



## **2005 Revenue Requirements**

### **7. Forecasts**

#### **7.3 Power Purchase and Wheeling Forecast**

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## 1 Introduction

This 2005 Power Purchase Forecast includes an estimate of 2004 power purchase expenses based on “actuals” through September, with an estimate for October through December, and a forecast of expenses for 2005 (see Tables 7.1 and 7.2 attached).

### 1. Review of 2004

The winter of 2003/2004 saw slightly below normal snow pack throughout the Columbia River Basin with the 2004 summer run-off being normal due to August and September rains. Above average natural gas prices continued to support strong energy prices with no significant relief anticipated in the near-term.

This year's peak period market purchase prices have been lower than forecast while off-peak summer surplus prices were higher than forecast. These positive market price impacts combined with favourable TeckCominco capacity contracts, BC Hydro capacity savings, and improved exchange rates have resulted in savings of approximately \$2.24 million compared to the load adjusted plan. Severe winter weather was experienced over the New Year's long weekend with a record system peak of 718 MW being set on January 5, 2004.

There was a normal program of annual generator maintenance and a few forced outages, both of which were provided for in the 2004 forecast. There were also capital projects requiring outages, including life extension and upgrade work at Upper Bonnington Unit 5 which was completed in March 2004 and the Upper Bonnington Unit 6 life extension which should be completed in December 2004. In addition, the Kootenay 230 kV System Development Project included improvements at the generating plants and switchyards which necessitated outages. Overall, the capital projects resulted in a total of approximately 240 days of unit outages at various plants. The increased power purchase costs that resulted from these projects were offset with a charge against the capital cost of

1 the projects and therefore did not impact the power purchase expense. (see Line 87 of  
2 Table 7.1)

## 3 4 **2. Power Purchases**

5  
6 Tables 7.1 and 7.2 set out power purchase volumes and expenses for 2004 (actuals  
7 through September, with projections through to the end of the year) along with a forecast  
8 of volumes and associated expenses for 2005.

9 The Company's resource acquisition policy continues to be to meet the customer's load  
10 requirements at low cost with minimal environmental impacts, while recognizing  
11 ongoing uncertainties as outlined below.

### 12 13 **A. Power Purchase Uncertainty**

#### 14 **Load Uncertainty**

15  
16  
17 The Company's Transmission Access Tariff ("Tariff") was approved by a Commission  
18 Decision dated March 10, 1999. The Tariff provides Eligible Customers, including all  
19 wholesale customers and a number of the Company's major industrial customers, with  
20 the opportunity to take supply from third parties located either within or outside the  
21 Company's service territory. The Company has contracts with its wholesale customers  
22 which allow the wholesale customers to move to third party supply with relatively short  
23 notice. This introduced some uncertainty related to the Company's future load  
24 obligation, which impacts the decision of whether or not to take advantage of  
25 opportunities to enter into long-term power supply contracts.

26  
27 Combined with this consideration is the usual uncertainty associated with forecasting  
28 future load growth. The Customer and Load Forecast can be found at Volume 1, Tab 7,  
29 subsection 7.

**Resource Uncertainty**

The Company has long-term, firm resources from which it can supply over 98 percent of the annual energy requirements. The small shortfall is due to system capacity constraints during peak load days

Due to the uncertainty associated with loads, and because the amounts of energy required to supply the peak are small, the Company continues to rely on short term purchases from the market to meet the shortfall. Advance purchases of winter capacity or energy block purchases are generally made to minimize or reduce real-time purchases from the market and have been assumed in this forecast (see below). A Resource Planning Study is underway to assess this strategy and the Company's long-term needs

The Canal Plant Agreement ("CPA") issues concerning base and upgrade entitlement (reported in our 2004 Revenue Requirements submission) have been negotiated with BC Hydro and is presently undergoing an approval process, after which it will be filed with the BC Utilities Commission. FortisBC will receive increased entitlements for Unit 5 at Upper Bonnington, as well as the previously completed upgrades: Unit 2 at South Slocan and Unit 2 at Lower Bonnington (see below for summary). The generation life extension program, which may include turbine upgrades in some cases, is planned to continue over the next number of years and may add further to the entitlements. This is discussed further in the 2005 Capital Plan at Tab 9.

**B. Power Purchase Costs**

Power purchase costs in the forecast have been determined using contract prices plus a forecast of future market prices.



1 The Company has firm supply contracts which include the Brilliant Power Purchase  
2 Agreement (a 125 MW contract terminating in 2056) an amendment to the Brilliant  
3 Power Purchase Agreement which reflects the purchase of the Brilliant Upgrade power  
4 (20 MW); a number of small Independent Power Producer contracts, and a 200 MW  
5 contract with BC Hydro under BC Hydro Schedule 3808 that terminates September 30,  
6 2013. For 2005 maximum use of the BC Hydro contract is being made with a capacity  
7 nomination of 200 MW.

