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BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-52-05

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IN THE MATTER OF

the Utilities Commission Act, RSBC 1996, Chapter 473, as amended

and

An Application by FortisBC Inc.
for Approval of 2005 Revenue Requirements,
2005-2024 System Development Plan and 2005 Resource Plan

BEFORE: L.F. Kelsey, Commissioner and Panel Chair
P.G. Bradley, Commissioner May 31, 2005

O R D E R

WHEREAS:

A. On November 26, 2004, FortisBC Inc. ("FortisBC") submitted its 2005 Revenue Requirements Application, which also included its Transition Plan and 2005 Capital Plan ("Submission 1"). On the same date, under separate cover, FortisBC also filed its 2005-2024 System Development Plan ("Submission 2"). On December 21, 2004, FortisBC submitted its 2005 Resource Plan ("Submission 3"); and

B. In Submission 1 FortisBC requested approval of a 2005 Revenue Requirement of $184,388,000 and a general rate increase of 4.4 percent; and

C. On December 14, 2004, the Commission issued Order No. G-111-04, establishing a series of Workshops, a Pre-hearing Conference, and approving an interim rate increase of 3.7 percent, effective January 1, 2005, subject to refund with interest calculated at the average prime rate of the principal bank with which FortisBC conducts its business; and

D. A Pre-hearing Conference was held on January 21, 2005 in Kelowna, B.C. to discuss the major issues to be examined, and the steps and timetable for an Oral Public Hearing. Registered Intervenors and FortisBC made their submissions for consideration by the Commission; and

E. Order No. G-14-05 dated January 24, 2005, set out an amended Regulatory Timetable and Issues List and established an Oral Public Hearing to commence on March 21, 2005 in Kelowna, B.C.; and

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F. By letter dated January 27, 2005, FortisBC requested a revision to the Regulatory Timetable and process to include a Negotiated Settlement Process ("NSP"). The Commission issued Letter No. L-9-05 dated January 28, 2005, rejecting the request for an NSP because it was concerned that FortisBC and its predecessors have gone for many years without a detailed review of the utility operations in an oral public hearing process; and

G. On March 10, 2005, FortisBC filed a revised 2005 Revenue Requirements Application ("Submission 4") reflecting the impact of updated 2004 actual energy sales and financial results. In Submission 4 FortisBC sought approval for a revised 2005 Revenue Requirement of $179,980,000 and a general rate increase of 4.1 percent, effective January 1, 2005; and

H. On March 18, 2005, FortisBC filed a second revised 2005 Revenue Requirements Application ("Submission 5") primarily reflecting the impact of updates to 2004 power purchase incentive adjustments and 2005 income tax expense. In Submission 5 FortisBC sought approval for a revised 2005 Revenue Requirement of $179,250,000 and a general rate increase of 3.6 percent, effective January 1, 2005; and

I. The Oral Public Hearing proceeded as scheduled in Kelowna, B.C. on March 21 through March 24, 2005. During the Oral Public Hearing, on March 22, 2005, FortisBC filed a third revised 2005 Revenue Requirements Application ("Submission 6") incorporating a correction to the 2004 Actual and 2005 Forecast Mid-Year Rate Base. In Submission 6 FortisBC sought approval for a revised 2005 Revenue Requirement of $179,991,000 and a general rate increase of 4.1 percent, effective January 1, 2005; and

J. Written Final Arguments and Reply Arguments were completed on April 29, 2005; and

K. The Commission Panel has considered Submissions 1 through 6 and all of the related evidence and arguments.

NOW THEREFORE the Commission orders as follows:

1. FortisBC is directed to file complete financial schedules showing:

   (a) The requested 2005 Revenue Requirement of $179,991,000 as per Submission 6;
   (b) All adjustments set out in the Decision issued concurrently with this Order; and
   (c) The final resultant 2005 Revenue Requirement and general rate increase.

   The Commission approves the final resultant 2005 Revenue Requirement and general rate increase consistent with all adjustments set out in the Decision issued concurrently with this Order.

2. If the final general rate increase is less than the 3.7 percent general rate increase granted on an interim refundable basis as per Order No. G-111-04, then refunds should be made to customers as soon as practicable, with interest calculated at the average prime rate of the principal bank with which FortisBC conducts its business. FortisBC is directed to file all relevant refund calculations with the Commission.

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3. If the final general rate increase is greater than the 3.7 percent general rate increase granted on an interim refundable basis as per Order No. G-111-04, the additional monies will be recovered through a rate rider based on forecast consumption for the period July 1, 2005 to December 31, 2005. FortisBC is directed to file all relevant rate rider calculations with the Commission.

4. FortisBC is also directed to comply with all other determinations and instructions set out in the Decision that is issued concurrently with this Order.

DATED at the City of Vancouver, in the Province of British Columbia, this 31st day of May 2005.

BY ORDER

Original signed by:

L.F. Kelsey
Commissioner and Panel Chair

Attachment

IN THE MATTER OF

FORTISBC INC.

2005 REVENUE REQUIREMENTS APPLICATION
2005-2024 SYSTEM DEVELOPMENT PLAN
2005 RESOURCE PLAN

DECISION

MAY 31, 2005

Before:

L.F. Kelsey, Commissioner and Panel Chair
P.G. Bradley, Commissioner

TABLE OF CONTENTS

Page No.

1.0 INTRODUCTION 1

1.1 Background and Historical Context 1

1.2 FortisBC Filings and Procedural Summary 2

2.0 2005 REVENUE REQUIREMENTS APPLICATION 7

2.1 Forecasts 7
2.1.1 Load Forecast 7
2.1.2 Power Purchase and Wheeling Forecast 10

2.2 Common Equity Component and Return on Common Equity 11
2.2.1 Direct Evidence of Ms. McShane 12
2.2.2 Direct Evidence of Dr. Booth 17
2.2.3 Submissions 19
2.2.4 Commission Panel Determinations 23

2.3 2005 Revenue Requirements 27
2.3.1 Rate Base 27
2.3.2 Power Supply 27
2.3.3 Operations and Maintenance Expenses and Capitalized Overheads 28
2.3.4 Pensions 30
2.3.5 Other Post-retirement Benefits 30
2.3.6 Employee Stock Option Expense 32
2.3.7 2004 Incentive Sharing Adjustments 32

2.4 2005 Incentive Sharing Mechanisms 33
2.4.1 DSM and Power Purchase Incentives and Flow-through Costs 33
2.4.2 Operating Expense Incentive 34
2.4.3 Review of PBR 37

2.5 2005 Demand Side Management Expenditure Plan 38
2.5.1 Application 38
2.5.2 Demand Side Management Technical Committee 38
2.5.3 Commission Panel Determinations 39

2.6 Transition Plan 40
2.6.1 Introduction 40
2.6.2 Customer Service 40
2.6.3 Establishment of a Stand-alone utility 41
2.6.4 Field Services 41
2.6.5 Submissions 42
2.6.6 Commission Panel Determinations 43

2.7 Customer Service 43
2.7.1 Metrics and Strategies 44
2.7.2 Commission Panel Determinations 46

TABLE OF CONTENTS
(continued)

Page No.

2.8 Accounting Issues 47
2.8.1 Depreciation and Amortization Study 47
2.8.2 Adjustment for Capital Expenditures 48
2.8.3 Allowance for Funds Used During Construction 48
2.8.4 Capitalization of PowerSense Costs 50
2.8.5 Deferred Charges 50
2.8.6 Provision for Income Tax Audits 53
2.8.7 Capital Tax Refund 54

3.0 2005 CAPITAL PLAN AND 2005-2024 SYSTEM DEVELOPMENT PLAN 56

3.1 Introduction 56

3.2 2005-2024 System Development Plan 56
3.2.1 Bulk Transmission Plan 57
3.2.2 Transmission and Distribution 57
3.2.3 Rate Impacts 57
3.2.4 Submissions 58
3.2.5 Commission Panel Determinations 59

3.3 2005 Capital Plan 59
3.3.1 2005 Capital Plan Summary 59
3.3.2 New Projects 60
3.3.3 Commission Panel Determinations 61

4.0 2005 RESOURCE PLAN 63

4.1 Background 63

4.2 2005 Resource Plan Summary 63

4.3 Submissions 67

4.4 Commission Panel Determinations 67

ORDER NO. G-52-05

APPENDICES

APPENDIX A – Appearances
APPENDIX B – List of Exhibits

1.0 INTRODUCTION

1.1 Background and Historical Context

In 1986 UtiliCorp United and UtiliCorp BC applied to the British Columbia Utilities Commission ("Commission") to acquire a reviewable interest in West Kootenay Power and Light Company Ltd. Following an extensive review, that application was approved by the Commission. The West Kootenay Power and Light Company Ltd. name remained for some time, was subsequently changed several times, eventually to become Aquila Networks Canada (British Columbia) Ltd. ("Aquila(BC)") (the "Utility").

In October 1998, as part of its Preliminary 1999 Revenue Requirements and Incentive Mechanism Review Application, the Utility applied for an Order that a Negotiated Settlement Process ("NSP") be implemented. Commission Order No. G-123-98 approved that application. Following negotiations with Intervenors, wherein a settlement was reached, Commission Order No. G-134-99 approved the November 22, 1999 Settlement Agreement for the period beginning January 1, 2000 and ending December 31, 2002. The terms of the 1999 Settlement Agreement required that the Utility institute an NSP and an Annual Review process to allow the public to examine the filed material, to submit other issues for determination by the Commission and to discuss all issues prior to the final rate application being made.

On November 15, 2002, the Utility requested that the 1999 Settlement Agreement be extended for a period of one year ending December 31, 2003, filing a Preliminary 2003 Revenue Requirements Application in support. Commission Order No. G-83-02 established a 2002 Annual Review and an NSP to determine rates for 2003. The proceedings were held in Penticton B.C. in January 2003. A Public Information Town Hall Meeting was scheduled for those parties not able to participate in the Annual Review. Commission Order No. G-10-03 approved the Negotiated Settlement as issued. This Settlement was a simple extension of the 2000-2002 rate adjustment mechanism approved by the November 22, 1999 Settlement Agreement. The Utility agreed at that time to provide a detailed revenue requirements application for 2004 that would contain a full analysis in support of any proposed rebasing of in the cost categories.

