

FortisBC Inc.
2005 Revenue Requirements Application,
2005-2024 System Development Plan and 2005 Resource Plan

30.0 Reference: Volume 1, Tab 6, p. 5, Table 6.2 A

Q30.1 Please provide a list of the individual (major) asset additions/upgrades comprising the increases in the following items from 2003 to 2004 and from 2004 to 2005.

- i. Hydraulic Production Plant #1**
- ii. Hydraulic Production Plants #2, #3, and #4**
- iii. Transmission Plant**
- iv. Distribution Plant**
- v. General Plant**

A30.1 Please refer to Tables 1 – A -1(2004) and 1 – A -1(2005) in the Rate Base Schedules.

Q30.2 For each of the projects identified above, please state what the primary project driver was (or is), e.g., customer requests, capital maintenance, general load growth, etc.

A30.2 Please refer to Tables 1 – A -1(2004) and 1 – A -1(2005) in the Rate Base Schedules. These drivers are discussed in detail in Volume 1, Tab 9 of the Application. Please see attachment BCUC A30.2.

BCUC A30.2

TABLE 1 - A - 1 (2004)
UTILITY PLANT UNDER CONSTRUCTION AS AT DECEMBER 31, 2004

Application Reference: Tab 6 Table 6.x.x

	CWIP Dec 31, 2003	Expenditures	CWIP Dec 31, 2004	Additions to Plant in Service	Primary Driver
Hydraulic Production					
P2U5 Upgrade life extension	7,702	4,572	-	12,274	Life extension
P2U6 Upgrade life extension	53	9,088	-	9,140	Life extension
P2U5 Headgate rebuild	226	306	-	532	Capital Maintenance
P1U1 Upgrade & Life Extensions	-	624	624	-	Life extension
P2U6 Headgate Rebuild	-	607	607	-	Capital Maintenance
Asbestos Abatement	-	629	-	629	Environmental Clean-up
230kV project - P1 Upstream	-	1,030	-	1,030	Kootenay 230kV SDP
230kV project - P2 Upstream	-	1,703	-	1,703	Kootenay 230kV SDP
230kV project - P3 Upstream	-	5,553	-	5,553	Kootenay 230kV SDP
230kV project - P4 Upstream	-	1,202	-	1,202	Kootenay 230kV SDP
P1 Powerhouse roof upgrade	-	157	-	157	Capital Maintenance
P1 Headgate Ballast	-	72	-	72	Capital Maintenance
P1U2 Control Cabinet Cooling	-	5	-	5	Capital Maintenance
P2U1 OCB Upgrade	-	81	-	81	Safety/environmental
Budget Project Only	-	30	-	30	
Trash Rack Gantry	-	166	-	166	Equipment Reliability/Safety
P3 South Slocan	-	11	-	11	Capital Maintenance
P3U3 Roller Trains both Gates	-	117	-	117	Life extension
P3 Upgrade Brake Air Receiver	-	19	-	19	Legislation
Battery Room Upgrade	-	41	-	41	Equipment Reliability/Safety
All Plants GED	-	10	-	10	Efficiency
P4 Upgrade Spillway Gate	-	164	-	164	Technology Upgrade
P4 Ext. Spillway Gate/ Gantry Crt.	-	62	-	62	Technology Upgrade
P4 Spillway Gantry Bar	-	6	-	6	Technology Upgrade
Power Purchase	730	(730)	-	-	Accounting Transfer
	<u>8,711</u>	<u>25,522</u>	<u>1,231</u>	<u>33,002</u>	
Transmission Plant					
Line 32 rehabilitation	198	41	-	239	Sustaining capital
11 Line rehabilitation	92	-	-	92	Sustaining capital
Salmo rehabilitation	1	-	-	1	Sustaining capital
Harmonic remediation	103	3	-	106	Sustaining capital
South Okanagan Supply	4,274	22,376	26,650	-	Growth capital
230kV project	8,420	16,286	-	24,706	Growth capital
Joe Rich Reconductoring 2004	-	1,024	-	1,024	Growth capital
Lee Terminal Upgrade	-	2,757	2,757	-	Growth capital
PCB Program	-	79	79	-	Sustaining capital
Row Reclamations	-	23	-	23	Sustaining capital
Transmission Line Rehabs	-	1,209	-	1,209	Sustaining capital
Transmission Line Urgent Repairs	-	192	-	192	Sustaining capital
Transmission Line Enhancements	-	45	-	45	Sustaining capital
2004 Right of Way Easement Acquisitions	-	41	-	41	Sustaining capital
Right of Way Reclamation	-	501	-	501	Sustaining capital
Glenmerry Soil Reclamation	-	351	-	351	Sustaining capital
Station Urgent Repairs	-	239	-	239	Sustaining capital
Substation Condition Assessment	-	150	-	150	Sustaining capital
Protection Upgrade	-	52	-	52	Sustaining capital
Glenmerry Underground Rebuild	-	81	81	-	Sustaining capital
	<u>13,088</u>	<u>45,448</u>	<u>29,567</u>	<u>28,970</u>	
Distribution Plant					
32 MVA substation	28	1	-	29	Growth capital
Sexsmith feeder upgrade	105	45	-	149	Growth capital
Passmore feeder capacity upgrade	149	2	-	151	Growth capital
Kaleden feeder upgrade	197	6	-	203	Growth capital
New hollywood feeder & breaker	118	(8)	-	110	Growth capital
6/8 Mobile substation	29	1	-	31	Sustaining capital
Midway Substation Rehab	-	160	160	-	Sustaining capital
Substation Metering Automation	-	37	-	37	Sustaining capital
Station Rehabilitations	-	303	-	303	Sustaining capital

BCUC A30.2

System Capacity Increase 2004	-	2,374	-	2,374	Growth capital
Urgent Repairs 2004	-	917	-	917	Sustaining capital
Forced Upgrades and Line Moves	-	481	-	481	Sustaining capital
Line Rehabilitations 2004	-	553	-	553	Sustaining capital
Planned Maintenance Projects	-	345	-	345	Sustaining capital
Planned Maintenance Programs	-	1,293	-	1,293	Sustaining capital
Pole Management & Testing 2004	-	110	-	110	Sustaining capital
BC Lakeshore Road Upgrade	-	6	-	6	Sustaining capital
Fire Restoration - Okanagan	-	755	-	755	Sustaining capital
Urgt Line Rep 2003 (UnforeDistRehab)	-	(64)	-	(64)	Sustaining capital
Distribution New Extension 2003	-	(420)	-	(420)	Growth capital
Distribution New Extension 2004	-	5,503	-	5,503	Growth capital
West trail voltage conversion	667	1,155	-	1,822	Sustaining capital
Lambert Substation Rehabilitation	1,287	2,631	-	3,918	Sustaining capital
Joe Rich circuit	755	318	-	1,073	Sustaining capital
Other	-	6	-	6	Sustaining capital
	<u>3,335</u>	<u>16,510</u>	<u>160</u>	<u>19,685</u>	
General Plant					
Miscellaneous telecommunications equipment	3	147	-	150	Sustaining capital
Narrow Spectrum Convrsion Telecomm.	-	50	-	50	Sustaining capital
Warfield Okanagan Fibre Optic comm	-	50	-	50	Sustaining capital
Installation of Remote Meters	-	31	-	31	Sustaining capital
Retest Metering	-	20	-	20	Sustaining capital
Meters	-	657	-	657	Sustaining capital
Vehicles 2004	-	192	-	192	Sustaining capital
Upgrade Hardware Software 2004	-	299	-	299	Sustaining capital
Infrastructure Upgrade 2004	-	185	-	185	Sustaining capital
Disaster Recovery HW & SW 2004	-	250	-	250	Sustaining capital
Intergraph Build and Develop 2004	-	25	-	25	Sustaining capital
Welding Shop Upgrade	-	29	-	29	Sustaining capital
Buildings 2004	-	177	-	177	Sustaining capital
Steel Cabinets for Mechanical Shop	-	16	-	16	Sustaining capital
Repower Generation Office and Shops	-	27	-	27	Sustaining capital
2004 Furniture	-	129	-	129	Sustaining capital
Generation Furniture and Fixtures 2004	-	27	-	27	Sustaining capital
Generation Base Capital Acctg. Only	-	64	-	64	Sustaining capital
Generation Mechanical Tools 2004	-	141	-	141	Sustaining capital
Generation Electrical Tools 2004	-	85	-	85	Sustaining capital
2004 Tools- Facilities	-	14	-	14	Sustaining capital
2004 Fleet Tools	-	20	-	20	Sustaining capital
Tools T&D 2004	-	255	-	255	Sustaining capital
PST	336	(336)	-	-	Sustaining capital
Other	-	(30)	-	(30)	Sustaining capital
	<u>339</u>	<u>2,525</u>	<u>-</u>	<u>2,864</u>	
Total	<u>25,474</u>	<u>90,005</u>	<u>30,958</u>	<u>84,521</u>	