### 8 9 **Brilliant Power Purchase Agreement**

10  
11 The Company purchases power under both the Brilliant Power Purchase Agreement and  
12 under the Brilliant Power Purchase Second Amendment Agreement, both of which have  
13 been approved by the Commission. The prices paid under the former are based on  
14 forecasts from the owner, Columbia Power Corporation, of the annual operating and  
15 maintenance costs and sustaining capital charges for the plant.

16  
17 The price for the latter is as follows: for the unregulated-flow component of the upgrade  
18 power, price is based on a forecast of the all-in capital cost of the upgrades. For the  
19 regulated-flow component, price is tied to BC Hydro Rate Schedule 3808. Power from  
20 the base plant and from the unregulated-flow component of the upgrade includes capacity  
21 and energy in the form of entitlements under the Canal Plant Agreement and are take or  
22 pay. The regulated flow component is entitlement energy only, is not take or pay, and is  
23 recallable by the owner on 90 days notice.

Forecast of the prices for these various categories are as follows:

**Table 7.2 B**

	<b>Energy</b>	<b>2004</b>	<b>2005</b>
1	Base (mills/kW.h)	31.68	31.24
2	% Change		(1.4%)
3	Upgrade - unregulated	24.26	20.71
4	% Change		(14.6%)
5	Upgrade – regulated	26.91	27.25
6	% Change		1.3%

This price for 2005 in the base component includes a “true-up” adjustment for prior years, which is the difference between the forecast and actual costs as allowed under the Agreements. In the past, for these Agreements, the Company has consistently flowed any difference between forecast and actual costs through to the customer. For 2005 the adjustment amounts to a decrease in costs of \$1.68 million, based on the difference between forecast and actual costs for 2003.

The Company proposes that this “flow-through” treatment continue in the future.

The upgrade regulated-flow rate for 2004 is an average for the year and includes the interim BC Hydro rate increase of 7.23 percent on April 1. Since the approved BC Hydro rate increase is now 4.85 percent instead of 7.23 percent there will be a small overcharge in the 2004 Power Purchase Expense which has been applied as a flow-through reduction to the 2005 costs, as described in Section 4 below.

The regulated-flow rate for 2005 is tied to the BC Hydro rate and incorporates the 4.85 percent increase instead of the 7.23 percent.

1 **Independent Power Producers (IPPs)**  
2

3 The Company has five small power purchase contracts with Independent Power  
4 Producers, at different rates, and the rate forecast used to calculate power purchase  
5 expenses is a composite of the cost of the expected power from these contracts.  
6

7 No change in the rate is forecast for 2005 as set out below.  
8

**Table 7.2 C**

1	<b>Energy</b>	<b>2004</b>	<b>2005</b>
2	Volume (GW.h)	16.50	26.00
3	% Change		57.8%
4	Mills/kW.h	25.85	25.87
5	% Change		0.0%

9  
10 **BC Hydro**  
11

12 The rates under our Power Purchase Agreement with BC Hydro (under Rate Schedule  
13 3808) are shown in the table below:  
14

**Table 7.2 D**

1	<b>Energy</b>	<b>2004</b>	<b>2005</b>
2	Mills/kW.h	27.16	27.25
3	% Change		0.3%
4	<b>Capacity</b>		
5	\$/MW-Month	4,642	4,625
6	% Change		(0.4%)

The rates shown in 2004 are the average rates for the year, including an interim rate increase of 7.23 percent effective April 1, 2004. Since the final rate increase is now 4.85 percent, there is a flow-through adjustment required and this has been used to reduce 2005 costs.

15

**Market Purchases**

Small amounts of energy are required to be purchased from the market for peak load days because of capacity constraints.

The strategy is generally to purchase part of these market requirements several months in advance of the winter peak and, to avoid over-purchasing, leave the remainder to the spot market.

**Market Purchases Made in Advance**

Recently, cost-effective capacity block purchases from TeckCominco have been available and have been purchased through the winter of 2004/05. There is an expectation that the Company will be able to purchase capacity blocks for the following winter as well, although a price has not yet been negotiated. These capacity block purchases are included in the forecast for November and December 2005 at a price estimate based on the forecast price differential between heavy-load hour and light-load hour energy blocks.

The forecast is taken from the November 16, 2004 "Avista Energy Distributed Report" and also the "Energy Market Report", an Economic Insight Publication.

The Company proposes to flow-through the difference between the estimated price and the final price of these November-December 2005 capacity blocks.

The following is a summary of capacity purchases from TeckCominco that have been made or planned:

1

**Table 7.2 E**

	<b>Month</b>	<b>Amount (MW)</b>	<b>Cost (\$CAN)</b>	<b>\$/MW</b>
1	January 2004	100	499,000	4,990
2	February	50	277,000	5,540
3	November	25	97,000	3,880
4	December	100	387,000	3,870
5	January 2005	100	404,000	4,040
6	February	25	101,000	4,040
7	November (estimate)	25	163,000	6,520
8	December (estimate)	100	654,000	6,540

2 In addition to the above capacity purchases, the Company has purchased a 50 MW Pre-  
3 Schedule Call Option from Avista Energy at \$26,000 per month for November 2004  
4 through February 2005. This charge is a standby fee for capacity only. Energy taken is at  
5 110 percent of the Daily Dow Jones Mid-C Firm on-peak high price which is forecast at  
6 \$129.60 and \$119.21/MW.h for January and February respectively based on the Avista  
7 Energy report. Any energy expected to be required must be pre-scheduled by 06:00 hrs  
8 “day-ahead”.

