ROBERT J. PELLATT
COMMISSION SECRETARY
Commission.Secretary@bcuc.com
web site: http://www.bcuc.com

BRITISH COLUMBIA UTILITIES COMMISSION

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. 12605

VIA E-MAIL
david.bennett@fortisbc.com
lavern.humphrey@fortisbc.com

May 23, 2006

Mr. David Bennett
General Counsel and Corporate Secretary
FortisBC Inc.
5th Floor
1628 Dixon Avenue
Kelowna, B.C. V1Y 9X1

Dear Mr. Bennett:

Re: FortisBC Inc. ("FortisBC")
Project No. 3689410/Order No. G-130-05
2006 Revenue Requirements Application ("Application")

Further to your November 24, 2005 application for approval of FortisBC's 2006 Revenue Requirements, we enclose Commission Order No. G-58-06 and attached Appendix 1 Settlement Agreement.

Yours truly,

Original signed by:

Robert J. Pellatt

RJP/cms
Enclosure(s)
cc: Registered Intervenors & Interested Parties

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER G-58-06

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

and

An Application by FortisBC Inc.
for Approval of its F2006 Revenue Requirement Application and
Establishment of a Multi-Year Performance Based Regulation Mechanism

BEFORE: L.F. Kelsey, Panel Chair
and Commissioner
L.A. O'Hara, Commissioner

May 19, 2006

O R D E R

WHEREAS:

A. On November 24, 2005, FortisBC Inc. ("FortisBC") filed for approval of its 2006 Revenue Requirements and to establish a Multi-Year Performance Based Regulation Mechanism (the "Application") with the British Columbia Utilities Commission ("Commission") pursuant to Sections 60 and 61 of the Utilities Commission Act (the "Act"); and

B. The Application requested an interim rate increase of 5.9 percent, effective January 1, 2006. The increase is based, in part, on significant capital expenditures, a change in the amortization rates for various assets and an increase in the amount of overheads charged to capital; and

C. The Application also proposed a Performance Based Regulation ("PBR") mechanism to determine Revenue Requirements for the years 2007 to 2009; and

D. Commission Order No. G-52-05 dated May 31, 2005 approving FortisBC's 2005 Revenue Requirements Application, directed an Annual Review of the 2005 incentive sharing mechanism along with a Review of the Performance Based Regulation Mechanism; and

E. The Commission issued Order No. G-130-05 dated December 2, 2005 approving for FortisBC an interim rate increase of 5.9 percent effective January 1, 2006, and established a regulatory timetable for an Annual Review and Workshop on Thursday, February 9, 2006 and a Pre-hearing Conference on Friday, February 10, 2006; and

F. At the 2005 Annual Review held on February 9, 2006 in Kelowna, BC, FortisBC presented actual 2005 incentive adjustments for both shared and flow-through components along with Performance Standards on System Reliability, Customer Service and Informational Metrics; and

G. The Intervenors had no comments with respect to the 2005 Incentive Sharing by the due date of February 16, 2006. The Commission issued Order No. G-21-06 on March 9, 2006 approving the Incentive Adjustments; and

H. On February 14, 2005, FortisBC filed its Evidentiary Update with a net reduction in the rate increase from 5.9 percent to 4.6 percent. The rate increase was further revised to 5.8 percent on April 11, 2006 pursuant to Commission Order No. G-14-06 amending the Automatic Adjustment Mechanism for setting Return on Equity ("ROE") which increased FortisBC's allowed ROE from 8.69 percent to 9.20 percent effective January 1, 2006; and

I. By Order No. G-13-06, the Commission established a regulatory timetable for a Negotiated Settlement Process for reviewing the Application starting April 18, 2006. If a Negotiated Settlement was not reached, an Oral Public Hearing would commence on June 20, 2006; and

J. The Negotiated Settlement discussions regarding the Application were held on April 18 and 19, 2006, and a proposed Settlement Agreement with a net rate increase of 5.9 percent was agreed to by FortisBC and most of the Intervenors with assistance from Commission Staff; and

K. The Participants at the Negotiated Settlement provided Letters of Support by May 8, 2006 for the Settlement Agreement with the exception of one Participant and by the due date of May 15, 2006 no comments were received from Registered Intervenors who had not participated in the Settlement process; 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 for FortisBC the Settlement Agreement for its 2006 Revenue Requirements and the Multi-Year Performance Based Regulation Plan for 2007 to 2009 attached as Appendix 1 to this Order, the Terms of Settlement.

2. The interim rates for FortisBC established by Order No. G-130-05 are approved as permanent rates effective January 1, 2006.

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

…/3

4. FortisBC is to inform all affected customers of the final rates by way of a customer notice.

DATED at the City of Vancouver, in the Province of British Columbia, this 23rd day of May 2006.

BY ORDER

Original signed by:

Len Kelsey
Panel Chair and Commissioner

Attachment

TERMS OF SETTLEMENT

2006 Revenue Requirements and
Multi-Year Performance Based Regulation Plan for 2007 – 2009
FortisBC Inc.

Negotiated Settlement

FortisBC Inc. ("FortisBC" or the "Company") filed an Application on November 24, 2005 for its 2006 Revenue Requirements, and for a multi-year Performance Based Regulation ("PBR") Plan for the period 2007 to 2009. The Company's 2005 rates had been set (Order G-52-05) following an oral public hearing which examined in detail not only FortisBC's cost of service, capital structure and Return on Equity premium, but its long-term System Development Plan and its Resource Plan. The Application proposed a two-stage Negotiated Settlement Process ("NSP") to set 2006 rates, followed by a second stage to determine the parameters of a PBR mechanism for a further three year period.

By Order G-130-05, the Commission approved FortisBC's request for an interim, refundable rate increase of 5.9 percent effective January 1, 2006. The Order also established a Regulatory Timetable for the Company's 2005 Annual Review and a workshop to review the 2006 Revenue Requirements on February 9, 2006. A Pre-Hearing Conference was scheduled for February 10, 2006. Subsequently the Commission issued Order G-13-06 amending and finalizing the Regulatory Timetable. Following the submission of Information Requests by interested parties and responses by the Company, negotiations commenced on April 18, 2006. The Regulatory Timetable provided for a further process culminating in an oral public hearing if a Negotiated Settlement Agreement ("NSA") could not be reached.

FortisBC and a group of Intervenors concluded negotiations on April 19, 2006, leading to the settlement terms contained in this document and its appendices, and encompassing both the 2006 Revenue Requirements and a PBR Plan for the years 2007 to 2009 inclusive. A comprehensive list of issues considered in the negotiation of the 2006 Revenue Requirements, and their resolution, together with an Overview of 2006 Revenue Requirements and supporting

Schedules, is included as Appendix A to this document. The list of issues and resolution in regard to the PBR Plan is included as Appendix B.

The Parties to the NSA are:

- FortisBC Inc.;
- The British Columbia Old Age Pensioners Association et al.;
- Commercial Energy Consumers;
- The Interior Municipal Electricity Utilities;
- Natural Resource Industries and Hedley Improvement District;
- Buryl Slack, registered intervenor; and
- Alan Wait, registered intervenor.

The Parties' letters of support and comments of the NSA are attached as Appendix C.

<u>2006 Revenue Requirements</u>

2006 Revenue Requirements will become the base year for the PBR term, and was therefore reviewed in detail. The Company filed in a separate process in August 2005 its 2006 Capital Expenditure Plan ("CEP"), and Order G-8-06 dated January 31, 2006 substantially approved the CEP, resulting in just two capital projects to be disposed of during the Revenue Requirements process (see Appendix A, Issues 3 and 4). It was agreed by the Parties that the CEP applications will be dealt with in a separate process for the term of the PBR Plan.