BCUC A30.2

TABLE 1 - A - 1 (2005)
UTILITY PLANT UNDER CONSTRUCTION AS AT DECEMBER 31, 2005

Application Reference: Tab 6 Table 6.x.x

Hydraulic Production	CWIP Dec 31, 2004	Expenditures	CWIP Dec 31, 2005	Additions to Plant in Service	Primary Driver
PIU1 Upgrade & Life Extensions	624	-	-	624	Life extension
P2U6 Headgate Rebuild	607	-	-	607	Capital maintenance
Turbine Upgrades	-	16,288	1,000	15,288	Life extension
Capital Maintenance and Enhancement	-	1,484	-	1,484	Capital maintenance
	<u>1,231</u>	<u>17,772</u>	<u>1,000</u>	<u>18,003</u>	
Transmission Plant					
KOOTENAY 230 KV DEVELOPMENT	-	(3,133)	-	(3,133)	Growth capital
SOK PROJECT (VASEUX LAKE TERMINAL)	26,650	42,152	11,905	56,897	Growth capital
KELOWNA AREA UPGRADE	2,757	8,901	5,690	5,968	Growth capital
230/161/138 BENTLEY TERMINAL	81	-	-	81	Growth capital
BIG WHITE 138 kV LINE & SUBSTATION	-	3,255	3,255	0	Growth capital
ELLISON DISTRIBUTION SOURCE	-	271	-	271	Growth capital
BLACK MOUNTAIN DISTRIBUTION SOURCE	-	271	-	271	Growth capital
FAULT LEVEL REDUCTION	-	1,085	1,085	(0)	Sustaining capital
WATERFORD UPGRADE	-	1,844	-	1,844	Growth capital
NARAMATA REHABILITATION	-	2,170	2,170	(0)	Sustaining capital
NEW EAST OSOYOOS SOURCE	-	271	-	271	Growth capital
KETTLE VALLEY DISTRIBUTION SOURCE	-	163	-	163	Sustaining capital
PCB Program	79	-	-	79	Sustaining capital
Transmission Line Sustaining	-	9,352	-	9,352	Sustaining capital
Station Sustaining	-	6,563	-	6,563	Sustaining capital
	<u>29,567</u>	<u>73,165</u>	<u>24,104</u>	<u>78,627</u>	
Distribution Plant					
Midway Substation Rehab	160	-	-	160	Sustaining capital
Distribution Growth	-	7,778	2,650	5,128	Growth capital
Customer New Connects	-	9,364	-	9,364	Customer requests
Distribution Sustaining	-	8,476	-	8,476	Sustaining capital
	<u>160</u>	<u>25,619</u>	<u>2,650</u>	<u>23,129</u>	
General Plant					
Communications and Automation	-	651	-	651	Sustaining capital
Protection and Communications Rehabilitation	-	1,526	-	1,526	Sustaining capital
Vehicles	-	2,940	-	2,940	Sustaining capital
Metering	-	(67)	-	(67)	Sustaining capital
Information Systems	-	1,545	-	1,545	Sustaining capital
Telecommunications	-	175	-	175	Sustaining capital
Buildings	-	734	-	734	Sustaining capital
Furniture & Fixtures	-	177	-	177	Sustaining capital
Tools & Equipment	-	711	-	711	Sustaining capital
	<u>-</u>	<u>8,393</u>	<u>-</u>	<u>8,393</u>	
Total	<u>30,958</u>	<u>124,948</u>	<u>27,754</u>	<u>128,152</u>	

FortisBC Inc.
2005 Revenue Requirements Application,
2005-2024 System Development Plan and 2005 Resource Plan

31.0 Reference: Volume 1, Tab 6, p. 5

Q31.1 Please describe the plant listed under “Other Production Plant”.

A31.1 The only plant in this category is the Whatshan Substation, which was located near South Slocan. The substation was removed from service in 1995 and has a net book value of zero.

Q31.2 Please explain why the plant #1 is given separate treatment from plants #2, 3 and 4.

A31.2 The Company acquired the Upper Bonnington (Plant 2), South Slocan (Plant 3) and Corra Linn (Plant 4) generating plants in 1982. Plant 1, Lower Bonnington, had been owned since 1898, and rebuilt in 1925. At the time of purchase, the existing (P1) plant had different depreciation rates than the newly-acquired plants. Order G-37-84, determined that the remaining life, and the depreciation rates, for Plants 2, 3 and 4 should be applied to Plant 1, with the exception of certain accounts that were fully depreciated.

Plant 1 has been the subject of significant capital expenditures since that time, however the depreciation rates have not since been addressed. The depreciation rates of all generating plant assets will be addressed as part of the 2005 Depreciation Study.

Q31.3 Please explain the reasons for the 2004 forecast additions and compare these costs to the costs approved by CPCN for the various projects. Where there is a difference please explain the cause of the variance.

A31.3 The information requested is provided below.

FortisBC Inc.
2005 Revenue Requirements Application,
2005-2024 System Development Plan and 2005 Resource Plan

Project	CPCN No	Approved Project Cost	Forecast Project Cost	Forecast 2004 Expenditures	Forecast 2004 Additions to Plant	Comments
<u>Generating Plant</u>						
1 Upper Bonnington Unit 5 Upgrade Life Extension	C-2-01	14,606	13,300	4,572	12,274	New agreement regarding upgrade entitlements reduced cost of outages by approx. \$1 million
2 Upper Bonnington Unit 5 Headgate Rebuild	C-9-03	813	532	306	532	Cost reductions due to efficiencies in mobilization and use of site facilities.
3 Upper Bonnington Unit 6 Upgrade Life Extension	C-17-03	11,570	10,214	9,088	9,140	New agreement regarding upgrade entitlements reduced cost of outages by approx. \$1 million
4 Upper Bonnington Unit 6 Headgate Rebuild	C-4-04	607	520	480	480	Condition of major portion of gate supports and seals found to be within specifications.
5 Lower Bonnington Unit 1 Upgrade Life Extension			12,904	624	-	project deferred pending agreement on entitlement by BCH and FortisBC
6 Kootenay 230kV System Development	C-10-00			9,488	9,488	Project Cost included in Line 9
7 Asbestos Abatement		702	629	629	629	
8 Other 2004 Expenditures				208	332	
Please see the response to Q135.1 for the information on Transmission and Distribution projects						
<u>Transmission and Distribution</u>						
9 Kootenay 230kV System Development	C-10-00	8,420		16,286	24,706	
10 South Okanagan Supply Reinforcement	C-3-03	69,900	75,900	22,376	-	
11 Joe Rich Reconductoring 2002 / 2003	C-11-02	1,232	1,460	318	1,073	
12 Joe Rich Reconductoring 2004	C-6-04	1,160	1,024	1,024	1,024	
13 Kelowna Area Capacity and Reliability Upgrade	C-18-04	14,660	14,630	2,757	-	
14 West Trail Voltage Conversion	C-1-03	1,500	2,450	1,155	1,822	
15 Lambert Substation Rebuild	C-2-03	4,258	4,260	2,631	3,918	
16 Distribution Extensions				5,083	5,083	
17 Other Transmission Projects				1,488	1,881	
18 Other Substation Projects				824	744	
19 Other Distribution Projects				7,227	7,614	
20 ROW and Reclamation Projects				917	917	
21 <u>General Plant</u>				2,525	2,864	
22 Total per Line 100, Table 1 - A - 1 (2004)				90,006	84,521	

FortisBC Inc.
2005 Revenue Requirements Application,
2005-2024 System Development Plan and 2005 Resource Plan

**Q32.0 Reference: Volume 1, Tab 6, Rate Base, Section 2, p. 7, Table 6.2 D and Table 6.2 E;
Volume 1, Tab 9, 2005 Capital Plan, Section 7, p. 62
General Plant**

Please reconcile the 2005 forecast expenditures shown on Table 6.2 E and those on Table 9.7.1. Please explain any differences.

A32.0 In total the capital expenditures in Tab 6 are the same as in Tab 9, but are classified in different categories. To the extent General plant is lower in Tab 9, Transmission and Distribution is higher by the same amount. This apparent discrepancy is caused by the difference in BCUC capital accounts vs. the Company's responsibility based capital accounts.

2005 General Plant Capital	<u>(\$000s)</u>
General Plant Expenditures per Volume 1 Tab 9 Page 62 Table 9.7.1	6,215
Communications Projects (in Telecom, SCADA & Protection Control Projects)	
Communications and Automation	651
Protection and Communications Rehabilitation	<u>1,526</u>
Total Communications Projects (in Telecom, SCADA & Protection Control Projects)	2,177
Land Acquisitions (in Transmission Projects)	
Ellison Distribution Source	271
Black Mountain Distribution Source	271
New East Osoyoos Source	271
Kettle Valley Distribution Source	<u>163</u>
Total Land Acquisitions (in Transmission Projects)	976
Meters in Distribution Projects	<u>67</u>
Total General Plant Capital per Volume 1 Tab 6 Page 7 Table 6.2E	<u>9,436</u>

FortisBC Inc.
2005 Revenue Requirements Application,
2005-2024 System Development Plan and 2005 Resource Plan

- 33.0 Reference: Volume 1, Tab 6, Rate Base, Section 3, pp. 8-10
Accumulated Depreciation and Amortization**
- Q33.1 Please provide the full detailed 2004 and 2005 Accumulated Depreciation and Amortization continuity schedules for Tables 6.3 B and C. Include details by BCUC account, asset balance, depreciation rate, depreciation, opening and closing balances, retirements, retirement costs, proceeds on disposal, and adjustments for both depreciation and amortization.**
- A33.1 Please refer to Tables 1 – C (2004) and 1 – C (2005) of the Rate Base Schedules. Retirements, retirement costs and proceeds on disposal are all netted in “Charges less Recoveries”. A separate breakdown is not readily available.
- Q33.2 Also, please provide the Actual 2003 Accumulated Depreciation and Amortization continuity schedules in a similar format to the 2004 and 2005 information requested above.**
- A33.2 Please refer to Table 1 – C (2003) of the Rate Base Schedules.
- Q33.3 Please provide the supporting calculations for Portion of CIAC Amortized for 2003, 2004 and 2005. Is CIAC amortized by individual identifiable asset or grouped into pools of assets?**
- A33.3 Please refer to Table 1 – D of the Rate Base Schedules. FortisBC uses a pooled approach to depreciation of assets and amortization of CIAC.
- Q33.4 Please reconcile the 2004 and 2005 Depreciation and Amortization amounts shown in line 28 of Schedule 2 Earned Return (Tab 4, page 5) to Tables 6.3 B and C. Schedule 2 shows Depreciation and Amortization of \$16.854 million for Estimate 2004 and \$18.766 million for Forecast 2005. However, Table 6.3 B, line 17 shows \$15.007 million for Forecast 2004 and Table 6.3 C, line 15 shows \$16.855 million for Forecast 2005.**
- A33.4 Depreciation and Amortization on Schedule 2 includes both the depreciation of fixed assets and the amortization of deferred charges. Please refer to lines 51-53 of Table 1-C (2004) and Table 1-C (2005) of the Rate Base Schedules.
- Q33.5 Please explain the tax treatment of software tax savings and how it is shown in the financial schedules. How does the utility propose to address the inter-generational and ‘mis-matching’ issues of 100 percent CCA deduction compared to a 10 percent depreciation provision for software? Will the 2005 and future accounting treatment of software additions address this issue?**
- A33.5 Computer software additions are included in either the class 10 or class 12 capital cost allowance (CCA) pools for purposes of calculating the income tax provision, depending on the
-

FortisBC Inc.
2005 Revenue Requirements Application,
2005-2024 System Development Plan and 2005 Resource Plan

specific nature of the software additions. For amounts included in class 10, 30 percent of the balance of the pool is deducted from income for tax purposes by way of the CCA deduction on line 10 of Schedule 3. For amounts included in class 12, 100 percent of the balance of the pool is deducted from income for tax purposes by way of the same CCA deduction.

