While the allocation methods are different, it is still evident that the
9 increase in electricity trade income is a result of increased trading activity.

1 **5 Depreciation and Amortization**

2 Depreciation and amortization expense has increased by \$114 million from F1994 to F2003
 3 as shown in Table 12.

4 **Table 12. Comparison of Depreciation and Amortization Expense**

(\$ millions)	F1994	F2003
Depreciation and Amortization	\$300	\$414

5 Notes:

6 1. Amounts for F1994 have been reclassified to conform to F2003 presentation (see Schedule 1).

7 The increase is primarily due to asset and deferred capital expenditure additions of over
 8 \$4.0 billion during this period and increases in future removal and site restoration
 9 amortization. These increases are partially offset by a reduction in amortization of deferred
 10 projects, such as Site C which was amortized in 1994, and increased contributions in-aid of
 11 construction.

12 Changes in depreciation and amortization are shown in Table 13.

13 **Table 13. Changes in Depreciation and Amortization**

(\$ millions)	F1994	F2003	% change
Depreciation and Amortization	\$300	\$414	38%
Variance		(114)	
VARIANCE EXPLAINED			
Asset Depreciation			
Generation		(18)	
Transmission		(9)	
Transformation		(14)	
Distribution		(34)	
Building, furniture and equipment		(11)	
Computer hardware and software		(25)	
Vehicles		(4)	
Contributions in aid of construction		7	
Amortization of deferred projects (Note 1)		20	
Asset write-offs and write-downs (Note 2)		(10)	
Power Smart amortization		(2)	
Future Removal & Site Restoration (Note 3)		(14)	
Total Variance	n/a	(114)	

14 Notes:

15 1. The decrease in amortization of deferred projects from 1994 to 2003 is due to Site C being
 16 amortized in F1994.

17 2. See Table 14.

18 3. The increase in Future Removal & Site Restoration amortization is due to the following:

- 19 • asset additions during the period;

- 1 • increased amortization rates for some assets based on a comprehensive review of the rates
- 2 prior to 1995; and
- 3 • recording of an additional provision for site restoration of Coursier Dam which was
- 4 decommissioned and the write-off of salvage provision balances unlikely to be realized in
- 5 F2003.

6 Table 14 shows the change in asset write-offs and write-downs.

7 **Table 14. Changes Resulting from Write-offs and Write-downs**

(\$ millions)	F1994	F2003	Change
Write-offs/write-downs less than \$1 M individually	\$2	\$5	\$3
Thermal intake screens and retirement of Kelly Lake shunt capacitor	2	-	(2)
Write-down of Hat Creek Land to Net Realizable value	-	6	6
5RX5 Shunt Reactor Retirement Loss	-	3	3
Total	\$4	\$14	\$10

8

1 **5.1 Capital Assets**

2 A summary of BC Hydro's capital assets is shown in Table 15.

3 **Table 15. Summary of Capital Assets**

(\$ millions)	F1994			F2003		
	Capital Assets in Service	Accumulated Depreciation	Unfinished Construction	Capital Assets in Service	Accumulated Depreciation	Unfinished Construction
Generation						
Hydraulic	\$5,009	\$1,090	60	\$5,193	\$1,638	\$207
Thermal	220	160	9	425	207	133
	5,229	1,250	69	5,618	1,845	340
Distribution	2,096	627	125	3,395	1,135	90
Transmission Lines	2,398	749	93	2,789	1,256	27
Substations	1,480	530	24	1,917	963	73
Other						
Buildings and Equipment	818	291	63	1,068	529	129
Service Vehicles	84	48	-	124	76	-
Sundry	39	6	-	29	12	10
	941	345	63	1,221	617	139
Total	\$12,144	\$3,501	\$374	\$14,940	\$5,816	\$669
Change F1994 to F2003				23%	66%	

4 Notes:

5 1. Certain F1994 amounts have been reclassified to conform to the presentation used in F2003.