9

10 A call option purchase of 25 MW has been assumed for December at the same capacity  
11 rate, with energy rates forecast at \$131.42.

12

### 13 **Spot Market Purchases**

14

15 Any remaining requirements will be purchased day-ahead or in real-time with the rates  
16 forecast as follows:

17

**Table 7.2 F**

	<b>Energy</b>	<b>2004</b>	<b>2005</b>
1			
2	Mills/kW.h	87	113
3	% Change		30%

18

1 The 2004 and 2005 rates include the call-option energy. The 2005 rates are based on the  
 2 energy block rates forecast in the Avista Energy report with an adjustment to account for  
 3 the fact that these purchases are made for the most valuable hours in the energy block.

4  
 5 Overall the costs of purchases from the market, including advance and spot purchases,  
 6 are expected to be about \$2.15 million compared to about \$3.23 million in 2004. Even  
 7 though spot rates, advance purchase rates and loads are forecast to be higher, less energy  
 8 is expected to be required from the market in 2005 due to increased capacity resources  
 9 and slightly lower forecasted peaks in critical months.

### 11 3. Summer Surplus

12  
 13 The Company generally has small amounts of surplus available in the months of May,  
 14 June and July because its firm resources, including the entitlements under the Canal Plant  
 15 Agreement, exceed the load in that period.

16  
 17 The Pacific Northwest Region experienced less than expected early run-off and higher  
 18 than expected natural gas prices in 2004 leading to higher than forecast prices for our  
 19 summer surplus. For 2005, summer surplus volumes will be reduced mainly due to  
 20 higher loads forecast for that period, compared to 2004. Prices are also expected to be  
 21 lower, based on the Avista and the Energy Market Report forecasts for that period, for  
 22 the light load hours.

23 **Table 7.3 A**

1	Energy	2004	2005
2	Volume (GW.h)	66.30	19.20
3	% Change		(71.0%)
4	Mills/kW.h	46.75	38.67
5	% Change		(17.3%)

24  
 25 Overall the revenue from summer surplus sales is expected to drop to approximately  
 26 \$744,000 in 2005 from approximately \$3.1 million in 2004 (both figures are gross

1 revenue before wheeling costs). This is due to the combined effect of the expected  
2 reduction in volume and price.

#### 3 4 **4. Power Purchase Mechanism for 2004 and 2005**

5 A sharing mechanism is applicable to 2004 Power Purchase Expenses as follows:  
6  
7

8  
9 In accordance with Commission Order G-134-99, the Company and customers will share  
10 in certain power purchase costs or savings. The Company is responsible for the power  
11 purchase variances resulting from load variations. This is the difference between the  
12 Forecast Power Purchase Expense ("FPPE") and the Adjusted Power Purchase Expense  
13 ("APPE").  
14

15 The APPE is simply the FPPE going into the test year with forecast loads replaced with  
16 actual loads. The difference between the adjusted and the actual power purchase expense  
17 (the price variance) is shared between the customers and the Company.  
18

19 The sharing mechanism is set so that any resulting costs or savings up to \$1.0 million is  
20 shared 65 percent to customers and 35 percent to the Company. For savings in excess of  
21 \$1.0 million, the sharing is 75 percent to customers and 25 percent to the Company.  
22

23 The Company is proposing to continue this mechanism in 2005.  
24

25 Table 7.4A shows the preliminary incentive calculation for 2004. It also includes a  
26 reduction to 2004 Power Purchase Expense arising from the Commission Order reducing  
27 the 2004 BC Hydro rate increase from an interim increase of 7.23 percent effective April  
28 1, 2004, to firm increase of 4.85 percent effective the same date. BC Hydro rate changes  
29 are treated as flow-through. Also included is a reduction for the costs related to the  
30 Brilliant Upgrades (Regulated) which is indexed to the BC Hydro rate as described  
31 previously.



1 **5. Summary**  
2

3 The 2005 Power Purchase Expense is forecast at \$62.64 million compared to \$60.39  
4 million estimated for 2004. The increase is due to the forecast load increase and reduced  
5 summer surplus, offset by an increase in resources under the Canal Plant Agreement  
6 Entitlement Adjustment Agreement and a reduction in the Brilliant Power Purchase rates.