FortisBC accounts for income taxes according to the “flow-through” method in accordance with BCUC Order G-37-84. In the Order, the Commission concluded that “a shift in tax treatment would be essentially neutral in any impact on inter-generational equity and that the shifting of such costs, if any, in the case of WKPL consumers is not significant”. Therefore, in this context, the question of inter-generational equity relates to the depreciation rate for software and whether the rate is appropriate for customers now and in the future. The Company will be undertaking a depreciation study in 2005 that will address the life of all depreciable assets. Please also refer to the response to BCUC IR1 Q33.6.

Q33.6 As stated on page 9: “FortisBC intends to undertake a Depreciation and Amortization study during 2005, for submission with the 2005 Revenue Requirements application.”

Q33.6.1 When was the last formal depreciation and amortization study undertaken? Was an external consultant used? How much was the cost of this study?

A33.6.1 The last formal study was undertaken in 1983 based on plant in service as of December 31, 1982. The firm of General Appraisal of Canada Limited was engaged to perform the study at a cost of approximately \$60,000.

Q33.6.2 Has the cost of the intended Depreciation and Amortization study been included in the 2005 Revenue Requirements? If so, where is this cost included in the financial schedules? What is the estimated cost of this study?

A33.6.2 The cost of the Depreciation and Amortization study has been included in the 2005 Revenue Requirements in the amount of \$30,000 and is included in Administration and General Expense in Volume 1, Tab 8, Table 8.2.5, of the Application.

Q33.6.3 Will the study address the ‘apparently’ high estimated life of computer software at 10 years?

A33.6.3 Yes, the study will address the life of all depreciable assets.

Q33.6.4 Account 392 Transportation Equipment has a depreciation rate of 5 percent. What kind of transportation equipment does the utility have that lasts 20 years or more?

A33.6.4 Other than some transportation equipment such as pole trailers, most transportation equipment does not last 20 years or more. The depreciation study will address the life of all depreciable assets, including transportation equipment.

FortisBC Inc.
2005 Revenue Requirements Application,
2005-2024 System Development Plan and 2005 Resource Plan

Q33.7 On page 9 it states: “Commission Order G-134-99 approving the Rate Stabilization provision also increased, on a prospective basis, an increase in the amortization period from 35 to 50 years for depreciation of Transmission and Distribution assets.”

Q33.7.1 Please list the BCUC accounts (with account name and number) that changed its depreciation rate from 35 to 50 years.

A33.7.1 The following accounts were affected:

Transmission Account No	353	Station Equipment
	355	Poles and Fixtures
	356	Conductors and Devices
Distribution Account No	362	Station Equipment
	364	Poles and Fixtures
	365	Conductors and Devices
	368	Line Transformers
	369	Services

Q33.7.2 For year 2000 what was the estimated change in depreciation expense as a result of this change from 35 to 50 years?

A33.7.2 Actual depreciation expense for 2000 was \$3.36 million lower than would have been the case without the change in rates.

Q33.7.3 If any other accounts have changed depreciation rates since 2000 please provide the list of accounts with the old and revised depreciation rates.

A33.7.3 No other depreciation rates have changed since 2000.

Q33.7.4 Is the utility proposing that the 50 year depreciation for these assets be continued for 2005? Does the utility currently have any evidence supporting this lower depreciation rate?

A33.7.4 The Company does not propose any changes in depreciation rates or methodologies until such time as a comprehensive depreciation study is completed. The depreciation study will be carried out in 2005.

In 1999 the Company completed a Discussion Paper on the service life of its transmission and distribution assets. Tab 7 of the 2000 – 2002 Revenue Requirements contained a summary of the analysis and is included in the attached document BCUC A 33.7.4. The discussion paper questioned the appropriateness of a 35 year average service life based on selected data. While the paper suggested that a 50 year average useful life for Transmission and Distribution assets was reasonable and appropriate, this conclusion has not been verified by way of independent study. The 2005 depreciation study will address the life of the Company’s Transmission and Distribution assets.

Amortization of Transmission
& Distribution Assets

Discussion Paper

AMORTIZATION OF TRANSMISSION & DISTRIBUTION ASSETS
Discussion Paper

1 **1. Background**

2

3 Amortization is calculated by grouping all Transmission & Distribution (“T&D”) assets
4 into approximately 14 categories and applying a rate specific to each category. The rate is
5 based on management’s best estimate of the useful economic life of the assets in that
6 category. Historically, the estimated useful lives range from 20 to 50 years (with a few
7 insignificant categories as high as 100 years). Historically, the effective average useful
8 life for all T&D assets has been approximately 35 years.

9

10 There has been some question as to the appropriateness of an average of 35 years given
11 WKP’s specific experience and the age of the assets still in service. A review of the
12 estimates of the useful lives of the T&D assets is required.

13

14 **2. Data**

15

16 WKP reviewed industry statistics, the policies of its parent company and its own
17 experience in determining the useful lives of T&D assets.

18

19 Industry statistics from the U.S. Bureau of Reclamation indicate an average useful life of
20 approximately 40 years. UtiliCorp United filed a formal amortization study in 1998 with
21 the Missouri regulator which supported useful lives ranging from 33 to 50 years on most
22 of its T&D assets.

23

24 WKP reviewed its T&D plant in service to determine its own historic experience.

25 Transmission lines 1 to 8 were placed into service beginning in 1905 and have not had
26 significant reconstruction during their 95 year life. It is proposed that they be replaced in
27 the next few years. 43 Line (Oliver to Princeton) was reconstructed in 1996 after 60 years

AMORTIZATION OF TRANSMISSION & DISTRIBUTION ASSETS
Discussion Paper

1 of service. 44 line (Oliver to Osoyoos) was rebuilt during 1999 after 63 years of service.
 2 49 Line (Penticton to Summerland) was rebuilt in 1998 after 77 years of service. Many
 3 other transmission lines are in the range of 40 to 60 years old and are still in service
 4 without undergoing reconstruction. Many of the substations still in service were
 5 constructed in the 1930 to 1950's. Clearly, WKP is obtaining useful service lives of its
 6 transmission and distribution assets of at least 50 years.

7

8 WKP believes that its pole treatment and stubbing programs have allowed it to realize
 9 these extended useful lives of its transmission and distribution line assets.

10

11 In summary, WKP's operating policies have extended the useful lives of its T&D assets
 12 beyond the industry standard. WKP believes that although many of its assets are
 13 performing beyond 50 years, an average useful life of 50 years is reasonable and
 14 appropriate.

15

16 **3. Amortization Rate Adjustment**

17

18 Prospectively, the useful lives of the following categories of WKP's existing and future
 19 T&D assets is adjusted to equal 50 years:

20

	<u>Previous</u>	<u>Amended</u>
21 Station equipment	33 years	50 years
22 Poles, Towers and Fixtures - transmission	33 years	50 years
23 Poles, Towers and Fixtures - distribution	25 years	50 years
24 Conductors and Devices - distribution	33 years	50 years
25 Line Transformers	33 years	50 years

26

AMORTIZATION OF TRANSMISSION & DISTRIBUTION ASSETS
Discussion Paper

1 In addition to the change in amortization expense, we determined the effects on carrying
2 costs and taxes as a result of the amended estimate of useful lives and included these in
3 the rate impact percentage shown below.

4
5 A summary of the effects of the above adjustments is as follows:

6	7 Year	8 Previous 9 Amortization	Decrease	Amended Amortization	Rate Impact
10	2000	10,177,618	3,305,436	6,872,182	(2.3)%
11	2001	10,837,268	3,496,706	7,340,562	(2.1)%
12	2002	12,351,458	3,881,916	8,469,542	(2.0)%

13
14 **4. Rate Stabilization Account**

15
16 Retroactively, the useful lives of the following categories of WKP's existing T&D assets
17 have been adjusted to equal 50 years:

18		<u>Previous</u>	<u>Amended</u>
19	Station equipment	33 years	50 years
20	Poles, Towers and Fixtures - transmission	33 years	50 years
21	Poles, Towers and Fixtures - distribution	25 years	50 years
22	Conductors and Devices - distribution	33 years	50 years
23	Line Transformers	33 years	50 years

24
25 Given that rates set in the past have been based on an estimate that understated the useful
26 life of the T&D assets and thereby caused rates that were higher than necessary, WKP's
27 rate payers should receive the benefit of a revised estimate of the useful lives for those
28 years. An adjustment that captures the excess amortization over the past 20 years is
29 reasonable.

AMORTIZATION OF TRANSMISSION & DISTRIBUTION ASSETS

Discussion Paper

1

2 The accumulation of the annual effects of the adjustment over the last 20 years totals to
3 \$32.9 million. It is proposed that this amount become a Rate Stabilization Account and
4 be carried on the balance sheet as a deferred credit. The net book value of plant and
5 equipment will be increased by reducing accumulated amortization.

6

7 Once created, the Rate Stabilization Account can be brought into rates in future years in a
8 manner which minimizes the rate impact of WKP's capital expenditure program. The
9 account can be amortized using a fixed, smoothed level each year or can be amortized
10 selectively each year to manage any rate increase that would otherwise occur.

11

12 The proposal is to amortize the Rate Stabilization Account selectively during the years
13 covered by this application as follows. These credits to income will appear as reductions
14 to amortization expense and are shown as "rate stabilization account" on Table 2-A
15 Revenue Requirements in Tab 2, page 3.

16

17	Year	<u>Amortization</u>	<u>Rate Impact</u>
18	2000	1,000,000	(0.6)%
19	2001	1,900,000	(1.1)%
20	2002	3,400,000	(1.9)%

21

22 Note that the rate impact indicated includes the effects on carrying costs and taxes as a
23 result of the amortization as shown.

24

25 This amortization schedule would result in a balance of \$31.9 million at the end of 2000.
26 A decision on the actual remaining balance of the Rate Stabilization Account for years
27 beyond 2000 will be made during the Negotiated Settlement for those years.

AMORTIZATION OF TRANSMISSION & DISTRIBUTION ASSETS

Discussion Paper

1	Year	Opening	Creation	Annual	Closing
2		Balance	of Account	Amortization	Balance
3					
4	2000	nil	\$32,900,000	\$1,000,000	\$31,900,000
5	2001	\$31,900,000	n/a	\$1,900,000	\$30,000,000
6	2002	\$30,000,000	n/a	\$3,400,000	\$26,600,000
7					

8 5. Conclusion

9

10 WKP has applied the prospective adjustment to the useful lives of the T&D assets in the
11 calculation of amortization for the Years 2000 to 2002.

12

13 WKP proposes to record the Rate Stabilization Account effective January 1, 2000 and to
14 amortize \$1.0 million of this account in the 2000 Revenue Requirements.