Two significant accounting issues were addressed in the Application, both of which are issues that had not been reviewed in a number of years. The results of an expert-prepared Depreciation Study recommended changes to the depreciation rates of the Company's assets which have the effect of increasing the composite depreciation rate. The Company also reviewed its Capitalized Overheads policy and proposed a new methodology that more appropriately reflects the increased levels of corporate support for the extensive capital program underway. The Parties reached agreement on these two issues for 2006 and the subsequent PBR term, and also agreed to review these issues at the conclusion of the PBR term. The parties did not arrive at a principled decision on the appropriateness of the recommendations in the Depreciation Study or in the Capitalized Overheads Policy proposed by the Company and rather arrived at agreements on depreciation rates and the capitalized overheads on a negotiated basis. No precedent value is established by the settlement.

The provisions of the NSA for 2006 Revenue Requirements are itemized in Appendix A and, as seen on page 15 of Appendix A, result in a required general rate increase, effective January 1, 2006, equal to the existing interim increase of 5.9%.

As proposed in the Application, the sharing mechanism adopted for the PBR term will apply to the 2006 year, subject to the 2006 Performance Standards listed at page 14 of Appendix A. The sharing mechanism and the conditions related to Performance Standards are described in the following section, and in Appendix B.

<u>Performance-Based Regulation Mechanism</u>

The PBR Mechanism included in this Settlement Agreement resembles the Company's previous mechanism with regard to the rate-setting and Annual Review processes, except that Capital Expenditures will be tested in a separate process. Stakeholders have the opportunity to review and provide input to the Revenue Requirements by means of Information Request and workshop processes, during which the Company will provide explanations/justification for its forecasts.

For the term of the PBR, Gross Operating and Maintenance ("O&M") Expenses before Capitalized Overheads will be set annually by the formula set out in issue 2.3 of Appendix B incorporating a Growth Escalator (customer growth) and an Inflation Factor (the Consumer Price Index for British Columbia), minus an agreed Productivity Improvement Factor ("PIF"). PIFs of 2% in 2007, 2% in 2008 and 3% in 2009 (if PBR is extended) were agreed to, in recognition that FortisBC is in the early stages of its transition to a stand-alone, locally managed utility, and that progress in achieving efficiencies will accelerate throughout the term of the PBR.

Capitalized Overheads will also be determined annually by formula, at 20% of Gross O&M Expense. All other cost accounts will be forecast annually. The Capital Structure and Return on Equity as approved by Order G-52-05 and modified by Order G-14-06 will apply for the term of the PBR Plan.

In place of the previous multiple-component mechanism, the Parties agreed to a sharing based on actual financial performance compared to the Company's allowed ROE. All variances, positive or negative, equal to or less than 2.0%, will be shared equally between customers and the company. If the variance exceeds 2.0%, the excess will be placed in a deferral account for review at the next Annual Review. In addition to this safeguard, the 2008 Annual Review will include a review of the PBR mechanism, and the extension of the PBR Plan to 2009 will be contingent upon the mutual agreement of the Parties, as described in Appendix B, Issue 1.

The PBR Plan in this Settlement Agreement expands the number and range of non-financial Performance Standards from previous agreements, ensures a thorough review and analysis of annual performance, and provides a framework for determining eligibility for any incentives earned. Under this framework, failure to meet one (or more) performance standard(s) does not necessarily constitute unacceptable performance. When determining whether an incentive payment should be paid to FortisBC the Commission will take into account the reasons given by the Company on why certain performance targets were not met and why the Company should be entitled to an incentive payment. The ultimate decision as to whether the Company earns its incentive payment in a given year rests with the Commission.

Investigation into other possible measures to be included is included in the NSA, ensuring that the Company's Performance Standards will continue to evolve throughout the term of the PBR.

Further detail of the PBR Mechanisms is included in Appendix B.

Appendix A

FortisBC Inc. ("FortisBC" or the "Company")
2006 Revenue Requirements Application
Negotiated Settlement Agreement ("NSA")

<table>
<tr><th>FortisBC Application</th><th>Resolution</th><th>Reference</th></tr>
<tr><td>
1. Load and Revenue Forecast
<table>
<tr><th>Load Forecast</th><th>Energy Sales(GWh)</th><th>Revenue ($000)</th></tr>
<tr><td>• Residential</td><td>1,080</td><td>78,625</td></tr>
<tr><td>• General</td><td>589</td><td>42,252</td></tr>
<tr><td>• Industrial</td><td>369</td><td>19,219</td></tr>
<tr><td>• Wholesale</td><td>935</td><td>41,371</td></tr>
<tr><td>• Other</td><td>58</td><td>3,764</td></tr>
<tr><td>Total</td><td>3,031</td><td>$185,541</td></tr>
<tr><td></td><td></td><td></td></tr>
</table>
</td><td>Residential revenue will be increased by 1% to $79.417 million.

All other components of load and revenue forecast accepted as filed.</td><td>Ex B-7, Tab 6a, 6b</td></tr>
<tr><td>2. Adjustment for Overstatement of 2005 Rate Base

In Exhibit B-7, Tab 5, page 30 the Company calculated an Adjustment for Overstatement of 2005 Rate Base. The Company proposes a direct offset of $349,000 to 2006 Revenue Requirements leaving 2006 Rate Base unchanged (Exhibit B-7, page 2). In response to BCOAPO 18a and BCUC 46.3.1 the Company indicated that it will include in the refund an adjustment for the 2005 Large Corporation Tax, and interest for 2005 on the over-collected revenues.</td><td>The Company will also include interest for a half year in 2006 on the $349,000 adjustment plus the LCT.</td><td>Ex B-7, Tab 5, p. 30; Ex B-7, p. 2; BCUC 46.3.1; BCOAPO 18a</td></tr>
<tr><td>3. Capital Expenditures – SAP Upgrade

FortisBC's 2006 Capital Expenditure Plan, filed in August 2005 was substantially approved via Commission Order G-8-06. The CEP included a project to convert the Company's SAP software to Great Plains. FortisBC later proposed to update SAP rather than convert to Great Plains.</td><td>2006 Rate Base will be reduced by $1.4 million to reflect the reduction in IT capital resulting from the SAP upgrade compared to the conversion.</td><td>• Cap Plan Aug. 16, 2006. p.9
• Ex B-7, Tab 5, p. 44
• Ex B-12 BCUC IR 47.2.1
• Ex B-7, Tab 5, p. 31; Ex B-9; BCUC 47.1; Commission Order G-8-06</td></tr>
</table>

4. Capital Expenditures – Vehicle Lease vs. Ownership The 2006 CEP proposed the buy-out of a number of existing leases of fleet vehicles. Order G-8-06 denied the Vehicle Lease to Ownership Conversion project subject to confirmation of a net benefit to customers. The analysis provided by the Company (Exhibit B-9) indicates a net benefit to owning the vehicles.	The $1.653 million expenditure to buy out the vehicle leases is approved.	• Cap Plan Aug. 16, 2006. p.9 • Ex B-7, Tab 5, p. 44 • Ex B-7, Tab 5, p. 31; Ex B-9; BCUC 47.1; Commission Order G-8-06
5. Financing Costs The Company's Forecast 2006 long-term embedded cost of debt is $25.096 million based on an embedded interest rate of 6.50% (Exhibit B-14, Tab 4, page 10, Schedule 5, lines 3 & 5). The Company's Forecast 2006 short-term cost of debt is $1.479 million. With an average principal of $20.518 million this results in an average interest rate of 7.21% ($1.479/20.518). The short-term debt is composed of Bankers Acceptance at 5.10%, Prime Loans at 5.68%, and Bank Fees of $350,000 (BCUC IR 48.5.1)	The long-term and short-term financing costs are accepted. FortisBC agrees to an interest deferral account to capture the difference between the actual 2006 interest costs and the forecast and to amortize the difference fully in 2007. The effect of the interest deferral account is that any difference between forecast and incurred interest will not affect the achieved ROE.	Ex B-7, Tab 5, pp.22-23
6. Pension, Post Retirement Benefits, Insurance, Trail Office Lease Cost Pension and Post Retirement Benefits have increased significantly as a result of the phased-in accrual amount for the 2005 and 2006 years as per the Commission's directive set out in Order No. G-52-05. The Company has indicated that these two items along with the lease costs from the Trail Office will be excluded from the O&M formula for the term of the PBR.	2006 Forecasts of Pension and Post-Retirement Benefits, Insurance expense, and the Trail Office lease costs are accepted as filed. These items will be excluded	• Ex B-12, BCUC IRs 84.6, 54.3.2, and 14 • Ex B-1 p.7, Ex B-12, BCUC IR 5.2, 6.0 • Ex B-12, BCUC IRs