7 **Table 7.5**  
8 **Total Power Purchase Expense**  
9 **(\$000)**

	<u>2004</u>	<u>2005</u>	<u>Difference</u>
1 Surplus Revenues	(3,048)	(705)	2,342
2 Brilliant	30,482	29,828	(654)
3 BC Hydro	31,551	30,896	(655)
4 Market Spot Purchase & Com Capacity	3,228	2,152	(1,076)
5 Independent Power Producers	426	673	247
6 Upgrade Life Extension Credit Adjustment	(1,761)	(200)	1,561
7 * Special & Accounting Adjustments	(489)	-	489
8 <b>TOTAL</b>	<u>60,389</u>	<u>62,644</u>	<u>2,225</u>
9 * Includes the overcharges for BC Hydro and the regulated-flow component of the Brilliant 10 Upgrade purchase. See Line 88 in Table 7.1			

**6. Wheeling Expenses**

The 2005 Wheeling Expense Forecast includes an estimate of 2004 expenses based on actuals through September and an estimate of the remaining expenses. The expenses include wheeling service provided by BC Hydro under the General Wheeling Agreement (“GWA”) made in 1986 and also wheeling provided by BC Hydro under its wholesale transmission tariff, as needed to supply the Company’s loads in the Okanagan from Vernon, at Creston and at Princeton.

Rates under the General Wheeling Agreement are specified in BC Hydro’s filed Rate Schedule 3817. In 2005, GWA costs are forecast to account for all but \$80,000 (2%) of the total wheeling expense.

The expenses are forecast to increase slightly from approximately \$3.785 million in 2004 to approximately \$3.878 million in 2005.

The increase is to allow increased deliveries to the Okanagan owing to expected load growth and at Princeton to allow for greater operating flexibility.

1

**Table 7.6.1**  
**Analysis Of Forecast Wheeling Expense**  
**For The Year Ending December 31, 2004**  
**BC Hydro Wheeling Schedule 3817**

	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC	TOTAL
1													
2													
3													
4													
5	<b>NOMINATION (MW)</b>												
6	- Vernon	155	155	155	155	155	155	155	155	160	160	160	
7	- Creston	32	32	32	32	32	32	32	32	33	33	33	
8	<b>RATE (\$/MW/Month)</b>												
9	- Vernon	1,782	1,782	1,782	1,782	1,782	1,782	1,782	1,782	1,782	1,782	1,782	21,384
10	- Creston	1,032	1,032	1,032	1,032	1,032	1,032	1,032	1,032	1,032	1,032	1,032	12,384
11	<b>COST (\$000)</b>												
12	- Vernon	\$276	\$276	\$276	\$276	\$276	\$276	\$276	\$276	\$285	\$285	\$285	\$3,341
13	- Creston	\$33	\$33	\$33	\$33	\$33	\$33	\$33	\$33	\$34	\$34	\$34	\$399
14	<b>EXCESS WHEELING COSTS (\$000)</b>												
15													
16	BC Hydro Ad Hoc	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$5
17	Purchase Wheeling												
18	Costs												
19	PRINCETON WTS												
20	Wheeling	\$4	\$1	\$0	\$0	\$0	\$11	\$24	\$0				\$40
21	<b>TOTAL WHEELING COSTS (\$000)</b>												
22		\$314	\$310	\$310	\$310	\$310	\$321	\$333	\$310	\$310	\$320	\$320	\$3,785

**Table 7.6.2**  
**Analysis Of Forecast Wheeling Expense**  
**For The Year Ending December 31, 2005**  
**BC Hydro Wheeling Schedule 3817**

	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC	TOTAL
1													
2													
3													
4													
5													
6	<b>NOMINATION (MW)</b>												
7	- Vernon/Okanagan	160	160	160	160	160	160	160	160	160	160	160	160
8	- Creston	33	33	33	33	33	33	33	33	33	33	33	33
9	<b>RATE (\$/MW/Month)</b>												
10	- Vernon/Okanagan	1,782	1,782	1,782	1,782	1,782	1,782	1,782	1,782	1,782	1,782	1,583	21,185
11	- Creston	1,032	1,032	1,032	1,032	1,032	1,032	1,032	1,032	1,032	1,032	1,032	12,384
12	<b>COST (\$000)</b>												
13	- Vernon/Okanagan	\$285	\$285	\$285	\$285	\$285	\$285	\$285	\$285	\$285	\$285	\$253	\$3,390
14	- Creston	\$34	\$34	\$34	\$34	\$34	\$34	\$34	\$34	\$34	\$34	\$34	\$409
15	<b>EXCESS WHEELING COSTS (\$000)</b>												
16													
17	BC Hydro Ad Hoc	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$5
18	Purchase Wheeling												
19	Costs												
20	PRINCETON WTS												
21	Wheeling					\$25	\$25	\$25					\$75
22	<b>TOTAL WHEELING COSTS (\$000)</b>												
23													
24		\$320	\$320	\$320	\$320	\$345	\$345	\$345	\$320	\$320	\$320	\$288	\$3,878