FortisBC Inc.
2005 Revenue Requirements Application,
2005-2024 System Development Plan and 2005 Resource Plan

Q33.8 On pages 8 and 9 it states: “The Rate Stabilization Adjustment of \$3.1 million was the result of a Negotiated Settlement Process, and provided for an adjustment of Accumulated Depreciation in respect of Transmission and Distribution plant, in order to hold rate increases at or below 5 percent for the period in 2000 to 2002. ... Both the Rate Stabilization provision and the change in depreciation rates were grounded in a desire to mitigate rate increases during a period of very high rate base additions.”

Q33.8.1 Please briefly explain the nature of this adjustment to accumulated depreciation. How did the past reduced rate increases affect this adjustment account? This Rate Stabilization Adjustment is a debit to accumulated depreciation. Where and what is the corresponding credit to this account?

A33.8.1 The Rate Stabilization Adjustment of \$3.1 million represents a notional reversal of accumulated depreciation for prior periods based on the premise that a 35 year life was used to calculate depreciation expense as opposed to a 50 year life suggested for Transmission and Distribution assets in the Discussion Paper referred to in the response to BCUC IR1 Q33.7.4. The adjustment offset 2001 Revenue Requirements and limited the 2001 rate increase to 5 percent by way of a corresponding credit entry to depreciation expense.

Q33.8.2 The \$3.1 million Rate Stabilization Adjustment is a reduction of the accumulated depreciation and amortization balance, which makes net plant in service and rate base higher. Table 6.3 A shows the balance of this account from 2002 to 2005 has not changed.

Why is this there no amortization of this account? How does the utility propose to dispose of this account? Will the anticipated Depreciation and Amortization study address the disposal of this account?

A33.8.2 As noted above, the Rate Stabilization Adjustment represented a notional reversal of accumulated depreciation from prior periods.

The purpose of the Rate Stabilization Adjustment was to limit annual rate increases to no more than 5 percent during the period covered by the negotiated settlement (2000-2002). It was utilized only once, in 2001. Rate increases in 2000 and in 2002 were below 5 percent and therefore did not trigger further rate stabilization adjustments in those years.

The depreciation study to be conducted in 2005 will include an analysis of the Company’s reserve for accumulated depreciation based on estimated service lives for all depreciable assets and the resulting depreciation rates recommended for use on a go-forward basis. Based on this analysis the depreciation consultant will recommend a procedure by which any excess or shortfall in the accumulated depreciation reserve, including the \$3.1 million rate stabilization adjustment, should be amortized.

FortisBC Inc.
2005 Revenue Requirements Application,
2005-2024 System Development Plan and 2005 Resource Plan

Q33.9 Table 6.3 B and Table 6.3 C shows Forecast Charges less Recoveries of \$7.6 million in 2004 and \$3.1 million in 2005. Please explain this \$4.5 million difference.

A33.9 The difference between the forecast 2004 amount of \$7.6 million and the forecast 2005 amount of \$3.1 million reflects the fact that in the 2004 forecast we anticipated the removal of the 63 kV lines associated with the Kootenay 230 kV project, distribution asset retirements associated with the Okanagan fires, and other miscellaneous non-routine retirements consisting primarily of fleet vehicles and meters, to be completed in 2004.

FortisBC Inc.
2005 Revenue Requirements Application,
2005-2024 System Development Plan and 2005 Resource Plan

**Q34.0 Reference: Volume 1, Tab 6, Rate Base, Section 4, pp. 10-14
Deferred Charges and Credits**

**Table 6.4 A on page 12 and Table 6.4 B on page 13 show the Forecast 2004 and 2005
Deferred Charges and Credits.**

**Q34.1 Are these amounts pre-tax or net-of-tax? If some are pre-tax and others are net-of-tax
please identify for each account. What is the tax rate used for the deferral accounts with
net-of-tax treatment in the years 2003, 2004 and 2005?**

A34.1 Only the Demand Side Management expenditures are booked net of income tax, as required by BCUC Order No. G-55-95. The tax rate used in each year is the combined federal and provincial statutory rate, which is 37.32 percent in 2003, 35.62 percent in 2004, and 35.62 percent in 2005.

**Q34.2 Please provide the full continuity of Deferred Charges and Credits schedules for Actual
2002, Actual 2003, Forecast 2004, and Forecast 2005. Please include in these continuity
schedules the opening balance, gross additions (pre-tax), tax, net additions, amortization,
and closing balance for each account. Provide Actual 2004, when available.**

A34.2 Please refer to Tables 1 – B (2002), 1 – B (2003), 1 – B (2004) and 1-B (2005) of the Rate Base Schedules.

**Q34.3 For each deferral account please provide: a brief description; approval order (if
applicable for the amount and the approved amortization period, identify separately);
amortization period; and reason for additions. Also, please indicate the status of each
deferral account if it is a continuation with an existing approval order, a new deferral
request, or an existing deferral requesting approval for additions or amortization.**

A34.3 The information is provided below.

The requested information is provided below.

Account	Year	Description	Amortization Period	Order for Deferral	Order for Disposition
Energy Management Status - ongoing	all	Costs of developing and delivering Energy Management programs	G-47-89	G-123-98	
		Expenses booked net of income tax		G-55-95	
		Set amortization rate to 12.5%	8 years		G-73-96
Deferred Revenue					
Operating and Power	all	Customer portion of		G-73-96	G-5-98

FortisBC Inc.
2005 Revenue Requirements Application,
2005-2024 System Development Plan and 2005 Resource Plan

Account	Year	Description	Amortization Period	Order for Deferral	Order for Disposition
Purchase Incentives Status – balance to be amortized in 2005		approved preliminary adjustments is deferred and returned to revenue in the next year to offset rate revenue		G-123-98	G-123-98 G-134-99 G-130-00 G-133-01 G-10-03 G-38-04
Audit Provisions Status – balance to be amortized in 2005	all	Accounting practice requires a provision for future liability based on Company expectations of the final incentive. This has a shareholder impact and no customer rate impact.		n/a	n/a
Series 1 Refinancing Status: fully amortized	2002 - 2003	Order G-42-02 approved a mid-year interest rate increase. Associated revenue requirement deferred for recovery in 2003	1	G-10-03	G-10-03
<u>Deferred Regulatory Expense</u>	all	Costs of regulatory proceedings are deferred pending BCUC approval for disposition.			
2000 – 2002 NSP Status: fully amortized	2002	Cost of multi-year application and negotiated settlement	2	G-73-96	G-130-00
2001 Revenue Requirements Status: fully amortized	2002	Cost of 2000 Annual Review and 2001 application	1	G-134-99	G-133-01
2002 Revenue Requirements Status: fully amortized	2001 – 2003	Cost of 2001 Annual Review and 2002 application	1	G-134-99	G-10-03
2003 Revenue Requirements and NSP Status: fully amortized	2002 – 2004	Cost of 2003 application and negotiated settlement	1	G-134-99	G-38-04
2004 Revenue Requirements and NSP Status: application for disposition	2003 – 2004	Cost of 2004 application and negotiated settlement	1	G-10-03	n/a
2005 Revenue Requirements Status: ongoing	2004 – 2005	Cost of 2005 cost of service application		G-38-04	
2006 Revenue Requirements Status: Application for	2005	Cost of 2006 application		G-38-04	

FortisBC Inc.
2005 Revenue Requirements Application,
2005-2024 System Development Plan and 2005 Resource Plan

Account	Year	Description	Amortization Period	Order for Deferral	Order for Disposition
deferral only					
Transmission Access Tariff Status – fully amortized	2002	Costs of Transmission Access and Access Principles Application	3	G-123-98	G-142-99
Return on Equity Hearing	2002 – 2003	Costs of the 2001 public hearing on generic ROE	3	G-123-98	G-130-00
Proposed Settlement Guidelines Revision	2002	Costs of participating in review of Negotiated Settlement Guidelines	2	G-123-98	G-130-00
Time of Use Rates – Implementation	2002	Cost of advertising and promoting Time of Use Rates Status – fully amortized	3	G-15-98	G-142-99
Other Regulatory Proceedings Status: Application is for deferral only	2005	Provision for costs of 2006 Revenue Requirements, ROE and possibly other proceedings		G-38-04	
<u>Preliminary and Investigative Charges</u>	all	Preliminary engineering costs associated with feasibility of capital projects. Costs transferred to capital projects.	n/a	n/a	n/a
<u>Other Deferred Charges and Credits</u>					
Head Office Lease Costs	all	Legal and brokerage fees associated with the sale and leaseback of the Trail office building	30		G-41-94
Trail Office Rental Revenue Status; ongoing	all	Prepaid rental and purchase option for tenant in Trail office amortized to rental revenue and interest expense		n/a	n/a
Kootenay Damage Claims Status: fully amortized	2002-2003	Claims in excess of insurance reserves resulting from a 1999 Generation islanding incident	3		G-130-00
Prepaid Pension Costs Status: ongoing	all	Annual difference between pension expense	n/a	n/a	n/a

FortisBC Inc.
2005 Revenue Requirements Application,
2005-2024 System Development Plan and 2005 Resource Plan

Account	Year	Description	Amortization Period	Order for Deferral	Order for Disposition
Series J Status: ongoing	all		7	G-130 00	G-10-03
Series 1 Status: costs transferred to affiliate	2002	Series 1 was redeemed early and the outstanding issue expense written off to nonregulated affiliate	5	G-134-99	G-134-99
Series 04 – 1 Status: application for disposition	2004 - 2005	\$140 million public debt issued in November 2004	10	G-10-03	

Q34.4 On page 11 for **Other Deferred Charges and Credits** it states: “Costs of investigation and feasibility studies preliminary to undertaking capital projects are deferred and, once approved, charged to the appropriate capital projects. Deferral and disposition of other items approved by the Commission are also included.”

Q34.4.1 Please segment and identify these accounts in Tables 6.4 A and B between those accounts that are costs of investigation and feasibility studies that are transferred to capital accounts and those that are subject to Commission disposition or amortization. The distinction within ‘Other Deferred Charges and Credits’ grouping is unclear. Within this grouping some accounts have activity in only the Forecast Additions (Reductions) column (some of the reduction go to capital and other to operating expense) and other accounts have activity in the amortization column. In your response please clarify and identify (by grouping with similar treatment) the different types of accounting treatment for these accounts.

A34.4.1 Please refer to Tables 1 – B (2002), 1 – B (2003), 1 – B (2004) and 1-B (2005) of the Rate Base Schedules. Please also refer to the response to BCUC IR1 Q34.5.3.