	from the O&M formula.	11 &15.2 • Ex B-7 p.79, Table A2.5
7. Operating and Maintenance ("O&M") Expense Total Gross OM&A Expense is forecast to be $ 42,708 million in 2006, including the accounts in Item 6 above.	Gross O&M will be reduced by $0.8 million to $41,908	• Ex B-12, BCUC IRs 84.6, 54.3.2, and 14 • Ex B-1 p.7, Ex B-12, BCUC IR 5.2, 6.0 • Ex B-12, BCUC IRs 11 &15.2 • Ex B-7 p.79, Table A2.5
8. Materials Services Costs The Company proposes to allocate the cost of Materials Services (warehousing), which was referred to in the application as Procurement costs, to capital and O&M proportionately with the materials used.	The change in allocating materials services costs is accepted. The change results in an increase $0.8 million of allocations to capital.	
9. Income Tax FortisBC records deferred charges on a net-of-tax basis. Additions to deferred charges are included in the timing differences, gross of tax, with an offsetting tax effect, resulting in net zero tax expense (Exhibit B-1, Tab 4, page 6 Schedule 3, lines 13 and 30). Terasen Gas Inc. does not include additions for deferred charges in its income tax schedule.	FortisBC agrees to use the Terasen Gas Inc. method of calculating Income Tax Expense for deferred charge net of tax additions.	Ex B-12, BCUC IR 18 Ex B-7 Tab 5, p.63
10. AFUDC Rate for 2006 Based on FortisBC's allowed Return on Equity of 9.20% and its forecast Weighted Average Cost of Debt, the AFUDC rate for 2006 is 6.26% (BCUC IR 54.1.4), rounded to 6.3%.	The AFUDC rate of 6.3% is accepted.	• Ex B-12; BCUC 54.1.4
11. Application of AFUDC to Capital Projects FortisBC has historically applied AFUDC only to projects of at least three months' duration and costing more than $100,000. The company proposes to remove these criteria with one exception. AFUDC would not be calculated on small distribution projects such as new customer connects and urgent repairs.	The existing thresholds of three months' duration and $100,000 will continue to apply. AFUDC is reduced by $30,000.	• Ex B-7, Tab 5, p. 76; BCUC 55.1-55.2

12. Capitalized Overhead The Company proposes to change its capitalized overhead methodology to one based on the principles of activity-based costing. The proposed methodology includes indirect overhead costs not previously allocated to capital expenditures (Exhibit B-1, Tab 5 page 66). FortisBC proposes capitalized overhead of $11.736 million in 2006, 27.5% of Gross O&M expenses.	Capitalized Overhead is set at 20% of forecast Gross O&M for 2006, or $8.382 million. The forecast will be the actual Capitalized Overhead for the year.	Ex B-7, Tab 5, pp. 77-80; BCUC 56.1-56.13
13. Other Income (Exhibit B-1, Tab 5, page 15) ($000s) • Apparatus and Facilities Rental: 2,034 • Contract Revenue: 1,816 • Miscellaneous Revenue: 534 • Investment Income: 334 Total: 4,718	Investment Income is adjusted to $350,000. Other components are accepted as filed. Total Other Income is $4.734 million.	Ex B-7, Tab 5, p.60, Table 2-G
14. Depreciation Expense FortisBC applies to implement depreciation rate changes based on the results of a Depreciation Study performed by Gannett Fleming (see response to BCUC IR 52.1.1). The proposal includes: a. New proposed rates resulting in a composite depreciation rate of 3.6% for 2006; b. Amortization of the $3.091 million Rate Stabilization Account ("RSA") at 3.4% based on the composite life for transmission assets; c. Aggregation of Plants 1, 2, 3 and 4 into a single classification for depreciation purposes; and d. A change from "mass property group accounting" to "amortization accounting" for Accounts 391, 391.1, 394 and 397 (see response to BCUC IR 57.5)	The Company and Participants agreed to change the proposed depreciation rates for six accounts: 353.0, 355.0, 356.0, 364.0, 365.0, and 390.1 are adjusted to 3.0% in order to reflect longer average service lives for those assets. The RSA is to be amortized over a ten-year period beginning in 2006. Aggregation of Plants 1, 2, 3 and 4 is accepted. Amortization accounting for Accounts 391, 391.1, 394 and 397 is accepted.	• Ex B-12, BCUC A52.1.1 • Ex B-7, Tab 5, p. 71 • Ex B-7, Tab 5, p. 70 • Ex B-12, BCUC 57.5

	The Company and the Participants hold differing views on negative salvage values in the depreciation study. The Parties agree to defer analysis of the issue of negative net salvage value in the depreciation study for the term of the PBR ending in 2008 or 2009. The parties did not agree that the findings of the Depreciation Study were otherwise appropriate and no precedent value is attached to the Depreciation Study. The current practice of depreciating assets based on Plant in Service at the beginning of the year will continue.	
15. Amortization of Demand Side Management Expenditures The Company proposes to change the amortization period for its DSM expenditures from 8 years to 10 years in aggregate, based on a weighted amortization of individual program lives (Exhibit B-1, Tab 5, page 61 and Tab 10 Appendix C). Individual programs have lives ranging from 5 to 30 years, with a weighted amortization period of 11 years. BC Hydro: a. amortizes the Power Smart costs to appropriately match the costs with the energy savings benefits over future years, but in any case not to exceed 10 years. b. Costs incurred by BC Hydro in the concept development phase are not capitalized. Program-specific and non-specific portfolio development and implementation costs are capitalized and amortized	Program costs up to and including 2005 will continue to be amortized over the existing 8 year period. 2006 and future costs will be amortized in a manner consistent with BC Hydro. Concept development costs will continue to be capitalized. Amortization commences in the year following the expenditure, as currently. DSM expenditures	• Ex B-1, Tab 5, p.61, Tab 10 • Ex B-12, BCUC IR 26.2.1

over the period of benefit of the respective programs. c. BC Hydro commences amortization in the year following the year in which the expenditure is incurred. d. DSM expenditures associated with cancelled programs are written off in the year in which the program is cancelled.	associated with cancelled programs are written off in the year in which the program is cancelled. FortisBC is to file a continuity schedule pre- and post changes to the amortization rates.	
16. 2006 DSM Capital Expenditures 2006 DSM capital expenditures are forecast at $2.236 million (Exhibit B-7, Tab 10, page 3)	The 2006 DSM expenditures are approved.	• Ex B-7, Tab 10, p.3 • Ex B-1, Tab 10, p.7