**POWER PURCHASE EXPENSE FOR 2004**

**TABLE 7.1**

2004 ANALYSIS OF FORECAST POWER PURCHASE EXPENSE FOR THE YEAR ENDING DECEMBER 31, 2004														23-Nov
	2	3	4	5	6	7	8	9	10	11	12	13		
	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC	TOTAL	
<b>ENERGY GW.h</b>	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Estimated	Forecast	Forecast		
FortisBC	117.869	118.724	148.282	119.630	113.809	127.728	138.346	101.622	94.815	127	135	140	1483.262	
Brilliant Base Plant	79.585	57.475	52.118	76.081	82.569	75.628	84.542	85.047	78.995	62	60	63	856.740	
Brilliant Upgrade	3.000	1.968	2.200	9.000	7.500	10.700	8.200	11.100	3.200	3	3	3	65.168	
Brilliant Regulated	6.900	6.836	4.600	3.200	6.600	2.700	5.800	3.100	-1.400	0	11	11	60.436	
TeckCominco	0.260	1.635	0.696	0.000	0.000	0.000	0.036	0.000	0.000	0	0	0	2.627	
Small Misc IPP Resource	1.070	1.563	0.831	0.534	0.494	0.467	0.848	3.109	3.160	1	2	2	16.476	
Market Capacity - ENERGY	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0	0	0	0.336	
Call Option	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0	2	3	4.723	
DSM	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0	1	1	2.487	
City of Nelson Special Adjustment	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0	0	0	0.000	
Turbine Upgrades	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0	0	0	0.000	
Market Energy Purchase	2.188	0.306	0.932	0.000	0.000	2.595	0.445	1.780	0.452	1	0	0	9.208	
BCH Purchase	132.573	106.419	65.520	24.292	29.527	52.316	44.989	48.270	42.824	58.4	85	118	808.324	
Gross Load	343.445	294.926	275.179	232.737	224.999	240.604	263.946	254.028	222.046	252.1	298	341	3243.497	
Surplus	0.000	0.000	0.000	0.000	15.500	31.530	19.260	0.000	0.000	0	0	0	66.290	
<b>RATE (Mills/kW.h)</b>													Pwr Pur = 1824.038	
Surplus Rate	65.12	63.95	59.26	34.55	44.98	47.86	46.37	45.07	43.72	58.05	63.01	66.10		
Brilliant Base Plant	31.6832	31.6832	31.6832	31.6832	31.6832	31.6832	31.6832	31.6832	31.6832	31.6832	31.6832	31.6832		
Brilliant Upgrade	24.2632	24.2632	24.2632	24.2632	24.2632	24.2632	24.2632	24.2632	24.2632	24.2632	24.2632	24.2632		
Brilliant Regulated	26.0000	26.0000	26.0000	27.8700	27.8700	27.8700	27.87	27.8700	27.8700	27.8700	27.8700	27.8700		
Call Option	75.86	76.41	71.05	60.29	48.35	46.14	65.46	77.38	72.73	65.25	123.81	138.37		
Market Rate	82.53	58.41	54.63			77.32	85.28	60.24	23.74	83.93	112.55	125.79		
BCH : Purchase	25.99	25.99	25.99	27.87	27.87	27.87	27.87	27.87	27.87	27.87	27.87	27.87		
IPP Rate	26.37	25.96	25.62	25.39	22.58	23.93	23.85	25.75	25.90	26.61	26.85	26.78		
<b>ENERGY EXPENSE (\$000)</b>														
Surplus Revenue	\$0.000	\$0.000	\$0.000	\$0.000	(\$697.167)	(\$1,509.010)	(\$893.105)	\$0.000	\$0.000	\$0	\$0	\$0	(\$3,099.282)	
Brilliant Base Plant	\$2,521.983	\$1,896.502	\$1,669.705	\$2,433.270	\$2,617.032	\$2,398.418	\$2,683.567	\$2,696.240	\$2,506.141	\$1,968	\$1,895	\$1,990	\$27,274.745	
Brilliant Upgrade	\$72.790	\$47.747	\$53.379	\$218.369	\$181.974	\$259.616	\$198.958	\$269.322	\$77.642	\$70	\$63	\$68	\$1,581.181	
Brilliant Regulated	\$179.348	\$159.295	\$115.362	\$88.348	\$183.886	\$75.193	\$161.395	\$86.341	(\$38.962)	\$6	\$301	\$309	\$1,626.133	
Call Option	\$0	\$0	\$0.000	\$0.000	\$0.000	\$0.000	\$0.000	\$0.000	\$0.000	\$0	\$233	\$393	\$626.139	
IPP Costs	\$28.216	\$40.576	\$21.286	\$13.560	\$11.156	\$11.177	\$20.223	\$80.050	\$81.841	\$29	\$40	\$48	\$425.836	
BCH Purchase	\$3,445.572	\$2,765.830	\$1,702.865	\$677.018	\$822.917	\$1,458.047	\$1,253.843	\$1,345.285	\$1,193.505	\$1,627	\$2,370	\$3,293	\$21,955.500	
Market Purchase	\$202.022	\$113.365	\$88.942	\$0.000	\$0.000	\$200.644	\$41.019	\$107.235	\$10.733	\$43	\$5	\$36	\$848.352	
Surplus	\$6,449.931	\$5,023.314	\$3,651.539	\$3,430.564	\$3,119.800	\$2,894.086	\$3,465.901	\$4,584.473	\$3,830.900	\$3,743	\$4,908	\$6,137	\$51,238.604	