Q34.4.2 Is AFUDC included in the amounts identified as costs of investigation and feasibility studies?

A34.4.2 AFUDC is not applied to investigative or feasibility studies until such time as a capital project is approved, either by the BCUC for projects requiring a CPCN, or by FortisBC’s management for those that do not.

Q34.5 In Table 6.4 A and Table 6.4 B the column Forecast Additions (Reductions) sometimes have negative amounts for additions. It appears that some of these costs are “amortized to operating expense” as noted on page 13.

Q34.5.1 Is the utility requesting for approval of the amortization period of those accounts with costs ‘amortized to operating expense’?

FortisBC Inc.
2005 Revenue Requirements Application,
2005-2024 System Development Plan and 2005 Resource Plan

A34.5.1 Yes.

Q34.5.2 Please separate this Forecast Additions (Reductions) column between three columns: Additions; Reduction to Capital; and Amortization to Operating Expense. After the separation, if any account in the Additions column is negative please explain.

A34.5.2 Please refer to Tables 1 – B (2004) and 1-B (2005) of the Rate Base Schedules.

The following deferral accounts have negative or credit additions:

- (a) Incentive Accounts: additions to these accounts may be debits or credits depending on the Incentive Adjustments from year to year.
- (b) Trail Office Rental: This account holds a prepaid amount for that portion of the Trail Office building that is sub-leased to the School Board. The account is credited with interest on the balance, and debited for rental costs.
- (c) Prepaid Pension Costs. Additions to this account may be debits or credits, depending on the funding requirements of the Company's Pension plans compared to actuarial expense in each year. Further detail is provided in the response to BCUC IR1 Q34.8.

Q34.5.3 Why are some accounts (such as the Resource Plan Study) amortized to operating expense and some other accounts are in the regular amortization expense column? How is this consistent?

A34.5.3 This treatment evolved under PBR agreements, in which a base level of operating expense was target-driven. Deferred costs that were irregular and variable were not contemplated in Base O&M expense and were included in amortization expense. The Canal Plant Agreement Renegotiation costs are an example of such an item. The Resource Plan and System Development Plan, on the other hand, while cyclical in nature, are ongoing expenses, and should be treated as part of the "base" level of expense.

Q34.5.4 Should all regulatory deferral accounts (except preliminary investigation and feasibility accounts which are transferred to capital) be treated net-of-tax and amortized accordingly to the approved amortization period?

A34.5.4 The Company proposes that items to be shared in 2005 under the proposed sharing mechanism be treated net-of-tax. By doing so, income tax will be accurately matched to the items attributed to either the customer or the shareholder. The income tax provision in the original 2005 Revenue Requirement does not reflect this proposed treatment.

The Company proposes that Demand Side Management costs continue to be treated

FortisBC Inc.
2005 Revenue Requirements Application,
2005-2024 System Development Plan and 2005 Resource Plan

on a net-of-tax basis.

The Company does not propose to treat any other regulatory deferral accounts net-of-tax, other than the two items discussed above.

Q34.5.5 Please identify the total amounts for each year from 2002 to 2005 amortized to operating expenses.

A34.5.5 The amounts amortized to operating expenses for each year from 2002 to 2005 are as follows.

	2002	2003	2004	2005
	(\$000s)			
1998 System Master Plan	82	82	0	0
Fleet Reengineering Study	34	0	0	0
2004 System Development Plan	0	0	0	160
2004 Resource Plan Study	0	0	0	20
Total	116	82	0	180

Q34.5.6 What is the tax timing difference as a result of transferring expenditures to operating expense? Is the full tax deductibility taken at the time of expenditure or when expensed in the future? How has this timing difference between cash payment and recognition of expense reflected in the tax schedules?

A34.5.6 For the most part, a full tax deduction is taken at the time of the expenditure. When the item is amortized to income in a future period, the amount is added back for tax purposes on line 19 of Schedule 3, Tab 4 (amortization of deferred charges). There are some exceptions to this treatment, including the following:

- a) Deferred debt issue expenses – debt issue costs are expensed for tax purposes over a five year period.
 - b) Energy management – energy management costs are shown on Tables 6.4 A and B net of tax. On Schedule 3 of Tab 4, the gross amount of the expenditure has been deducted from income for tax purposes as part of the deduction on line 13. The tax amount that has been netted against the gross deferred charge addition is then included in the income tax provision calculation on line 31.
 - c) Incentive adjustment and power purchase incentive – the additions to deferred charges and the amortization of these amounts in subsequent periods are not included in the calculation of the income tax provision on Schedule 3 of Tab 4.
-

FortisBC Inc.
2005 Revenue Requirements Application,
2005-2024 System Development Plan and 2005 Resource Plan

Under the proposed net-of tax treatment for the 2005 sharing mechanism discussed in the response to BCUC IR1 Q34.5.4, an amount equal to the 2005 deferred charge gross addition multiplied by the statutory income tax rate will be netted against the gross deferred charge addition, with the offset to the income tax provision. In computing income taxes payable for the year, the amount of the net deferred charge addition will not be included in the income tax provision calculation.

Q34.5.7 The 20 Year Transmission System Plan in Table 6.4 A for 2004 shows \$800,000 in additions. This amount is then reduced by \$160,000 in Table 6.4 B for 2005 for transfer to operating expense. Please provide the itemized estimated budget for this account by resource code. Why is the five year amortization to operating expense appropriate?

A34.5.7 The System Development Plan (“SDP”) will be revised and updated on a five year cycle. It is required to ensure that the capital completed over this period is prudent and meets the needs of customers and stakeholders. With the benefits of the planning study covering the multiyear period it was felt appropriate to amortize the expense over the five years.

The cost estimates were:

20 Year System Development Plan	
Carried over from Deferred (Investigative)	\$20,000
Stakeholder Consultation	50,000
Plan Development (Consultant Contracts)	650,000
Technical Evaluation	10,000
Report Publication	10,000
Project Administration	40,000
Contingency	20,000
	\$800,000

Q34.5.8 Page 14 states: “...the renegotiation of the Canal Plant agreement will also be amortized to operating expense over a five year period beginning in 2005.” In Table 6.4 B it shows an addition of \$135,000 in 2005. Please provide a summary of all costs and amortization from inception to the last Forecast expected year of additions to this account.

A34.5.8 This statement was made in error. It should read “Finally, the deferred charges associated with the **Resource Plan** will be amortized to operating expense over a five-year period beginning in 2005”. FortisBC is not applying for disposition of the Canal Plant Renegotiation costs in this Application.

For information, the costs of the Canal Plant Agreement renegotiation incurred to January 31,

FortisBC Inc.
2005 Revenue Requirements Application,
2005-2024 System Development Plan and 2005 Resource Plan

2005, are as follows:

External Legal Counsel	\$ 252,731
Technical Consultant Costs	100,564
Internal Staff Labour	75,223
Internal Staff Expenses	<u>21,277</u>
Total	449,795
Expected Costs (to completion in 2005)	<u>50,000</u>
Total approximate costs	<u>\$ 500,000</u>

Q34.5.9 The Brilliant Terminal Station 2003 Expense has \$363,000 of additions in 2004. Why are there additions for a 2003 expense? For this account provide a schedule showing the gross additions from inception, tax, net additions, amortization, opening and closing balance for each year up to the last Forecast year of amortization.

A34.5.9 The Brilliant Terminal Station (BTS) was placed into service in mid-2003. Commission Order No. G-2-04 approved the deferral of BTS expenses for 2003, and Order No. G-10-03 approved the amortization of this account over two years beginning in 2004. Under the terms of the BTS Facilities Interconnection and Investment Agreement, FortisBC is billed semi-annually in arrears for the BTS expense, in May and November of each year. A portion of the invoice received in May 2004 related to BTS services in 2003. The Company did not book a provision for accrual of that amount until 2004. This account is not booked net of tax. The deferral account history is as follows:

		<u>(\$000s)</u>
2003	Opening Balance	0
	Additions	<u>672</u>
	Closing Balance	672
2004	Additions	363
	Amortization	<u>(543)</u>
	Closing Balance	492
2005	Amortization	<u>(492)</u>
	Closing Balance	<u>0</u>

FortisBC Inc.
2005 Revenue Requirements Application,
2005-2024 System Development Plan and 2005 Resource Plan

Q34.6 Table 6.4 B shows \$350,000 of costs for the 2005 Revenue Requirements. Please provide the 2004 and 2005 Forecast expenditures by BCUC resource code (e.g. labour, supplies, travel, consulting, etc.).

A34.6 The forecast expenditure is as follows:

	<u>2004</u>	<u>2005</u>	<u>Total</u>
Consulting Fees	61,000	20,000	81,000
Legal Fees	20,000	70,000	90,000
Commission and Intervenor Expenses		125,000	125,000
Facilities Rental	3,000	5,000	8,000
Transcription Services		10,000	10,000
Meals and Travel Expenses	10,000	10,000	20,000
Supplies	<u>6,000</u>	<u>10,000</u>	<u>16,000</u>
Total	100,000	250,000	350,000

Q34.7 Table 6.4 B shows \$150,000 for Other Regulatory Proceedings. Please breakdown these costs by project and by BCUC resource code.

A34.7 This account is included as a provision for expected and unexpected regulatory proceedings during the year. The most significant of these will be the 2005 generic Return on Equity hearing. Should the Company be required to intervene in the proceedings of other utilities in the interests of its customers, for example a BC Hydro's Rate Design hearing, the costs would be treated in the same manner. It is not possible to estimate costs with a reasonable degree of certainty until the scope and process of a proceeding has been determined. The Company is requesting approval for deferring the costs, and will apply for disposition of prudently-incurred costs at a later date.

Q34.8 Please explain the nature and inclusion of the Prepaid Pension Costs account shown in Tables 6.4 A and B. Should all costs paid to the pension plan be included in the pension plan itself? Why are there a reduction of \$72,000 in 2004 and an addition of \$700,000 in 2005? Please provide a detailed schedule of this account's activity from 2000 to 2005.

A34.8 The Company's independent actuary provides the Company with a calculation of pension expense for the year based on the terms of the pension plans as well as assumptions about the expected rate of return on plan assets, rates of pay increases, expected average remaining service life of employees, inflation rates, etc. The Company's actuary also provides a calculation of the required funding for the employees and the Company in the upcoming year. The amount of pension expense and the amount of annual funding to the pension plans by the Company generally will not match in a given year. The difference between these two amounts is recorded as an increase or decrease in the Prepaid Pension Costs account in deferred charges. In 2004, pension expense exceeded funding by \$72,000, while the 2005 forecast estimates

FortisBC Inc.
2005 Revenue Requirements Application,
2005-2024 System Development Plan and 2005 Resource Plan

funding will exceed expense by \$700,000. The following table shows the activity of the Prepaid Pension Cost account for 2000 to 2005.