6 See Chapter 11 for a summary of major capital projects during the period F1995 to F2003.

1 **6 Taxes**

2 **6.1 Summary of Changes, F1994 to F2003**

3 Tax expense decreased by \$25 million, or 15%, between F1994 and F2003, as shown in
4 Table 16.

5 **Table 16. Comparison of Tax Expense**

(\$ millions)	F1994	F2003
Grants	\$34	\$42
School Taxes	106	100
Corporation Capital Taxes	30	3
Total	\$170	\$145

6 The reduction in tax expense is largely a result of the elimination of the Corporation Capital
7 tax, effective September 30, 2002. Lower schools taxes as a result of lower tax rates also
8 contributed to the decrease in tax expense. An increase in the revenue grant, largely due to
9 an increase in domestic revenues, partly offset the total decrease in tax expense.

1 **7 Finance Charges**

2 **7.1 Summary of Changes**

3 Finance charges decreased by \$222 million, or 33%, between F1994 and F2003, as shown
4 in Table 17.

5 **Table 17. Comparison of Finance Charges**

(\$ millions)	F1994	F2003
Interest on Debt Securities		
- bonds, notes and debentures	\$864	\$536
- revolving borrowings	27	5
Amortization of deferred debt costs and other expenses	21	26
	912	567
Less:		
Sinking fund income	(117)	(60)
Other income	(93)	(26)
Finance charges capitalized to unfinished construction	(23)	(24)
	(233)	(110)
Total	\$679	\$457

6 The decrease was mainly due to declining debt levels as a result of improved cashflows and
7 the refinancing of debt during this period at much lower rates. The refinancing of debt
8 related to approximately \$1.3 billion of US debt with rates of 12.5 to 15.5 percent that was
9 refinanced at rates ranging from 5.5 to 7.25 percent. This refinancing program largely took
10 place during F1997 and F1999. A decline in market interest rates has also contributed to
11 the decrease in finance charges. Average short-term interest rates declined from 4.4 per
12 cent in F1994 to 2.5 per cent in F2003. The decline in finance charges has been partly
13 offset by the impact of the weakening Canadian dollar against the US dollar. The Canadian
14 dollar averaged USD\$0.7590 in F1994 compared to USD\$0.6474 in F2003. The foreign
15 exchange rate impacts BC Hydro's interest payments on US dollar debt.

16 Other income of \$93 million in F1994 includes approximately \$50 million in interest income
17 from BC Hydro's repurchased debt. These bonds were called as part of the refinancing
18 program during F1997 and F1999. Other income also includes income from interest rate
19 and cross currency swaps.

1 **7.2 Composition of Long-Term Debt**

2 Total long-term debt has decreased by approximately \$950 million from F1994¹ to F2003, as
3 shown in Table 18.

4 **Table 18. Composition of Long-Term Debt** (Note 1)

(\$ million)	F1993	F2003	Change
Bonds, notes and debentures			
Canadian	\$5,467	\$4,888	\$(579)
Foreign	2,603	2,671	68
	<hr/>	<hr/>	<hr/>
	\$8,070	\$7,559	\$(511)
Revolving Borrowings	777	331	(446)
Long-term Debt	<hr/>	<hr/>	<hr/>
	\$8,847	\$7,890	\$(957)
Less:			
Sinking Funds	1,228	1,037	(191)
Repurchased Debt	331		(331)
Net Long-term Debt	<hr/>	<hr/>	<hr/>
	\$7,288	\$6,853	\$(435)

5 Notes:

6 1. as at March 31.

7 The decrease in Canadian dollar debt of \$580 million, due to many debt series maturities
8 financed with cash flows from operations, has been responsible for most of the reduction in
9 debt. A decrease in revolving borrowings of approximately \$450 million since 1993 has also
10 contributed to the overall decrease in long-term debt. The amount of US dollar debt
11 decreased approximately \$50 million. The decrease in volume of approximately USD\$340
12 million (CAD\$495 million) was partially offset by the depreciation of the Canadian dollar from
13 USD\$0.7954 on March 31, 1993 to USD\$0.6806 on March 31, 2003 which increased the
14 Canadian equivalent of the value of US debt by approximately \$440 million. BC Hydro also
15 held \$125 million in Japanese yen debt in F2003 compared to none in 1993.