**Table 7.1 cont'd**

	ANALYSIS OF FORECAST POWER PURCHASE EXPENSE FOR THE YEAR ENDING DECEMBER 31,													23-Nov
	2	3	4	5	6	7	8	9	10	11	12	13	TOTAL	
	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC	TOTAL	
46														
47 <b>CAPACITY (MW)</b>														
48 FortisBC	175	172	171	186	180	172	183	179	180	181	181	183	2141	
49 Brilliant Base Plant	122	87	87	118	112	105	114	118	118	118	122	122	1345	
50 Brilliant Upgrade	20	20	20	20	20	20	20	20	20	20	20	20	238	
51 TeckCominco	9	39	71	13	0	3	10	0	0	0	0	0	145	
52 Market Capacity	105	20	0	0	0	65	30	55	0	10	10	30	326	
53													0	
54 Call Option	0	0	0	0	0	0	0	0	0	0	50	50	100	
55 DSM	0	0	0	0	0	0	0	0	0	2	2	2	6	
56	0	0	0	0	0	0	0	0	0	0	0	0	0	
57 Turbine Upgrades	0	0	0	0	0	0	0	0	0	0	0	0	0	
58 TeckCominco Market Capacity	100	50	0	0	0	0	0	0	0	0	25	100	275	
59	0	0	0	0	0	0	0	0	0	0	0	0	0	
60 BCH : Billing Capacity	206.4	189.0	166.0	154.8	154.8	157.0	172.0	160	155	163	170	185	2033	
61 BCH : Used for Load	187	180	156	85	81	136	141	139	84	155	170	185	1700	
62 BCH : Excess Purch	0	0	0	0	0	0	0	0	0	0	0	0	0	
63	----	----	----	----	----	----	----	----	----	----	----	----	----	
64 Gross FortisBC Monthly Peak	718	568	505	422	392	501	498	511	398	486	581	692	6273	
65 Required Reserve	0	0	0	0	0	0	0	0	0	0	58	69		
66 Capacity Planning Load	718	568	505	422	392	501	498	511	398	486	639	762		
67 <b>RATE (\$/MW-month) / EXPENSE (\$000)</b>														
68 BCH 3808 Rate	4411	4411	4411	4730	4730	4730	4730	4730	4730	4730	4730	4730		
69 BCH 3808 Capacity Charge	\$910.430	\$833.679	\$732.226	\$732.204	\$732.204	\$742.610	\$813.560	\$756.800	\$732.204	\$771	\$805	\$875	\$9,437.264	
70													\$0.000	
71 Market Capacity Charge	\$353.908	\$46.804	\$34.323			\$1.528					\$25	\$25	\$486.451	
72 TeckCominco Capacity Charge	\$499.050	\$276.917	\$0.000	\$0.000	\$0.000	\$7.800	\$0.000	\$0.000	\$0.000	\$0	\$97	\$387	\$1,267.056	
73														
74 Total Capacity EXPENSE(\$000)	\$1,763.388	\$1,157.399	\$766.549	\$732.204	\$732.204	\$751.938	\$813.560	\$756.800	\$732.204	\$771	\$927	\$1,287	\$11,190.771	
75														
76 <b>TOTAL POWER PURCH EXPENSE(\$000)</b>														
77 Surplus Revenues	\$0.000	\$0.000	\$0.000	\$0.000	(\$697.167)	(\$1,509.010)	(\$893.105)	\$0.000	\$0.000	\$0	\$0	\$0	(\$3,099.282)	
78 Export Wheeling Costs	\$0.000	\$0.000	\$0.000	\$0.000	\$0.000	\$0.490	\$51.198	\$0.000	\$0.000	\$0	\$0	\$0	\$51.688	
79 Brilliant	\$2,774.120	\$2,103.543	\$1,838.446	\$2,739.986	\$2,982.893	\$2,733.228	\$3,043.920	\$3,051.903	\$2,544.821	\$2,043	\$2,259	\$2,367	\$30,482.059	
80														
81 BCH	\$4,356.003	\$3,599.509	\$2,435.091	\$1,409.222	\$1,555.121	\$2,200.657	\$2,067.403	\$2,102.085	\$1,925.709	\$2,398	\$3,176	\$4,168	\$31,392.764	
82														
83 Call Option	\$0.000	\$0.000	\$0.000	\$0.000	\$0.000	\$0.000	\$0.000	\$0.000	\$0.000	\$0	\$258	\$418	\$676.027	
84 Market	\$1,054.980	\$437.086	\$123.266	\$0.000	\$0.000	\$209.972	\$41.019	\$107.235	\$10.733	\$43	\$102	\$423	\$2,551.971	
85 IPP	\$28.216	\$40.576	\$21.286	\$13.560	\$11.156	\$11.177	\$20.223	\$80.050	\$81.841	\$29	\$40	\$48	\$425.836	
86 - BCH Excess/Unallocated Costs	\$0.168	\$0.055	\$1.462	\$10.217	\$6.116	\$36.199	\$66.679	\$8.102	\$12.422	\$14.5	(\$0)	\$2	\$158.262	
87 - ULE/230 kV Credit Adjustment	(\$427.070)	(\$234.710)	(\$133.665)	(\$79.660)	(\$51.492)	(\$1.820)	\$0.000	(\$50.000)	(\$50.000)	\$0	(\$293)	(\$439)	(\$1,760.650)	
88 Special & Accounting Adjustments			\$7.569				(\$1.162)						(\$496)	(\$489.430)
89	----	----	----	----	----	----	----	----	----	----	----	----	----	
90 <b>TOTAL</b>	\$7,786.417	\$5,946.058	\$4,293.454	\$4,093.326	\$3,806.628	\$3,680.893	\$4,396.177	\$5,299.375	\$4,525.525	\$4,528	\$5,541	\$6,492	\$60,389.246	