	2000	2001	2002	2003	2004	2005
					(forecast)	(forecast)
Prepaid pension costs, opening balance	5,195	5,795	6,611	6,775	5,814	5,742
Pension expense	(2,543)	(1,653)	(2,411)	(3,094)	(3,335)	(3,860)
Pension funding	3,143	2,469	2,575	2,133	3,263	4,560
Prepaid pension costs, closing balance	5,795	6,611	6,775	5,814	5,742	6,442

FortisBC Inc.
2005 Revenue Requirements Application,
2005-2024 System Development Plan and 2005 Resource Plan

Q35.0 Reference: Volume 1, Tab 6, p. 12

Please describe the work carried out under the Turbine and Generation Studies, the Preliminary Engineering Studies and Deferred Telecommunications Planning.

A35.0 The work carried out under the preliminary engineering studies includes the preliminary planning and engineering required to complete the scopes and estimates for the projects listed below.

- Station Labeling Investigative Spending
- Distribution Base 2004
- Creston Dist Feeder Upgrade
- Grand Forks Noise Mitigation
- Naramata Rebuild
- Transmission Base
- Big White Capacity Upgrade - Investigative Spending
- Boundary Area Upgrade

The work completed under the Deferred Telecommunications Planning was the WKP Communications Study - Final Report May 1, 2001.

The work carried out under the Turbine and Generator studies was preparation of detailed scopes and feasibility level estimates for projects presented in the 2005 Capital plan. More specifically:

- Generation small sustaining projects - options development and selection, preparation of scope, feasibility level estimate and Business Case.
 - P1-P4 river optimization (P2 re-powering) - review of previous reports from consultants and an in-depth inspection (condition assessment) of the Upper Bonnington Old Plant facilities and generating equipment.
 - P1U3 Upgrade and Life extension - scope of work definition, initial contact with suppliers on long delivery items for preliminary budget quotes, development of budget, drafting of preliminary CPCN document, preliminary design and engineering.
 - P1U1 Headgate Rebuild – review of previous projects, options development and selection, preparation of scope, feasibility level estimate and Business Case.
-

FortisBC Inc.
2005 Revenue Requirements Application,
2005-2024 System Development Plan and 2005 Resource Plan

**Q36.0 Reference: Volume 1, Tab 6, Rate Base, Section 5, pp. 14-16
Allowance for Working Capital**

**Q36.1 Tables 6.5 A and B shows the 2004 and 2005 Forecast allowance for working capital.
Please provide the Actual 2002 and 2003 schedules.**

A36.1 Please refer to Schedule 1-E (2002) and 1-E (2003) of the Rate Base Schedules.

**Q36.2 Page 14 states: “The Allowance for Working Capital is determined through a lead-lag
study.” When was the last comprehensive lead-lag study carried out?**

A36.2 A study was carried out for this 2005 Revenue Requirements Application.

**Q36.3 Some of the accounts lag (lead) days have changed between years as shown Table 6.1 A
for 2004 and in Table 6.5 B for 2005. Please provide the detailed calculations of the Tariff
Revenue change from 39.1 days to 46.0 days. Why has the Salaries & Wages decreased
from 26.3 days to 5.3 days?**

A36.3 The Tariff Revenue lags for 2004 and 2005 are shown below.

2004 Tariff Revenue Lag

	Consumption (Service Period to Meter Read)	Processing (Meter Read to Billing)	Clearing (Billing to Collection)	Total Lag (Lead) Days	2004 Forecast (\$000s)	Weighted Average Lag (Lead) Days
Residential (18.5% monthly billing)	28.7	3.0	14.0	45.7	74,725	19.4
General Service (67.5% monthly)	20.1	3.0	14.0	37.1	38,783	8.2
Large General Service (Industrial)	15.2	3.0	14.0	32.2	41,507	7.6
Wholesale	15.2	3.0	14.0	32.2	16,924	3.1
Irrigation	30.4	3.0	14.0	47.4	1,390	0.4
Lighting	15.2	3.0	14.0	32.2	2,274	0.4
					\$ 175,603	39.1

2005 Tariff Revenue Lag

	Consumption (Service Period to Meter Read)	Processing (Meter Read to Billing)	Clearing (Billing to Collection)	Total Lag (Lead) Days	2005 Forecast (\$000s)	Weighted Average Lag (Lead) Days
Residential (18.5% monthly billing)	28.7	3.0	30.0	61.7	78,222	26.2
General Service (67.5% monthly)	20.1	3.0	14.0	37.1	41,587	8.4
Large General Service (Industrial)	15.2	3.0	14.0	32.2	18,069	3.2
Wholesale	15.2	3.0	14.0	32.2	43,055	7.5
Irrigation	30.4	3.0	14.0	47.4	2,140	0.6
Lighting	15.2	3.0	14.0	32.2	1,334	0.2
					\$ 184,406	46.0

FortisBC Inc.
2005 Revenue Requirements Application,
2005-2024 System Development Plan and 2005 Resource Plan

There was an error in the calculation of the lag for Salaries and Wages in 2004 due to an inconsistency in the treatment of certain benefits. The 2005 lag is correct.

Q36.4 For Table 6.5 A please provide the detailed calculation of the \$2.013 million in 2004 Lead-Lag Study Allowance.

A36.4 The calculation is as follows:

$$\text{Net lag days x total expenses} = \frac{38.8 - 33.7}{365} \times \$143,179 = \$2,013,000$$

Q36.5 For Table 6.5 B please provide the detailed calculation of the \$4.398 million in 2005 Lead-Lag Study Allowance.

A36.5 The calculation is as follows:

$$\text{Net lag days x total expenses} = \frac{45.8 - 35.6}{365} \times \$158,163 = \$4,398,000$$

Q36.6 How much of the \$2.385 million increase in Lead-Lag Study Allowance for 2005 is a result of the change in payment periods for residential customers?

A36.6 The Lead-Lag Study Allowance increased by \$2.9 million as a result of the change. Other components of the Working Capital calculation partially offset this increase, with the net result being the \$2.385 million increase over 2004.

Q36.7 Why has Customer Loans (related to energy management) reduced from \$3.329 million in 2004 to \$2.305 million in 2005?

A36.7 The 2005 Customer Loans forecast was in error. Energy Management Loans are expected to increase in 2005.

Q36.8 Please provide the inventory supporting schedules for 2004 and 2005.

A36.8 The 2004 value is a 13-month average of inventory balances, and is shown below. The 2005 forecast was derived by adding a five percent provision for inflation and the higher volume of capital work in 2005.

FortisBC Inc.
2005 Revenue Requirements Application,
2005-2024 System Development Plan and 2005 Resource Plan

	Inventory Balance
December 2003	4,680
January	4,878
February	4,865
March	4,984
April	5,057
May	4,953
June	5,001
July	5,001
August	5,032
September	5,010
October	4,960
November	5,020
December 2004	5,020
Average Monthly Inventory	<u>4,958</u>
Add 5%	<u>248</u>
Forecast 2005 Average Inventory	5,206

FortisBC Inc.
2005 Revenue Requirements Application,
2005-2024 System Development Plan and 2005 Resource Plan

37.0 Reference: Volume 1, Tab 6, Rate Base, Section 6, pp. 17-18
Adjustment for Capital Expenditures

37.1 Tables 6.6 A and B shows the 2004 and 2005 Forecast Adjustment for Capital Expenditures.

Q37.1.1 Please provide the Actual 2002 and 2003 schedules similar to Tables 6.6 A and B.

A37.1.1 Please refer to Tables 1-F (2002) and 1-F (2003) of the Rate Base Schedules

Q37.1.2 Please provide a 13-month calculation of the capital expenditures adjustment schedule for 2003, 2004 and 2005.

A37.1.2 The requested information is provided in the tables below.

Adjustment for Capital Expenditures 2003
(13 Month Calculation)

		Actual Expenditures (1) (\$000's)	Months in Rate Base	Actual Weighted Expenditures (\$000's)
December	2002	19,787	12	18,265
January	2003	2,852	11	2,413
February	2003	3,232	10	2,486
March	2003	3,007	9	2,082
April	2003	8,548	8	5,260
May	2003	2,324	7	1,251
June	2003	1,593	6	735
July	2003	5,038	5	1,938
August	2003	6,262	4	1,927
September	2003	10,936	3	2,524
October	2003	3,897	2	600
November	2003	4,122	1	317
December	2003	2,684	0	0
13 Month Total		74,281		39,798
Simple Average				<u>37,141</u>
Adjustment for Capital Additions				<u>2,657</u>
Adjustment per 2003 Annual Report to the BCUC				<u>(1,826)</u>

Note: Expenditures are reduced by Contributions in Aid of Construction

FortisBC Inc.
2005 Revenue Requirements Application,
2005-2024 System Development Plan and 2005 Resource Plan

Adjustment for Capital Expenditures 2004

(13 Month Calculation)

		Actual Expenditures (1) (\$000's)	Months in Rate Base	Actual Weighted Expenditures (\$000's)
December	2003	2,684	12	2,477
January	2004	3,686	11	3,119
February	2004	5,524	10	4,249
March	2004	7,186	9	4,975
April	2004	7,941	8	4,887
May	2004	6,361	7	3,425
June	2004	4,873	6	2,249
July	2004	5,184	5	1,994
August	2004	5,940	4	1,828
September	2004	6,051	3	1,396
October	2004	3,892	2	599
November	2004	7,783	1	599
December	2004	20,021	0	0
13 Month Total		87,126		31,797
Simple Average				<u>43,563</u>
Adjustment for Capital Additions				<u>(11,766)</u>
Adjustment per November 26, 2004 Application				<u>(5,487)</u>

Note: Expenditures are reduced by Contributions in Aid of Construction

FortisBC Inc.
2005 Revenue Requirements Application,
2005-2024 System Development Plan and 2005 Resource Plan

Adjustment for Capital Expenditures 2005
(13 Month Calculation)

		Actual Expenditures (1) (\$000's)	Months in Rate Base	Actual Weighted Expenditures (\$000's)
December	2004	20,021	12	18,481
January	2005	5,010	11	4,239
February	2005	4,943	10	3,802
March	2005	8,845	9	6,123
April	2005	8,054	8	4,956
May	2005	8,266	7	4,451
June	2005	8,315	6	3,838
July	2005	12,913	5	4,967
August	2005	13,298	4	4,092
September	2005	14,140	3	3,263
October	2005	12,322	2	1,896
November	2005	11,770	1	905
December	2005	12,510	0	0
13 Month Total		140,407		61,013
Simple Average				<u>70,203</u>
Adjustment for Capital Additions				<u>(9,190)</u>
Adjustment per November 26, 2004 Application				<u>(8,641)</u>

Note: Expenditures are reduced by Contributions in Aid of Construction

Q37.1.3 In Table 6.1 on page 4 the mid-year utility rate base is calculated by adding the mean depreciated utility rate base plus allowance for working capital and subtracting the adjustment for capital expenditures. Please explain why the mid-year rate base is not calculated based on a 13-month average? What is the difference between the utility's mid-year rate base calculation and the 13-month average method?

