BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER G-162-09

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, B.C. V6Z 2N3 CANADA
web site: http://www.bcuc.com

TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

An Application by FortisBC Inc.
2009 Annual Review, 2010 Revenue Requirements and
Negotiated Settlement Process

BEFORE: L.F. Kelsey, Commissioner
D.A. Cote, Commissioner
P.E. Vivian, Commissioner December 17, 2009

O R D E R

WHEREAS:

A. British Columbia Utilities Commission ("Commission") Order G-58-06 approved for FortisBC Inc. ("FortisBC" or "Company") a Settlement Agreement for its 2006 Revenue Requirements (the "2006 Settlement Agreement") and a Performance Based Regulation Settlement for the years 2007, 2008 and potentially 2009 (the "PBR Settlement"). The PBR Settlement requires FortisBC to hold an Annual Review, Workshop and Negotiated Settlement Process ("NSP") each November with a goal of achieving firm rates by December 1st for the following year; and

B. The Annual Review compares the Company's actual performance for the recently completed year to the approved targets for the Performance Standards to determine whether the Company is entitled to an incentive payment. The Revenue Requirements Workshop is to focus on future test periods and the NSP is conducted to establish rates for the following year; and

C. Commission Order G-193-08 issued on December 11, 2008, approved an extension of the 2007-2009 Performance-Based Rate Plan for the years 2009-2011; and

D. On October 1, 2009, FortisBC filed its Preliminary 2010 Revenue Requirements, which sought a 4.6 percent general rate increase to be effective January 1, 2010; and

E. By Order G-118-09 dated October 1, 2009, the Commission established a Regulatory Timetable for the 2009 Annual Review and a 2010 Revenue Requirements Workshop on November 17, 2009 in Kelowna, BC, followed by an NSP on November 18, 2009; and

F. On October 16, 2009, the Commission and Intervenors issued Information Requests to FortisBC which were responded to on October 30, 2009; and

G. On November 2, 2009, FortisBC filed the 2010 Revenue Requirements Update, which incorporated financial results and forecasts as of September 30, 2009, including financial Performance Standards for the period October 1, 2008 to September 30, 2009, and reduced the general rate increase sought to 4.0 percent, effective January 1, 2010; and

H. As a result of the 2009 Annual Review on November 17, 2009 and 2010 Revenue Requirements Settlement discussions on November 18, 2009, a Settlement Agreement was proposed and agreed to by FortisBC and most Intervenors in attendance, with the participation of Commission Staff. The proposed Settlement Agreement, which results in a general rate increase of 3.5 percent effective January 1, 2010, was circulated to the participants and registered Intervenors on December 4, 2009; and

I. The proposed Settlement Agreement's financial schedules reflect FortisBC's Return on Equity, which is set relative to the benchmark low risk utility, Terasen Gas Inc. If a decision in the Terasen Utilities' Return on Equity and Cost of Capital Application is issued prior to determining final 2010 rates for FortisBC, the resulting FortisBC Return on Equity will be included in final rates. Otherwise, FortisBC would implement any resulting change to 2010 Revenue Requirements and rates by way of a flow-through adjustment at the time of that decision; and

J. Letters of support to the proposed Settlement Agreement were received from the British Columbia Old Age Pensioners' Organization *et al.*, Mr. Al Wait, the British Columbia Municipal Electric Utilities, and FortisBC; and

K. By the due date of December 11, 2009, no comments were received from any Registered Intervenors who had not participated in the Settlement negotiation; and

L. The Commission has reviewed the proposed Settlement Agreement and considers that approval is warranted.

NOW THEREFORE the Commission orders as follows:

1. The Commission approves the Negotiated Settlement Agreement attached as Appendix A to this Order, and the Terms of Settlement along with financial schedules showing the effect of changes arising from the Negotiated Settlement.

2. The Commission will accept, subject to timely filing, amended Electric Tariff Rate Schedules in accordance with the terms of this Order.

DATED at the City of Vancouver, in the Province of British Columbia, this 18th day of December 2009.

BY ORDER

Original signed by:

D.A. Cote
Commissioner

Attachment

WILLIAM J. GRANT
Consultant TO BCUC
bill.grant@bcuc.com
web site: http://www.bcuc.com

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SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, B.C. CANADA V6Z 2N3
TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

Log No. 30898

VIA E-MAIL

December 4, 2009

To: Registered Intervenors (FortisBC Inc.2010RR)

Dear Registered Intervenors:

Re: FortisBC Inc. ("FortisBC")
Negotiated Settlement Agreement
2010 Revenue Requirements Application

Enclosed with this letter is the proposed settlement package for FortisBC's 2010 Revenue Requirements Application.

This settlement package is now public and is being submitted to the Commission and all Intervenors. Also enclosed are Letters of Support and Comment received to date from the participants in the negotiated settlement process.

Prior to consideration by the Commission, Intervenors who did not participate in the settlement negotiations will be requested to provide to the Commission their comments on the settlement package by Friday, December 11, 2009. Thereafter, the Commission will consider the settlement package. A public hearing may not be required unless there is significant opposition to the proposed settlement.

Yours truly,

for:
William J. Grant

YD/rt
Attachments
cc: Mr. Dennis Swanson
Director, Regulatory Affairs
FortisBC Inc.
regulatory@fortisbc.com

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FortisBC Inc.
2010 Revenue Requirements

NEGOTIATED SETTLEMENT AGREEMENT

Introduction

FortisBC Inc. (“FortisBC” or the “Company”) filed its Preliminary 2010 Revenue Requirements (the “Application”) on October 1, 2009. The Application materials were filed on the basis of the Performance Based Regulation (“PBR”) plan negotiated between FortisBC and its Stakeholders in 2006 and extended in 2008 for the years 2009-2011.

The Application reflected a general rate increase of 4.6 percent effective January 1, 2010. Following the submission of Information Requests by the Commission and Registered Intervenors and filing of responses, the Company filed an update to the Application on November 2, 2009 (the “Update”), incorporating financial results and forecasts as of September 30, 2009, final Performance Standards for the period October 1, 2008 to September 30, 2009, and other current information. The requested rate increase was reduced, as a net result of the adjustments, to 4.0 percent, effective January 1, 2010, subject to the Commission’s determination of the 2009 Return on Equity (“ROE”), and the outcome of a Negotiated Settlement Process (“NSP”).

The Application also requested Commission approval of certain non-rate base deferral accounts required for implementation of International Financial Reporting Standards (“IFRS”). As these deferral accounts are excluded from rate base, they do not impact customer rates for 2010.

The 2009 Annual Review and 2010 Revenue Requirements Workshop were held in Kelowna, BC on November 17, 2009. FortisBC and a group of Intervenors participated in a NSP on November 18, 2008, and reached a Negotiated Settlement Agreement (“NSA”), which is attached. The NSA results in a general rate increase of 3.5 percent effective January 1, 2010. Also attached are 2010 Revenue Requirements Schedules in accordance with the NSA, which reflect a forecast 2010 Return on Equity of 8.78 percent, the reduction of the 2010 Power Purchase Expense forecast by $0.5 million, the transfer of Advanced Metering Infrastructure development costs to a non-rate base deferral account, an increase in 2010 Residential and General Service forecast load and related Power Purchase Expense, the final actuary determined Pension and Post Retirement benefit expense, and other adjustments pursuant to the NSA.

As agreed in the NSA, final rates will be adjusted to incorporate FortisBC’s 2010 ROE, as determined by the Commission following its decision on the Terasen Utilities’ ROE and Capital Structure application.

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FortisBC Inc.
2010 Revenue Requirements

The following Parties participated in the NSP:

Participant	**Party**
W.J. Grant	British Columbia Utilities Commission
P. Nakoneshny	British Columbia Utilities Commission
Y. Domingo	British Columbia Utilities Commission
B. Pedret	Consultant for British Columbia Utilities Commission
E. Switlishoff	Consultant for British Columbia Utilities Commission
T. Andreychuk	The British Columbia Municipal Electricity Utilities, The City of Penticton
V. Kumar	The British Columbia Municipal Electricity Utilities, The City of Grand Forks
A. Love	The British Columbia Municipal Electricity Utilities, Nelson Hydro
J. Creron	The British Columbia Municipal Electricity Utilities The City of Kelowna
K. Ostraat	The British Columbia Municipal Electricity Utilities, The District of Summerland
S. Khan	British Columbia Old Age Pensioners Organization et al.
C.P. Weafer	Counsel for The BC Municipal Electric Utilities
A. Wait	FortisBC Ratepayer
N. Gabana	FortisBC Ratepayer
L. Bertsch	Consultant for the Okanagan Environmental Industry Alliance
M. Leeners	FortisBC Inc.
J. Martin	FortisBC Inc.
D. Swanson	FortisBC Inc.

Settlement Agreement

With the exception of the Okanagan Environmental Industry Alliance, all other Parties accept the 2010 Revenue Requirements Application, including the recognition of IFRS-related non-rate base deferral accounts, as filed, subject to the following:

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FortisBC Inc.
2010 Revenue Requirements

ISSUES		ISSUE DESCRIPTION	RESOLUTION	REFERENCE
Tab 3 – Revenue Requirements				
1	Customer Rates	Customer Rates are increasing largely as a result of capital expenditure and rate base increases. Of particular concern are Transmission, Communications and Automation, Mandatory Reliability Standards and Computer related capital expenditures.	FortisBC recognizes that the stakeholders in the Negotiated Settlement Process have serious concern about the escalation of customer rates due to the capital program. The Company will prudently manage costs, as it can, to mitigate future rate increases.	Exhibit B-3, BCUC IR 1.1, 1.2, & 8.1
2	Forecast 2010 Power Purchase Expense	FortisBC has not reflected the lower cost of gas in their energy purchases in 2010. There is a history of actual costs being below forecast.	Reduce 2010 forecast by $0.5 million.	Exhibit B-3, BCUC IR 1.1
3	Future Generation Projects and Integrated System Plan deferral accounts	FortisBC should scale back plans until after results from the Section 5 Inquiry, FortisBC's Resource Plan review and 3808 Renewal are better known. More information is required.	FortisBC recognizes the concern and will monitor the progress of the Section 5 Inquiry and 3808 renewal, as well as disposition of the Resource Plan. The Company will minimize commitments with regards to further development and the timing of regulatory filings; however if opportunities arise FortisBC will take a prudent course of action on behalf of its customers with respect to those regulatory filings	Exhibit B-3, BCUC IR 9.1 & 14.3
4	FortisBC has continued pursuit of Automated Metering Initiative (AMI) despite rejection of CPCN in Order G-168-08. In this order, "(t)he Commission Panel encourage(d) FortisBC to explore coordinating its meter technology selection with that of BC Hydro"	Order G-168-08 denied FortisBC's AMI Project CPCN. In that Decision, the Commission Panel provides guidance to FortisBC for its next CPCN, which includes the exploration of coordinating meter technology selection with that of BC Hydro.	FortisBC believes that the costs incurred are consistent with Commission Order G-168-08 and that all such costs should be included in rate base. However FortisBC agrees, for the purpose of this NSA, to record the AMI development costs in a non-rate base deferral account that will attract AFUDC for the 2010 Revenue Requirement, on a without prejudice basis.	Exhibit B-3, BCUC IR 11.1, OEIA IR 4.5

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FortisBC Inc.
2010 Revenue Requirements