**POWER PURCHASE EXPENSE FOR 2005**

**TABLE 7.2**

2005 ANALYSIS OF FORECAST POWER PURCHASE EXPENSE FOR THE YEAR ENDING DECEMBER 31, 2005															23-Nov
	2	3	4	5	6	7	8	9	10	11	12	13			
	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC	TOTAL		
5 ENERGY GW.h	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast			
6 FortisBC (Includes Entitlement Adjust.)	140	142	154	119	133	123	135	125	151	120	102	128	1573.165		
7 Brilliant Base Plant	82	63	58	82	79	72	79	86	66	62	63	65	858.326		
8 Brilliant Upgrade	1	0	0	10	13	13	13	12	1	1	1	1	64.615		
9 Brilliant Regulated	9	9	7	2	1	1	1	1	1	2	13	13	60.684		
10 TeckCominco	0	0	0	0	0	0	0	0	0	0	0	0	0.000		
11 Small Misc IPP Resource	2	2	2	3	3	2	3	3	2	2	2	2	26.000		
12 Market Capacity - ENERGY	1	0	1	0	0	0	0	0	0	0	3	0	4.401		
13	0	0	0	0	0	0	0	0	0	0	0	0	0.000		
14 Call Option	0	1	0	0	0	0	0	0	0	0	0	1	2.377		
15	0	0	0	0	0	0	0	0	0	0	0	0	0.000		
16 DSM	0	0	0	1	1	1	1	1	1	1	1	2	9.000		
17 City of Nelson Special Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0.000		
18 Turbine Upgrades	0	0	0	0	0	0	0	0	0	0	0	0	0.000		
19 Market Energy Purchase	0	0	0	0	0	0	0	0	0	0	0	0	0.000		
20 BCH Purchase	113	106	90	72	44	34	30	36	41	63	76	92	796.525		
21	----	----	----	----	----	----	----	----	----	----	----	----	----		
22 Gross Load	347	323	313	288	274	245	242	264	263	252	260	304	3375.855		
23 Surplus	0	0	0	0	0	0	19	0	0	0	0	0	19.238		
24 RATE (Mills/kW.h)												Pwr Pur =	1812.929		
25 Surplus Rate	65.12	63.95	59.26	34.55	23.93	23.49	38.67	45.07	43.72	58.05	63.01	66.3			
26 Brilliant Base Plant	31.24	31.24	31.24	31.24	31.24	31.24	31.24	31.24	31.24	31.24	31.24	31.24			
27 Brilliant Upgrade	20.71	20.71	20.71	20.71	20.71	20.71	20.71	20.71	20.71	20.71	20.71	20.71			
28 Brilliant Regulated	27.25	27.25	27.25	27.25	27.25	27.25	27.25	27.25	27.25	27.25	27.25	27.25			
29 Call Option	129.60	119.21	69.63	59.08	47.38	45.22	64.15	75.83	71.28	63.95	79.00	131.42			
30															
31 Market Rate	117.82	108.37	87.13	73.79	58.39	65.52	100.34	118.85	106.61	99.22	106.93	119.47			
32 BCH : Purchase	27.25	27.25	27.25	27.25	27.25	27.25	27.25	27.25	27.25	27.25	27.25	27.25			
33 IPP Rate	26.90	26.48	26.13	25.90	23.04	24.41	24.33	26.26	27.06	27.15	27.38	27.32			
34 ENERGY EXPENSE (\$000)															
35 Surplus Revenue	\$0	\$0	\$0	\$0	\$0	\$0	(\$744)	\$0	\$0	\$0	\$0	\$0	(\$743.948)		
36 Brilliant Base Plant	\$2,559	\$1,969	\$1,841	\$2,556	\$2,476	\$2,257	\$2,479	\$2,690	\$2,064	\$1,945	\$1,966	\$2,034	\$26,836.631		
37 Brilliant Upgrade	\$24	\$0	\$0	\$200	\$261	\$261	\$261	\$257	\$26	\$20	\$14	\$12	\$1,338.000		
38 Brilliant Regulated	\$242	\$237	\$189	\$53	\$37	\$19	\$40	\$32	\$32	\$61	\$346	\$365	\$1,653.708		
39 Call Option	\$11	\$134	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$153	\$298.499		
40	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0.000		
41 IPP Costs	\$48	\$45	\$60	\$67	\$58	\$54	\$66	\$79	\$60	\$46	\$41	\$49	\$672.565		
42 BCH Purchase	\$3,077	\$2,886	\$2,457	\$1,963	\$1,200	\$917	\$820	\$979	\$1,109	\$1,720	\$2,069	\$2,510	\$21,706.112		
43 Market Purchase	\$61	\$0	\$47	\$2	\$2	\$2	\$3	\$4	\$2	\$3	\$288	\$52	\$466.423		
44	----	----	----	----	----	----	----	----	----	----	----	----	----		
45	\$6,022	\$5,270	\$4,595	\$4,842	\$4,034	\$3,509	\$2,925	\$4,041	\$3,293	\$3,796	\$4,724	\$5,175	\$52,227.991		