17. DSM Incentive for 2006 The DSM Technical Committee proposed (Exhibit B-13, page 8): a. Continuation of the DSM incentive mechanism subject to a change in the net benefits baseline to the average of the last three years' actual net benefits; b. Change in the calculation of gross benefits from a fixed 1999 BC Hydro Rate 3808 to the prevailing rate; and c. Implementing two avoided capacity rates, one for heat sensitive and another for non heat sensitive programs.	The proposal to change the calculation of the net benefits baseline to the average of the last three years' actual net benefits is accepted. The 1999 value for RS 3808 will be changed to the prevailing rate for calculating gross benefits. The implementation of two avoided capacity rates is not accepted. FortisBC agrees to provide further information on this proposal at its 2006 Annual Review.	• Ex B-5 • Ex B-12 BCUC IR 44.3.2, NRI Q3 • Willis Energy Comments 03/17/2006
18. Aesthetic and Environmental Upgrades Program (AEUP) The AEUP is a new initiative similar to BC Hydro's Beautification program, with a proposed annual budget of $100,000 to be awarded to up to 10 participants. (Exhibit B-1. Tab 11, page 2).	The program is accepted as proposed. It will be implemented for the last half of 2006 with a budget of $50,000.	• Ex B-1 Tab 11, p.2 • Ex B-12, BCUC IR 73

	Project details and actual expenditures will be provided on an annual basis.	
19. Power Purchase and Wheeling Expense Power Purchase Expense of $65.067 million and Wheeling Expense of $3.742 million are forecast for 2006. (Exhibit B-7 Tab 7 Update). The Company proposes that, as in previous years, any changes to the BC Hydro rates will be flowed through to customers. FortisBC forecasts 185 MW of BC Hydro capacity at peak. This allows an additional 15 MW to be used for required reserve capacity.	Power Purchase Expense and Wheeling Expense accepted as filed. Flow-through treatment for BC Hydro rate increases is approved.	• Ex B-7 Tab 2, p.3 • Exhibit B-2 BCUC IR 23, • Exhibit B-13, Power Purchases Technical Committee Report, page 3.
20. Technical Committees The Application proposes that Technical Committees will be struck to review its Load Forecast, Power Purchase Expense, and DSM Expenditure Forecast, prior to the Revenue Requirements workshop.	The Parties agree that the Load Forecast and Power Purchase Expense forecast will be examined through the workshop and IR process without the use of technical committees. The DSM Incentive Committee will be renamed the DSM Advisory Committee to recognize the greater impact of its advice and to review Power Sense planning and target setting. BCUC staff will serve *ex officio.*	• Ex B-1 Tab3, p.6 • Ex B-12. BCUC IR 25.1 • Technical Committee material / minutes
21. 2005 Resource Plan Action Plan Commission Order G-52-05 directed FortisBC to file status updates on the progress of negotiations with BC Hydro in regard to the Power Purchase Agreement, and on the progress of its study of a new market strategy.	FortisBC will file with the Commission, and provide to intervenors, the requested reports.	May 31, 2005 Decision on 2005 Resource Plan p.68

22. Revenue Protection Project 2005 deferred costs for the Revenue Protection project are $146,500, and forecast 2006 costs are $598,000. The Company proposes to amortize the costs over five years.	2005 costs are to be fully amortized in 2006. 2006 costs in the amount of $300,000 are approved and will be amortized in the following year. The Company will report annually on the costs and tangible benefits of the program.	Ex B-7, Tab 5, pp. 34-35; BCUC 20.1-20.3 & 21.1
23. Deferred Charges a. 2005 Revenue Requirements - $705,000 b. 2006 Revenue Requirements - $225,000 c. 2007 Revenue Requirements - $150,000 d. BC Hydro Rate Design - $150,000 e. Terasen Gas ROE Application - $ 75,000 f. CCA Rate Change Deferral - $503,000	The Company will provide further variance explanation for the 2005 Revenue Requirements to Commission Staff. If approved, the costs will be amortized over a four year period beginning in 2006. An explanation for the 2006 Revenue Requirements General and Staff Expenses will be provided to Commission Staff. The costs are to be amortized over three years beginning in 2007. Forecast costs for the 2007 Revenue Requirements application are accepted. Costs for the BC Hydro Rate Design Application are removed from the forecast as the Application is not expected to be filed before late 2006. The Company will provide detail of consulting and	• Ex B-7, Tab 5, pp. 32-33 & 46 (lines 12-13); BCUC 19.1 • Ex B-7 Tab 5, p. 46 Table 1 – B (2006), line 12-13; BCUC 19.3.1

	legal costs incurred in the Terasen Gas ROE Application to Commission Staff. Costs are to be fully amortized in 2006. The CCA Rate Deferral Account will remain in Rate Base pending outcome of the legislation. If the legislation is not enacted prior to the 2006 Annual Review, the Company will bring forward a proposal for the disposition of the deferral account.	
24. CWIP Attracting AFUDC in Rate Base FortisBC includes CWIP subject to AFUDC in Rate Base, and reduces Revenue Requirements by the amount of AFUDC. Other Canadian utilities include only CWIP not subject to AFUDC in Rate Base and calculate interest expense and the cost of equity only on Plant in Service and other costs approved for Rate Base treatment (Exhibit B-1 Tab 5, page 62).	CWIP will be included in Rate Base for 2006. Beginning in 2007 the Company will change to the method used by other utilities.	Ex B-7, Tab 5, pp. 73-75; BCUC 53.1-53.4

25. 2006 Performance Standards

The following Performance Standards are proposed, using an October 1 to September 30 year (Exhibit B-1 Tab 9a):

Performance Standard	Proposed Target
SAIDI	3.14
SAIFI	3.01
Forced Outage Rate	0.50%
Billing Accuracy	0.075% of bills rejected by system
Commitment to read meters	95% of meters read as scheduled
Contact Center Performance	70% of calls answered within 30 sec
Emergency Response Time	85% response within 2 hours
Residential Service Connections	85% in less than 6 working days
Extensions - Time to Quote	75% in less than 35 working days
Extensions - Time to Complete	75% in less than 30 working days
All Injury Frequency Rate	4.83
Injury Severity Rate	24.62
Recordable Vehicle Incidents	4.72
Customer Survey	Informational only

The proposed measures and timeframe are accepted.

Target
3 year average of 2.62 + 10% = 2.88
3 year average of 2.51 + 10% = 2.76
0.35%
0.072%
97%
70% of calls answered within 30 seconds.
85% response within 2 hours
85% in less than 6 working days
75% in less than 35 working days
75% in less than 30 working days
4.83
24.62
4.72
To be included as a performance standard. Directional measure only.
The Company will investigate a means of measuring First Contact Resolution and present results at the 2006 Annual Review

Appendix A

Revenue Requirements Overview

		Approved 2005	Increase or (Decrease)	2006
			($ 000s)	
1	Sales Volume (GW.h)	2,924		3,031
2	Rate Base (000s)	597,688		675,906
3	Return on Rate Base	7.69%		7.60%
4				
5	**REVENUE DEFICIENCY**		($000s)	
6				
7	**POWER SUPPLY**			
8	Power Purchases	59,451	5,616	65,067
9				
10	**OPERATING**			
11	O&M Expense	39,629	2,279	41,908
12	Capitalized Overhead	(3,396)	(4,986)	(8,382)
13	Wheeling	3,878	(136)	3,742
14	Other Income	(3,970)	(764)	(4,734)
15		36,141	(3,607)	32,534
16	**TAXES**			
17	Property and Capital Taxes	9,986	687	10,673
18	Water Fees	7,681	698	8,379
19	Income Taxes	5,581	(93)	5,488
20		23,248	1,292	24,540
21	**FINANCING**			
22	Cost of Debt	23,443	3,080	26,523
23	Cost of Equity	22,544	2,329	24,873
24	Depreciation and Amortization	18,789	7,951	26,740
25	AFUDC	(3,005)	984	(2,021)
26		61,771	14,344	76,115
27				
28	**INCENTIVE ADJUSTMENTS**	(1,791)	1,316	(475)
29				
30	**TOTAL REVENUE REQUIREMENT**	178,820	18,961	197,781
31				
32	OF WHICH LOAD GROWTH:			
31				
32	Adjustment for Overstatement			
33	of 2005 Rate Base			(377)
34				
35	ADJUSTED REVENUE REQUIREMENT			197,404
36	**Less: REVENUE AT APPROVED RATES**			186,327
37	**REVENUE DEFICIENCY for Rate Setting**			11,077
38				
39	**RATE INCREASE**			**5.9%**