16 Repurchased debt related to BC Hydro bonds that were repurchased from the market as
17 part of BC Hydro's hedging strategy. These bonds were called as part of the refinancing
18 program during F1997 and F1999.

¹ End of year F1993 represents the starting point for F1994.

1 **8 Operations, Maintenance, and Administration**

2 **8.1 Summary of OMA Changes**

3 The 17% increase in the number of domestic customers since F1994 has placed upward
 4 pressure on BC Hydro’s operating expenses. Additional pressures on BC Hydro’s OMA
 5 costs have included factors such as:

- 6 • changes to accounting requirements for post retirement benefits;
- 7 • changes to maintenance requirements because of ageing equipment;
- 8 • changes in the demographics of employees; and
- 9 • major IT system implementation projects.

10 OMA expenses increased by \$73 million, or 17%, between F1994 and F2003, as shown in
 11 Table 19.

12 **Table 19. Comparison of OMA Expense**

(\$ millions)	F1994	F2003
Domestic OMA Expense	\$433 <i>(Note 1)</i>	\$506

13 Notes:

14 1. F1994 has been reclassified to conform to F2003 presentation (see schedule 1).

15 A number of factors have contributed to the increase in OMA expense between F1994 and
 16 F2003, as shown in Table 20.

1 **Table 20. Summary of OMA Changes**

F1994 OMA (Note 1)		\$433
Increased Employee Benefit Costs		
Increases in employee current benefit costs	16	
Increases in employee future benefit costs	47	
Total Increased Employee Benefit Costs		63
Increased Wholesale Transmission Costs		
WTS Infrastructure	7	
RTO	2	
Total Increased Wholesale Transmission Costs		9
Completion of PMSI maintenance program		(23)
Increase in Maintenance and Emergency Restoration due to aging assets		10
Addition of Catastrophic Risk Insurance		6
Loss of recoveries from Terasen		4
Closure of BCHIL		(4)
Workforce Renewal Initiative		8
Funding for 2003 IT initiatives		7
Net impact of cost reduction efforts offset by general cost increases		(7)
Total OMA Changes		\$73
F1994 + Changes = F2003 OMA		\$506

2 Notes:

3 1. Reported F1994 OMA was \$410 million. This has been reclassified as \$433 million to be
4 presented on a comparable basis to F2003 OMA (see schedule 1).

5 The following sections discuss the OMA changes between F1994 and F2003.

6 **8.2 Increased Employee Benefit Costs**

7 The cost of employee benefits increased by \$63 million between F1994 and F2003, as a
8 result of increases in employee current (\$16 million) and future (\$47 million) benefit costs.

9 **8.2.1 Increases in Employee Current Benefit Costs**

10 Employee current benefits costs include Canada Pension Plan (CPP), Employment
11 Insurance, income continuance, BC Medical, workers compensation, extended health plan,
12 dental plan and group life insurance.

13 CPP, extended health plan, dental plan and long-term disability costs have all increased
14 significantly as follows:

- 15 • CPP costs have increased because of higher premiums;

- 1 • extended health plan costs have increased because the cost of prescription drugs has
2 increased at an average of 15% per year over the past 10 years, amongst other factors;
- 3 • dental plan costs have increased primarily due to fee increases of approximately 3% per
4 year and increased employee utilization of the plan;
- 5 • long-term disability costs have increased because of increased costs per claim, and
6 increased number of claims due to BC Hydro's ageing workforce.

7 8.2.2 Increases in Employee Future Benefit Costs

8 8.2.2.1 BC Hydro Pension Plan

9 BC Hydro's pension plan costs increased from \$21 million in F1994 to \$26 million in F2003.

10 The current service cost component of pension costs for F2003 increased by approximately
11 \$15 million over F1994. Current service cost is the annual cost of providing future pension
12 benefits to currently active employees when they retire. Of the \$15 million increase, \$6
13 million was due to higher plan earnings in F2003 over F1994, which resulted from an
14 increase in the number of employees, an increase in salaries and wages, and IBEW and
15 OPEIU gainsharing becoming pensionable. For a discussion of gainsharing see chapter 3,
16 section 8.3.3.5).