On November 19, 2003, the Utility filed a Preliminary 2004 Revenue Requirements Application with the Commission. Due to the impending sale of the Canadian business of Aquila(BC) to Fortis Inc. and the potential for restructuring, the Utility proposed a one-year extension of the current Settlement Agreement, which was due to expire on December 31, 2003 subject to certain changes as described in the Application. Further, the Utility proposed an NSP to determine the 2004 Revenue Requirements and the parameters of the Incentive Mechanism.

The Utility also requested that the 2003 Annual Review of its performance be scheduled prior to the NSP.

By Order No. G-6-04 the Commission approved an NSP to determine rates for 2004. Following negotiations, Commission Order No. G-38-04 approved the terms of the negotiated settlement agreement.

As contemplated in the Preliminary 2004 Revenue Requirements Application, on December 1, 2003, Fortis Pacific Holdings Inc. ("Fortis Pacific") applied pursuant to Section 54 of the Utilities Commission Act ("UCA") for an Order approving the acquisition of a reviewable interest in Aquila Networks Canada (British Columbia) Ltd. from Aquila Networks British Columbia Ltd. On the same date, Aquila Networks Canada (British Columbia) Ltd applied pursuant to Section 54(5) of the UCA for approval to register a transfer of 100 percent of its Common Shares to Fortis Pacific.

Following a written hearing, the Commission, by Order No. G-39-04 approved the acquisition by Fortis Pacific of a reviewable interest in Aquila Networks Canada (British Columbia) Ltd. The company was renamed FortisBC Inc ("FortisBC").

In response to a Commission information request during the acquisition hearing, FortisBC stated that it anticipated that it would file a general rate application in the fourth quarter of 2004 that would "set out in detail the plans for re-establishing the Utility on a stand-alone basis." FortisBC also stated that the rate application would "provide a basis for full public scrutiny of a more detailed plan including a definitive timetable, a forecast of proposed costs and an assessment of customer benefits, as well as a reasonable record for the Commission's consideration of matters relating to this issue."

1.2 FortisBC Filings and Procedural Summary

On November 26, 2004, FortisBC filed its 2005 Revenue Requirements Application with the Commission ("November Application") (Exhibit B-1). FortisBC applies for an Order, pursuant to the applicable provisions of the UCA including Sections 23, 45, 57, 60, and 61, approving the November Application for the purpose of setting rates and other ancillary matters. Included with this filing, and in compliance with Commission Order No. G-39-04, FortisBC submitted its Transition Plan outlining the steps being taken to move the utility to a stand-alone basis. FortisBC included its 2005 Capital Plan with its November Application and filed under separate cover its 2005-2024 System Development Plan (Exhibit B-2). It filed these plans to address high priority work needed to maintain and expand the electrical system to meet its obligation to provide reliable electricity service to its customers. FortisBC filed its 2005 Resource Plan (Exhibit B-4) in accordance with the Commission's Resource Planning Guidelines and the Commission's directives to utilities in this regard.

FortisBC's November Application requests approval of a general rate increase of 4.4 percent, reflecting principally an increased rate base, an increased cost of financing that rate base and a forecast increase in 2005 expenses, including operating and maintenance expenses and power purchases. The November Application included a request for an interim refundable general rate increase of 4.4 percent, effective January 1, 2005. The increase was based, in part, on a proposal to increase the equity risk premium of FortisBC from 40 to 75 basis points. In response to a Commission staff request, FortisBC determined that the general rate increase would equal 3.7 percent if derived on the basis of its existing equity risk premium of 40 basis points. On December 14, 2004, the Commission issued Order No. G-111-04 approving for FortisBC an interim rate increase of 3.7 percent, effective January 1, 2005, subject to refund with interest calculated for the refund period at the average prime rate of the principal bank with which FortisBC conducts its business. By this Order the Commission also established a series of Application Workshops and a Pre-hearing Conference.

The Commission held the Pre-Hearing Conference in Kelowna, B.C. on January 21, 2005, wherein the Commission Panel considered submissions by participants on finalizing the issues, process steps and regulatory schedule for the proceeding. As part of its consideration of process steps, the Commission Panel heard submissions by parties on whether certain issues would be appropriately reviewed by Technical Committees.

Following the Pre-Hearing Conference, on January 24, 2005 the Commission issued Order No. G-14-05, which set out an amended Regulatory Timetable and Issues. Commission Order No. G-14-05 established an Oral Public Hearing ("Hearing") to commence on March 21, 2005 in Kelowna, and specified that issues associated with the Load Forecast, Demand Side Management ("DSM"), Power Purchases, and Capital Additions would be reviewed by four separate Technical Committees as an adjunct to the Hearing. The Commission directed each Technical Committee to submit a report with recommendations to the Commission by Monday, March 14, 2005, one week prior to the commencement of the Hearing.

By letter dated January 27, 2005, FortisBC requested that the regulatory timetable and process be revised to include an NSP (Exhibit B-8). FortisBC indicated that on the condition that the NSP was successful it would defer its application for an increase to its equity risk premium until the fall of 2005 in anticipation of a Commission process regarding the return on equity adjustment mechanism at that time. FortisBC reported that its proposed revision to the regulatory timetable and process was supported by most Intervenors.

The Commission issued Letter No. L-9-05 on January 28, 2005 rejecting FortisBC's request for an NSP for 2005. The Commission was concerned that FortisBC and its predecessors have gone for many years without a detailed review of the utility operations in an oral public hearing process, while noting that in each of the last two settlements the participants agreed that an oral public hearing was timely and should occur the following year. At the request of FortisBC, and for reasons that are a matter of public record, oral public hearings did not occur. The Commission believed that it was timely to review the finances and revenue requirement of the new B.C.-based utility in an oral public hearing this year. The Commission commented that following such a detailed review and decision, it may then be timely to consider an NSP thereafter. The Commission also noted that successful work by the four Technical Committees would go a considerable distance to streamlining the Hearing.

On March 9, 2005, FortisBC filed the reports of the DSM and Load Forecast Technical Committees (Exhibits B-17 and B-18, respectively). Each Committee recommended that there would be no need to call hearing panels in their respective subject areas. On March 11, 2005, FortisBC filed the reports of the Capital Additions and Power Purchases Technical Committees (Exhibits B-20 and B-21, respectively). The Capital Additions and Power Purchases Technical Committees reported that the meetings were helpful, but recommended that these matters should be addressed at the Hearing.

On March 11, 2005, the Commission wrote to Registered Intervenors requesting that they indicate by March 16, 2005 whether or not they were supportive of the recommendations of the DSM and Load Forecast Committees that there is no need to call hearing panels in their respective subject areas (Exhibit A-14). The Commission indicated in its letter that it would consider no response to indicate support of the Committee recommendations. Out of those intervenors that did not participate in the work of these Committees, the Commission received one letter of support, from the B.C. Old Age Pensioners Association *et al.* ("BCOAPO"), and zero letters of no support. By letter dated March 17, 2005 the Commission accepted the recommendations of the DSM and Load Forecast Committees that there is no need to call hearing panels in the respective subject areas (Exhibit A-16).

On March 10, 2005, FortisBC filed a revised 2005 Revenue Requirements Application (the "Revised Application") (Exhibit B-19). FortisBC indicates that its Revised Application reflects the impact of updates to 2004 actual results on 2005 energy sales and revenue forecasts, and 2004 incentive adjustments. FortisBC reported that its Revised Application includes revisions arising from events subsequent to the November Application, such as FortisBC's Capital Tax appeal and changes to property tax assessment procedures. FortisBC's Revised Application sought approval of a 2005 Revenue Requirement of approximately $180.0 million, and a general rate increase of 4.1 percent, effective January 1, 2005.

On March 18, 2005, FortisBC filed a second revised 2005 Revenue Requirements Application (the "Second Revised Application") reflecting the impact of updates to 2004 power purchase incentive adjustments and 2005 income tax expense (Exhibit B-25). The Second Revised Application also reflects actual issue costs related to FortisBC's Series 04-01 Senior Unsecured Debentures equal to $2,091,000, which is less than the forecast of $2,150,000 in the initial Application. The Second Revised Application requests approval to defer and amortize the actual amount. FortisBC's Second Revised Application seeks approval of a 2005 Revenue Requirement of approximately $179.3 million, and a general rate increase of 3.6 percent, effective January 1, 2005.

The Hearing proceeded as scheduled in Kelowna on March 21 through March 24, 2005.

On March 22, the second day of the Hearing, FortisBC filed a third revised 2005 Revenue Requirements Application (the "Third Revised Application") (Exhibit B-26). FortisBC indicated that the Third Revised Application incorporates a correction to the 2004 Actual and 2005 Forecast Mid-Year Rate Base; namely that the Mid-Year Rate Base had been understated in the Second Revised Application by approximately $3.0 million in 2004 and $8.3 million in 2005. FortisBC states that the understatement of Rate Base was caused by the incorrect reduction of net additions to plant in service by the amount of new Contributions in Aid of Construction ("CIAC"). FortisBC's Third Revised Application seeks approval of a 2005 Revenue Requirement of approximately $180.0 million, and a general rate increase of 4.1 percent, effective January 1, 2005.

Following the Hearing, written argument was received by FortisBC on April 15, 2005 ("FortisBC Argument"). On April 22, 2005, the Commission received argument from Natural Resources Industries ("NRI", "NRI Argument"), Interior Municipal Electric Utilities ("IMEU", "IMEU Argument"), Mr. Alan Wait ("Mr. Wait", "Wait Argument"), Kootenay-Okanagan Electric Consumers Association ("KOECA", "KOECA Argument"), and BCOAPO ("BCOAPO Argument"). FortisBC filed its reply argument on April 29, 2005 ("FortisBC Reply Argument").