Appendix A

SCHEDULE 1
UTILITY RATE BASE

		Note	Actual 2004	Actual 2005	Forecast 2006
				($ 000s)	
1	Plant in Service, January 1		630,676	709,762	820,436
2	Net Additions		79,086	110,674	107,816
3	Plant in Service, December 31		709,762	820,436	928,252
4	Construction Work in Progress	1.	39,946	39,359	30,613
5	Plant Held for Future Use		-	-	-
6	Plant Acquisition Adjustment		11,912	11,912	11,912
7	Deferred and Preliminary Charges		14,773	16,972	17,083
8			776,393	888,679	987,860
9	Less:				
	Accumulated Depreciation				
10	and Amortization		184,560	198,524	216,720
11	Contributions in Aid of Construction		53,661	58,924	63,295
12			238,221	257,448	280,015
13	Depreciated Rate Base		538,172	631,231	707,845
14	Prior Year Depreciated Utility Rate Base		456,285	538,172	631,231
15	Mean Depreciated Utility Rate Base		497,229	584,702	669,538
16					
17	Allowance for Working Capital		5,235	8,633	7,662
18	Adjustment for Capital Additions		(3,489)	(3,490)	(1,294)
19	Mid-Year Utility Rate Base		498,974	589,845	675,906

20 Note 1. In 2005, FortisBC reclassified its inventory purchased for capital projects, in accordance with the Uniform System of Accounts, to Account No. 107. Previously this inventory was included in Account No. 154, Materials and Supplies. 2004 Rate Base has been restated to reflect this change, which has the effect of increasing Construction Work in Progress by $4.5 million, and reducing the Allowance for Working Capital by an approximately equal amount. The net impact on Rate Base is zero.

SCHEDULE 2
EARNED RETURN

		Actual 2004	Actual 2005	Forecast 2006
			($ 000s)	
1	SALES VOLUME (GW.h)	2,874	2,969	3,031
2				
3	ELECTRICITY SALES REVENUE	174,881	183,120	197,781
4				
5	EXPENSES			
6	Power Purchases	59,014	60,404	65,067
7	Wheeling	3,817	3,956	3,742
8		62,831	64,360	68,809
9				
10	Operating Expenses	36,042	37,680	33,526
11				
12	Taxes			
13	Property Tax	10,047	9,540	10,673
14	Water Fees	7,399	7,679	8,379
15		17,446	17,219	19,052
16				
17	Depreciation and Amortization	16,817	18,840	26,740
18				
19	Other Income	(4,472)	(4,342)	(4,734)
20	AFUDC	(2,434)	(3,335)	(2,021)
21	Incentive Adjustments	(2,300)	(1,219)	(475)
22	UTILITY INCOME BEFORE TAX	50,951	53,917	56,884
23	Less:			
24	INCOME TAXES	8,333	7,148	5,488
25				
26	RETURN ON RATE BASE	42,618	46,769	51,396
27				
28	Utility Rate Base	498,974	589,845	675,906
29	Return on Rate Base	8.54%	7.93%	7.60%

Appendix A

SCHEDULE 3
INCOME TAX EXPENSE

		Actual 2004	Actual 2005	Forecast 2006
			($ 000s)	
1	UTILITY INCOME BEFORE TAX	50,951	53,917	56,884
2	Deduct:			
3	Interest Expense	19,033	22,389	26,523
4	ACCOUNTING INCOME	31,918	31,527	30,361
5	Deductions			
6	Capital Cost Allowance	19,020	22,760	31,555
7	Capitalized Overhead	2,563	3,392	8,382
8	AFUDC	2,434	3,335	2,021
9	Net Deductable Deferred Charge Additions	3,036	3,412	-
10	Incentive & Revenue Deferrals	2,284	1,219	475
11	Financing Fees	229	766	766
12	All Other (net effect)	(155)	265	120
13		29,411	35,149	43,319
14				
15	Additions			
16	Amortization of Deferred Charges	1,849	1,873	2,236
17	Depreciation	14,969	16,967	24,504
18		16,818	18,840	26,740
19				
20	TAXABLE INCOME	19,324	15,219	13,782
21				
22	Tax Rate	35.62%	34.87%	34.12%
23				
24	Taxes Payable	6,883	5,307	4,703
25	Prior Years' Overprovisions/(Underprovisions)	(208)	(8)	-
26	Tax Impact of Deferred Charges	789	1,334	105
27	Large Corporations Tax	819	865	680
28	Allowance for tax audit	50	(350)	-
29				
30	REGULATORY TAX PROVISION	8,333	7,148	5,488

Note: At line 26, Tax Impact of Deferred Charges for the year 2006 refers to the tax effect of deferred debt issue costs only.

Appendix A

SCHEDULE 4
COMMON SHARE EQUITY

		Actual 2004	Actual 2005	Forecast 2006
			($000s)	
1	Share Capital	76,500	106,500	128,000
2	Retained Earnings	114,487	128,346	144,726
3				
4	COMMON EQUITY - OPENING BALANCE	190,987	234,846	272,726
5				
6	Less: Common Dividends	(9,726)	(8,000)	(10,000)
7				
8	Add: Net Income	23,585	24,380	24,873
9	Shares Issued	30,000	21,500	-
10				
11	COMMON EQUITY - CLOSING BALANCE	234,846	272,726	287,599
12				
13	SIMPLE AVERAGE	212,917	253,786	280,162
14				
15	Adjustment for Shares Issued	7,603	(6,934)	-
16	Deemed Equity Adjustment	-	-	(9,799)
17				
18	COMMON EQUITY - AVERAGE	220,519	246,851	270,363

Note: The opening balance for 2004 Retained Earnings has been restated. Previously it included an adjustment for weather normalization of the previous year's income in the amount of $(155,000). The restatement has the effect of increasing average common equity by $155,000 in each year. The rate of Return on Equity is unchanged.

Appendix A

SCHEDULE 5
RETURN ON CAPITAL

		Actual 2004	Actual 2005	Forecast 2006
1	Secured and Senior Unsecured Debt	159,331	300,607	385,968
2	Proportion	31.09%	50.80%	57.10%
3	Embedded Cost	7.93%	6.75%	6.50%
4	Cost Component	2.47%	3.43%	3.71%
5	Return	12,637	20,278	25,096
6	Short Term Debt	132,575	44,317	19,575
7	Proportion	25.87%	7.49%	2.90%
8	Embedded Cost	4.82%	4.76%	5.50%
9	Cost Component	1.25%	0.36%	0.16%
10	Return (including fees)	6,396	2,111	1,427
21	Common Equity	220,519	246,851	270,363
22	Proportion	43.03%	41.71%	40.00%
23	Embedded Cost	10.70%	9.88%	9.20%
24	Cost Component	4.60%	4.12%	3.68%
25	Return	23,585	24,380	24,873
26	TOTAL CAPITALIZATION	512,425	591,775	675,906
27	RATE BASE	498,974	589,845	675,906
28	Earned Return	42,618	46,769	51,396
29	RETURN ON CAPITAL	8.32%	7.90%	7.60%
30	RETURN ON RATE BASE	8.54%	7.93%	7.60%

Note: The Common Equity component of Capitalization in each year has been re-stated (see Note to Schedule 4). The restatement has the effect of increasing average common equity by $155,000 in each year. The rate of Return on Equity is unchanged.