ISSUES		ISSUE DESCRIPTION	RESOLUTION	REFERENCE
Tab 5 – Load and Customer Forecast				
1	2010 forecast Residential volume understated	1. Increase forecasted Residential energy volume for 2010. The forecast UPC of 12.69 GWh is accepted but the forecast number of customers is disputed.	Increase forecasted Residential energy volume for 2010 from 1,226 MWh to 1,248 MWh based on a 3-year regression. For 2010, FortisBC to adjust Power Purchase Expense and decrease Revenue Requirement accordingly. Total (Residential and General Service) increase to Revenue from prior year rates of $1.7Million is partially offset by an increase of $1.3 Million to 2010 Power Purchase Expense.	Exhibit B-3, BCUC IR 52
2	2010 forecast General Service volume understated	1. Increase forecasted General Service volume. The forecast UPC of 59.04 GWh is accepted but the forecast number of customers is disputed.	Increase forecasted General Service volume from 681 MWh to 682 MWh based on a 3-year regression. For 2010, FortisBC to adjust Power Purchase Expense and decrease Revenue Requirement accordingly. Total (Residential and General Service) increase to Revenue from prior year rates of $1.7Million is partially offset by an increase of $1.3 Million to 2010 Power Purchase Expense.	Exhibit B-3, BCUC IR 52
3	FortisBC is not tracking the Measurement and Evaluation expenditures for DSM in sufficient detail.	Require FortisBC to track DSM expenditures in terms of the following annual expenditures: 1. Program development; 2. Implementation; 3. Assessment and verification, and 4. Impact assessment and reporting.	The Company will track and report measurement and evaluation DSM expenditures, including the following expenditures: 1. Program development; 2. Implementation; 3. Assessment and verification, and 4. Impact assessment and reporting.	Exhibit B-3, BCUC IR 35.3
Tab 6 – Power Purchase and Wheeling				
1	Brilliant Power Purchase Agreement – True-ups are required every year to adjust for what should have been recovered in rates compared to what was recovered.	FortisBC was asked to supply a reconciliation of which Brilliant PPA cost components were under-budget (and by what amounts) in 2007, 2008, and 2009, and consider reducing the 2010 PPA recoveries by the average of these three years.	1. The BPPA expenditure true up will continue to occur annually in its normal course. 2. The terms of the Brilliant Agreements including the mechanism for recovery of O&M costs have already been approved by the BCUC and therefore the information requested is not required.	Exhibit B-1, Tab 6, p.6 Exhibit B-3, BCOAPO IR 15

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FortisBC Inc.

2010 Revenue Requirements

ISSUES		ISSUE DESCRIPTION	RESOLUTION	REFERENCE
2	Purchase Power costs in Upgrade /Life Extension (ULE) Outage Costs are being capitalized	According to section 3061 of the CICA Handbook, costs that are allowed to be capitalized into PPE broadly include acquisition, construction, development, and betterment cost. Accordingly, in BC Hydro's Application for the Mica Gas Insulated Switchgear Project, its response to CECBC IR 7.1 claims that no capitalization of outage costs are allowed under this accounting policy.	FortisBC to provide Commission staff with its accounting opinion that capitalization is consistent with the CICA Handbook's section 3061.	Exhibit B-3, BCUC IR 55.1 & 56.1 BC Hydro's Application for the Mica Gas Insulated Switchgear Project, Exhibit B-6, CECBC IR 7.0
3	FortisBC states that the 2009 Resource Plan (or the 2009 & 2010 DSM program) does not have to comply with the Ministerial Order because it was filed May 29 while the Ministerial Order was June 1 /09.	FortisBC should comply with Ministerial Order M271 when it issues the update.	This will be addressed in the Regulatory Process concerning the Resource Plan.	Exhibit B-3, OEIA IR 6.4
Tab 8 – Performance Standards				
1	Injury Severity Rate - FortisBC's 2010 forecast is 25.54, calculated as the 3-year average which includes an exceptional increase in 2007.	The increase is a result of an unfortunate event in 2007. BCUC did not seek any denial of revenue sharing in the past. The 17.53 is more representative of a realistic target for 2010.	The Injury Severity Rate will remain at 17.53 for 2010. Future targets will be set in accordance with the 2006 NSA.	Exhibit B-1, Tab 8, p.6 Exhibit B-3, BCUC IR 81.2
Tab – Appendix A – Prior Years Directives				
1	Worst Performing Circuits report to lower SAIDI and improve CAIDI	FortisBC should annually report to the Commission, broken down by month, and totalled. Although a Worst Performing Feeder Program may not be warranted, FortisBC should at least review the worst performing feeders on a regular basis.	The Company does review the performance of its feeders on a monthly basis and will continue to review feeder performance and prepare a report annually for the Commission.	Exhibit B-3, BCUC IR 85.1
Tab – Appendix B – Accounting Changes				
1	Losses from Disposal of Assets	BCUC needs to be able to clearly identify these losses in order to make an assessment of its disposition, as will be requested in the next RRA.	FortisBC will clearly identify losses from disposal of assets in the 2011 RRA.	Exhibit B-3, BCUC IR 90.2 & 90.3

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FortisBC Inc.

2010 Revenue Requirements

ISSUES		ISSUE DESCRIPTION	RESOLUTION	REFERENCE
Other Issues				
1	Industrial load forecast increases due to increased sales to Zellstoff Celgar	It is unclear whether it is appropriate to allow Zellstoff Celgar to increase its FortisBC load while selling generation to BC Hydro.	The appropriate venue for this issue to be raised is FBC's Rate Design Application. There is no wheeling revenue associated with these sales.	Exhibit B-1, Tab 5, p.8 Exhibit B-3, BCMEU IR 6.0
3	Canal Plant Agreement	FBC identified a $54,000 overstatement of Power Purchase Expense associated with the Canal Plant Agreement.	Revenue Requirement reduction of $54,000.	
4	Pension and Post Retirement Benefit	Final Letter from the Actuary not yet received or incorporated into Revenue Requirements.	2010 rates will reflect the final actuary determined expense.	
5	ROE risk premium		FortisBC will conform with any applicable determinations from the upcoming TGI/TGVI/TGW ROE and Capital Structure Decision.	
6	CPI for O&M Formula	RBC, one of the 4 defined sources for CPI, is no longer producing a CPI forecast.	Replace RBC with BMO for the term of the PBR.	
7	Presentation of Future Revenue Requirement Applications	Current format of overview tables show current year approved and test year forecast.	For the term of the PBR, the Company will also include prior year actual in the overview tables.	
8	Rate Increases	Stakeholders are concerned about the size of rate increases.	Based on the information presented in the 2010 Revenue Requirements Workshop and the results of the NSP, the calculated rate increase will not exceed 3.5%. The final rate increase could be higher or lower than the 3.5% subject to any subsequent external events including, but not limited to, the final ROE determination.	

FORTISBC

2010 Revenue Requirements
Negotiated Settlement Agreement

Financial Schedules

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REVENUE REQUIREMENTS OVERVIEW

		Approved 2009	Increase or (Decrease)	Forecast 2010
			($000s)	
1	Sales Volume (GWh)	3,107		3,199
2	Rate Base	907,977		974,944
3	Return on Rate Base	7.38%		7.28%
4				
5	**REVENUE DEFICIENCY**			
6				
7	**POWER SUPPLY**			
8	Power Purchases	70,944	6,883	77,827
9	Water Fees	8,480	588	9,068
10		79,424	7,471	86,895
11	**OPERATING**			
12	O&M Expense	46,573	1,072	47,645
13	Capitalized Overhead	(9,315)	(214)	(9,529)
14	Wheeling	4,010	9	4,019
15	Other Income	(4,915)	(110)	(5,025)
16		36,353	756	37,109
17	**TAXES**			
18	Property Taxes	11,561	987	12,548
19	Income Taxes	4,354	(698)	3,656
20		15,915	289	16,204
21	**FINANCING**			
22	Cost of Debt	34,803	1,957	36,760
23	Cost of Equity	32,215	2,025	34,240
24	Depreciation and Amortization	37,504	4,524	42,028
25		104,522	8,507	113,028
26				
27	Prior Year Incentive True Up	173	(495)	(322)
28	Flow Through Adjustments	(435)	(633)	(1,068)
29	AFUDC / CWIP shortfall	-		-
30	ROE Sharing Incentives	(1,181)	(118)	(1,300)
31		(1,443)	(1,247)	(2,690)
32				
33	**TOTAL REVENUE REQUIREMENT**	**234,771**	**15,776**	**250,547**
34				
35	Carrying Cost on Rate Base Deferral Account	(8)	8	-
36	ADJUSTED REVENUE REQUIREMENT	234,763	15,784	**250,547**
37	**LESS: REVENUE AT APPROVED RATES**			**242,031**
38	**REVENUE DEFICIENCY for Rate Setting**			**8,516**
39				
40	**RATE INCREASE**			**3.50%**

SCHEDULE 1 – UTILITY RATE BASE

		Actual 2008	Forecast 2009	Forecast 2010
			($000s)	
1	Plant in Service, January 1	1,062,070	1,165,457	1,278,904
2	Net Additions	103,387	113,447	155,585
3	Plant in Service, December 31	1,165,457	1,278,904	1,434,489
4				
5	Add:			
6	CWIP not subject to AFUDC	7,214	6,382	6,135
7	Plant Acquisition Adjustment	11,912	11,912	11,912
8	Deferred and Preliminary Charges	16,227	16,918	19,094
9				
10		1,200,810	1,314,117	1,471,630
11	Less:			
12	Accumulated Depreciation			
13	and Amortization	275,128	304,592	336,919
14	Contributions in Aid of Construction	86,783	89,625	94,173
15		361,911	394,217	431,092
16				
17	Depreciated Rate Base	838,899	919,900	1,040,538
18				
19	Prior Year Depreciated Utility Rate Base	772,893	838,899	919,900
20				
21	Mean Depreciated Utility Rate Base	805,896	879,400	980,219
22	Add:			
23	Allowance for Working Capital	8,261	7,765	6,984
24	Adjustment for Capital Additions	(11,591)	(18,055)	(12,259)
25				
26	**Mid-Year Utility Rate Base**	**802,566**	**869,110**	**974,944**

Schedule 1A – Non Rate Base Assets

		Deferral Recognition	Regulatory Asset / (Regulatory Liability) 2009	2010
			($000s)	
1	Capitalization of Depreciation on Assets Used in Construction			(3,700)
2	Property, Plant & Equipment - Gains and Losses on Disposal of Assets			2,000
3	Customer Contributions Amortization Rate and Timing			(510)
4	Depreciation Changes for Property, Plant & Equipment			7,500
5	Depreciation of Major Inspections			160
6	Deferred Income Taxes	G-37-84 & G-193-08 & G-2-04	82,168	92,050
7	Pension and Employee Future Benefit Costs - Cumulative Unamortized Actuarial Gains and Losses, Past Service Costs and Changes in Measurement Date Upon Transition			29,890
8	Brilliant Terminal Station Capital Lease	G-2-04 & G-193-08	4,484	5,090
9	Other post-retirement benefits	G-52-05 & G-193-08	4,083	3,536
10	Trail Office Building Lease	G-41-93 & G-193-08	1,409	1,249
11	**Total**		**92,144**	**137,265**

Table 1 – A – Utility Plant in Service (2009)