FortisBC adopted the convention in its written argument that its November Application, together with its Revised Application, Second Revised Application and Third Revised Application, would be collectively referred to as the "Application". The Commission uses the same referencing convention in this Decision unless it is necessary to refer to a specific filing, as appropriate.

FortisBC summarizes in its written argument that it seeks an Order of the Commission (FortisBC Argument, pp. 3-5):

- approving a 2005 Revenue Requirement of $179,991,000;
- approving the deferral of the cost of regulatory and related activities and the issue cost of the Series 04-1 Senior Unsecured Debentures in the amount of $2,091,000;
- approving the amortization of: the issue cost of the Series 04-1 Senior Unsecured Debentures in the amount of $2,091,000 over ten years commencing on January 1, 2005; the costs incurred in FortisBC's 2004 Revenue Requirements negotiated settlement process; and the costs of the 2005-2024 System Development Plan and 2005 Resource Plan, in an aggregate amount of $900,000 over five years commencing on January 1, 2005;
- approving the continuation of the current Demand Side Management and Power Purchase incentive mechanisms for 2005;
- approving the continuation of the flow through to customers of forecast and actual property tax, provincial water fees, and the Power Purchase expense related to the Brilliant contracts for 2005;
- approving the flow-through treatment of the costs of capacity block power purchases forecast for November and December 2005;
- approving an operating and Maintenance expense program with a forecast value of $36,173,000 and a sharing mechanism for expense above or below this amount;
- approving a cost of capital for rate making purposes that reflects a return on equity 75 basis points above that set by the Commission for a benchmark low-risk utility and a common equity ratio of 40 percent of total capitalization;
- acknowledging that the 2005 Capital Plan satisfies the requirements of Section 45 of the Utilities Commission Act and that specified capital projects are in the public interest;
- acknowledging that the 2005 Resource Plan meets the requirements of Section 45 of the Utilities Commission Act, and is in the public interest;
- acknowledging that the 2005 Demand Side Management ("DSM") Expenditures Plan meets the requirements of Section 45 of the Act, and is in the public interest;
- approving a change in the accounting treatment of certain PowerSense costs, such that the costs in the amount of $85,000 are charged to capital rather than operations;
- approving deferral and recovery in 2006 of higher income tax expense that will arise in 2005 if the new Capital Cost Allowance rates announced in the February 23, 2005 Federal Budget are not enacted prior to December 31, 2005; and
- approving a general rate increase of 4.1 percent effective January 1, 2005.

The following sections of this Decision address, in turn, the issues associated with the 2005 Revenue Requirements Application, the 2005 Capital Plan and 2005-2024 System Development Plan, and the 2005 Resource Plan.

2.0 2005 REVENUE REQUIREMENTS APPLICATION

2.1 Forecasts

2.1.1 Load Forecast

FortisBC describes its service area as experiencing population growth at an increased rate over the last several years. FortisBC observed that in 2004 the growth in energy consumption and the number of customer accounts has been significantly above the long term population growth rate in its service area. To account for these patterns of growth, FortisBC modified its load forecast methodology to decouple population growth from its forecast of energy consumption and customer accounts for the period 2004-2009. FortisBC anticipates that by 2009, energy consumption and customer growth rates will return to the long term rates of population growth. FortisBC normalized all temperature sensitive load data to eliminate the effect of temperature prior to conducting its load forecast and associated statistical analyses. In its November Application, FortisBC forecast a total gross load of 3,368 GWh, subsequently adjusted downward by 78 GWh to 3,290 GWh based on updates to 2004 actual data, and a revised industrial forecast (Exhibit B-1, pp. 4, 9; Exhibit B-19, p. 4). The components of this change are described in greater detail below. The following sections include a summary of the load forecast for each customer class in turn.

Residential

The Residential load forecast is comprised of a forecast of customer accounts and a forecast of use per customer.

FortisBC forecasts the growth rate in its customer accounts based on the long-term linear trend in population growth rates in its service area, augmented by adjustments that reflect actual and expected growth in the short-term. The short-term adjustments encompass the decoupling of the forecast from population growth, as described above. FortisBC forecasts 85,926 Residential customer accounts by 2005 year-end (Exhibit B-1, pp. 4, 10; Exhibit B-12, Q. 38.1, Q. 41.0).

FortisBC forecasts Residential use per customer based on a 19-year average annual decline rate between 1985 and 2003 of 67 kWh/customer. FortisBC indicates that possible explanations for this decline rate are the availability of more efficient electrical appliances and declining dependence on electricity as a primary source of energy for heating and cooling (Exhibit B-1, p. 4; Exhibit B-12, Q. 41.0).

Based on these components, FortisBC initially forecast a Residential load of 1,064 GWh. Subsequent to its November Application, FortisBC adjusted this forecast downward by 10 GWh, to 1,054 GWh, to reflect the impact of actual and normalized 2004 Residential energy consumption that was below forecast despite strong growth in Residential customer accounts (Exhibit B-1, p. 9; Exhibit B-19, p. 4).

General Service

FortisBC's General Service class includes commercial and small industrial customers, as well as schools, hospitals and recreation facilities. FortisBC indicates that it is more difficult to forecast energy consumption in this class because of the diversity in customer size and the lumpiness of load additions.

Applying the same methodology as it uses for the Residential class, FortisBC forecasts 10,306 customer accounts by 2005 year-end. FortisBC forecasts General Service use per customer based on a 25-year average annual incline rate of 26 kWh/customer (Exhibit B-1, pp. 5, 10; Exhibit B-12, Q.42.0). Based on these components, FortisBC initially forecast a General Service load of 570 GWh. Subsequent to its November Application, FortisBC adjusted this forecast downward by 24 GWh, to 546 GWh, to reflect the impact of actual and normalized 2004 General Service energy consumption that was below forecast despite strong growth in General Service customer accounts (Exhibit B-1, p. 9; Exhibit B-19, p. 4).

Industrial

FortisBC forecasts its Industrial load by estimating the annual energy consumption of Celgar, its single largest industrial customer, and adding this amount to a forecast of the remainder of Industrial load determined on the basis of the historical relationship of this portion of Industrial load to overall system load. FortisBC initially estimated Industrial load of 343 GWh, including Celgar load of 65 GWh based on recent Celgar projections, or nearly 20 percent of overall Industrial load. Subsequent to its November Application, FortisBC adjusted this forecast downward by 34 GWh, to 309 GWh, to reflect a new 2005 load forecast projection by Celgar of 31 GWh (Exhibit B-1, pp. 5, 9; Exhibit B-19, p. 4).

Wholesale

FortisBC's Wholesale class is comprised mainly of municipal electric utilities, with a corresponding composition of residential, commercial and industrial customers. Given that this load is largely sensitive to population growth trends, FortisBC forecasts Wholesale consumption based on the relationship between population growth trends and temperature normalized historical consumption in this class (Exhibit B-1, p. 6).

FortisBC initially forecast Wholesale load of 964 GWh. Subsequent to its November Application, FortisBC adjusted this forecast downward by 6 GWh, to 958 GWh, to reflect the impact of actual and normalized 2004 Wholesale energy consumption that was below forecast (Exhibit B-1, p. 9; Exhibit B-19, p. 4).

Irrigation and Lighting

FortisBC forecasts Irrigation load of 47 GWh based on a five-year average load, and assumes that this level will remain constant for the duration of the forecast period. Similarly, forecast Lighting load of 10 GWh is assumed to remain constant for the duration of the forecast period.

System Losses

FortisBC forecasts losses of 369 GWh on the basis that annual losses consistently amount to roughly 12 percent of historical net system load. FortisBC adjusted its forecast losses downward by 3 GWh, to 366 GWh, based on the updates to the load forecast of the respective customer classes described above.

Load Forecast Technical Committee

Commission Order No. G-14-05 specified that issues associated with the Load Forecast would be reviewed by a Technical Committee as an adjunct to the Hearing. The Committee comprised FortisBC and Commission staff as well as Registered Intervenors that expressed an interest to participate. The Commission directed the Load Forecast Technical Committee to submit a report with recommendations to the Commission one-week prior to the commencement of the Hearing (Exhibit A-4).

FortisBC filed the Report of the Load Forecast Technical Committee on March 9, 2005 (Exhibit B-18). The Committee considered several methodological issues in detail over the course of two meetings; most notably a review of the assumptions underlying the regression analyses for the Residential and General Service use per customer forecasts. Further detail of the issues discussed, and the undertakings completed by FortisBC in response, may be referenced in the Report (Exhibit B-18). Committee members concluded that there were no serious methodological concerns with the load forecast. Committee members were provided with the revised forecast, as summarized above, prior to the filing of the report. No concerns were raised about the revised forecast.

The Committee suggested that FortisBC improve upon the communication and transparency of the technical detail and associated calculation spreadsheets for the load forecast. The Committee recommended that there would be no need to call a load forecast panel at the Hearing. After canvassing comment from those Registered

Intervenors that did not participate in the Load Forecast Technical Committee, the Commission accepted this recommendation (Exhibit A-16). A load forecast panel was not called at the Hearing and no load forecast issues were otherwise addressed in the Hearing. No written submissions on the load forecast were received in argument by any party.

Commission Panel Determinations

The Commission Panel has reviewed the FortisBC Load Forecast and the Report of the Load Forecast Technical Committee. **The Commission Panel accepts the revised FortisBC gross load forecast of 3,290 GWh.**

The Commission Panel is mindful of the Technical Committee suggestion that FortisBC improve upon the communication and transparency of the technical detail and associated calculation spreadsheets for the load forecast. Accordingly, the Commission Panel encourages FortisBC to improve its efforts in this regard. The Commission Panel also encourages FortisBC to consult with its Wholesale customers to determine whether any other means exist to obtain a more rigorous and comprehensive load forecast for this customer class. In addition, the Commission Panel has some concern about whether FortisBC's load forecast adequately accounts for diverse regional characteristics that exist across its service area, particularly in light of its reliance on more general population trends in its load forecast methodology. The Commission Panel encourages FortisBC to investigate alternatives to its current load forecast methodology to determine whether any benefit can be gained by segmenting its load forecast by specific regions in its service area, as FortisBC would define them.