17 The remaining increase of \$9 million was due a higher cost of service rate in F2003 over
18 F1994. The cost of service rate had increased as a result of plan improvements, an
19 actuarial change in the early retirement assumption, changes to the actuarial assumptions
20 surrounding mortality, and a decrease in the discount rate.

21 Offsetting the above increases were net cumulative experience gains with respect to the
22 assets and liabilities over the period from F1994 to F2003, resulting in a net decrease in
23 pension costs of approximately \$10 million.

24 8.2.2.2 BC Hydro Supplemental Pension Plan

25 The annual cost of BC Hydro's supplemental pension plan increased by from \$1 million in
26 F1994 to \$13 million in F2003. Of the \$12 million increase:

- 27 • \$7 million relates to the cost of a plan improvement that made annual incentive pay to
28 management and professional employees pensionable, subject to a maximum limit, and

- 1 • \$5 million is attributable to new accounting rules, CICA 3461 “Employee Future
2 Benefits”, that became effective in F2001. CICA 3461 requires full accrual accounting
3 for all forms of post retirement benefit plans.

4 8.2.2.3 Other Post Retirement Benefits

5 BC Hydro retirees also receive non-pension benefits such as medical, extended health, life
6 insurance and dental, which are called “other post retirement benefits.” The annual cost of
7 these benefits has increased from \$3 million in F1994 to \$33 million in F2003. Of the \$30
8 million increase:

- 9 • \$27 million is attributable to CICA 3461, which requires all forms of post retirement
10 benefit plans to be accounted for on an accrual basis; and
11 • \$3 million relates to a plan improvement entitling retirees to limited dental care benefits.

12 **8.3 Increased Wholesale Transmission Costs**

13 Transmission System Operations costs increased because of increases transmission
14 system operation costs and new spending on the RTO West initiative.

15 In F1995 BC Hydro established Grid Operations business unit and began offering open
16 access transmission services under the Wholesale Transmission Service (WTS) tariff. With
17 the rapid growth and increasing complexity of the WTS business, and the need to comply
18 with FERC Orders 888 and 889, Grid Operations initiated the Grid Operations Upgrade
19 Project in F2000 to design and build business and system capability for the business. This
20 project was completed in F2002. The ongoing operating costs of the WTS infrastructure are
21 \$7 million, which are associated with transmission scheduling, settlement and billing, WTS
22 tariff development and administration, and new technology. (see chapter 6, section 4.2)

23 In December 1999, FERC issued Order 2000, which addressed the issue of non-
24 discriminatory access to transmission systems to facilitate the wholesale market for
25 electricity in the United States. Order 2000 sets out the criteria for the creation of regional
26 transmission organizations (RTOs) and called on FERC jurisdictional electric utilities that
27 own, operate or control interstate transmission facilities to file their plans to form and/or
28 participate in such organizations. BC Hydro has earned significant income from electricity
29 trade undertaken in US wholesale electricity markets. BC Hydro has been participating in

1 the development of RTO West in the Pacific Northwest, and expects that its efforts in this
2 regard will protect and enhance that electricity trade value. Expenditures of \$2 million were
3 incurred in F2003 consisting primarily of consulting and outside service costs.

4 **8.4 Completion of PMSI Maintenance Program**

5 OMA expenses in F1994 included \$23 million in funding for the Production Strategic
6 Maintenance Initiative (PMSI). The program reduced maintenance backlogs, primarily in
7 generating stations, and was approved by the Commission. The PMSI program was
8 completed in 1997.