Line	Account		December 31 2008	Additions	Retirements	December 31 2009
		Hydraulic Production Plant		($000s)		
1	330	Land Rights	847	-	-	847
2	331	Structures and Improvements	11,280	658	-	11,938
3	332	Reservoirs, Dams & Waterways	21,040	3,247	(5)	24,282
4	333	Water Wheels, Turbines and Gen.	56,545	12,962	(181)	69,326
5	334	Accessory Equipment	22,911	2,484	(142)	25,252
6	335	Other Power Plant Equipment	38,349	692	(30)	39,011
7	336	Roads, Railroads and Bridges	1,053	-	-	1,053
8			152,024	20,044	(358)	171,710
9		**Transmission Plant**				
10	350	Land Rights-R/W	7,079	389	-	7,468
11	350.1	Land Rights-Clearing	4,496	389	-	4,885
12	353	Station Equipment	167,529	29,851	-	197,380
13	355	Poles Towers & Fixtures	74,499	12,039	(15)	86,523
14	356	Conductors and Devices	71,955	11,605	-	83,560
15	359	Roads and Trails	817	194	-	1,011
16			326,374	54,468	(15)	380,827
17		**Distribution Plant**				
18	360	Land Rights-R/W	2,986	1,214	-	4,200
19	360.1	Land Rights-Clearing	7,106	1,214	-	8,320
20	362	Station Equipment	116,942	-	(73)	116,868
21	364	Poles Towers & Fixtures	114,210	11,644	(354)	125,500
22	365	Conductors and Devices	186,542	9,073	(588)	195,026
23	368	Line Transformers	88,933	3,973	(1,462)	91,445
24	369	Services	7,292	-	-	7,292
25	370	Meters	13,189	591	(298)	13,483
26	371	Installation on Customers' Premises	5,336	2,782	-	8,118
27	373	Street Lighting and Signal System	7,272	-	(46)	7,226
28			549,806	30,491	(2,821)	577,477
29		**General Plant**				
30	389	Land	5,800	-	-	5,800
31	390	Structures-Frame & Iron	337	-	-	337
32	390.1	Structures-Masonry	24,533	1,314	-	25,847
33	391	Office Furniture & Equipment	5,596	583	(1)	6,178
34	391.1	Computer Equipment	50,977	6,499	(163)	57,313
35	392	Transportation Equipment	16,563	2,042	(1,512)	17,094
36	394	Tools and Work Equipment	10,566	601	-	11,167
37	397	Communication Structures and Equipment	22,880	2,274	-	25,154
38			137,252	13,313	(1,675)	148,890
39						
40	101	**Plant in Service**	1,165,457	118,316	(4,869)	1,278,904
41	107.1	Plant under construction not subject				
42		to AFUDC	7,214			6,382
43	107.2	Plant under construction				
44		subject to AFUDC	54,177			51,290
45	114	Utility Plant Acquisition Adjustment	11,912			11,912
46	105	Plant held for future use	-			-
47						
48	105	Utility Plant per Balance Sheet	1,238,760			1,348,488

Table 1 – A – Utility Plant in Service (2010)

Line	Account		December 31 2009	Additions	Retirements	December 31 2010
		Hydraulic Production Plant		($000s)		
1	330	Land Rights	847	-	-	847
2	331	Structures and Improvements	11,938	362	-	12,300
3	332	Reservoirs, Dams & Waterways	24,282	3,590	(5)	27,868
4	333	Water Wheels, Turbines and Gen.	69,326	16,794	(181)	85,939
5	334	Accessory Equipment	25,252	1,966	(142)	27,076
6	335	Other Power Plant Equipment	39,011	278	(30)	39,259
7	336	Roads, Railroads and Bridges	1,053	-	-	1,053
8			171,710	22,990	(358)	194,342
9		**Transmission Plant**				
10	350	Land Rights-R/W	7,468	1,180	-	8,648
11	350.1	Land Rights-Clearing	4,885	1,180	-	6,065
12	353	Station Equipment	197,380	49,671	-	247,051
13	355	Poles, Towers & Fixtures	86,523	19,930	(15)	106,438
14	356	Conductors and Devices	83,560	13,429	-	96,989
15	359	Roads and Trails	1,011	332	-	1,344
16			380,827	85,724	(15)	466,535
17		**Distribution Plant**				
18	360	Land Rights-R/W	4,200	777	-	4,977
19	360.1	Land Rights-Clearing	8,320	777	-	9,097
20	362	Station Equipment	116,868	-	(73)	116,795
21	364	Poles Towers & Fixtures	125,500	15,658	(354)	140,804
22	365	Conductors and Devices	195,026	11,471	(588)	205,910
23	368	Line Transformers	91,445	5,035	(1,462)	95,018
24	369	Services	7,292	-	-	7,292
25	370	Meters	13,483	718	(298)	13,903
26	371	Installation on Customers' Premises	8,118	3,433	-	11,550
27	373	Street Lighting and Signal System	7,226	-	(46)	7,180
28			577,477	37,869	(2,821)	612,526
29		**General Plant**				
30	389	Land	5,800	-	-	5,800
31	390	Structures-Frame & Iron	337	-	-	337
32	390.1	Structures-Masonry	25,847	961	-	26,808
33	391	Office Furniture & Equipment	6,178	813	(1)	6,991
34	391.1	Computer Equipment	57,313	6,418	(163)	63,567
35	392	Transportation Equipment	17,094	2,000	(1,512)	17,582
36	394	Tools and Work Equipment	11,167	556	-	11,723
37	397	Communication Structures and Equipment	25,154	3,124	-	28,278
38			148,890	13,871	(1,675)	161,086
39						
40	101	**Plant in Service**	1,278,904	160,454	(4,869)	1,434,489
41	107.1	Plant under construction not subject				
42		to AFUDC	6,382			6,135
43	107.2	Plant under construction				
44		subject to AFUDC	51,290			53,797
45	114	Utility Plant Acquisition Adjustment	11,912			11,912
46	105	Plant held for future use	-			-
47						
48	105	Utility Plant per Balance Sheet	1,348,488			1,506,333

Table 1 – A – 1 – Additions to Plant in Service (2009)

		CWIP Dec. 31, 2008	Expenditures 2009	CWIP Dec 31, 2009	Additions to Plant in Service
			($000s)		
	Hydraulic Production				
1	All Plants Spare Unit Transformer	43	1,032	-	1,075
2	LBO & UBO Comm. Network Comp.	-	87	87	-
3	All Plants Fire Safety Upgrade Ph.1	-	35	-	35
4	SLC U1 Life Extension (replace turbine)	5,616	8,618	14,234	-
5	SLC U1 Head Gate Rebuild	1	687	-	688
6	All Plants Public Safety & Security Ph.1	-	15	15	-
7	SLC U3 Life Extension (no Turbine)	10,878	1,943	-	12,821
8	P1 Gen Plant Cooling System + P3 Gen Office Emergency Power Feed	-	3	-	3
9	P3U3 Headgate Rebuild	-	(2)	-	(2)
10	P3 Poleyard Contaminated Site	-	41	-	41
11	P3 Tailrace Vent Cover Screen Upgrade 2008 Project	35	(1)	-	34
12	P1 P4 Capital Planning 2008 Project	(5)	-	-	(5)
13	UBO Old Unit Repowering (Ph.1)	179	929	-	1,108
14	All Plants Upgrade Station Service Supply	1,170	618	208	1,580
15	SLC H/G Hoist, Control, Wire Rope Upgrade	181	737	-	918
16	SLC Plant Completion	1,268	694	1,481	481
17	COR U1 Life Extension (replace Turbine)	752	2,938	3,690	-
18	COR U2 Life Extension (replace Turbine)	-	17	17	-
19	SLC Dam Rehabilitation Study	-	12	12	-
20	LBO Power House Crane Upgrade	-	160	-	160
21	All Plants Spare Exciter Transformer	-	33	33	-
22	LBO Intake Area Upgrade Ph.1	-	353	-	353
23	SLC Domestic Water Supply Ph.3	-	42	42	-
24	All Plants 2009 Pump Upgrades	-	128	128	-
25	UBO & COR Deluge Valves	-	45	-	45
26	All Plants Lighting Upgrade	-	423	-	423
27	LBO, UBO, & COR Sump Oil Alarm Sys U/G	-	116	-	116
28	LBO & UBO Upgrade Spillway Gate Cntrl Ph.1	-	6	-	6
29	UBO & SLC Airwash Tank Rehab	-	104	-	104
30	Queen's Bay Level Gauge Building Ph.1	-	60	-	60
31		**20,118**	**19,873**	**19,947**	**20,044**
32					
	Transmission Plant				
33	Ellison Distribution Source	11,501	6,545	-	18,046
34	Black Mountain Distribution Source	7,523	7,196	-	14,719
35	Okanagan Transmission Reinforcement	7,256	21,405	24,398	4,263
36	Benvoulin Distribution Source	-	4,432	4,432	-
37	Big White 138 KV Line & Substation	-	110	-	110
38	Kettle Valley	1,401	321	-	1,722
39	Naramata Rehab	3,384	3,003	-	6,387
40	Ooteschenia substation	-	142	-	142
41	Capitalized Inventory	7,214	(1,079)	6,135	-
42	Recreation Capacity Increase Stage 1,2,3	-	696	696	-
43	Tarry's Capacity Increase	-	363	-	363
44	Kelowna Distribution Capacity Requirements	-	355	-	355
45	30L Conversion	-	1,567	1,567	-
46	Transmission Sustaining	-	3,134	-	3,134
47	Station Sustaining	1,233	4,491	497	5,227
48		**39,511**	**52,681**	**37,725**	**54,468**
49					
	Distribution Plant				
50	Small Capacity Improvements Unplanned	-	340	-	340
51	New Connects System Wide	-	15,453	-	15,453
52	New Glenmore Feeder	-	788	-	788
53	Christina Lake Feeder-1 Capacity Upgrade (Denied?)	-	6	-	6
54	HOL1 - OKM1 Tie KLO Rd	48	270	-	318
55	VAL1 Feeder Capacity Upgrade	171	728	-	899
56	LEE2 - HOL5 Tie Add N.O.	163	346	-	509
57	Distribution Sustaining	-	12,178	-	12,178
58		**382**	**30,109**	**-**	**30,491**
	General Plant				
59	Distribution Station Automation	656	1,957	-	2,613
60	Protection, Harmonic Remediation, Communications & Rehabilitation	-	797	-	797
61	Vehicles	-	2,042	-	2,042
62	Metering	-	526	-	526
63	Information Systems	668	4,416	-	5,084
64	Telecommunications	-	93	-	93
65	Buildings	55	1,305	-	1,360
66	Furniture & Fixtures	-	276	-	276
67	Tools & Equipment	-	522	-	522
68		**1,379**	**11,934**	**-**	**13,313**
69					
70	**TOTAL**	**61,391**	**114,597**	**57,672**	**118,316**

Table 1 – A – 1 – Additions to Plant in Service (2010)