A37.1.3 The adjustment for Capital Expenditure is a proxy for the timing differences between the two methods. For simplicity purposes, the mid-year rate base is used as opposed to the 13-month average. Over the long-term both methods should yield similar results.

FortisBC Inc.
2005 Revenue Requirements Application,
2005-2024 System Development Plan and 2005 Resource Plan

Q37.2 Table 6.6 A (Forecast 2004 Adjustment for Capital Expenditures) in line 5 on page 17 shows \$90.005 million for 2004 of Forecast Expenditures with a note that it has been reduced by contributions in aid of construction (CIAC). In Table 6.2 C it shows \$90.006 million of Forecast Expenditures without a note. In Table 6.1 C it appears that the resulting \$84.521 million of 2004 Additions adjusted by subtracting \$7.596 million of Disposals equals the \$76.925 million of net additions which is shown in Table 6.1 line 2.

In Table 6.1 it appears that CIAC is included in line 12. Is there any double-counting of CIAC? Please reconcile any discrepancy.

A37.2 In Table 6.6 A, expenditures were not reduced by CIAC, as intended. A revised Table 6.6 A is provided below. The impact on utility Rate Base is immaterial.

Forecast 2004 Adjustment for Capital Expenditures

	Forecast Expenditures (1) (\$000's)	Months in Rate Base	Forecast Weighted Expenditures (\$000's)
Quarter One	16,396	10.5	14,347
Quarter Two	19,175	7.5	11,984
Quarter Three	17,175	4.5	6,441
Quarter Four	31,696	1.5	3,962
	<u>84,442</u>		<u>36,734</u>
Simple Average			<u>42,221</u>
Required Adjustment			<u>(5,488)</u>

(1) Expenditures are reduced by contributions in aid of construction

Q37.3 Table 6.6 B (Forecast 2005 Adjustment For Capital Expenditures) in line 5 on page 18 shows \$120.386 million of 2005 Forecast Expenditures reduced by CIAC. In Table 6.2 E it shows \$124.948 million of 2005 Forecast Expenditures.

Is the difference of \$4.562 million a result of the CIAC being deducted in Table 6.6 B?

A37.3 Yes. The difference between the \$120.386 million of forecast capital expenditures in Table 6.6B and the \$124.948 million in Table 6.2E is the \$4.562 million of CIAC deducted from the forecast capital expenditures in Table 6.6B. The calculation of the Adjustment for Capital Expenditures in Table 6.6B is based on capital expenditures net of CIAC.

FortisBC Inc.
2005 Revenue Requirements Application,
2005-2024 System Development Plan and 2005 Resource Plan

38.0 Reference: Volume 1, Tab 7.1, pp. 2, 4, 9

At page 2, the Application states, “The residential, general service and wholesale loads ... have historically exhibited a strong correlation to population levels and population growth rates.” It further states, “The 2005 load forecast is based on the population growth forecast generated by BC Stats and customized for the FortisBC service area.” On page 4, the Application states, “In 2004, FortisBC has been experiencing strong growth in terms of energy consumption and the number of customer accounts. The growth rate has been significantly above the long term growth rate set by the population growth. In order to account for this exceptional growth, the forecast of energy consumption and number of accounts from 2004 to 2009 has been decoupled from the population growth and adjusted to reflect the growth pattern experienced in 2004.”

Q38.1 Please describe the load forecast methodology prior to the decoupling. For how many years was this methodology employed?

A38.1 The sentence “The growth rate has been significantly above the long term growth rate set by the population growth.” should read “The growth rate in customers has been significantly above the long term growth shown in BC Stats’ population forecast.” The methodology has not changed noticeably. The “decoupling” is actually a blending of a short term forecast into the long term trend. Each year BC Stats produces a long run population forecast for the FortisBC service territory. The forecast is the result of an age cohort survival model, which predicts population growth as a function of births, deaths and net in-migration to the service territory. It is the basis for the long term forecast.

Unfortunately in years between population censuses (which occur every five years) BC Stats’ estimates of in migration often do not reflect growth that is actually being experienced in the service territory, and reflected in our customer addition figures. In such instances, in the past, and in this forecast, the near term growth rates are adjusted to reflect both actual experience and the expectations of our frontline customer service personnel and sources such as CMHC.

Thus the short term forecast may reflect higher growth rates than forecast by BC Stats, but long term growth rates will be trended to the BC Stats projection, in this case by 2009.

Ignoring what’s actually been happening to customer additions (and hence population) in the last two years would dramatically underestimate customer counts and workloads. As can be seen from the historical data (Volume 1 Tab 7.1 Table 7.6.3), customer additions have increased from 1,389 in 2001 to a forecast value of 2,400 in forecast 2004. The actual increase in 2004 was 2,305. The forecast for 2005 is 2,227 customer additions.

FortisBC Inc.
2005 Revenue Requirements Application,
2005-2024 System Development Plan and 2005 Resource Plan

Q38.2 Please provide the spreadsheet(s) containing the historical data upon which the forecasts were based. Please include relevant population and temperature data. Please highlight the data on population and customer growth rates that support the change in methodology.

A38.2 Please refer to the attachment BCUC A38.2

Adjustments are shown in red, column B, pages “Residential Accounts”, “General Service Accounts” and “Wholesale”. The green highlighted numbers in Column F on the same pages indicate what the forecast would have been without the “decoupling”.

Q38.3 Please confirm that the forecasts for 2005 through 2009 were based on the single “anomalous” year 2004. If not so confirmed, please clarify the basis for the forecast from 2005 through 2009.

A38.3 Please see the response to BCUC IR1 Q38.1.

Q38.4 Further to the preceding question, if confirmed, please explain the basis for adjusting the methodology based on the growth patterns observed in the one year, 2004. Why does FortisBC consider this to be indicative of future growth rates? Why was the cut-off for “exceptional growth” forecasts taken to be 2009?

A38.4 Please see the response to BCUC IR1 Q38.1.

Q38.5 For each customer class, please provide the incremental effect on the load forecast from this change in methodology.

A38.5 Please refer to the attachment BCUC A38.5. Please also see the response to BCUC IR Q38.1

Q38.6 Has there been a shift in the service area’s demographics that could account for the load growth above the historical relationship between load growth and population growth?

A38.6 We have not analyzed the impact of demographics in detail. The forecast model only correlates the account numbers (Residential and General Service class) and energy (Wholesale class) to the overall population numbers.

BCUC A38.2

annual growth (accounts/year) 0.454624277

Year	Res Customers	WKP POP Update	
1977	43270		
1978	45059	190397	
1979	46423	193754	
1980	48522	197169	
1981	50463	200292	
1982	52236	200553	
1983	53369	200814	
1984	52620	201075	
1985	52838	201337	
1986	53200	201596	
1987	54516	202796	
1988	55658	205541	
1989	57544	210463	
1990	59971	218432	
1991	62258	226133	
1992	65203	236146	
1993	67748	245372	
1994	70061	253848	
1995	71844	259406	
1996	73413	264175	
1997	74934	267856	
1998	76172	269961	
1999	77101	270923	
2000	78008	271788	1.01176379
2001	79121	272845	1.014267767
2002	80275	274402	1.014585255
2003	82174	275772	1.023656182
2004	84076	277630	1.023146007
2005	85926	279806	1.022
2006	87645	282261	1.02
2007	89223	284969	1.018
2008	90695	287854	1.0165
2009	92101	290947	1.015502508
2010	93597	294238	1.016243038
2011	95144	297640	1.016528308
2012	96727	301122	1.016637938
2013	98370	304737	1.01698595
2014	100081	308501	1.017393514
2015	101795	312271	1.017126128
2016	103475	315966	1.016503758
2017	105149	319649	1.016177821
2018	106774	323224	1.01545426
2019	108383	326763	
2020	109974	330262	
2021	111530	333684	
2022	113103	337143	
2023	114662	340573	

manually adjusted rate
manually adjusted rate
manually adjusted rate
manually adjusted rate

BCUC A38.2

annual growth (acc) **0.050867052**

X2

Customer
accounts based
on the LT trend

Year Com Customers WKP Pop Update

1978	4907	190397		
1979	5112	193754		
1980	5349	1971694		
1981	5578	200292		
1982	5806	200553		
1983	5678	200814		
1984	5894	201075		
1985	6141	201337		
1986	6210	201596		
1987	6285	202796		
1988	6633	205541		
1989	6922	210463		
1990	7007	218432		
1991	7242	226133		
1992	7566	236146		
1993	7766	245372		
1994	7968	253848		
1995	7888	259406		
1996	8041	264175		
1997	8195	267856		
1998	8378	269961		
1999	8512	270923		
2000	8700	271788	1.022086466	
2001	8974	272845	1.031494253	
2002	9153	274402	1.019946512	
2003	9433	275772	1.030591063	
2004	9929	277630	1.052581363	
2005	10306	279806	1.038 manually adjusted rate	10040
2006	10564	282261	1.025 manually adjusted rate	10431
2007	10754	284969	1.018 manually adjusted rate	10702
2008	10915	287854	1.015 manually adjusted rate	10901
2009	11072	290947	1.014383875	11072
2010	11239	294238	1.015083092	11239
2011	11412	297640	1.015392829	11412
2012	11589	301122	1.015509989	11589
2013	11773	304737	1.015877125	11773
2014	11964	308501	1.016223562	11964
2015	12156	312271	1.016048144	12156
2016	12344	315966	1.015465614	12344
2017	12531	319649	1.01514906	12531
2018	12713	323224	1.014523981	12713
2019	12893	326763	1.014158735	12893
2020	13071	330262	1.013805941	13071
2021	13245	333684	1.013311912	13245
2022	13421	337143	1.013288033	13421
2023	13595	340573	1.012964757	13595