2.1.2 Power Purchase and Wheeling Forecast

In its November Application, FortisBC forecast Power Purchase and Wheeling expenses (including water fees) of $74.26 million (Exhibit B-1, Tab 7). Power Purchase expenses alone are forecast to be $62.44 million for 2005, compared to an estimated amount for 2004 of $60.39 million. FortisBC noted that the Power Purchase expense forecast contains uncertainty with respect to load volumes and resource uncertainty. The resource uncertainty is related to market purchases required to supply a small shortfall between its firm resources and forecast loads. In its Revised Application FortisBC reduced the Forecast Power Purchase Expense to $59.45 million as a result of a change in load forecasts. This change reduced total forecast Power supply costs (including wheeling and water fees) to $71.01 million (Exhibit B-19, and Exhibit B-26).

As discussed in the 2005 Resource Plan, FortisBC meets the majority of its needs through its own generation plants and from long-term power purchase agreements, as well as from BC Hydro's Rate Schedule 3808. The remaining amount (mainly for capacity at peak load periods) is acquired through spot market purchases or block purchases from TeckCominco ("Cominco"). In 2004 these purchases were made in advance of need through the purchase of blocks of capacity from Cominco and through the purchase of a call option from Avista Energy (Exhibit B-1, Tab 7, pp. 10-11). The 2005 forecast includes market purchases and Cominco block purchases for January and February (actual) and November and December (estimated). The estimated amount of block purchases from Cominco is for 25MW in November and 100MW in December at estimated prices of $65.20/MW and $65.40/MW, respectively. Spot Market purchases for capacity (with a small amount of energy) are purchased year round depending on whether spot market prices are better than under BC Hydro Rate Schedule 3808. However, in the year 2005 for the months of January and February, and November and December, when FortisBC may be forced to purchase from the market, the forecast prices are 113 mills/KWh (11.3 cents/kWh). These prices are based on the Avista Energy Report and adjusted for the most valuable hours in the block (Exhibit B-1, Tab 7, p. 12). FortisBC provided an example of how this calculation is made in Appendix 1 to Exhibit B-21.

In past years FortisBC forecasted that its shortfall would be made up by market purchases because it does not have a firm contract with Cominco. However, the company typically was able to enter contracts late in the year at below market prices. The resulting difference was shared 50-50 between the company and its customers. This arrangement has been criticized because it appeared that the block purchases, although not firm, were predictable.

For this application FortisBC is proposing that the block purchases for November and December be taken out of the incentive mechanism and be treated as flow-through expense (Exhibit B1, Tab7, p 11).

No intervenor expressed objections to the Power Purchase forecast.

<u>Commission Panel Determinations</u>

The Commission Panel approves the forecast Power Purchases expense of $71,010,000, as revised by Exhibit B-19. Approval of the Power Purchase expense mechanism is addressed in this Decision in Section 2.4: 2005 Incentive Sharing Mechanisms.

2.2 Common Equity Component and Return on Common Equity

FortisBC applies to the Commission for approval of a cost of capital for rate making purposes that reflects a common equity ratio of 40 percent of total capitalization and a return on equity of 75 basis points above that set by the Commission for a benchmark low-risk utility.

In support of this application, FortisBC filed expert evidence titled *Opinion on Capital Structure and Equity Risk Premium for FortisBC*, prepared by Kathleen C. McShane ("Ms. McShane") of Foster Associates Inc., an economic consulting firm (Exhibit B-1, Tab 5). Ms. McShane concluded that a 40 percent common equity ratio, representative of FortisBC's actual capital structure, is reasonable but should be viewed as the minimum necessary to provide adequate financing flexibility. Ms. McShane recommends that FortisBC be allowed an incremental risk premium of 50 to 100 basis points (a mid-point of 75 basis points) relative to that applicable to a low risk benchmark utility.

BCOAPO filed expert evidence titled *Business Risk, Capital Structure and ROE for FortisBC*, prepared by Dr. Laurence D. Booth ("Dr. Booth"), a professor of finance in the Rotman School of Management at the University of Toronto (Exhibit C5-5). Dr. Booth recommends that the current 40 percent common equity ratio be maintained, but that the current FortisBC incremental risk premium of 40 basis points should be reduced to zero rather than increased to 75 basis points.

The following sections summarize the evidence and submissions on these issues, and the Commission's determinations in this regard.

2.2.1 Direct Evidence of Ms. McShane

Ms. McShane's approach to assessing the appropriate capital structure and return on equity ("ROE") for FortisBC was based on: 1) evaluating the reasonableness of the actual capital structure that has been maintained by FortisBC in terms of its compatibility with the business risks of the utility; and 2) accepting the Commission's ROE for a benchmark low risk utility as a point of departure for estimating the equity risk premium for FortisBC at the proposed capital structure (Exhibit B-1, Tab 5, p. 3).

Ms. McShane's evidence is premised on the stand-alone principle and an assessment of the market, supply and regulatory business risks and financial risks faced by of FortisBC. In regard to the stand-alone principle, Ms. McShane comments that there is no reason that FortisBC's capital structure or the fair return on equity should change simply because the identity of the shareholder has changed, but should continue to be premised on the risks faced by FortisBC. Ms. McShane notes that each of the Fortis utilities is financed on a stand-alone basis, so FortisBC's credit will be assessed on its own business risks and ability to generate adequate cash flows (Exhibit B-1, Tab 5, pp. 4-5).

<u>Business Risk</u>

Ms. McShane assesses FortisBC's business risks while noting the following factors:

- FortisBC is a relatively small utility serving a generally rural service area;
- Major industries served by FortisBC include forestry/pulp and paper, agriculture and tourism;
- Population growth in its service area has been strong over the past decade;
- Economic growth in B.C., dependent on the strength of commodity prices and the strength of the US economy, is expected to continue to outpace that of the country as a whole;
- Recent NAFTA rulings in favour of the Canadian forest industry may ultimately be beneficial;
- Increased demand for B.C.'s exports, not just those of the forest products industry, is anticipated from the economies of the Pacific Rim;
- Long-term B.C. economic growth is expected to be at a somewhat lower rate than the country as a whole;
- FortisBC has significant heating load (in competition with natural gas), with approximately one-third of direct residential (and likely wholesale) sales for heating purposes;
- FortisBC has no rate-stabilization mechanism to dampen the effects of weather volatility;
- FortisBC competes to some extent with alternative suppliers of electric power, such as BC Hydro, given the customer choice available to wholesale and large industrial customers;
- Technological change is expected to increasingly create competitive alternatives;
- FortisBC generates 45 percent of its supply from its own hydroelectric plants, obtaining the remainder of its supply through long-term contracts and market purchases; and
- FortisBC has a power purchase incentive mechanism to mitigate its exposure to market price volatility (Exhibit B-1, Tab 5, pp. 7-13).

Ms. McShane assesses three factors associated with the regulatory component of FortisBC business risk: deferral accounts, performance-based regulation ("PBR") and depreciation expense. Ms. McShane states that, in contrast to many Canadian utilities, FortisBC has operated with few deferral accounts: it has no deferral account for short-term interest expense, it has no rate-stabilization mechanism to dampen the effects of weather volatility; and, while it has shared deviations from purchased power costs with customers, it has not operated with a pass-through mechanism for such costs (Exhibit B-1, Tab 5, p. 13).

In her discussion of the impact of FortisBC's PBR from 1996-2004, Ms. McShane notes that the Dominion Bond Rating Service ("DBRS") considers the regulatory environment in B.C. among the more progressive in Canada. In comparison to traditional cost of service ratemaking, Ms. McShane considers that the FortisBC PBR plan, which retains a link to actual costs and includes sharing, exposes the shareholder to a moderately higher level of business risk (Exhibit B-1, Tab 5, pp. 14-15).

Ms. McShane points out that the settlement agreement in the 2000 NSP included a PBR rate stabilization mechanism to limit rate increases to 5 percent or less, with a reduction in annual depreciation expense as necessary to achieve this end. In addition, the same agreement lowered the depreciation rate on transmission assets. Ms. McShane states that both factors have contributed to the free cash flow deficits currently faced by FortisBC (Exhibit B-1, Tab 5, p. 15).

Ms. McShane concludes that FortisBC faces above average business risk relative to its Canadian electric and gas peers, and relative to the low-risk benchmark utility.

Financial Risk

Ms. McShane defines financial risk as the additional risk incurred as a result of assuming debt, which results in the incurrence of additional fixed obligations that must be met before the equity investor is entitled to any of the operating income generated by the utility. Ms. McShane assesses capital structure ratios, interest coverage ratios and debt ratings as points of departure for analyzing the financial risk faced by FortisBC.

Ms. McShane calculates that the actual common equity ratio of FortisBC between 1999 and 2004 has averaged 40.1 percent. While slightly higher than the proposed 40 percent common equity ratio, it is nonetheless consistent with the maintenance of a roughly 60%/40% debt/equity capital structure for at least the last ten years (Exhibit B-1, Tab 5, pp. 16-17). Ms. McShane compares FortisBC's forecast common equity ratio to other Canadian electric utilities and concludes that it is in line with the allowed common equity ratios of other investor-owned electric utilities (Exhibit B-1, Tab 5, pp. 17-20).

Ms. McShane discusses FortisBC's interest coverage ratios as one factor that determines the level of its financial risk. Ms. McShane reports that the pre-tax interest coverage ratio in 2003 equaled 2.1 and that the average pre-tax interest coverage ratio for the five-year period ending 2003 was 2.1. Ms. McShane says that while the 2003 ratio of 2.1 is a material improvement from the ratio of 1.8 in 2002, the five-year average ratio is a deterioration from the previous five-year average ratio of 2.4 calculated over the period 1994-1998. Further, Ms. McShane offers the comparison that the 1999-2003 average ratio of 2.1 is less than the average ratio of 2.4 across other major Canadian electric utilities over the same period. Ms. McShane states that the declining interest coverage ratios of FortisBC reflect, in part, that its allowed returns on equity have generally declined more rapidly than its embedded debt costs (Exhibit B-1, Tab 5, pp. 20-21).