9 **8.5 Increase in Maintenance and Emergency Restoration Costs**

10 Funding for distribution maintenance and trouble response has been increased in response
11 to maintenance and reliability shortfalls. In F2003 the increase was \$10 million over F1994
12 levels. As noted in chapter 7, funding levels continue to be adjusted in response to reliability
13 concerns.

14 **8.6 Addition of Catastrophic Risk Insurance**

15 This program was established in F2000. Upon completion of a catastrophic risk financing
16 study in the fall of 1998, BC Hydro transferred potential catastrophic losses to the insurance
17 market which would otherwise be financed out of shareholder dividends and rate increases.
18 This strategy was implemented in F2000 and is consistent with the approach of other
19 Canadian hydroelectric utilities.

20 Over the last 2 years insurance markets have reduced their capacity to provide catastrophic
21 coverage leading to an increase in premiums. In F2003, BC Hydro's cost of catastrophic
22 risk insurance was \$6 million.

23 **8.7 Loss of Recoveries from Terasen**

24 Terasen (then BC Gas) repatriated the following revenue cycle services in June 2002: call
25 centres, billing, payment processing, walk-in, and credit and collection. The repatriation of
26 these services resulted in approximately \$4 million lower recoveries in F2003 than in F1994.
27 The impact of the repatriation in future years is an annual reduction in recoveries of \$8

1 million. The lower recoveries in future years will be offset by \$4 million in expected cost
2 reductions due to decreased volumes of work as well as other cost reduction initiatives.

3 **8.8 Closure of BCHIL**

4 BC Hydro International Ltd. (“BCHIL”) was a wholly owned subsidiary used by BC Hydro to
5 sell products and services to external parties. BC Hydro ceased the operations of BCHIL in
6 F2002.

7 **8.9 Workforce Renewal Initiative**

8 BC Hydro initiated a strategic workforce planning initiative in F2001 to mitigate the impact of
9 increased retirements and renew critical workforce capability, as discussed in chapter 3,
10 section 8.3.3.1. Each year, initiative funding has been targeted to hire apprentices and
11 trainees in trades, engineering, technical and management positions. F2003 funding was
12 approximately \$8 million.

13 **8.10 Funding for F2003 IT Initiatives**

14 Three significant IT system implementation projects – Northstar, Indus Work
15 Management/Supply Chain replacement and Finance Business Transformation – were in
16 progress in F2003. Although these projects are primarily capital projects in nature, due to
17 accounting pronouncements issued by the CICA in 1998 and 2001, portions of the project
18 costs (\$7 million in F2003) have been classified as OMA. Had similar costs been incurred in
19 1994, they would have been capitalized under accounting principles in effect at that time.
20 The two accounting pronouncements – Emerging Issues Committee pronouncements EIC-
21 86 and EIC-118 – resulted in a narrowing of the circumstances in which certain costs for IT
22 implementation projects can be capitalized.

1 **Schedule 1. Summary of Accounting Reclassifications**

2 **Accounting Reclassification Items**

3 Several accounting classifications were reclassified in F2001 to reflect a more appropriate
4 accounting treatment given the increasing materiality of these items in recent years. These
5 reclassifications were also applied retroactively to F1994 to F2000 for reporting purposes.
6 The accounting reclassifications do not have a bottom line impact for F1994 to F2000.

7 The accounting reclassifications include:

- 8 • Consolidation of Subsidiaries. Only external net income from BC Hydro's subsidiaries
9 (excluding Powerex) was previously included in miscellaneous revenues. All
10 subsidiaries are now consolidated to disclose external gross revenues and gross
11 expenses.
- 12 • Recoveries. A number of receipts from external parties such as Terasen vehicle rentals
13 were previously treated as cost recovery (OMA reductions). Recoveries having a profit
14 component are now treated as revenues. Recoveries that are pure cost recoveries and
15 have no profit component continue to be reported as an OMA reduction.
- 16 • Vehicle Services and NCS Depreciation. These were previously charged out as capital
17 or OMA and are now treated as depreciation.
- 18 • Burrard Generating Station Operating Costs. These costs were classified as cost of
19 energy and are now classified as OMA.