BCUC A38.2

annual growth (MWh) **3.9517**

Wholesale Energy
based on the LT
trend

Year	WS Load MWh	WKP Pop Update		
1981	607,961.90	200292	1.058546145	
1982	632,548.00	200553	1.040440199	
1983	616,541.00	200814	0.966968673	
1984	648,474.90	201075	1.06019873	
1985	681,991.00	201337	1.051684499	
1986	632,719.00	201596	0.927752712	
1987	652,913.00	202796	1.031916222	
1988	694,765.00	205541	1.064100424	
1989	714,069.00	210463	1.027784934	
1990	740,445.00	218432	1.036937607	
1991	756,297.00	226133	1.021408747	
1992	767,546.00	236146	1.014873786	
1993	803,759.00	245372	1.047180234	
1994	813,561.00	253848	1.012195198	
1995	829,361.00	259406	1.019420793	
1996	875,648.00	264175	1.055810437	
1997	843,527.00	267856	0.963317452	
1998	837,462.00	269961	0.992809952	
1999	847,369.00	270923	1.01182979	
2000	863,388.60	271788	1.018905102	
2001	882,528.22	272845	1.022168032	
2002	876,903.37	274402	0.993626432	
2003	910,657.40	275772	1.038492306	
2004	942530.41	277630	1.035 manually adjusted rate	917999.657
2005	966093.67	279806	1.025 manually adjusted rate	951129.3059
2006	983483.36	282261	1.018 manually adjusted rate	975795.0898
2007	998235.61	284969	1.015 manually adjusted rate	994184.5554
2008	1011212.67	287854	1.013 manually adjusted rate	1009636.256
2009	1023435.272	290947	1.012087259	1023435.272
2010	1036440.309	294238	1.012707434	1036440.309
2011	1049883.983	297640	1.012971204	1049883.983
2012	1063643.794	301122	1.013106226	1063643.794
2013	1077929.181	304737	1.013430809	1077929.181
2014	1092803.37	308501	1.013799057	1092803.37
2015	1107701.269	312271	1.013632931	1107701.269
2016	1122302.792	315966	1.01318201	1122302.792
2017	1136856.894	319649	1.012968252	1136856.894
2018	1150984.212	323224	1.012426818	1150984.212
2019	1164969.269	326763	1.012150686	1164969.269
2020	1178796.259	330262	1.011869133	1178796.259
2021	1192318.968	333684	1.011471778	1192318.968
2022	1205987.889	337143	1.011464299	1205987.889
2023	1219542.212	340573	1.011239332	1219542.212

BCUC A38.2

Year	Residenti al Count	Commerc ial Count	Residenti al Sales	Commer cial Sales	WS Sales MWh	Ind Sales (MWh)	System Sales GWh	Res UPC	Com UPC
1977	43270	5171	533708	201533	498,406.00	137252	1546.8	12.33	38.97
1978	45059	4907	576227	211250	522,926.00	133035	1621.8	12.79	43.05
1979	46423	5112	619083	237734	484,017.40	122927	1583.5	13.34	46.51
1980	48522	5349	636750	246221	574,336.70	171987	1688.7	13.12	46.03
1981	50463	5578	658684	264946	607,961.90	245036	1837.8	13.05	47.50
1982	52236	5806	666827	392690	632,548.00	147210	1938.4	12.77	67.64
1983	53369	5678	678014	385619	616,541.00	155750	1894.5	12.70	67.91
1984	52620	5894	731995	409915	648,474.90	126835	1966.9	13.91	69.55
1985	52838	6141	765000	420538	681,991.00	148522	2075.8	14.48	68.48
1986	53200	6210	720643	293520	632,719.00	279799	1982.5	13.55	47.27
1987	54516	6285	681513	298364	652,913.00	360227	2054.5	12.50	47.47
1988	55658	6633	740395	318720	694,765.00	417358	2230	13.30	48.05
1989	57544	6922	768263	336938	714,069.00	454859	2327.8	13.35	48.68
1990	59971	7007	813203	351957	740,445.00	458782	2412.3	13.56	50.23
1991	62258	7242	845530	362862	756,297.00	432662	2452	13.58	50.11
1992	65203	7566	849894	378200	767,546.00	425934	2479.5	13.03	49.99
1993	67748	7766	930646	408720	803,759.00	490858	2679.6	13.74	52.63
1994	70061	7968	888748	399523	813,561.00	367778	2525	12.69	50.14
1995	71844	7888	932515	425322	829,361.00	327062	2572	12.98	53.92
1996	73413	8041	1003817	464575	875,648.00	312807	2711.2	13.67	57.78
1997	74934	8195	939734	459436	843,527.00	289310	2580.5	12.54	56.06
1998	76172	8378	937869	482777	837,462.00	262814	2580.9	12.31	57.62
1999	77101	8512	944808	484801	847,369.00	273408	2607.2	12.25	56.96
2000	78008	8700	985000	512000	840,000.00	290000	2682	12.63	58.85
2001	79121	8974	986000	514000	857,000.00	323000	2733	12.46	57.28
2002	80421	9153	997000	517000	873,000.00	347000	2791	12.40	56.48
2003	82174	9433	1005000	516000	915,000.00	338000	2834	12.23	54.70
2004	84076	9929						12.20	

BCUC A38.5

Year	Residential Customers with decoupling	Residential Customers without decoupling	Temperature Corrected Residential UPC	Residential load with decoupling	Residential load without decoupling	Difference (MWh)
2004	84076	84076	12471.98967	1048595.003	1048595.003	0
2005	85926	85065	12404.88967	1065902.549	1055221.939	10680.61
2006	87645	87042	12337.78967	1081345.575	1073905.888	7439.687168
2007	89223	88876	12270.68967	1094827.744	1090569.815	4257.929314
2008	90695	90535	12203.58967	1106804.565	1104851.99	1952.574347
2009	92101	92101	12136.48967	1117782.835	1117782.835	0
2010	93597	93597	12069.38967	1129658.665	1129658.665	0
2011	95144	95144	12002.28967	1141945.848	1141945.848	0
2012	96727	96727	11935.18967	1154455.091	1154455.091	0
2013	98370	98370	11868.08967	1167463.98	1167463.98	0
2014	100081	100081	11800.98967	1181054.847	1181054.847	0
2015	101795	101795	11733.88967	1194451.299	1194451.299	0
2016	103475	103475	11666.78967	1207221.061	1207221.061	0
2017	105149	105149	11599.68967	1219695.769	1219695.769	0
2018	106774	106774	11532.58967	1231380.729	1231380.729	0
2019	108383	108383	11465.48967	1242664.166	1242664.166	0
2020	109974	109974	11398.38967	1253526.505	1253526.505	0
2021	111530	111530	11331.28967	1263778.736	1263778.736	0
2022	113103	113103	11264.18967	1274013.644	1274013.644	0
2023	114662	114662	11197.08967	1283880.695	1283880.695	0

BCUC A38.5

Year	General Service Customers with decoupling	General Service Customers without decoupling	Temperature Corrected General Service UPC	General Service load with decoupling	General Service load without decoupling	Difference (MWh)
2004	9929	9929	55530.59255	551363.2534	551363.2534	0
2005	10306	10040	55556.59255	572566.2428	557788.1892	14778.05362
2006	10564	10431	55582.59255	587174.5077	579782.0229	7392.484809
2007	10754	10702	55608.59255	598014.8043	595123.1575	2891.646813
2008	10915	10901	55634.59255	607251.5777	606472.6934	778.8842957
2009	11072	11072	55660.59255	616274.0807	616274.0807	0
2010	11239	11239	55686.59255	625861.6137	625861.6137	0
2011	11412	11412	55712.59255	635792.1062	635792.1062	0
2012	11589	11589	55738.59255	645954.549	645954.549	0
2013	11773	11773	55764.59255	656516.5481	656516.5481	0
2014	11964	11964	55790.59255	667478.6493	667478.6493	0
2015	12156	12156	55816.59255	678506.499	678506.499	0
2016	12344	12344	55842.59255	689320.9624	689320.9624	0
2017	12531	12531	55868.59255	700089.3332	700089.3332	0
2018	12713	12713	55894.59255	710587.9551	710587.9551	0
2019	12893	12893	55920.59255	720984.1997	720984.1997	0
2020	13071	13071	55946.59255	731277.9112	731277.9112	0
2021	13245	13245	55972.59255	741356.9883	741356.9883	0
2022	13421	13421	55998.59255	751557.1106	751557.1106	0
2023	13595	13595	56024.59255	761654.3357	761654.3357	0

BCUC A38.5

Year	Temperature Corrected Wholesale Load with decoupling (MWh)	Temperature Corrected Wholesale Load without decoupling (MWh)	Difference (MWh)
2004	942530.4122	917999.657	24530.76
2005	966093.6725	951129.3059	14964.37
2006	983483.3586	975795.0898	7688.27
2007	998235.6089	994184.5554	4051.05
2008	1011212.672	1009636.256	1576.42
2009	1023435.272	1023435.272	0.00
2010	1036440.309	1036440.309	0.00
2011	1049883.983	1049883.983	0.00
2012	1063643.794	1063643.794	0.00
2013	1077929.181	1077929.181	0.00
2014	1092803.37	1092803.37	0.00
2015	1107701.269	1107701.269	0.00
2016	1122302.792	1122302.792	0.00
2017	1136856.894	1136856.894	0.00
2018	1150984.212	1150984.212	0.00
2019	1164969.269	1164969.269	0.00
2020	1178796.259	1178796.259	0.00
2021	1192318.968	1192318.968	0.00
2022	1205987.889	1205987.889	0.00
2023	1219542.212	1219542.212	0.00

FortisBC Inc.
2005 Revenue Requirements Application,
2005-2024 System Development Plan and 2005 Resource Plan

Q39.0 Reference: Volume 1, Tab 7.1, p. 2

“The 2005 load forecast is based on the population growth forecast generated by BC Stats and customized for the FortisBC service area. ...Industry specific information collected from major local industrial customers was used to forecast the volumes of industrial load.”

For what fraction of the total industrial load was a customer-supplied forecast available?

A39.0 The industry specific information was collected only from Celgar Pulp. It is the single biggest industrial customer in the service area. At the time of the forecast the similar type of information was not readily available from other industrial customers. Anecdotal information was also provided by key account representatives. Celgar Pulp was factored in the forecast with an annual consumption of 65 GWh, constant throughout the forecast period. This value represents the view of the plant operation by their Management at the time of the forecast.

In 2003 Celgar load accounted for 17 percent of the total industrial load in the area.