FortisBC Inc. ("FortisBC" or the "Company")
Performance Based Regulation ("PBR") Mechanism
Negotiated Settlement Agreement ("NSA")

PBR - Application Requests (Exhibit B-1, Tab 3)	Resolution	Reference
1. Term of the Proposed PBR The NSA for the 2006 Revenue Requirements will be the basis for a PBR mechanism for 2007 – 2009. Performance Standards and the incentive mechanism will apply in 2006.	The PBR term of 2007-2008 is accepted, with an option to extend the term to 2009 under the terms set out in Appendix B, if the Company and its stakeholders agree to the extension. The Parties agree to conduct a review of the PBR mechanism during the 2008 Annual Review. Intervenors will provide input as to how the review will take place. At the 2008 Annual Review, the Company and its stakeholders will determine whether to extend the PBR term until 2009. For the purposes of this determination stakeholders will mean the registered intervenors at the 2008 Annual Review. If a consensus is not reached among the stakeholders on whether to continue using the PBR mechanism for 2009, the matter will be determined by the Commission, after hearing submission from the Parties. In the event that PBR is not extended, FortisBC will file a Revenue Requirements Application for 2009 rates, subject to any Order of the Commission.	Exhibit B-1, Tab3, P.2, lines 5 & 6; Exhibit B-12, BCUC IR 74.0 and 76.1; CEC IR 3.0

2. Determination of Annual Revenue Requirements The Company will file a Preliminary Revenue Requirements Application in October of each year, or earlier, to set rates for the subsequent year. The Application will be followed by a workshop to be held in conjunction with the Annual Review, and will be followed by a Negotiated Settlement Process. Individual Cost Accounts will be determined as described in the following sections:	The conceptual framework proposed by FortisBC is accepted for 2006, 2007, and 2008. For 2009, in the event that the PBR period is not continued, FortisBC will file a revenue requirement application for the setting of 2009 rates.	Exhibit B-1, Tab 3, P.6, lines 13 to 17; Exhibit B-12, BCUC IR 83.0; CEC IR 9.0
2.1 The Application proposes that these line items will be reviewed annually by technical committees. • Load Forecast • Power Purchase Expense • Demand Side Management	The Load Forecast and Power Purchase Expense forecast will be reviewed through the Revenue Requirements workshop and Information Request processes and approved annually by the Commission. There will be no Technical Committees. The DSM Incentive Committee will be renamed the DSM Advisory Committee, and will review and make recommendations at the Annual Review in regard to annual DSM expenditures. Amortization of DSM expenditures, beginning in 2007, will be consistent with the practice of BC Hydro, as described in Issue 15 of the 2006 Revenue Requirements NSA.	• Exhibit B-1, Tab 3, P.6, lines 20 to 23 • Ex B-1, Tab 5, p.61, Tab 10 • Ex B-12, BCUC IR 26.2.1
2.2 Capital Expenditures The Application proposes that its annual Capital Expenditure Plans (CEP) will be approved as part of a separate annual filing or update, subject to application for a CPCN for major projects as directed by the Commission	A separate application process for the Company's Capital Expenditure plans is accepted. The amount of the net addition brought into Rate Base along with the AFUDC calculation will	Exhibit B-1, Tab 3, P.7, lines 1 to 3

	be examined at the Revenue Requirements Workshop and approved by the Commission's subsequent Order. For information purposes only, operating savings claimed in the 2006 and future CEP and CPCN applications will be tabulated and presented at each Annual Review.	
2.3 Gross Operating & Maintenance ("O&M") Expenses O&M Expenses for the years 2007 to 2009 will be determined by formula, similar to the previous PBR mechanism. 2006 Base O&M will be adjusted using a Cost Escalator and a Growth Escalator. A Productivity Improvement Factor will be negotiated for the term of the PBR.	The proposed formula method for determining 2007 to 2009 Gross O&M expense is accepted, subject to the conditions for individual components described in the following sections.	Exhibit B-1, Tab 3, P.6, lines 24 to 30
2.3.1 Determination of Base amount for Gross O&M expenses / customer The proposed formula is: O&M = Cost/Customer x BC CPI x Customer Growth x PIF Pension and Post Retirement Benefits and the lease costs for the Trail Office are excluded from the Base O&M calculation.	The proposed formula is accepted. The base Cost/ Customer is determined by 2006 Gross O&M expense arising from the 2006 Revenue Requirements NSA, excluding Pension and Post Retirement Benefits and the Trail Office lease costs.	Exhibit B-5, Proposed Mechanism, Slide #8; Exhibit B-12, BCUC IR 84.6
2.3.2 Cost Escalator (CPI) The Company proposes to use the forecast BC CPI for the Cost Escalator, and to reforecast for each year of the PBR term.	BC CPI is accepted as the Cost Escalator. The forecast will be the average of the most recent forecasts from the Conference Board of Canada, the BC Ministry of Finance, the RBC Financial Group, and the Toronto-Dominion Bank. There is no true-up of target O&M expense for actual CPI.	Exhibit B-1, Tab 3, P.6, lines 24 to 30; Exhibit B-12, BCUC IR 76.1 & 84.5

2.3.3 Growth Escalator Forecast average annual customer growth is proposed as the Growth Escalator. Each year's forecast will be updated with the most recent actual customer count.	The proposal is accepted. There is no true-up of target O&M expense for actual customer growth.	Exhibit B-1, Tab 3, P.6, lines 24 to 30; Exhibit B-12, BCUC IR 24.1, 84.4
2.3.4 Productivity Improvement Factor (PIF) The Company proposes PIFs of: 1% for 2007 2% for 2008 3% for 2009	The Parties agree to PIFs of: 2% for 2007 2% for 2008 3% for 2009 (if PBR is extended)	Exhibit B-1, Tab 3, P.6, lines 24 to 30; Exhibit B-12, BCUC IR 84.1, 84.2, 84.3; BCUC Decision, dated May 31, 2005
2.3.5 Pension and Post-Retirement Benefits and Trial Office Lease Cost The cost of Pension and Post-Retirement Benefits are forecast to increase substantially in 2007, partially as a result of FortisBC's phase-in of accrued liability as directed in Order G-52-05. The Trail Office lease costs, as approved by Order G-41-94, will increase substantially in 2008. The Company proposes to exclude these items from the calculation of Gross O&M and to forecast them annually for determining Revenue Requirements.	Pension and Post Retirement Benefits, and the Trail Office lease costs will be excluded from Base O&M and approved annually.	Exhibit B-12, BCUC IR 84.6
2.3.6 Capitalized Overhead	Capitalized Overhead is set at 20% of forecast Gross O&M for the term of the PBR. The forecast will be the actual Capitalized Overhead for each year. The parties acknowledge that the Capitalized Overhead Policy is premised on the extensive capital	None

	program that FortisBC is currently undertaking, therefore the Company's Capitalized Overhead methodology will be reviewed at the end of the PBR term.	
2.4 All other Cost of Service Line Items All other cost of service line items will be forecast by the Company and subject to review at the annual Revenue Requirement Workshop	The proposal is accepted, subject to conditions for the Annual Review and Revenue Requirements workshops described in Issue 5.	Exhibit B-1, Tab 3, P.7, lines 4 and 5
3. Type of PBR sharing mechanism The proposed mechanism is "collared ROE" mechanism which creates a true incentive based on overall actual financial performance compared to the Company's allowed ROE	The general form of the ROE sharing mechanism is accepted subject to the following.	Exhibit B-1, Tab 3, P.2, lines 8 to 30
3.1 Detailed aspects of the ROE sharing mechanism The Application proposes sharing the actual earnings in excess of the target ROE according to a graduated formula: • A symmetrical dead band of 0.5% around the approved ROE, adjusted for tax, to the account of the shareholders • The next band of 1.5% to be shared equally between customers and the Company • Differences in ROE greater than 2.0% are to be placed in a deferral account for review and disposition at the next Annual Review.	There will be no deadband. Within a 2% band around the approved ROE, customers and the shareholder will share equally any positive or negative variance, adjusted for income tax. Differences in ROE greater than 2.0% are to be placed in a deferral account for review and disposition at the next Annual Review.	Exhibit B-1, Tab 3, P.3, lines 1 to 23; Exhibit B-12, BCUC IR 78, 79, 80; Exhibit B-12, CEC IR 5
3.2 Demand Side Management – Incentive Mechanism Proposal The DSM Technical Committee proposed (Exhibit B-13, page 8): e. Continuation of the DSM incentive	As described in Issue 17 of the 2006 Revenue Requirements NSA, the change in the net	Exhibit B-1, Tab 10, P.P. 13 to 15