With respect to debt ratings, Ms. McShane reports that DBRS rates FortisBC debt BBB(high) with a “Stable” trend, and has consistently rated it such since 1996. Ms. McShane notes that this is the lowest DBRS rating of the investor-owned electric utilities in Canada. DBRS confirmed its ratings in June 2004 and provided a full evaluation of the company in November 2004. Ms. McShane summarizes the November 2004 DBRS report with the following points:

- The FortisBC financial profile has weakened in recent years due to a variety of factors including free cash flow deficits and low allowed ROEs;
- Relatively large anticipated capital expenditures over the next 4 years will contribute to large free cash flow deficits;
- The rate-stabilization mechanism on depreciation expense may keep cash flows weaker, but the projected free cash flow deficits could be reduced if this mechanism is eliminated;
- A key challenge to the financial profile remains a low interest rate environment; and
- Despite the free cash flow deficits, FortisBC’s financial profile is expected to remain acceptable for the ratings.

Ms. McShane reports that the Moody’s Investors Service (“Moody’s”) rated FortisBC Baa3 in November 2004, its first debt rating of the Company. Ms. McShane notes that the rating is premised on low business risk, a significant capital expenditure plan over the next four to five years, the need for rate increase to implement the plan, a low depreciation rate, a tight liquidity position, cash flow deficits and the need for equity infusions from the parent during the period of high capital expenditures. Ms. McShane states that a Baa3 is the lowest investment grade rating, providing little “cushion” should there be any deterioration in the business risk profile or financial parameters (Exhibit B-1, Tab 5, pp. 23-24).

Based on her assessment of FortisBC’s business and financial risks, Ms. McShane concludes that a common equity ratio in the range of 40-45 percent is reasonable, compatible with its business risks and adequate to maintain a stand-alone rating of DBRS BBB(high). However, she notes that, given the forecast level of capital expenditures in the near to medium term and expected free cash flow deficits, a 40 percent common equity ratio should be regarded as the floor required to ensure adequate financing flexibility. Ms. McShane concludes that at a 40 percent common equity ratio, “FortisBC would be of higher investment risk than a benchmark Canadian utility, which requires the addition of an incremental equity risk premium to the equity return applicable to the benchmark low-risk utility” (Exhibit B-1, Tab 5, pp. 20-29).

Equity Risk Premium

As noted above, Ms. McShane accepts the Commission's ROE for a benchmark low risk utility as a point of departure for estimating the equity risk premium for FortisBC at the proposed common equity ratio of 40 percent. With this frame of reference, Ms. McShane calculates a range of equity risk premiums for FortisBC relative to a low-risk benchmark utility by estimating the risk differential as between, or as impacted by, PBR versus Cost of Service regulation, utility size, debt costs and relative costs of equity.

To assess the impact of PBR versus Cost of Service regulation, Ms. McShane utilizes a study prepared by the World Bank, which concluded that the difference between the asset (business risk) betas of energy utilities operating under rate of return regulation and price or revenue cap regulation was close to 0.40. Ms. McShane suggests that FortisBC has a risk position in the middle of the two extremes used in the World bank study, or a beta differential of 0.20. Using the Commission's market risk premium of 5.0 percent as reported in its 1999 Decision on Return on Common Equity for a Benchmark Utility, Ms. McShane concludes that the difference between PBR and Cost of Service regulation translates into a difference of 100 basis points (i.e. a 0.20 beta differential multiplied by 5 percent) (Exhibit B-1, Tab 5, p. 15).

To assess the impact of utility size, Ms. McShane utilized a study of historic returns and betas for companies of different sizes to compare the asset betas between a typical publicly-traded Canadian utility, defined by Ms. McShane as a Mid-Cap stock, and FortisBC, defined by Ms. McShane as a Low-Cap stock. Using the differential result of 0.14 and a market risk premium of 5.0 percent, Ms. McShane concludes that the size of FortisBC could justify it receiving an equity risk premium of 70 basis points (Exhibit B-1, Tab 5, p. 31).

To assess the difference between the debt costs of FortisBC and a low-risk benchmark utility, Ms. McShane assumed that a low-risk benchmark utility would be able to achieve a solid A rating on its debt. By comparing the 2002 average spread for a seven-year issue for Canadian utilities rated A(low)/A- or higher (95 basis points) to a FortisBC (Aquila(BC)) 2002 seven-year debt issue at 170 basis points above the benchmark seven-year Canada, Ms. McShane concludes that the difference in debt costs between FortisBC and a low-risk benchmark utility translates into an equity risk premium of 75 basis points (Exhibit B-1, Tab 5, pp. 32-33).

To estimate an equity risk premium for FortisBC using relative costs of equity, Ms. McShane compares the average beta of a group of A rated U.S. utilities, as proxies for the low-risk benchmark utility, to the average beta of a group of BBB rated U.S. utilities, as proxies for FortisBC. Ms. McShane concludes that the differential of 0.10 between the average betas of the two sample groups translates into an equity risk premium of 50 basis points if using a market risk premium of 5.0 percent (Exhibit B-1, Tab 5, pp. 33-35).

In sum, Ms. McShane concludes that a reasonable range for an incremental equity risk premium for FortisBC relative to the low-risk benchmark utility is in the range of 50-100 basis points, with a mid-point of 75 basis points.

2.2.2 Direct Evidence of Dr. Booth

Dr. Booth was asked by BCOAPO to provide an independent assessment of the appropriate common equity ratio and fair return for FortisBC, to assess its business risk and financial flexibility, and to make recommendations to ensure that rates are fair and reasonable. Dr. Booth indicates that his evidence is organized, in part, around: 1) a discussion of the business risk of FortisBC from a capital markets perspective, 2) a discussion of financial market access concerns and questions surrounding "rising" credit standards, and 3) a discussion about coverage ratios and how the capital market reacts to current financial metrics. The following is a brief summary of the evidence of Dr. Booth (Exhibit C5-5).

Dr. Booth considers the business risk of FortisBC to be low. Dr. Booth considers that FortisBC has little "generating" risk given that it is primarily reliant on hydroelectric generation and purchased power. Dr. Booth notes that electricity demand in FortisBC's service area is growing at a slightly higher rate than in B.C. generally, and that compared to electric utilities operating elsewhere in Canada, the regulatory regime in B.C. is stable. Dr. Booth asserts that the main impact of the FortisBC PBR is to provide an incentive to the company to operate more efficiently and earn a higher ROE, not to expose it to material risk. Further, Dr. Booth points to data on actual versus allowed ROE for FortisBC's regulated operations from 1986 through 2004 to conclude that after FortisBC moved to a PBR mechanism in 1996, the actual ROE has been above the allowed ROE (aside from 2002 when the failure to earn the allowed ROE was due to integration expenses and software write-offs). Dr. Booth notes that rather than the DBRS view that FortisBC has a consistent history of earning the regulated ROE, he would define the result rather as "over-earning." Dr. Booth sees "no reason for adding a bonus to the ROE for a system that already effectively enhances the company's ROE and does not increase its risk" (Exhibit C5-5, p. 22).

In association with his discussion of business risk, Dr. Booth provides evidence to show that he usually judges transmission operations as warranting a 30 percent common equity ratio and distribution 35 percent, while more recently, for example, the Alberta Energy and Utilities Board has awarded slightly higher common equity ratios of 33 percent and 37 percent, respectively. In this context, and given his judgment of business risk, Dr. Booth judges the applied-for 40 percent common equity ratio as excessive.

Dr. Booth presents evidence on the degree to which FortisBC is compensated for its risk by utilizing the theoretical relationship between the risk of a firm with financial leverage to a firm without financial leverage plus a financial leverage risk premium. While recognizing that equating the effect of a higher common equity ratio and a higher allowed ROE is largely a matter of judgment, Dr. Booth determines that a higher ROE and common equity ratio awarded FortisBC (then West Kootenay Power) in a 1994 Commission decision is equivalent to 55 basis points above Terasen Gas Inc. ("Terasen Gas") (then BC Gas), the low-risk benchmark utility. Dr. Booth states that one implication of this is that it is important for the Commission to take into account all the ways that it manages the risk of FortisBC and to not double count the same risks in different areas. Dr. Booth judges that FortisBC is marginally riskier than Terasen Gas, but that this risk is more than offset by FortisBC's higher common equity ratio.

Dr. Booth comments on the debt rating implications of FortisBC being a very small electricity company issuing debt in the capital markets under its own name. Dr. Booth states that size is a factor in bond ratings, and it also affects the liquidity of the bond issue. He notes that the result is that smaller issuers tend to issue shorter term debt and have inferior bond ratings than large issuers, all else equal. Dr. Booth comments that the problems associated with the size of FortisBC, in combination with the significant growth in rate base that is anticipated as the utility refurbishes its generation, transmission and distribution plant, may pose capital market access problems. Dr. Booth notes, however, that this access problem could be mitigated with equity infusions from its parent, and ultimately recede as the rate base expansion is completed.

Dr. Booth presents some example calculations of interest coverage ratios to argue that it makes no sense to target a particular interest coverage ratio and allow a higher ROE simply because a company has a high embedded cost of debt. Dr. Booth argues that if the allowed ROE and deemed common equity ratios are considered fair, but the resulting interest coverage is considered too low because of high embedded interest costs and there are capital market access problems, then the solution is to allow or deem some preferred shares, rather than give the equity holder a bonus to the fair ROE or equity ratio.

Dr. Booth assesses the market to book ratio associated with the purchase price of Aquila(BC) by Fortis, as well as the ratios associated with other utility purchases, in comparison to a target ratio of 1.15. He notes his view that values above 1.15 indicate that the rates are too high and that the equity holders are getting a more than fair and reasonable return. Dr. Booth approximates that for the FortisBC purchase the market to book ratio based on total rate base equaled 1.38, while the market to book ratio based on equity (based on assuming debt and valuing it close to book value) equaled 1.96.