		CWIP Dec. 31, 2009	Expenditures 2010	CWIP Dec 31, 2010	Additions to Plant in Service
			($000s)		
	Hydraulic Production				
1	All Plants Spare Unit Transformer	-	78	-	78
2	LBO & UBO Comm. Network Comp.	87	265	-	352
3	All Plants Fire Safety Upgrade Ph.1	-	100	-	100
4	SLC U1 Life Extension (replace turbine)	14,234	2,256	-	16,490
5	SLC U1 Head Gate Rebuild	-	77	-	77
6	All Plants Public Safety & Security Ph.1	15	92	-	107
7	UBO Old Unit Repowering (Ph.1)	-	461	-	461
8	All Plants Upgrade Station Service Supply	208	1,191	169	1,230
9	SLC Plant Completion	1,481	727	-	2,208
10	COR U1 Life Extension (replace Turbine)	3,690	9,680	13,370	-
11	COR U2 Life Extension (replace Turbine)	17	2,968	2,681	304
12	SLC Dam Rehabilitation Study	12	30	-	42
13	UBO Extension Trash Rack Gantry Replacement	-	417	-	417
14	All Plants Spare Exciter Transformer	33	107	-	140
15	LBO Intake Area Upgrade Ph.2	-	102	-	102
16	SLC Domestic Water Supply Ph.3	42	43	-	85
17	All Plants 2009 Pump Upgrades	128	80	-	208
18	All Plants Lighting Upgrade	-	306	-	306
19	LBO & UBO Upgrade Spillway Gate Cntrl Ph.1	-	30	-	30
20	SLC Tailrace Gate Corrosion Control	-	114	-	114
21	UBO U5/U6 Tailrace Gate Corrosion Control	-	139	-	139
22		**19,947**	**19,263**	**16,220**	**22,990**
23					
	Transmission Plant				
24	Ellison Distribution Source	-	500	-	500
25	Okanagan Transmission Reinforcement	24,398	62,208	37,577	49,029
26	Benvoulin Distribution Source	4,432	13,301	-	17,733
27	Huth Split Bus	-	413	-	413
28	Capitalized Inventory & Transformers	6,135	-	6,135	-
29	Recreation Capacity Increase Stage 1,2,3	696	2,257	-	2,953
30	Kelowna Distribution Capacity Requirements	-	517	-	517
31	30L Conversion Slocan / Coffee Creek S/Stns	1,567	2,340	-	3,907
32	Transmission Sustaining	-	4,871	-	4,871
33	Station Sustaining	497	5,304	-	5,801
34		**37,725**	**91,711**	**43,712**	**85,724**
35					
	Distribution Plant				
36	Small Capacity Improvements Unplanned	-	994	-	994
37	New Connects System Wide	-	19,070	-	19,070
38	Airport Way Upgrade (Ellison Feeder - 3)	-	1,551	-	1,551
39	Hollywood-3 & Sexsmith-4 Tie	-	365	-	365
40	Oliver Feeder-1 New Regulator	-	137	-	137
41	Beaver Park Feeder-2 to Fruitvale Feeder-1 Distribution Tie Upgrade	-	1,227	-	1,227
42	Distribution Sustaining	-	14,525	-	14,525
43		**-**	**37,869**	**-**	**37,869**
44					
	General Plant				
45	Distribution Station Automation	-	1,664	-	1,664
46	Protection, Harmonic Remediation, Communications & Rehabilitation	-	619	-	619
47	Mandatory Reliability Compliance (MRC)	-	2,399	-	2,399
48	Vehicles	-	2,000	-	2,000
49	Metering	-	559	-	559
50	Information Systems	-	4,494	-	4,494
51	Telecommunications	-	106	-	106
52	Buildings	-	1,062	-	1,062
53	Furniture & Fixtures	-	393	-	393
54	Tools & Equipment	-	575	-	575
55		**-**	**13,871**	**-**	**13,871**
56					
57	**TOTAL**	**57,672**	**162,714**	**59,932**	**160,454**

Table 1 – B – Deferred Charges and Credits (2009)

		Balance at Dec. 31, 2008	Additions and Transfers	Amortized / Transferred to Other Accounts	Amortization	Balance at Dec. 31, 2009
				($000s)		
1	**Demand Side Management**					
2	Demand Side Management Additions	19,783	3,447	-	(2,689)	20,542
3	Tax Impact	(13,165)	(1,034)	-	1,790	(12,409)
4	PLP Energy Management	36	-	-	(36)	-
5		**6,654**	**2,413**	**-**	**(934)**	**8,132**
6						
7	**Preliminary and Investigative Charges**	**664**	**868**	**(447)**	**-**	**1,085**
8						
9	**Deferred Regulatory Expense**					
10	Deferred Revenue - Incentive Adjustment	173	-	(173)	-	-
11	2008 Incentive	(1,938)	-	1,616	-	(322)
12	2009 Incentive	-	(2,368)	-	-	(2,368)
13	2005 Revenue Requirements	176	-	-	(176)	-
14	Tax Impact	(50)	-	-	50	-
15	2006 Revenue Requirements	54	-	-	(54)	-
16	Tax Impact	(17)	-	-	17	-
17	2008 Revenue Requirements	39	-	-	(39)	-
18	Tax Impact	(13)	-	-	13	-
19	2009 Revenue Requirements	15	27	-	-	43
20	Tax Impact	(5)	(8)	-	-	(13)
21	2010 Revenue Requirements	-	50	-	-	50
22	Tax Impact	-	(15)	-	-	(15)
23	2009 COSA & RDA	294	461	-	-	755
24	Tax Impact	(93)	(138)	-	-	(231)
25	BC Hydro Amendment to 3808 (PPA Proceedings)	-	125	-	-	125
26	Tax Impact	-	(37)	-	-	(37)
27	Section-5 Provincial Transmission Enquiry	-	100	-	-	100
28	Tax Impact	-	(30)	-	-	(30)
29	Renew BCH Power Purchase Agreement	18	202	-	-	220
30	Tax Impact	(6)	(61)	-	-	(66)
31	BC Hydro Waneta Transaction Application	-	125	-	-	125
32	Tax Impact	-	(38)	-	-	(38)
33	Terasen Gas ROE Application	-	60	-	-	60
34	Tax Impact	-	(18)	-	-	(18)
35		**(1,352)**	**(1,563)**	**1,443**	**(188)**	**(1,661)**
36						
37	**Other Deferred Charges and Credits**					
38	Trail Office Lease Costs	179	-	-	(12)	167
39	Trail Office Rental to SD#20	(636)	-	(44)	-	(679)
40	Prepaid Pension Costs	8,553	546	-	-	9,099
41	Tax Impact	(1,067)	(164)	-	-	(1,231)
42	Post Retirement Benefits	(5,679)	(2,003)	-	-	(7,682)
43	Tax Impact	1,858	601	-	-	2,459
44	2005 System Development Plan	164	-	-	(164)	-
45	Tax Impact	(7)	-	-	7	-
46	2008 System Development Plan Update	1,082	28	-	(541)	569
47	Tax Impact	(343)	(8)	-	172	(180)
48	Deferred Sensitivity	-	-	-	-	-
49	Deferred Tax Sensitivity	-	-	-	-	-
50	Advanced Metering Infrastructure	243	(243)	-	-	-
51	Tax Impact	(77)	77	-	-	-
52	2005 Resource Plan	31	-	-	(31)	-
53	Tax Impact	(3)	-	-	3	-
54	2009 Resource Plan Update	405	195	-	-	600
55	Tax Impact	(132)	(59)	-	-	(191)
56	Revenue Protection	183	220	-	(183)	220
57	Tax Impact	(57)	(66)	-	57	(66)
58	PLP Potential Substation	14	-	-	(14)	-
59	PLP Settlement Costs	32	-	-	(16)	16
60	PLP Computer Software	86	-	-	(23)	63
61	PLP Deferred Pension Credit	(70)	-	-	12	(58)
62	ROW Reclamation (Pine Beetle Kill)	2,507		-	(251)	2,257
63	Tax Impact	(777)	-	-	78	(700)
64	International Financial Reporting Standards	131	300	-	(131)	300
65	Tax Impact	(40)	(90)	-	40	(90)
66	Right of Way Encroachment Litigation	47	33	-	-	80
67	Tax Impact	(14)	(10)	-	-	(24)
68	2011-2030 Integrated System Plan	-	200	-	-	200
69	Tax Impact	-	(60)	-	-	(60)
70	DSM Study	-	100	-	-	100
71	Tax Impact	-	(30)	-	-	(30)
72	Joint Pole Use Audit 2008	-	155	-	(31)	124
73	Tax Impact	-	(47)	-	9	(37)
74	NERC / MRC Set up Cost	-	113	-	-	113
75	Tax Impact	-	(34)	-	-	(34)
76		**6,611**	**(245)**	**(44)**	**(1,019)**	**5,304**
77	**Deferred Debt Issue Costs**					
78	Series E	4	-	-	(4)	-
79	Series F	116	-	-	(13)	104
80	Series G	109	-	-	(9)	100
81	Series H	92	-	-	(14)	78
82	Series I	185	-	-	(14)	172
83	Series J	66	-	-	(66)	-
84	Series 04-1	1,286	-	-	(214)	1,072
85	Tax Impact	(63)	-	-	8	(55)
86	Series 05-1	1,114	-	-	(41)	1,073
87	Tax Impact	(314)	(90)	-	13	(391)
88	Series 07-1	1,216	-	-	(31)	1,184
89	Tax Impact	(160)	(87)	-	4	(243)
90	MTN-2009	-	1,025	-	-	1,025
91	Tax Impact	-	(62)	-	-	(62)
92		**3,651**	**787**	**-**	**(380)**	**4,058**
93						
94	TOTAL DEFERRED CHARGES RATE BASE	**16,228**	**2,259**	**952**	**(2,521)**	**16,918**
95						
96	BC Hydro Amendment to 3808 (PPA Proceedings)	37	(37)	-	-	-
97	Tax Impact	(11)	11	-	-	-
98	Advanced Metering Infrastructure	-	669	-	-	669
99	Tax Impact	-	(205)	-	-	(205)
100	**TOTAL DEFERRED CHARGES**	**16,253**	**2,697**	**952**	**(2,521)**	**17,382**

Note: In terms of the NSA of November 2009 the AMI development costs are being recorded in a non-rate base deferral account that will attract AFUDC for the 2010 Revenue Requirements on a without prejudice basis. (Refer to Lines 50, 51 and 98, 99)

Table 1 – B – Deferred Charges and Credits (2010)