mechanism subject to a change in the net benefits baseline to the average of the last three years' actual net benefits; f. Change in the calculation of gross benefits from a fixed 1999 BC Hydro Rate 3808 to the prevailing rate; and g. Implementing two avoided capacity rates, one for heat sensitive and another for non heat sensitive programs.	benefits baseline to the 3-year average, and the use of the prevailing RS 3808 are accepted. The proposal to implement two avoided capacity rates is not accepted at this time. FortisBC agrees to provide further information on this proposal at its 2006 Annual Review where the issue will be reviewed.	
3.3 Gross Annual Interest Expense and the Interest Component of AFUDC	Positive or negative variances in the gross annual interest expense and the interest component of AFUDC will be excluded from the collared ROE sharing mechanism. In other words these expenses will be treated as flow-through expenses to customers in the same manner as in 2005.	BCUC Decision, dated May 31, 2005; Letter L-97-05; Order No. G-129-05
3.4 Process for dealing with Extraordinary Items FortisBC proposes that extraordinary items be handled outside of the ROE sharing mechanism. Examples of extraordinary items are initiatives that the Company may propose for mutually beneficial items where investment recovery would exceed the term of the PBR. Such a mechanism will provide an incentive to undertake projects which would not otherwise return a benefit because of the limited term of the PBR. If FortisBC has an initiative that would fit this category, it is envisioned that the Company would make this proposal as part of its annual rate filing application which would then be subject to discussion, negotiation and disposition at the Annual Review.	The Company's proposal is accepted.	Exhibit B-1, Tab 3, P.3, lines 25 to 30; Exhibit B-12, BCUC IR 81.0

3.5 "Z" Factor Provision A "Z" factor provision is proposed to permit recovery or refund of extraordinary costs outside of the "steady state" operations as determined by the formula described for Base O&M expenses. "Z" factor circumstances limited to the following: • Directives of the BCUC or other competent regulatory agencies; • Acts of legislation or regulation of government; • Changes due to Generally Accepted Accounting Principles; • Changes to actuarial evaluations; • Force Majeure events; • Other extraordinary events as agreed to by the parties in the Negotiated Settlement Process. Where possible the items will be included in Revenue Requirements. In unforeseen circumstances the costs will be captured in a deferral account for consideration and disposition as part of the Annual Review.	The "Z "Factor provision is approved. FortisBC will comply with GAAP unless a variance is ordered by the Commission.	Exhibit B-1, Tab 3, P.4, lines 13 to 15 and P.5, lines 1 & 2; Exhibit B-12, BCUC IR 82.0
4. Type of Performance Standards The proposed Performance Standards are listed in Exhibit B-1, Tab 9a, Page 3 and listed individually below. Performance will be measured on the basis of the twelve-month period October 1 to September 31, to ensure that a full year of information is available at the Annual Review.	The list of Performance Standards is accepted, subject to the conditions described in this Section. The Oct. 1 to Sept. 30 timeframe is accepted for all Performance Standards. To be eligible for an incentive, FortisBC must show that it did not achieve the additional earnings as a direct result of deteriorated performance. It is also accepted that the failure to meet one or more performance targets will not necessarily result	Exhibit B-1, Tab 9a, P.3, line 1

	in disallowing the incentive payment. When determining whether an incentive payment should be paid to the Company the Commission will take into account the reasons given by the Company on why certain performance targets were not met and why the Company should be entitled to an incentive payment. FortisBC is accountable for its quality of service by reporting on its performance at the annual reviews, with an opportunity for stakeholders to argue to the Commission that FortisBC should not be awarded an incentive payment if the service quality has deteriorated. The final determination and decision for allowance/ disallowance of the incentive rests with the Commission.	
4.1 Targets for Performance Standards – Reliability The Application proposes the following targets: System Average Interruption Duration Index (SAIDI) 3.14 System Average Interruption Frequency Index (SAIFI) 3.01 Generator Forced Outage Rate (FOR) 0.50% Targets are to be adjusted on an annual basis by recalculating the normalized 3 year average and increasing it by 20% to account for annual variability and increased reliability exposure related to implementing the Capital Plan.	SAIDI and SAIFI targets will be calculated using the normalized results for the last three years, normalized. In 2006, the normalized results for each of 2003, 2004, and 2005 will be increased by 10% before averaging. The 10% cushion will be phased out as follows: In 2007, the average will consist of the actual results plus 10% for each of 2004 and 2005, and actual results for 2006. In 2008, the actual results plus 10% for 2005, and actual results for 2006	Exhibit B-1, Tab 9a, P.3, line 1; P.6, lines 16 to 19; P. 6, lines 21 to 26; P.7, lines 2 to 16

	and 2007 will make up the average. In 2009, the target will be the average of the actual results for 2006, 2007, and 2008. The Generator Forced Outage Rate is set at 0.35% for the term of the PBR.	
4.2 Targets for Performance Standards – Customer Service The proposed targets are: Billing Accuracy – 0.075% of bills rejected by system Commitment to Read Meters as Scheduled - 95% of meters read as scheduled. Contact Center Performance - 70% of calls answered within 30 seconds Emergency Response Time - 85% of trouble calls responded to within 2 hours Completion Time for New Requests Residential Std. Service Connections - 85% completed within 6 working days Residential Service Extensions Initial Contact to Quote – 75% completed within 35 working days Customer Acceptance to Construction Completion 75% completed within 30 working days	Accepted: 0.072% the PBR term. 97% for the PBR term 70% within 30 seconds for the PBR term 85% within 2 hours for the PBR term 85% within 6 working days for the term 75% in 2006 for Initial Contact to Quote and for Acceptance to Construction Completion. Phase in 3-year rolling average as results are available. The Company agrees to research First Contact Resolution and to report at the 2006 Annual Review.	Exhibit B-1, Tab 9a, PP. 9 to 13, Exhibit B-12, BCUC IR 59.0, 61.0, 62.0, 65.0, 66.0, 67.0.

4.3 Targets for Performance Standards – Health & Safety The proposed targets are: All Injury Frequency Rate (AIFR) 4.83 Injury Severity Rate (ISR) 24.62 Recordable Vehicle Incidents (RVI) 4.72	The targets will be set using a rolling 3-year average. For 2006: AIFR - 4.83 ISR - 24.62 RVI - 4.72	Exhibit B-1, Tab 9a, PP. 14 to 17
4.4 Informational Metrics – Customer Survey FortisBC proposes to present the results of its Customer Survey at the Annual Reviews, but that the results would not form part of the Performance Standards for incentive purposes.	The Customer Survey results will be a Performance Standard for consideration of incentives, but will be a directional measure only. No targets will be set. FortisBC agrees to research possible measures for First Contact Resolution provide results at the 2006 Annual Review.	Exhibit B-1, Tab 9a, P. 18; BCUC IR 63.0
5. Process – Annual Review, and Negotiated Settlement & Revenue Requirements Workshop Annual Review, Revenue Requirement Workshop and Negotiated Settlement Process according to the agenda and timetable set out in BCUC IR 83.1: For setting 2007 rates, the proposed process is; October 2 Application filed October 27 Information Requests received November 10 Responses to IRs November 14 2006 Annual Review November 23 Technical Committee Reports November 27 Revenue Requirements Workshop	The Parties agree that a schedule similar to that proposed (without the Technical Committee Reports) with a goal of achieving firm rates by December 1 for the following year. The Annual Review will focus on the results of the most recently completed fiscal year and whether the Company is entitled to an incentive payment. Part 1: Review and analysis of all material variances (+/-) pertaining to:	Exhibit B-1, Tab 3, P. 6 & Tab 9a, P. 2, Exhibit B-12, BCUC IR 83.1