In sum, Dr. Booth asserts that the currently approved 40 percent common equity ratio and 40 basis risk premium are excessively generous. Dr. Booth is of the view that there are no grounds for increasing the generosity of these financial metrics, but rather that the elimination of the 40 basis points risk premium would be a conservative roll back.

2.2.3 Submissions

The following sections summarize various arguments and submissions of FortisBC and intervenors with respect to business risk, financial risk, and the equity risk premium.

Business Risk

FortisBC reiterates in its argument that its business risk is greater now than it has been in the past. Using Dr. Booth's frame of reference as a point of departure, FortisBC submits, with reference also to its Resource Plan, that its risk regarding its energy needs is much greater than it was in 1994; it is far more reliant on the market for energy in 2005 than it was in 1994, and the market is more volatile. FortisBC also states that it faces increasing competition from natural gas, its industrial customers have the opportunity to switch to third party supply, and residential use per customer has been steadily declining. FortisBC submits that these factors, combined with its increased reliance on a volatile market, are evidence of its increased business risk (FortisBC Argument, pp. 18-20).

BCOAPO submits that an October 2004 FortisBC presentation to DBRS (Exhibit B-4, Response to BCOAPO IR 88.1) stands in contrast to the conclusion of Ms. McShane that FortisBC faces above average business risk relative to it Canadian electric peers, and relative to the low risk benchmark utility in the B.C. context. BCOAPO submits that FortisBC has told the investment community that it is a low cost, low risk franchise with supportive regulation and no problems in accessing capital, referring in support to the following summary of the FortisBC presentation highlights provided by FortisBC in response to an information request (BCOAPO Argument, pp. 9-10):

- Vertically integrated regulated electric utility,
- Supportive regulation – a low cost, low risk franchise,
- Solid franchise history with strong economic fundamentals,
- Diversified customer base,
- 205MW low cost hydro and long term PPAs in rate base,
- Power purchase costs flow through – limited commodity risk,

- Growing regulated rate base, and
- Strong balance sheet and supportive shareholder.

Further, BCOAPO submits that comparing Ms. McShane's definition of business risk (of exposing the shareholders to the risk of under-recovery of the required return on capital) to the evidence that FortisBC's actual ROE has exceeded its allowed ROE in every year since 1996 (except 2002) would lead it to conclude that there has been no business risk attached to the operations of FortisBC (BCOAPO Argument, p. 11).

BCOAPO submits that FortisBC's industrial load has not had a significant risk impact on the Company. BCOAPO describes that there is little dependence on industrial customers when measured by revenues, and there is minimal bypass risk. Further, there is opportunity for load retention rates should such customers wish to leave the system. BCOPAO points out that no large customers have bypassed the system in the last five years, perhaps explained in part by the possibility of such customers having to reimburse FortisBC for stranded assets should they choose to buy supplies elsewhere (BCOAPO Argument, pp. 12-14). BCOAPO also submits that "what holds in the face of bypass risk also holds in an absolute sense: FortisBC's reliance on low cost hydro makes its generation risk minimal. In practice there is minimal risk of the power not being dispatched or the assets being stranded" (BCOAPO Argument, p. 19).

BCOAPO submits that the risk associated with residential load is limited. In particular, it submits that FortisBC has incremental residential heating load to begin with because its rate are competitive due to its low generating cost. Further, BCOAPO says that the Company has not requested any weather normalizing rate stabilization mechanism in the past ten years. It submits therefore that the company does not consider the impact of weather volatility on residential load to be a material risk (BCOAPO Argument, pp. 12-13).

In regard to the risk associated with market purchases and market volatility, KOECA submits that it is unlikely that higher power purchase costs in the future will result in reduced returns for shareholders given its expectation that the Commission will ensure that this risk will be passed on to customers to keep the Company healthy. Further, KOECA submits that FortisBC does not address how separate risk factors may partially negate themselves, pointing out in example that a decline in residential use per customer, if it leads to a reduction in total residential demand, "would partially compensate for the supposed risk associated with power purchases" (KOECA Argument, pp. 4-5). KOECA submits that if there is uncertainty about the correct methodology to apply to an evaluation of FortisBC's risk, it makes sense to seek "ground truth" by paying attention to the actual experience of the company (KOECA Argument, p. 5).

Financial Risk

FortisBC argues that its financial risk is greater than it has been in the past. Noting again that the financial risk of a utility can be captured in its capital structure ratios, interest coverage ratios and debt ratings, FortisBC reiterates that its 1999-2003 pre-tax interest coverage ratio of 2.1 is significantly less than the previous 5 year average of 2.4 observed between 1994 and 1998. Further, it notes that its debt rating was downgraded by DBRS in 1996 to BBB(high), lower than any other Canadian electric utility in the sample provided by Ms. McShane in her evidence (FortisBC Argument, pp. 21-22), and its Moody's debt rating is Baa3 is lower still, equivalent to a DBRS rating of BBB(low).

FortisBC argues that Dr. Booth's interest coverage ratio calculations, and the conclusions that he draws from them, are flawed and inaccurate. FortisBC submits therefore that this evidence should be rejected (FortisBC Argument, pp. 22-26). FortisBC submits that it was unable to access 30-year bonds in 2004, substantially due to its low interest coverages and being regarded as too high risk (FortisBC Argument, pp. 22, 25-26).

BCOAPO notes that Dr. Booth indicated in cross-examination by FortisBC Counsel that he accepts the interest coverage ratios calculated by FortisBC. However, BCOAPO quotes Dr. Booth as noting that the interest coverage ratios are all temporary timing phenomenon, "basically waiting until the debt costs roll out and wait until its capital expenditure program is completed" (BCOAPO Argument, p. 22).

BCOAPO comments on the cross-examination by Commission Counsel of both Ms. McShane and Dr. Booth as to the impact of an increase in the equity risk premium from 40 to 75 basis points on the five credit challenges identified by Moody's in its November 2004 report. Those five credit challenges are a $450 million capital expenditure plan over next 5-years, rate increases to support the capital expenditure plan, relatively low depreciation rates, a tight liquidity position, and free cash flow deficits requiring equity infusions from its parent. BCOAPO submits that the testimony as to the marginal or non-existent impact of an increase in the equity risk premium on these credit challenges further undermines FortisBC's case for an increase in the equity risk premium (BCOAPO Argument, p. 21).

FortisBC proposes to maintain its current capital structure, with a common equity ratio of 40 percent, noting that the BCOAPO expert also recommends a common equity ratio of 40 percent. Further, FortisBC notes that in their written arguments, intervenors either endorsed this capital structure or had no comment. FortisBC submits that the supporting evidence and the absence of argument against the proposed capital structure strongly support an Order of the Commission approving a capital structure which includes a common equity ratio of 40 percent (FortisBC Argument, p. 17; FortisBC Reply Argument, p. 4).

Equity Risk Premium

BCOAPO presents argument that questions the relevance and justification of Ms. McShane's analysis of the appropriate equity risk premium for FortisBC relative to the low-risk benchmark utility. BCOAPO asserts that Terasen Gas is the BCUC low risk utility given its 33 percent common equity ratio and the fact that it is not granted an equity risk premium above the BCUC automatic ROE. The BCOAPO argues that Ms. McShane refused to accept that Terasen Gas is the BCUC low risk benchmark utility (BCOAPO Argument, p. 16). BCOAPO comments that financial risk compounds business risk and a low common equity ratio indicates low business risk. BCOAPO questions that if Terasen Gas is not the low risk benchmark then it is reasonable to ask what the proposed 75 basis points equity risk premium is over. To illustrate this point, BCOAPO suggests that it may be, for example, that Terasen Gas and FortisBC are now of equivalent risk in which case there would be no reason for a risk premium for FortisBC over the Commission's low risk benchmark (BCOAPO Argument, pp. 16-17).

BCOAPO expands upon its argument in this matter by commenting on the DBRS BBB(high) debt rating of Fortis (which Ms. McShane equates with a Standard & Poors (S&P) rating of BBB) relative to the debt rating of a low-risk benchmark (which Ms. McShane equates with an A rating). BCOAPO submits that Ms. McShane's methodology of assessing the differentials between A and BBB rated utilities is flawed, in part because it does not account for the impact of FortisBC's size on its debt rating (and the related matter that spreads may include liquidity premiums for smaller issues). BCOAPO submits that "if FortisBC were simply a larger firm its bond rating would be higher even if its business risk is unchanged, so basing the analysis on bond ratings in part simply awards FortisBC a higher ROE simply because it is small." BCOAPO submits further that Terasen Gas, with its DBRS A and S&P BBB debt ratings, could fit within the same rating group as FortisBC in Ms. McShane's analysis (BCOAPO Argument, pp. 17-18).

FortisBC submits that FortisBC and Terasen Gas cannot be regarded as having similar debt ratings, as suggested by BCOAPO, in part because: 1) BCOAPO is proceeding on the incorrect premise that Terasen Gas is equivalent to a low risk benchmark utility, when Ms. McShane states that a low risk benchmark utility would be an A rated utility, which Terasen Gas is not; and 2) FortisBC has two ratings in the BBB category and is therefore rated lower than Terasen Gas (FortisBC Reply Argument, pp. 10-11).

With respect to utility size, FortisBC replies that it remains a small utility, unable to diversify its risks to the same extent as larger utilities whose assets, geography and economic bases are less concentrated (FortisBC Reply Argument, p. 12).

In its argument, IMEU submits that FortisBC acquired the utility approximately one-year ago understanding the risks and rewards of its investment. It is of the view that the purchase price that was struck, for a significant premium over book value, was based on this understanding. Therefore, IMEU submits that an increased risk premium is inappropriate and not justified in the short-term, a conclusion it states is also supported by the evidence on FortisBC's risk factors (IMEU Argument, pp. 5-12).