		Balance at Dec. 31, 2009	Additions and Transfers	Amortized / Transferred to Other Accounts ($000s)	Amortization	Balance at Dec. 31, 2010
1	Demand Side Management					
2	Demand Side Management Additions	20,542	3,952	-	(3,272)	21,222
3	Tax Impact	(12,409)	(1,126)	-	933	(12,603)
4		**8,132**	**2,826**	**-**	**(2,339)**	**8,619**
5						
6	Preliminary and Investigative Charges	**1,085**	**2,876**	**(2,928)**	**-**	**1,032**
7						
8	Deferred Regulatory Expense					
9	2008 Incentive	(322)	-	322	-	-
10	2009 Incentive	(2,368)	-	2,368	-	-
11	2009 Revenue Requirements	43	-	-	(43)	-
12	Tax Impact	(13)	-	-	13	-
13	2010 Revenue Requirements	50	-	-	-	50
14	Tax Impact	(15)	-	-	-	(15)
15	2011 Revenue Requirements	-	50	-	-	50
16	Tax Impact	-	(14)	-	-	(14)
17	2009 COSA & RDA	755	245	-	-	1,000
18	Tax Impact	(231)	(70)	-	-	(301)
19	BC Hydro Amendment to 3808 (PPA Proceedings)	125	-	-	(42)	83
20	Tax Impact	(37)	-	-	12	(25)
21	Section-5 Provincial Transmission Enquiry	100	100	-	-	200
22	Tax Impact	(30)	(29)	-	-	(59)
23	Renew BCH Power Purchase Agreement	220	-	-	-	220
24	Tax Impact	(66)	-	-	-	(66)
25	BC Hydro Waneta Transaction Application	125	-	-	-	125
26	Tax Impact	(38)	-	-	-	(38)
27	Terasen Gas ROE Application	60	-	-	-	60
28	Tax Impact	(18)	-	-	-	(18)
29		**(1,661)**	**282**	**2,690**	**(59)**	**1,253**
30						
31	Other Deferred Charges and Credits					
32	Trail Office Lease Costs	167	-	-	(12)	155
33	Trail Office Rental to SD#20	(679)	-	(50)	-	(729)
34	Prepaid Pension Costs	9,099	(1,442)	-	-	7,657
35	Tax Impact	(1,231)	411	-	-	(820)
36	Post Retirement Benefits	(7,682)	(2,599)	-	-	(10,281)
37	Tax Impact	2,459	741	-	-	3,200
38	2008 System Development Plan Update	569	-	-	(569)	-
39	Tax Impact	(180)	-	-	180	-
40	2009 Resource Plan Update	600	360	-	-	960
41	Tax Impact	(191)	(103)	-	-	(293)
42	Revenue Protection	220	230	-	(220)	230
43	Tax Impact	(66)	(66)	-	66	(66)
44	PLP Settlement Costs	16	-	-	(16)	-
45	PLP Computer Software	63	-	-	(23)	40
46	PLP Deferred Pension Credit	(58)	-	-	12	(46)
47	ROW Reclamation (Pine Beetle Kill)	2,257		-	(251)	2,006
48	Tax Impact	(700)	-	-	78	(622)
49	International Financial Reporting Standards	300	223	-	(300)	223
50	Tax Impact	(90)	(64)	-	90	(64)
51	Right of Way Encroachment Litigation	80	40	-	-	120
52	Tax Impact	(24)	(11)	-	-	(36)
53	2011-2030 Integrated System Plan	200	1,000	-	-	1,200
54	Tax Impact	(60)	(285)	-	-	(345)
55	DSM Study	100	165	-	-	265
56	Tax Impact	(30)	(47)	-	-	(77)
57	Joint Pole Use Audit 2008	124	-	-	(31)	93
58	Tax Impact	(37)	-	-	9	(28)
59	NERC / MRC Set up Cost	113	1,017	-	-	1,130
60	Tax Impact	(34)	(290)	-	-	(324)
61		**5,304**	**(719)**	**(50)**	**(987)**	**3,548**
62	Deferred Debt Issue Costs					
63	Series F	104	-	-	(35)	69
64	Series G	100	-	-	(9)	92
65	Series H	78	-	-	(14)	64
66	Series I	172	-	-	(14)	158
67	Series 04-1	1,072	-	-	(214)	858
68	Tax Impact	(55)	-	-	11	(44)
69	Series 05-1	1,073	-	-	(41)	1,032
70	Tax Impact	(391)	-	-	15	(376)
71	Series 07-1	1,184	-	-	(31)	1,153
72	Tax Impact	(243)	(87)	-	6	(324)
73	MTN-2009	1,025	-	-	(34)	991
74	Tax Impact	(62)	(62)	-	2	(121)
75	MTN-2010	-	1,155	-	-	1,155
76	Tax Impact	-	(66)	-	-	(66)
77		**4,058**	**941**	**-**	**(357)**	**4,641**
78						
79	TOTAL DEFERRED CHARGES RATE BASE	**16,918**	**6,205**	**(287)**	**(3,742)**	**19,094**
80						
81	BC Hydro Amendment to 3808 (PPA Proceedings)	-	-	-	-	-
82	Tax Impact	-	-	-	-	-
83	Advanced Metering Infrastructure	669	717	-	-	1,386
84	Tax Impact	(205)	(204)	-	-	(410)
85		**17,382**	**6,718**	**(287)**	**(3,742)**	**20,070**

Note: In terms of the NSA of November 2009 the AMI development costs are being recorded in a non-rate base deferral account that will attract AFUDC for the 2010 Revenue Requirements on a without prejudice basis. (Refer to Lines 83, 84)

Table 1 – C – Accumulated Provision for Depreciation and Amortization (2009)

Line	Account		Acc. Prov. For Depreciation Dec. 31, 2008	Deprec. Rate	Asset Balance Dec. 31, 2008	Depreciation Expense Dec. 31, 2009	Charges less Recoveries	Acc. Prov. For Depreciation Dec. 31, 2009
						($000s)		
		Hydraulic Production Plant						
1	330	Land Rights	(735)	2.6%	847	22	-	(713)
2	331	Structures and Improvements	4,666	1.2%	11,280	135	(38)	4,762
3	332	Reservoirs, Dams and Waterways	3,133	1.7%	21,040	359	(194)	3,297
4	333	Water Wheels, Turbines & Generators	3,825	2.2%	56,545	1,246	(939)	4,133
5	334	Accessory Electrical Equipment	7,532	2.4%	22,911	551	(287)	7,795
6	335	Other Power Plant Equipment	7,175	2.3%	38,349	884	(71)	7,988
7	336	Roads, Railroads, and Bridges	216	1.4%	1,053	15	-	231
8			25,811	2.1%	152,024	3,212	(1,530)	27,494
9		Transmission Plant						
10	350	Land Rights - R/W	(72)	0.0%	7,079	-	-	(72)
11	350.1	Land Rights - Clearing	1,023	1.6%	4,496	72	-	1,095
12	353	Station Equipment	25,996	3.0%	167,529	5,036	(1,426)	29,606
13	355	Poles Towers & Fixtures	15,779	3.0%	74,499	2,239	(590)	17,428
14	356	Conductors and Devices	12,183	3.0%	71,955	2,163	(554)	13,792
15	359	Roads and Trails	33	2.9%	817	24	(9)	47
16			54,942	2.9%	326,374	9,534	(2,580)	61,896
17		Distribution Plant						
18	360	Land Rights - R/W	-	0.0%	2,986	-	-	-
19	360.1	Land Rights - Clearing	402	2.1%	7,106	149	-	552
20	362	Station Equipment	28,594	3.0%	116,942	3,515	(73)	32,036
21	364	Poles Towers & Fixtures	33,001	3.0%	114,210	3,433	(474)	35,959
22	365	Conductors and Devices	47,185	3.0%	186,542	5,607	(682)	52,110
23	368	Line Transformers	15,530	2.9%	88,933	2,584	(1,503)	16,611
24	369	Services	6,439	0.5%	7,292	36	-	6,475
25	370	Meters	4,857	3.5%	13,189	463	(304)	5,016
26	371	Installation on Customers' Premises	985	0.0%	5,336	-	(29)	956
27	373	Street Lighting and Signal Systems	1,600	2.4%	7,272	175	(46)	1,730
28			138,594	2.9%	549,806	15,962	(3,111)	151,445
29		General Plant						
30	389	Land	(11)	0.0%	5,800	-	-	(11)
31	390	Structures - Frame & Iron	531	0.8%	337	3	-	534
32	390.1	Structures - Masonry	2,992	3.0%	21,293	640	(16)	3,616
33	391	Office Furniture & Equipment	3,547	7.5%	5,596	421	(8)	3,960
34	391.1	Computer Equipment	30,118	10.6%	50,977	5,414	(242)	35,290
35	392	Transportation Equipment	2,941	0.4%	16,563	66	(1,536)	1,471
36	394	Tools and Work Equipment	5,607	9.5%	10,566	1,006	(7)	6,606
37	397	Communication Structures and Equipment	5,936	6.0%	22,880	1,376	(28)	7,284
38			51,661	6.7%	134,012	8,926	(1,836)	58,751
39								
40	108	Total Accumulated Depreciation	271,008	3.2%	1,162,217	37,634	(9,056)	299,585
41								
42		Deduct - Portion of CIAC Depreciated	-			(3,657)		
43								
44	403	Depreciation Expense				33,977		
45								
46		Other						
47	114	Utility Plant Acquisition Adjustment	4,652		11,912	186		4,838
48	390	Leasehold Improvements	1,645		3,240	389		2,034
49		Rate Stabilization Adjustment	(2,176)			311		(1,865)
50		Total Accumulated Amortization	4,121			886		5,006
51								
52		Accumulated Amortization per						
53		Balance Sheet	275,128			34,863		304,592

Table 1 – C – Accumulated Provision for Depreciation and Amortization (2010)

Line	Account		Acc. Prov. For Depreciation Dec. 31, 2009	Deprec. Rate	Asset Balance Dec. 31, 2009	Depreciation Expense Dec. 31, 2010	Charges less Recoveries	Acc. Prov. For Depreciation Dec. 31, 2010
			($000s)			($000s)		
		Hydraulic Production Plant 2,3, & 4 Plant						
1	330	Land Rights	(713)	2.6%	847	22	-	(691)
2	331	Structures and Improvements	4,762	1.2%	11,938	143	(18)	4,887
3	332	Reservoirs, Dams and Waterways	3,297	1.7%	24,282	413	(183)	3,527
4	333	Water Wheels, Turbines & Generators	4,133	2.2%	69,326	1,525	(1,017)	4,641
5	334	Accessory Electrical Equipment	7,795	2.4%	25,252	606	(240)	8,161
6	335	Other Power Plant Equipment	7,988	2.3%	39,011	897	(44)	8,841
7	336	Roads, Railroads, and Bridges	231	1.4%	1,053	15	-	246
9			27,494	2.1%	171,710	3,621	(1,502)	29,613
10		Transmission Plant	-					-
11	350	Land Rights - R/W	(72)	0.0%	7,468	-	-	(72)
12	350.1	Land Rights - Clearing	1,095	1.6%	4,885	78	-	1,173
13	353	Station Equipment	29,606	3.0%	197,380	5,921	(1,973)	33,554
14	355	Poles Towers & Fixtures	17,428	3.0%	86,523	2,596	(807)	19,217
15	356	Conductors and Devices	13,792	3.0%	83,560	2,507	(533)	15,766
16	359	Roads and Trails	47	2.9%	1,011	29	(13)	63
17			61,896	2.9%	380,827	11,131	(3,326)	69,701
18		Distribution Plant						
19	360	Land Rights - R/W	-	0.0%	4,200	-	-	-
20	360.1	Land Rights - Clearing	552	2.1%	8,320	175	-	727
21	362	Station Equipment	32,036	3.0%	116,868	3,506	(73)	35,469
22	364	Poles Towers & Fixtures	35,959	3.0%	125,500	3,765	(550)	39,174
23	365	Conductors and Devices	52,110	3.0%	195,026	5,851	(731)	57,230
24	368	Line Transformers	16,611	2.9%	91,445	2,652	(1,525)	17,739
25	369	Services	6,475	0.5%	7,292	36	-	6,511
26	370	Meters	5,016	3.5%	13,483	472	(307)	5,181
27	371	Installation on Customers' Premises	956	0.0%	8,118	-	(43)	913
28	373	Street Lighting and Signal Systems	1,730	2.4%	7,226	173	(46)	1,857
29			151,445	2.9%	577,477	16,630	(3,275)	164,800
30		General Plant						
31	389	Land	(11)	0.0%	5,800	-	-	(11)
32	390	Structures - Frame & Iron	534	0.8%	337	3	-	537
33	390.1	Structures - Masonry	3,616	3.0%	22,465	674	(2)	4,288
34	391	Office Furniture & Equipment	3,960	7.5%	6,178	463	(2)	4,421
35	391.1	Computer Equipment	35,290	10.6%	57,313	6,075	(178)	41,187
36	392	Transportation Equipment	1,471	0.4%	17,094	68	(1,516)	23
39	394	Tools and Work Equipment	6,606	9.5%	11,167	1,061	(1)	7,666
40	397	Communication Structures and Equipment	7,284	6.0%	25,154	1,509	(7)	8,786
41			58,751	6.8%	145,508	9,853	(1,707)	66,896
42								
43	108	Total Accumulated Depreciation	299,585	3.2%	1,275,522	41,235	(9,810)	331,010
44								
45		Deduct - Portion of CIAC Depreciated				(3,852)		
46								
47	403	Depreciation Expense				37,383		
48								
49		Other						
50	114	Utility Plant Acquisition Adjustment	4,838		11,912	186		5,024
51	390	Leasehold Improvements	2,034		3,382	406		2,440
52		Rate Stabilization Adjustment	(1,865)			311		(1,554)
53		Total Accumulated Amortization	5,006			903		5,909
54								
55		Accumulated Amortization per						
56		Balance Sheet	304,592			38,286		336,919