**Table 7.2 cont'd**

ANALYSIS OF FORECAST POWER PURCHASE EXPENSE														23-Nov
FOR THE YEAR ENDING DECEMBER 31,														
	2	3	4	5	6	7	8	9	10	11	12	13		
	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC	TOTAL	
	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast		
46														
47	<b>CAPACITY (MW)</b>													
48	196	198	192	189	183	174	185	196	204	196	190	191	2294	
49	123	122	108	117	106	100	106	115	119	119	123	123	1380	
50	20	20	20	20	20	20	20	20	20	20	20	20	238	
51	0	0	0	0	0	0	0	0	0	0	0	0	0	
52	39	0	34	10	10	10	10	10	7	10	71	35	246	
53													0	
54	50	50	0	0	0	0	0	0	0	0	0	25	125	
55	2	2	2	1	1	1	2	1	1	2	2	2	20	
56	0	0	0	0	0	0	0	0	0	0	0	0	0	
57	0	0	0	0	0	0	0	0	0	0	0	0	0	
58	100	25	0	0	0	0	0	0	0	0	25	100	250	
59	0	0	0	0	0	0	0	0	0	0	0	0	0	
60	185	175	185	140	139	148	178	143	139	148	185	185	1950	
61	185	175	185	140	108	148	178	143	63	148	185	185	1843	
62	0	0	0	0	0	0	0	0	0	0	0	0	0	
63	----	----	----	----	----	----	----	----	----	----	----	----	----	
64	715	583	541	478	428	453	500	485	413	494	616	681	6387	
65	72	58	54	24	21	23	25	24	21	49	62	68		
66	787	641	595	502	449	476	525	509	434	543	678	749		
67	<b>RATE (\$/MW-month) / EXPENSE (\$000)</b>													
68	4625	4625	4625	4625	4625	4625	4625	4625	4625	4625	4625	4625		
69	\$856	\$810	\$856	\$649	\$642	\$686	\$824	\$660	\$642	\$683	\$856	\$856	\$9,017.667	
70													\$0.000	
71	\$26	\$26										\$13	\$65.190	
72	\$404	\$101	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$163	\$654	\$1,321.788	
73														
74	\$1,286	\$937	\$856	\$649	\$642	\$686	\$824	\$660	\$642	\$683	\$1,019	\$1,522	\$10,404.644	
75														
76	<b>TOTAL POWER PURCH EXPENSE(\$000)</b>													
77	\$0	\$0	\$0	\$0	\$0	\$0	(\$744)	\$0	\$0	\$0	\$0	\$0	(\$743.948)	
78	\$0	\$0	\$0	\$0	\$0	\$0	\$38	\$0	\$0	\$0	\$0	\$0	\$38.477	
79	\$2,826	\$2,205	\$2,030	\$2,809	\$2,775	\$2,536	\$2,781	\$2,979	\$2,122	\$2,027	\$2,327	\$2,411	\$29,828.339	
80														
81	\$3,932	\$3,695	\$3,313	\$2,612	\$1,841	\$1,603	\$1,644	\$1,639	\$1,751	\$2,403	\$2,924	\$3,365	\$30,723.779	
82														
83	\$37	\$160	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$167	\$363.689	
84	\$465	\$101	\$47	\$2	\$2	\$2	\$3	\$4	\$2	\$3	\$451	\$705	\$1,788.211	
85	\$48	\$45	\$60	\$67	\$58	\$54	\$66	\$79	\$60	\$46	\$41	\$49	\$672.565	
86	\$0	\$0	\$1	\$10	\$6	\$37	\$68	\$8	\$13	\$26	(\$0)	\$2	\$172.417	
87	\$0	\$0	\$0	\$0	\$0	\$0	\$0	(\$19)	\$0	\$0	(\$90)	(\$90)	(\$199.861)	
88													\$0.000	
89	----	----	----	----	----	----	----	----	----	----	----	----	----	
90	<b>TOTAL</b>	\$7,308	\$6,207	\$5,452	\$5,501	\$4,682	\$4,232	\$3,856	\$4,690	\$3,947	\$4,505	\$5,653	\$6,609	\$62,643.668