BCOAPO states that with a 40 percent common equity ratio Fortis paid about $734 million to acquire $377 million in equity earning the Commission's automatic ROE plus 40 basis points, which results in a ratio of almost twice book value. BCOAPO submits that this is an excessive, unfair market to book ratio, and that the correct regulatory response should be to reduce the premium, not increase it to 75 basis points (BCOAPO Argument, p. 21).

In response to the issue of the premium over book value, FortisBC submits that the price to regulated book value on its purchase (1.8) reflects also the amount paid for the majority of regulated assets/companies sold in Canada over the last 7 years. Further, it submits that because it is required to engage upon an extensive capital expenditure program over the next several years the premium it paid will effectively be reduced (FortisBC Reply Argument, p. 15).

FortisBC submits that the debt market problem and fair return on equity are not independent from each other because capital structure and ROE (as a function of business risk profile) factor into the willingness of the bond market to lend funds under reasonable rates and terms. FortisBC submits that an increase in the equity risk premium that is fully compensatory with its business and financial risks, along with an increase in the depreciation rate, will address the Company's inability to access the long-term bond markets (FortisBC Reply Argument, p. 14).

2.2.4 Commission Panel Determinations

The Commission Panel has considered the evidence of FortisBC and BCOAPO, and the arguments of all parties. The following discussion highlights the Commission Panel's observations and conclusions in this regard.

With respect to market demand components of business risk, the Commission Panel believes that the prospects for FortisBC residential demand are good given the strong growth prospects in the Okanagan service area, in spite of the penetration of natural gas for heating new residential construction. The Commission Panel is persuaded by the argument that residential heating demand is incremental and not a significant business risk as FortisBC defines it. The Commission Panel notes that because FortisBC is a capacity constrained utility, a reduction to the heating component of demand could actually serve to reduce its business risk. Yet, to the extent the penetration of natural gas for heating could be regarded as a material risk, and to the extent that such risk could have a detrimental impact on FortisBC's credit rating, an increase in the equity risk premium would serve to increase this risk all else equal. The Commission Panel does not agree that a reduction in residential use per customer (as one factor of total demand) is an indication of a net increase in business risk for FortisBC, particularly in light of increasing load growth in the FortisBC service area generally. The Commission Panel also agrees with the evidence that suggests, in general, that population and economic growth will remain strong in the FortisBC service area.

With respect to supply risk factors, the Commission Panel acknowledges that FortisBC does compete to some extent with alternative suppliers of electricity given the customer choice available to wholesale and large industrial customers. The Commission Panel notes, however, that there are strong constraints on the likelihood of municipalities opting for alternative suppliers, and that the industrial component of load is not large and also unlikely to opt for alternative suppliers. The evidence and argument bear this out. Further, the Commission Panel acknowledges that there is risk associated with market purchases and market volatility, but it does not agree that this risk has increased to any measurable extent for FortisBC. FortisBC obtains low-cost supply from its own generating plants and long term contracts, with the remainder of its supply obtained through market purchases. Market purchases, while an increased share, are still limited, and FortisBC has a power purchase incentive mechanism to mitigate its exposure to market price volatility.

The Commission Panel agrees with the evidence that characterizes the regulatory environment in B.C. as progressive, believing it as well to be a positive consideration in respect of the regulatory risk that FortisBC faces. The Commission Panel observes that the progressive regulatory environment in B.C. is noted as a strength in the DBRS credit rating evaluation of FortisBC. The Commission Panel does not agree with the view that the FortisBC's PBR plan is inherently more risky than a traditional cost of service regulatory framework, particularly given the various sharing mechanisms that are components of this plan and the demonstrable evidence that FortisBC's actual ROE has, with one exception, met or exceeded its approved ROE since 1996. The Commission Panel does not consider the evidence of actual ROEs consistently exceeding allowed ROEs to imply, in and of itself, any conclusion about changes in the level of business risk, higher or lower. Even so, the Commission Panel considers the question of whether a utility has been able to meet its revenue requirements as a useful test of the reasonableness of an allowed ROE. In the period since 1994 FortisBC has with one exception met or exceeded its revenue requirements.

FortisBC emphasizes its interest coverage ratios, arguing in part that current low interest coverages are a substantial cause of its inability to access the 30-year bond market in 2004, and in turn that this circumstance is the main driver of its application for an increase in its equity risk premium. FortisBC argues that its interest coverages are significantly lower than in the past by comparing its average interest coverage ratio of 2.1 over the five-year period, 1999-2003, to its average interest coverage of 2.4 over the previous five-year period, 1994-1998. The Commission Panel finds that this comparison is not substantively informative. While Ms. McShane states that the decline reflects, in part, that allowed ROEs have generally declined more rapidly than the embedded debt costs, neither she nor FortisBC have provided any other detailed rationale or context to explain the differences between the two five-year periods. The Commission Panel observes that the consistent DBRS rating of BBB(high)-Stable trend since 1996 largely spans both of the five-year periods used in the averaging calculations. Further, the Commission Panel notes that FortisBC's actual 2004 pre-tax interest coverage ratio is 2.32 and its average pre-tax interest coverage ratio for the period 2000 to 2004 is 2.16, both of which represent increases, respectively, from its 2003 ratio of 2.1 and its 1999-2003 average ratio of 2.1 (Exhibit B-12, Response to BCUC IR 12.5). FortisBC has not explained how these increases should be interpreted in the context of the evidence of decreases that it presents in evidence and in argument. FortisBC notes that the difference between the average interest coverage ratios of the two five-year periods is significant, a difference equal to 0.3. The Commission Panel notes that in FortisBC's initial 2005 application the estimated interest coverage ratio is 2.06, and declined to 2.01 on the basis of assuming a 40 rather than 75 basis points risk premium (Exhibit B-12, Response to BCUC IR 12.7). The difference of 0.05 between these two ratios could be regarded in this context as less than significant and relatively insensitive to changes in the equity risk premium. In addition, the Commission Panel agrees that low interest coverages could be considered a temporary phenomenon in light of FortisBC's planned capital expenditures over the next four years and low depreciation rates currently. The Commission Panel believes that, even to the extent that FortisBC's interest coverages could be regarded as too low, declining, or more than a temporary phenomenon, an increase in the equity risk premium is not the appropriate means to first consider for improving FortisBC's interest coverages. The following discussion elaborates on this.

BCOAPO referred in argument to cross-examination of both Ms. McShane and Dr. Booth by Commission Counsel as to the expected impact of an increase in the equity risk premium on each of the five credit rating challenges identified by Moody's in its November 2004 report. Those credit rating challenges are (Exhibit B-12, Response to BCUC IR 15.0):

- A significant $450 million capital expenditure plan to be implemented over the next 4-5 years;
- The possible need for rate increases in each of the next few years to implement the capital expenditure plan;
- A relatively low depreciation rate for rate-making purposes;

- A liquidity position that is tight for a Baa3 utility company; and
- Free cash flow that is expected to be negative for the next few years, necessitating equity infusions from its parent, as well as additional debt issuance.

The Commission Panel is of the view that both experts' testimony as to the limited or non-existent impact of an increase in the equity risk premium on these credit challenges diminishes the FortisBC argument that an increase in the equity risk premium will materially affect its credit rating and its ability to access the long-term bond market. FortisBC acknowledges in response to a Commission information request that while a change in its equity risk premium from 40 to 75 basis would be a positive consideration, it alone would not likely result in an increase in FortisBC's credit rating. In their November 2004 credit rating reports, both DBRS and Moody's emphasize the issues of FortisBC's free cash flow deficits and low depreciation rates. DBRS notes in one instance that higher depreciation rates could reduce FortisBC free cash flow deficits. The Commission Panel observes that DBRS maintained its FortisBC debt rating of BBB(high)-Stable trend despite its concerns.

The Commission Panel believes that it would be untimely and inappropriate to increase the equity risk premium in response to the credit challenges noted above without measures being taken to more directly address these credit challenges, particularly in light of the Commission Panel's views as to the business risk of FortisBC. To this end, and in alignment with the November 2004 evaluations of both DBRS and Moody's, the Commission Panel has directed FortisBC in this Decision to file its forthcoming study of depreciation rates with its next revenue requirements application, and to have the new rates form part of that application. Also, the Commission Panel notes that the rate stabilization mechanism on depreciation expense is no longer in effect.

The Commission Panel has concerns about the methodology used by Ms. McShane to determine an incremental equity risk premium for FortisBC. For example, the Commission has determined that Terasen Gas is a low risk benchmark utility in B.C., and to ignore this as a reasonable proxy in the analysis calls into question the entire framework, particularly in light of the reliance, in part, on utilities based in the US as proxies for the low-risk benchmark. Further, the Commission Panel agrees with the BCOAPO submission in regard to the impact of size on credit ratings, which calls into question the methodology of comparing the credit ratings across utilities as a means to determine an incremental risk premium, without controlling for the impact of size.

The Commission Panel notes that a fundamental test of the appropriateness of an allowed ROE is whether the utility has been able to attract equity capital. Evidence of this test has been met: the willingness of FortisBC to purchase the equity of Aquila(BC) and to pay a premium in so doing.

The Commission Panel approves the FortisBC application to maintain a common equity ratio of 40 percent and denies the FortisBC application to increase its equity risk premium from 40 to 75 basis points. The Commission Panel denies the BCOAPO recommendation to reduce FortisBC's equity risk premium from 40 basis points to zero on the basis that there is insufficient evidence in support of this recommendation.

2.3 2005 Revenue Requirements

2.3.1 Rate Base

A utility's rate base represents the net investment in assets necessary to provide service. FortisBC's Rate Base, as described in Exhibit B-1 at Tab 6, is comprised principally of Plant in Service, Accumulated Depreciation and Amortization, Deferred Charges and Credits, Allowance for Working Capital, and an Adjustment for Capital Expenditures (FortisBC Argument, p. 29).

FortisBC submits that its forecast mid-year rate base for 2005 of $598,105,000, as provided in Schedule 1 to the Third Revised Application (Exhibit B-26), be approved for purposes of establishing 2005 Revenue Requirements and setting rates to customers effective January 1, 2005 (FortisBC Argument, p. 30).