Table 1 – D – Contributions in Aid of Construction (CIAC)

	Actual		Forecast		Forecast	
	2008 Additions	Dec. 31 2008	2009 Additions	Dec. 31 2009	2010 Additions	Dec. 31 2010
			($000s)			
1 Gross Book Value	11,736	121,890	6,500	128,390	8,400	136,790
2 Accumulated Depreciation	(3,305)	(35,109)	(3,657)	(38,766)	(3,852)	(42,618)
3 **Net Book Value**		**86,782**		**89,625**		**94,173**

Table 1 – E – Allowance for Working Capital (2010)

		Lag (Lead) Days	2010 Forecast ($000s)	2010 Extended ($000s)	Weighted Average Lag Days
1	**Revenue**				
2	Tariff Revenue	50.3	250,547	12,603	
3	*Other Revenue:*				
4	Apparatus and Facilities Rental	26.6	2,476	66	
5	Contract Revenue	44.3	1,648	73	
6	Miscellaneous Revenue	31.8	686	22	
7	Investment Income	15.0	217	3	
8			**255,573**	**12,766**	**50.0**
9					
10	**Expenses**				
11	Power Purchases	42.2	77,827	3,284	
12	Wheeling	40.2	4,019	162	
13	Water Fees	(1.0)	9,068	(9)	
14	*Operating Labour:*			0	
15	Salaries & Wages	5.3	15,142	80	
16	Employee Benefits	13.2	10,978	145	
17	Contracted Manpower	50.6	5,008	253	
18	Property Tax	2.6	12,548	33	
19	Rental of T&D Facilities	47.8	3,115	149	
20	Office Lease - Kelowna	(15.2)	222	(3)	
21	Office Lease - Trail	91.3	1,212	111	
22	Materials & Others	45.6	704	32	
23	Insurance	(182.5)	1,736	(317)	
24	Income Tax	15.2	3,656	56	
25	Interest	82.9	36,760	3,047	
26			**181,994**	**7,022**	**38.6**
27					
28	**Net Lag/(Lead) Days**				**11.4**
29					
30					
31	**Forecast Working Capital Allowance**				
32					
33	**Lead-Lag Study Allowance**				5,669
34	Net Lag Days/365 times Expenses				
35					
36	**Add Funds Unavailable:**				
37	Customer Loans (related to energy management)			3,680	
38	Employee Loans			310	
39	Uncollectable Accounts			1,305	
40	Inventory (forecast monthly average investment)			620	
41					5,915
42	**Less Funds Available:**				
43	Average Customer Deposits			3,700	
44	Average Employee Payroll Deductions			-	
45	Average Provincial Services Tax			500	
46	Average Goods and Services Tax			400	
47					4,600
48					
49	**2010 FORECAST ALLOWANCE FOR WORKING CAPITAL**				**6,984**

Table 1 – F – Adjustment for Capital Expenditures (2010)

		Plant in Service	Months in Rate Base	Weighted Value
		($000s)		($000s)
1	January	5,802	11.5	5,560
2	February	20,479	10.5	17,919
3	March	5,919	9.5	4,686
4	April	4,473	8.5	3,168
5	May	4,905	7.5	3,066
6	June	24,220	6.5	13,119
7	July	7,891	5.5	3,617
8	August	4,492	4.5	1,685
9	September	4,028	3.5	1,175
10	October	22,976	2.5	4,787
11	November	36,415	1.5	4,552
12	December	10,454	0.5	436
13	**Total**	**152,054**		**63,769**
14	**Less Simple Average**			76,027
15	**Adjustment to Rate Base**			**(12,259)**

Note: Plant in Service is reduced by Contributions in Aid of Construction

SCHEDULE 2 – EARNED RETURN

		Actual 2008	Forecast 2009	Forecast 2010
1	SALES VOLUME (GWh)	3,087	3,129	3,199
2			($000s)	
3	ELECTRICITY SALES REVENUE	220,909	235,595	250,547
4				
5	EXPENSES			
6	Power Purchases	66,010	69,638	77,827
7	Water Fees	7,878	8,656	9,068
8	Wheeling	3,655	3,994	4,019
9	Net O&M Expense	35,663	37,258	38,116
10	Property Tax	11,036	11,473	12,548
11	Depreciation and Amortization	34,016	37,384	42,028
12	Other Income	(5,035)	(5,178)	(5,025)
13	AFUDC	-	-	-
14	Incentive Adjustments	654	925	(2,690)
15	UTILITY INCOME BEFORE TAX	67,032	71,446	74,657
16	Less:			
17	INCOME TAXES	5,869	4,377	3,656
18				
19	**EARNED RETURN**	**61,163**	**67,069**	**71,000**
20	RETURN ON RATE BASE			
21	Utility Rate Base	802,566	869,110	974,944
22	Return on Rate Base	7.62%	7.72%	7.28%

Table 2 – A – 1 –Sales by Customer Class

		Actual 2008	Forecast 2009	Forecast 2010
			(GWh)	
1	Residential	1,221	1,265	1,248
2	General Service	666	665	682
3	Industrial	252	205	291
4	Wholesale	892	924	915
5	Lighting	14	17	13
6	Irrigation	42	53	50
7	Total Sales	3,087	3,129	3,199
9	Losses and Company Use	314	308	310
10	**Gross Load**	**3,401**	**3,437**	**3,509**

Table 2 – A – 2 – Sales Revenue by Customer Class

		Actual 2008	Forecast 2009	Forecast 2010
			($000s)	
11	Residential	102,600	110,412	109,526
12	General Service	53,820	56,867	58,631
13	Industrial	14,470	13,981	19,927
14	Wholesale	45,614	49,584	49,063
15	Lighting and Irrigation	4,405	4,752	4,885
17	**Total**	**220,909**	**235,595**	**242,031**
18	* Forecast at 2009 Re-approved rates			

Table 2 – A – 3 – Customer Count at Year-End

		Actual 2008	Forecast 2009	Forecast 2010
19	Residential	95,502	96,866	98,264
20	General Service	11,216	11,344	11,667
21	Wholesale	7	7	7
22	Industrial	36	34	34
23	Lighting & Irrigation	2,958	2,939	2,939
24	**Total**	**109,719**	**111,190**	**112,911**

Table 2 – B – Power Purchase Expense

		Actual 2008	Forecast 2009	Forecast 2010
			(GWh)	
1	FortisBC	1,610	1,553	1,596
2	DSM	-	7	30
3	Power Purchases (net of surplus sales)	1,791	1,884	1,913
4	Total System Load (before DSM savings)	3,401	3,444	3,539
5	Less DSM	-	(7)	(30)
6	**Total System Load (including DSM savings)**	**3,401**	**3,437**	**3,509**
			($000s)	
7	Expense - Energy	53,540	58,809	64,627
8	Expense - Capacity	12,624	12,050	14,090
9	Capital Proj., Special, Accounting & other B. Pool Adjustments	(154)	(1,221)	(890)
10	**Total Power Purchase Expense**	**66,010**	**69,638**	**77,827**

	Reconciliation of Power Purchase Expense	
11	Power Purchase Expense (November 2 Update)	77,125
12	Increase due to Residential and General Service Load Increases	1,256
13	Correction identified at Annual Review	(54)
14	Negotiated Reduction	(500)
15	**Power Purchase Expense (Negotiated Settlement Agreement)**	**77,827**

Table 2 – C – Water Fees

		Actual 2008	Forecast 2009	Forecast 2010
1	Plant Entitlement Use (GWh) in previous year	1,498	1,610	1,553
2	**Water Fees ($000s)**	**7,878**	**8,656**	**9,068**

Table 2 – D – Wheeling

		Actual 2008	Forecast 2009	Forecast 2010
1	**Wheeling Nomination**	(MW per year)		
2	Okanagan	1,965	2,115	2,160
3	Creston	402	420	420
4	**Expense**	($000s)		
5	Okanagan	3,223	3,500	3,546
6	Creston	425	453	449
7	Other	7	41	24
8	Woods Lake Wheeling Revenue (Estimated)			
9	**Total Wheeling Expense**	**3,655**	**3,994**	**4,019**

Table 2 – E – Operating and Maintenance Expense

		Approved 2009	Forecast 2010
1	O&M, Formula-Driven		
2	Base O&M Cost per Customer	$ 382.48	$ 379.04
3	**Consumer Price Index (British Columbia)**	2.1%	2.0%
4	Productivity Improvement Factor	-3.0%	-1.5%
5	O&M per Customer, Escalated	$ 379.04	$ 380.93
6			
7	Average Number of Customers (Line 22)	110,921	112,051
8			
9		($000s)	
10	Base O&M (Line 5 times Line 7)	42,043	42,684
11			
12	Pension and Post-Retirement Benefits (Note 1)	3,318	3,749
16	Trail Office Lease (Note 1)	1,212	1,212
17	**Total Operating and Maintenance Expense for Base O&M**	**46,573**	**47,645**
18			
19	Capitalized Overhead	(9,315)	(9,529)
20	**Net Operating & Maintenance Expense**	**37,258**	**38,116**
21			
22	Number of Customers		
23	Opening Count	109,928	111,190
24	Ending Count	111,913	112,911
25	**Average Number of Customers**	**110,921**	**112,051**

Note 1: Base O&M

Under the terms of the PBR Mechanism, Pension and Post-Retirement Benefits and the Trail Office Lease costs are excluded from the formula in calculating Base O&M.