	a. all relevant line items comprising the cost of service, and b. sales volumes (re revenues) for the historic period. Part 2: Review and analysis of the Company's actual performance compared to approved targets for the Performance Standards. After completion of the Annual Review, the Commission will issue an Order confirming the results of the Annual Review and the incentive payment. FortisBC is required to file detailed information with respect to Parts 1 and 2. A full round of written Information Requests as proposed in the timetable set out in response to BCUC IR 83.1 will take place prior to the Annual Review. The Revenue Requirements Workshop will focus on future test periods. The Technical Committees are abolished; hence the process step involving the filing of Technical Committee Reports is not required. After completion of the Revenue Requirements Workshop the Commission will issue an Order confirming the rates for Company for the following year.	

6. No Surprises	FortisBC is to advise all parties of any major changes planned for the Utility and nothing in this settlement provides FortisBC with any approval to change its business practices to the detriment of customers.	Exhibit B-12, BCUC IR 76.1
7. Errors Any errors in forecast and/or accounting data used in setting Revenue Requirements will be rectified before calculating the ROE variance for the sharing mechanism.	Accepted.	None

I.M.E.U.

Interior Municipal Electrical Utilities

Cities of Kelowna, Penticton, Grand Forks, District of Summerland, Nelson Hydro, Princeton Light & Power

May 8, 2006

British Columbia Utilities Commission
6^{th} Floor, 900 Howe Street
Vancouver, BC V6Z 2N3

Attention: William J. Grant, Transition Advisor
Regulatory Affairs & Planning

Dear Mr. Grant,

Re: FortisBC Inc. ("FortisBC") – Negotiated Settlement 2006 Revenue Requirements Application and Multi-Year Performance Based Regulation ("PBR") Mechanism

IMEU group agrees with the revised Negotiated Settlement Agreement and supporting documents as circulated by Commission staff on May 4, 2006 regarding FortisBC's 2006 Revenue Requirements and PBR Mechanism. We would also like to acknowledge the efforts of all parties and Commission staff in reaching this settlement.

If you have any questions, do not hesitate to contact us.

Yours truly,

CITY OF KELOWNA

Rod Carle, C.I.M. P.Mgr.
cc: IMEU group
Registered Intervenors

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: 23841/0016

May 8, 2006

VIA ELECTRONIC MAIL

CONFIDENTIAL

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

Attention: William J. Grant, Transition Advisor, Regulatory Affairs & Planning

Dear Sirs/Mesdames:

Re: FortisBC Inc. ("FortisBC") – Negotiated Settlement 2006 Revenue Requirements Application and Multi-Year Performance Based Regulation ("PBR") Mechanism

We have reviewed the Negotiated Settlement Agreement and supporting documents provided by the Commission's staff on May 4, 2006 with respect to the above-noted matter. The Commercial Energy Consumers Association of British Columbia agrees with the terms set out in the Negotiated Settlement Agreement and supporting documents.

We appreciate the significant effort that the parties and the Commission staff have put in to arrive at this settlement.

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

Yours truly,

OWEN BIRD LAW CORPORATION

Christopher P. Weafer

Christopher P. Weafer
CPW/jlb
cc: Fong Kwok
cc: CEC

The
British Columbia
Public Interest
Advocacy Centre
208–1090 West Pender Street
Vancouver, BC V6E 2N7
Tel: (604) 687-3063 Fax: (604) 682-7896
email: bcpiac@bcpiac.com
http://www.bcpiac.com

Richard J. Gathercole	687-3006
Sarah Khan	687-4134
Patricia MacDonald	687-3017
James L. Quail	687-3034
Leigha Worth	687-3044

Barristers & Solicitors

Valerie Conrad
Articled Student

Via email

May 8, 2006

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, BC V6Z 2N3

Attention: William J. Grant, Transition Advisor
Regulatory Affairs & Planning

Dear Mr. Grant,

Re: FortisBC Inc. ("FortisBC") – Negotiated Settlement 2006 Revenue Requirements Application and Multi-Year Performance Based Regulation ("PBR") Mechanism

BCOAPO *et al.* agrees with the revised Negotiated Settlement Agreement and supporting documents as circulated by Commission staff on May 4, 2006 regarding FortisBC's 2006 Revenue Requirements and PBR Mechanism. We would also like to acknowledge the efforts of all parties and Commission staff in reaching this settlement.

If you have any questions, do not hesitate to contact us.

Yours truly,

BC PUBLIC INTEREST ADVOCACY CENTRE

original signed by

Sarah Khan
Counsel for BCOAPO

c: BCUC, Attention: Fong Kwok
Registered Intervenors

APPENDIX C

May 8/06.

B.C.U.C.

Attention:- Fong Kwok,

Re: Fortis N.S.P.

I accept the final negotiated settlement agreement.

Buryl Slack

BURYL JONAS SLACK
Intervenor

Box 356, Osoyoos, B.C. V0H 1V0
Phone 1-250-495-6702

APPENDIX C

Alan Wait
Box 2663
Grand Forks, B.C.
V0H 1H0
alwait@telus.net
250-442-8341
May 8, 2006

British Columbia Utilities Commission
Sixth Floor
900 Howe St, Box 250,
Vancouver, B.C. V6Z 2N3

Att: Fong Kwok

Re: FortisBC Negotiated Settlement for 2006 Revenue Requirements

Dear Fong:

I am still unable to support the proposed settlement agreement, specifically in regards to item #14, Depreciation Expense.

I believe that the Depreciation study must be thoroughly examined, and understood by all parties before the new depreciation rates are accepted as is, or modified, and new depreciation rates are used in the revenue requirements for 2006 and future years.

My concerns as per my letter of May 1, 2006 stand.

I have also noticed a small error in item #15 on page 9 of the settlement, where the existing DSM costs are to be amortized "over the existing 12 year period". Presently DSM charges are amortized over 8 years. Tab 5, P.72, L.8

The Depreciation expense is too big an item to simply ignore for 2 to 3 years.

Respectfully submitted,

Alan Wait

APPENDIX C

From: Richard Tarnoff [rgt@nethop.net]

Sent: Monday, May 08, 2006 12:06 PM

To: Grant, Bill J BCUC:EX

Cc: Dick Gathercole; Chong, Doug BCUC:EX; Kwok, Fong Y BCUC:EX; Nakoneshny, Philip BCUC:EX; Tomen, Rose BCUC:EX; rleslie@city.nelson.bc.ca; Brian Parent; chuck.lee@fortisbc.com; david.bennett@fortisbc.com; don.debienne@fortisbc.com; john.walker@fortisbc.com; joyce.martin@fortisbc.com; Lavern Humphrey; michael.mulcahy@fortisbc.com; Rod Carle; cweafer@owenbird.com; Al Wait; Sarah Khan

Subject: Re: FortisBC 2006 RR and PBR Mechanism

May 8, 2006

BC Utilities Commission
900 Howe Street
Vancouver, BC, V6Z 2N3

Via E-mail

Dear Sirs and Madames,

Re: FortisBC 2006 Rev. Req. and PBR Mechanism

Natural Resource Industries and Hedley Improvement District approves the final Negotiated Settlement Agreement and supporting documents for the above named hearing. We would like to thank all participants for their efforts.

Yours truly,

Richard Tarnoff

cc: participants