Table 2 – F – Property Tax

		Actual 2008	Forecast 2009	Forecast 2010
			($000s)	
1	Generating Plant	2,459	2,548	2,760
2	Transmission and Distribution	5,209	5,405	5,651
3	Substation Equipment	2,855	3,000	3,535
4	Land and Buildings	513	520	602
5	**Total Property Tax**	**11,036**	**11,473**	**12,548**

Table 2 – G – Other Income

		Actual 2008	Forecast 2009	Forecast 2010
		($000s)		
1	Apparatus and Facilities Rental			
2	Electric Apparatus Rental	2,281	2,751	2,340
3	Lease Revenue	169	169	136
4		**2,450**	**2,920**	**2,476**
5	Contract Revenue			
6	Waneta Management Fee	368	299	393
7	Waneta Management Fee Capital	170	2	-
8	Waneta Carrying Costs	94	95	94
9				
10	Brilliant Management Fee	139	186	213
11	Brilliant Management Fee Capital	314	276	375
12				
13	Fortis Pacific Holdings Inc.	516	513	573
14		**1,601**	**1,371**	**1,648**
15	Miscellaneous Revenue			
16	Connection Charges	469	477	495
17	NSF Cheque Charges	9	9	9
18	Sundry Revenue	175	175	181
19		**652**	**661**	**686**
20				
21	Investment Income	**333**	**226**	**217**
22				
23	**Total**	**5,035**	**5,178**	**5,025**

Table 2 – H – 1 – 2009 Flow Through Adjustments

		Approved	Forecast	Variance	Income Tax Shield	After Tax Amount	Customer Share	Flow Through Adjustment
					($000s)			
1	2008 Incentive True Up	1,443	1,765	(322)	-	(322)	100%	**(322)**
2	Interest Expense	34,803	33,553	(1,250)	(375)	(875)	100%	(875)
3	CCA Change for Computer Hardware	-	(109)	(109)	-	(109)	100%	(109)
4	Nelson Hydro Export Sales	-	26	26	8	18	100%	18
5	Pension Expense	3,318	3,171	(147)	(44)	(103)	100%	(103)
6	Flow Through Adjustment							**(1,068)**

Table 2 – H – 2 – 2009 ROE Incentive Adjustment

		Approved	Forecast	Variance	Customer Share	ROE Incentive Adjustment
				($000s)		
7	Net Income for ROE Incentive	32,215	34,814	2,599	50%	(1,300)
8	Common Equity	363,191	347,644			
9	Allowed ROE	8.87%	10.01%	1.14%	50%	0.57%

SCHEDULE 3 – INCOME TAX EXPENSE

		Actual 2008	Forecast 2009	Forecast 2010
			($000s)	
1	UTILITY INCOME BEFORE TAX	67,032	71,446	74,657
2	Deduct:			
3	Interest Expense	30,163	33,554	36,760
4				
5	ACCOUNTING INCOME	36,869	37,892	37,896
6				
7	Deductions			
8	Capital Cost Allowance	42,886	50,421	54,511
9	Capitalized Overhead	9,062	9,315	9,529
10	Incentive & Revenue Deferrals	(654)	(925)	2,690
11	Financing Fees	922	912	681
12	Other	611	134	436
13		52,827	59,857	67,847
14				
15	Additions			
16	Amortization of Deferred Charges	2,539	2,521	3,742
17	Depreciation	31,477	34,863	38,286
18		34,016	37,384	42,028
19				
20	TAXABLE INCOME	18,058	15,419	12,077
21				
22	Tax Rate	31.0%	30.0%	28.5%
23				
24	Taxes Payable	5,598	4,626	3,442
25	Prior Years' Overprovisions/(Underprovisions)	87	(487)	-
26	Deferred Charges Tax Effect	184	239	214
27				
28	**REGULATORY TAX PROVISION**	**5,869**	**4,377**	**3,656**

Table 3 – A – Calculation of Capital Cost Allowance

Line	Class	2009 Closing UCC	2010 Additions	Half-Year Rule	CCA Rate	2010 CCA	2010 Closing UCC
				($000s)			
1	1A	259,731	2,283	1,142	4%	10,435	251,579
2	1B	2,144	1,062	531	6%	160	3,046
3	17	87,359	20,102	10,051	8%	7,793	99,668
4	2	25,490	-	-	6%	1,529	23,961
5	3	1,474	-	-	5%	74	1,400
6	6	11	-	-	10%	1	10
7	8	4,976	2,124	1,062	20%	1,208	5,892
8	10	6,603	2,574	1,287	30%	2,367	6,810
9	12	1,500	2,690	1,345	100%	2,845	1,345
10	13	1,958	-	-	est	150	1,808
11	42	4,320	-	-	12%	518	3,802
12	45	1,108	-	-	45%	499	609
13	47	251,650	105,846	52,923	8%	24,366	333,130
14	50	1,105	-	-	55%	608	497
15	52	-	1,958	-	100%	1,958	-
16		**649,430**	**138,640**	**68,341**		**54,511**	**733,558**
17							
18	Land		3,915				
19	Net Salvage		(4,941)				
20	AFUDC		4,911				
21	Capitalized Overhead		9,529				
22	CIAC		8,400				
23	Plant in Service		160,454				

SCHEDULE 4 – COMMON SHARE EQUITY

			Actual 2008	Forecast 2009	Forecast 2010
				($000s)	
1	Share Capital		163,000	178,000	193,000
2	Retained Earnings		159,673	177,255	196,269
3					
4	COMMON EQUITY - OPENING BALANCE		322,673	355,255	389,269
5					
6	Less:	Common Dividends	(13,400)	(14,500)	(15,000)
7					
8	Add:	Net Income	31,001	33,514	34,240
9		Share Adjustment	(19)	-	-
10		Shares Issued	15,000	15,000	30,000
11					
12	COMMON EQUITY - CLOSING BALANCE		355,255	389,269	438,509
13					
14	SIMPLE AVERAGE		338,964	372,262	413,889
15					
16	Adjustment for Shares Issued		(4,925)	(6,212)	(6,164)
17	Deemed Equity Adjustment		-	(18,406)	(17,747)
18					
19	**COMMON EQUITY - AVERAGE**		**334,039**	**347,644**	**389,978**

Table 4 – A – Calculation of Adjustment for Shares Issued

		Actual 2008	Forecast 2009	Forecast 2010
			($000s)	
20	Opening Balance	163,000	178,000	193,000
21	Adjustment to Opening Balance			
22	Shares Issued #1	10,000	5,000	10,000
23	Issue Date	Sep 29	Sept 30	June 30
24				
25	Shares Issued #2	5,000	10,000	15,000
26	Issue Date	Dec 29	Dec 30	Sep 30
27				
28	Shares Issued #2			5,000
29	Issue Date			Dec 30
30				
31	Opening Balance x Days in Effect /365	163,000	178,000	193,000
32	Share Adjustment			
33	Issue #1 times Days in Effect / 365	2,548	1,260	5,041
34	Issue #2 times Days in Effect / 365	27	27	3,781
35	Issue #3 times Days in Effect / 365			14
36		165,575	179,288	201,836
37	less: Simple Average	(170,500)	(185,500)	(208,000)
38	**Adjustment for Shares Issued**	**(4,925)**	**(6,212)**	**(6,164)**

SCHEDULE 5 – RETURN ON CAPITAL

		Actual 2008	Forecast 2009	Forecast 2010
			($000s)	
1	Secured and Senior Unsecured Debt	489,468	527,002	560,959
2	Proportion	61.04%	60.64%	57.54%
3	Embedded Cost	6.36%	6.31%	6.22%
4	Cost Component	3.88%	3.83%	3.58%
5	Return	31,116	33,250	34,880
6				
7	Short Term Debt	(21,633)	(5,535)	24,008
8	Proportion	-2.70%	-0.64%	2.46%
9	Embedded Cost	4.40%	-5.49%	7.83%
10	Cost Component	-0.12%	0.03%	0.19%
11	Return (including fees)	(953)	304	1,880
12				
13				
14	Common Equity	334,039	347,644	389,978
15	Proportion	41.66%	40.00%	40.00%
16	Embedded Cost	9.28%	9.64%	8.78%
17	Cost Component	3.87%	3.86%	3.51%
18	Return	31,001	33,514	34,240
19				
20	TOTAL CAPITALIZATION	801,875	869,110	974,944
21	RATE BASE	802,566	869,110	974,944
22				
23	Earned Return	61,164	67,068	71,000
24				
25	RETURN ON CAPITAL	7.63%	7.72%	7.28%
26	RETURN ON RATE BASE	7.62%	7.72%	7.28%

The
British Columbia
Public Interest
Advocacy Centre

208–1090 West Pender Street
Vancouver, BC V6E 2N7
Coast Salish Territory
Tel: (604) 687-3063 Fax: (604) 682-7896
email: bcpiac@bcpiac.com
http://www.bcpiac.com

Valerie Conrad	687-3017
Sarah Khan	687-4134
Eugene Kung	687-3006
James L. Quail	687-3034
Ros Salvador	488-1315
Leigha Worth	687-3044

Barristers & Solicitors

Peggy Lee
Articled Student

Via Email

December 1, 2009

Erica Hamilton
Commission Secretary
BC Utilities Commission
Sixth Floor - 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Ms. Hamilton:

Re: FortisBC 2009 Annual Review, 2010 Revenue Requirements and Negotiated Settlement Process: BCUC Project No. 369570

We are solicitors for BC Old Age Pensioners' Organization, BC Coalition of People with Disabilities, Council of Senior Citizens' Organizations of BC, federated anti-poverty groups of BC, and Tenant Resource and Advisory Centre (collectively known as BCOAPO), and write to provide our comments on the draft Negotiated Settlement Agreement (NSA) in this proceeding.

As noted during the Negotiated Settlement Process (NSP), BCOAPO is concerned about FortisBC's rising electricity rates and the impact that these rates are having on residential ratepayers, and in particular on low and fixed income residential ratepayers. During the NSP we joined with several other intervenors to say that should FortisBC apply for a rate increase for 2011 of more than 5%, we will take the position that the 2011 Revenue Requirements application should be dealt with at a full oral public hearing before the Commission. We are not requesting that this become an amendment to the NSA for 2010, but did state at the NSP that we would include this concern in our letter of comment.

We would like to thank Commission staff, FortisBC and the other parties for their efforts in reaching the NSA.

Yours truly,

BC PUBLIC INTEREST ADVOCACY CENTRE

Original on file signed by:

Sarah Khan
Barrister & Solicitor

c. FortisBC
Intervenors

Domingo, Yolanda BCUC:EX

From:	Sarah Khan [Skhan@bcpiac.com]
Sent:	Thursday, December 3, 2009 11:56 AM
To:	Domingo, Yolanda BCUC:EX
Subject:	RE: Project No. 369570 - FortisBC 2010 Revenue Requirements NSA

Hi Yolanda,

Yes, I can confirm that BCOAPO accepts the terms of the 2010 FortisBC Draft NSA and that we have no edits to the document.

Sarah Khan
Staff Lawyer, BC Public Interest Advocacy Centre
208 - 1090 West Pender Street Vancouver, BC V6E 2N7
Coast Salish Territory
Ph: 604.687.4134 Fax: 604.682-7896
www.bcpiac.com

Domingo, Yolanda BCUC:EX

To: Norm & Gail
Subject: RE: Letter of acceptance / rejection

From: Norm & Gail [mailto:gailkonkin@telus.net]
Sent: Friday, December 4, 2009 12:25 PM
To: Domingo, Yolanda BCUC:EX
Subject: Re: Letter of acceptance / rejection

Yolanda Thanks for the reminder.

I Norma Gabana reject the N S A with Fortis. My opinion too inflationary and shows no economy in existing operation.

N Gabana
Dec 4, 2009

Domingo, Yolanda BCUC:EX

To: Al Wait
Subject: RE: *Confidential* FortisBC Final NSA

From: Al Wait [mailto:alwait@telus.net]
Sent: Friday, December 4, 2009 11:28 AM
To: Domingo, Yolanda BCUC:EX; Nakoneshny, Philip BCUC:EX; Elroy Switlishoff; alove@nelson.ca; skhan@bcpiac.com; vkumar@grandforks.com; cweafer@owenbird.com; ngabana@telus.net; terry.andreychuk@penticton.ca; jcreron@kelowna.ca; michele.leeners@fortisbc.com; dennis.swanson@fortisbc.com; Martin, Joyce; fortis@horizontec.com; Emergepartner.com; Grant, Bill J BCUC:EX; kostraat@summerland.ca
Subject: Re: *Confidential* FortisBC Final NSA

To: BCUC:

This e-mail is to confirm my acceptance of the FortisBC 2010 Revenue Requirements Negotiated Settlement as distributed Dec. 2, 2009.

Alan Wait

OWEN • BIRD
LAW CORPORATION

PO Box 49130
Three Bentall Centre
2900-595 Burrard Street
Vancouver, BC
Canada V7X 1J5

Telephone 604 688-0401
Fax 604 688-2827
Website www.owenbird.com

Direct Line: 604 691-7557
Direct Fax: 604 632-4482
E-mail: cweafer@owenbird.com
Our File: 15072/0002

December 1, 2009

VIA ELECTRONIC MAIL

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, B.C.
V6Z 2N3

Attention: Erica M. Hamilton,
Commission Secretary

Dear Sirs/Mesdames:

Re: FortisBC Inc. ("Fortis") 2009 Annual Review, 2010 Revenue Requirements Application and Negotiated Settlement Process
Project No. 369570/Order G-118-09

We are counsel to the British Columbia Municipal Electric Utilities (the "BCMEU"). We confirm that the BCMEU accepts the terms and conditions of the Negotiated Settlement Agreement ("NSA") regarding the above-noted Application circulated by the Commission on November 27, 2009 and has no proposed changes to the NSA settlement documents.

As a comment on the NSA at Tab 3, item 1 "Customer Rates", the BCMEU took the position that in the event the rate increase sought by Fortis for 2011 was in excess of 5%, the 2011 Revenue Requirement process should go to a full public revenue requirement hearing. The consistent, material rate increases arising under the current Performance Based Ratemaking ("PBR") approach are in excess of what was reasonably anticipated by ratepayers when the PBR term was established. To be clear, the BCMEU is not requesting this as an amendment to the NSA but did indicate to the parties in accepting the NSA that we would note this concern in our letter of comment.

The BCMEU thanks the Commission staff and facilitator, Fortis and the other customer representatives for their efforts during these negotiations.

If you have any questions regarding the foregoing, please do not hesitate to contact the undersigned.

Yours truly,

OWEN BIRD LAW CORPORATION

Christopher P. Weafer

CPW/jlb
cc: BCMEU
cc: Fortis
cc: Registered Intervenors

FortisBC
2010 Revenue Requirements Application
Negotiated Settlement Agreement
Response

By: Ludo Bertsch, Horizon Technologies Inc. (250) 592-1488
For: Okanagan Environmental Industry Alliance
Date: December 3, 2009
BCUC Project Number: #3698570

On behalf of the Okanagan Environmental Industry Alliance, we do not support the NSP agreement as conducted on November 17, 2009.

The following section include summaries of our points – for full information, please refer to the indicated Appendices.

1 Cost of Service and RDA Application:

We submit that there is no documented support in the FortisBC RRA Application nor in the NSP agreement to support the increased cost to $1,000,000 for the Cost of Service and RDA costs (from $760,000 in the 2010 RRA documents). We suggest that the amount for the Cost of Service and RDA costs remain as stated in the original 2010 RRA documents at $760,000, and not as in the NSP agreement.

For full details, please refer to Appendix A.

2 Advanced Meter Infrastructure:

We submit that FortisBC is not pursuing the most cost effective approach for the Advanced Meter Infrastructure by its rapidly escalating costs and by spending $500,000 before stakeholder engagement.

We suggest that a report be submitted to BCUC to provide updated information on the AMI. We also suggest the initiation of an AMI working group where all interested stakeholders may attend or other type of suitable process where updates can given.

For full details, please refer to Appendix B.

3 CPR and Surveys in the DSM Study:

We submit that FortisBC did not deliver the CPR and End Use Surveys as committed in the 2009 RRA. One year ago, FortisBC said $100,000 was needed in 2009 to cover the CPR including End Use surveys for the DSM Study project. Now, FortisBC says that the full costs of the End Use surveys and CPR were not covered in the 2009 allocation, and therefore additional funding of $165,000 is required for the next year.

We suggest that this is indicative that FortisBC is not pursuing DSM fast enough and we suggest FortisBC should be directed to pursue DSM more aggressively.

For full details, please refer to Appendix C.

4 DSM Performance:

We submit that FortisBC continues to under-estimate the level of DSM savings that are achievable with 126%, 113%, 128% and 140% actual to planned DSM savings[1]. The June 30, 2009 report shows 121% actual to planned DSM savings[2].

We suggest that FortisBC should be more aggressive at setting DSM targets.

Similar to Item #3, we also suggest that this is also indicative that FortisBC is not pursuing enough DSM in its plans and we suggest FortisBC should be directed to pursue DSM more aggressively.

5 Full hearing:

We find that the issues above are difficult to handle through a NSP approach. We also note that there are yet other issues which also difficult to handle through a NSP approach. We suggest that the Negotiated Settlement Process is not providing the level of scrutiny that FortisBC should be given. We suggest that the NSP approach is not working properly nor effectively. Therefore, we suggest that FortisBC's application should be subject to a full public hearing – given the scheduling challenges, we suggest a written hearing for this 2010 RRA, and we suggest an oral hearing for the 2011 RRA.

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[1] Exhibit B-3, OEIA IR#1, Page 10, A 2.1.1 & A2.1.3.
[2] Exhibit B-3, OEIA IR#1, Page 10, A 2.1.2

<u>APPENDIX A</u>

Cost of Service Analysis and RDA Application costs:

We note that FortisBC had a forecast cost of $760,000 for the Cost of Service Analysis (COSA) and Rate Design Application costs in the 2009 RRA Application[3]. This is confirmed in the Financial Schedules (Exhibit B-1, Tab 4, Page 11, Table 1-B, Line 17).

However, the same table as finalized from the NSP (Negotiated Settlement Agreement, Financial Schedules, Page 12, Table 1-B, Line 17) includes a forecast cost of a significantly higher amount of $1,000,000. We do not find any reference in the Issues List of the NSP (Page 3 to Page 6) which addresses this increase.

We, therefore, submit that there is no documented support for the increase, and suggest that the amounts for Cost of Service and RDA cost should remain as in the original 2010 RRA at $760,000, and not as in the NSP agreement.

[3] Exhibit B-1, Tab 3, Page 24, Item 3.7.2 v

APPENDIX B

Advanced Meter Infrastructure (AMI):

It was only in October, 2009, through the 2010 RRA that it was learned that FortisBC was on its way to spend $500K in 2009 for the AMI and that it planned to spend $600K in 2010. This contrasts to only 1 year ago (Nov 19, 2008) at which time FortisBC had not projected any AMI expenditures in 2009 and 2010. These expenditures are expected in spite of the AMI application being denied (one week before, Nov 12, 2008).

In the 2009 RRA NSP, FortisBC also committed to “meaningful stakeholder engagement” before applying to the BCUC, but at this point has not entertained any stakeholder engagement.

We submit that the AMI costs are excessive, particularly considering that the application has been denied and that there is no evidence of the AMI work being done.

While the NSP agreement has shifted the AMI costs out of the rate base (for now) by allocating to a non-rate deferral account, it will have to be addressed at some time in the future. We submit that by spending $500,000 before FortisBC engages stakeholder is not pursuing the most cost effective approach.

We suggest that a report be submitted to BCUC to provide updated information on the AMI. We also suggest the initiation of an AMI working group where all interested stakeholders may attend or other type of suitable process where updates can given.

APPENDIX C

CPR and Surveys in DSM Study:

In the 2009 RRA, (Nov, 2008) FortisBC stated that: "*The $100,000 requested for the DSM Study . . . will focus on the preparation of an updated Conservation Potential Review ('CPR').*

The components of this review include:

- *Communication and Stakeholder Involvement Plan;*
- *Data Collection and Retrieval;*
- *Review of similar CPR studies;*
- *FortisBC customer segmentation;*
- *End-use equipment surveys;*
- *Market forecast of customer potential for reducing energy use and peak demand; and*
- *Recommendations for enhanced DSM programs in 2011-2020.*"[4]

In this 2010 RRA (Nov 2009), FortisBC states: "*The full cost of the **R/CEUS reports** and **2010 CPR** were not covered by the DSM allocation in 2009, therefore additional funding [$165,000] is required to complete the work*"[5].

We submit this is a contradiction from one year to the next and has occurred without recognition by FortisBC of a change or explanation. If FortisBC had other intentions last year, we submit they should have clearly indicated so at that time. We submit that FortisBC had committed to delivery of the CPR in the 2009 RRA, including the seven components for the $100,000, and should not need further funds to complete those items.

We also note that there are no reports or documents for the DSM Study ready for release[6], which further exasperates the challenges for evaluating the progress of FortisBC for DSM activities.

We suggest that these issues are indicative that FortisBC is not pursuing DSM aggressively enough and we suggest FortisBC should be directed to pursue DSM more aggressively.

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[4] Exhibit B-3, OEIA IR#1, Page 1, Q1.1 & FortisBC 2009 RRA, Exhibit B-4, BCUC IR#1, A26.1, Page 64
[5] Exhibit B-3, OEIA IR#1, Page 1, Q1.1
[6] Exhibit B-3, OEIA IR#1, Page 1, Q1.1.3 & A1.1.3

FORTISBC

Dennis Swanson
Director, Regulatory Affairs

FortisBC Inc.
Suite 100 - 1975 Springfield Road
Kelowna, BC V1Y 7V7
Ph: (250) 717-0890
Fax: 1-866-335-6295
regulatory@fortisbc.com
www.fortisbc.com

December 4, 2009

Via Email
Original via mail

Ms. Erica M. Hamilton
Commission Secretary
BC Utilities Commission
Sixth Floor, 900 Howe Street, Box 250
Vancouver, BC V6Z 2N3

Dear Ms. Hamilton:

Re: FortisBC Inc. 2010 Revenue Requirements Negotiated Settlement Agreement

FortisBC Inc. ("FortisBC" or the "Company") confirms its acceptance of the Negotiated Settlement Agreement concerning the 2010 Revenue Requirements (the "2010 NSA"), and thanks the Commission Staff and Registered Intervenors for their participation and assistance in reaching the 2010 NSA.

The Company notes that the British Columbia Municipal Electric Utilities ("BCMEU") and British Columbia Old Age Pensioners' Organization et al. ("BCOAPO"), while accepting the 2010 NSA, have taken the position that in the event the rate increase sought by FortisBC for 2011 was in excess of 5%, the 2011 Revenue Requirement process should go to a full public revenue requirement hearing. The terms of the negotiated settlement agreement approved by Commission Order G-193-08 between the parties, including the BCMEU and BCOAPO extend the term of the PBR Agreement to 2012 with an oral hearing contemplated in 2012. The Company believes these terms of the PBR Agreement should be followed. However, the Company notes that both the BCMEU and BCOAPO are only including this statement as a comment and not requesting an amendment to 2010 NSA.

The Company notes that the BCOAPO raises concern about rising electricity rates and their impact on customers. FortisBC shares this concern and believes that the PBR Plan has helped to mitigate the rate increases in recent years.

The BCMEU states that rate increases arising out of the current PBR approach are in excess of what was reasonably anticipated by ratepayers when the PBR term was established. The Company disagrees with this comment and notes that there was a full discussion of rate impacts prior to the 2006 NSA. For example in the 2005 Revenue Requirements oral hearing transcripts, at volume 2, page 228, line 26 through page 232, line 2, the Company discussed the forecast annual and forecast cumulative rate increases. This dialogue indicated an expectation of a cumulative rate increase of approximately 36% for the period of 2005 to 2010. As noted in the Company's opening comments to the 2009 Annual Review and 2010 Revenue Requirement workshop, the PBR Plan has helped to mitigate the cumulative rate increase from 36 to 28 percent. This was achieved despite the hyper inflationary period experienced during the middle of the System Development Plan capital expenditures.

FortisBC is concerned about rising electricity costs and submits that the PBR plan has and will likely continue to mitigate rate increase to its customers while delivering solid non-financial performance benefits.

Sincerely,

Dennis Swanson
Director, Regulatory Affairs