Rate Base costs include such items as cost of debt, cost of equity, income taxes, property and capital taxes, depreciation and amortization and Allowance for Funds Used During Construction ("AFUDC"). FortisBC seeks approval of forecast total Rate Base costs of $78,569,000 (Exhibit B-26, p.3; FortisBC Argument, pp. 31-38).

Commission Panel Determinations

The Commission Panel accepts the proposed mid-year rate base of $598,105,000 for 2005 subject to directions contained in this Decision that affect the components of rate base. Likewise, FortisBC should update its forecast Rate Base costs according to the relevant Commission Panel determinations elsewhere in this Decision.

2.3.2 Power Supply

The Commission Panel approves FortisBC's forecast Power Supply costs for 2005 of $71,010,000. This is discussed in Section 2.1.2: Power Purchase and Wheeling Forecast.

2.3.3 Operations and Maintenance Expenses and Capitalized Overheads

Forecast 2005 Operations and Maintenance ("O&M") Expenses, before and after capitalized overheads, increased significantly over the 2004 target levels that were part of the 2004 Negotiated Settlement Agreement approved by Order No. G-38-04. The following comparative schedule appears on page 1 of Exhibit B-66 and provides an overview and high level explanations of the major drivers for the increase.

	2004 Targeted O&M	2005 Forecast O&M	Increase/ (Decrease) over Targeted 2004 O&M	Increase due to Transition Plan	Increase due to Inflation	Other Increases
Total before capitalized overheads	$35,645,000	$39,569,000	$3,924,000	$1,158,000	$1,150,000	$1,616,000
Capitalized Overheads	($2,800,000)	($3,396,000)	($596,000)			
Total net of capitalized overheads	$32,845,000	$36,173,000	$3,328,000			

Of the total increase of $3,924,000, the portion caused by the Transition Plan activities, i.e. $1,158,000, is discussed in greater detail in Section 2.6, Transition Plan.

FortisBC states that the inflationary increase of $1,150,000 is the result of normal inflationary pressures on labour, materials and other costs. FortisBC indicates that of this amount, $500,000 is due to increases in benefits costs relating to medical, dental and vacation entitlements, $350,000 is due to wage increases for management and bargaining unit employees, averaging 2.5% to 3%, and $300,000 is the effect of non-labour inflation (i.e. 2%) on the 2005 budget (Exhibit B-66, pp. 1-2).

The amount of $1.6 million, identified as 'Other Increases', arises from additional activities planned in functional areas such as generation, transmission and distribution, and administration and general. The $1.6 million increase actually represents a net amount, which is comprised of various cost increases totaling $2.8 million that are offset by a $1.2 million decrease in insurance and vehicle lease costs. A significant portion (i.e. $1.6 million) of the 2.8 million cost increase is forecast to be spent in the transmission and distribution functional area. Increased activity for substation O&M, and transmission and distribution line maintenance is the major driver for the increase in this functional area and comprises $1.1 million of the $1.6 million. A further $850,000 of the total increase of $2.8 million is due to increased activity in internal audit and corporate governance and environmental, health and safety (Exhibit B-66. pp.2-5).

The increase in the amount of capitalized overheads is a direct function of capital activity, which increased for 2005.

Submissions

BCOAPO states that: “[they] are not in a position to review in detail the OM&A expenditures of the utility” (BCOAPO Argument, p. 25). Mr. Wait argues that the increase in the transmission and distribution expenses for 2005 appears to be excessive (Wait Argument, p.3). IMEU states: “[it] is also concerned that the impact of PBR settlements in past years has resulted in a loading up of costs which are being picked up in the 2005 Revenue Requirements for the Company” (IMEU Argument, p.18). IMEU asks the Commission to review closely the appropriateness of these significant increases through rebasing (IMEU Argument, p. 4).

FortisBC states that the Company has repeatedly expressed its position that base O&M targets have been too low and hence inappropriate on a go forward basis. The Company submits that a material portion of the proposed increase in O&M Expense for 2005 reflects FortisBC’s reassessment of the overall level of O&M expense required to meet service obligations to its customers in the areas of customer service, transmission and distribution, and administration and general costs (FortisBC Argument, pp. 40-41).

Commission Panel Determinations

The Commission Panel has considered all the evidence and arguments and concludes that the proposed increases in forecast 2005 O&M Expenses, before overheads capitalized, over the approved 2004 target levels, appear to be reasonable and required. The Commission Panel fully supports FortisBC’s strategic goals and specific objectives to meet and improve service obligations in various areas and in particular the areas of customer service and transmission and distribution (refer to Section 2.7 for a comprehensive discussion of customer service). The Commission Panel believes that FortisBC should be provided with the resources to allow it to achieve these goals and objectives. The inflationary increases of $1,150,000 are largely uncontrollable by the Company in the short term.

The Commission Panel approves for FortisBC the forecast 2005 O&M expenses, before capitalized overheads, of $39,569,000, subject to adjustments discussed elsewhere in this Decision. It is important to note that specific directives, as set out in Section 2.4.2 on the Operating Expense incentive mechanism, form an integral part of the approval for the above level of expenses. To be clear, the incentive mechanisms are designed to ensure that approved resources are in fact spent on planned programs and activities in 2005.

2.3.4 Pensions

FortisBC has three pension plans: the IBEW Pension Plan, the COPE Pension Plan, and the Fortis Retirement Income Plan (“FRIP”). The IBEW and COPE Pension Plans are defined benefit pension plans. The FRIP consists of a defined benefit provision and a defined contribution provision. Additionally, the Company also has a supplemental pension plan. At the end of 2004 the Pension Plan Funded status was a plan deficit of approximately $23 million (Exhibit B-12, BCUC IR 73.0).

The Company records its annual pension benefits costs on an accrual basis in accordance with the recommendations of CICA Handbook Section 3461 (Exhibit B-12; BCUC IR 73.1.1). The Company estimates the forecast 2005 pension expense to be $3,860,000 and pension funding to be $4,560,000; in 2005 funding will exceed expense by $700,000 (Exhibit B-80, p. 1). In general, the amount of pension expense and the amount of annual funding to the pension plans by the Company will not match in a given year. The difference between these two amounts is recorded as an increase or decrease in the Prepaid Pension Costs account in deferred charges (Exhibit B-12, BCUC IR 34.8). The additional $700,000 in excess of funding for 2005 results in a year end 2005 balance of $5,948,000 for deferred Prepaid Pension Costs account (Exhibit B-80, p. 1).

Commission Counsel questioned Mr. Meyers concerning the different pension costs reported in response to BCUC IR 34.8 and 73.4. Mr. Meyers explained that BCUC IR 73.4 reflected the updated actual year end financial statements for 2004. Also, Mr. Meyers acknowledged that the difference, which impacts 2005, is reflected in the revised applications (T5: 882).

Commission Panel Determinations

The Commission Panel accepts the Company’s forecast 2005 pension expense, pension funding amount, and the Prepaid Pension Costs account balance of $5,948,000 at year-end 2005.

2.3.5 Other Post-retirement Benefits

Other post-retirement benefits are benefits to employees for extended health, group MSP, and life insurance. Generally Accepted Accounting Principles (“GAAP”) require that all forms of post-retirement benefits be accounted for on an accrual basis as recommended in CICA Handbook Section 3461. The Company records its annual other post-retirement benefits costs on a cash basis, which is not in accordance with CICA Handbook

Section 3461. In the negotiated settlement for the 2000-2002 Revenue Requirements the parties agreed to a variance from GAAP to allow post-retirement benefits to be recorded on a cash basis. The negotiated settlement was approved by Commission Order No. G-134-99 (Exhibit B-12, BCUC IR 73.1-73.2).

For 2005 the Company proposes that the cash basis of accounting for other post-retirement benefits continue (Exhibit B-12, BCUC IR 73.1.2). Mr. Meyers explained in his testimony that the variance from GAAP was appropriate since the Company is required to fund pension expense, but not other post-retirement benefits. Also, the Company does not pay out cash for the other post-retirement benefits like it does for pension expense (T5: 884-886).

The Company estimates an expense of approximately $300,000 using the cash basis. If CICA Handbook Section 3461 were applied, the accrued expense would be $1,380,000. However, if the Company were to adopt the accrual basis prospectively beginning in 2005, the accumulated liability of $4,400,000 would also need to be amortized into expense. Amortization of the accumulated liability of $4,400,000 over approximately 14 years, based on the Expected Average Remaining Service Lifetime of the covered group, results in an additional annual amortization of about $320,000. In total the Company expects the total 2005 other post-retirement expense to be approximately $1,700,000 ($1,380,000 + $320,000) if Section 3461 were adopted. However, if the current variance from GAAP were continued, the Company estimates the accumulated liability to be $5,500,000 at December 31, 2005 (Exhibit B-12, BCUC IR 73.1.3).

Commission Panel Determinations

The Commission Panel notes that the other post-retirement benefits earned each year that were not expensed have already accumulated into a large future liability that continues to increase. However, full compliance and adoption of Section 3461 of the CICA Handbook in 2005 would result in a large rate increase. **The Commission Panel denies the request to continue to record other post-retirement benefits on a cash basis. The Commission Panel orders a variance from GAAP to require that the transition from the cash basis to accrual accounting for other post-retirement benefits be phased-in over a three-year period. For 2005 the Company will include in expense the current cost under the cash basis plus one-third of the accrued expense as if it were in full compliance with Section 3461 and the change were adopted prospectively beginning in 2005. Subsequently for 2006, the Company will include in expense the cost under the cash basis plus one-half of the accrued expense as if it were in full compliance. In the final transition year for 2007, the Company will include the full accrued expense and be in full compliance with Section 3461 of the CICA Handbook. In calculating the Company's 2005 and future revenue requirements, the portion of other post-retirement benefits expense not expected to be paid-out in cash is to be credited to rate base.**

2.3.6 Employee Stock Option Expense

The Company's stated in its response to BCUC IR 74.0 that the Company has not included employee stock option expense in the utility financial schedules in 2005 or in any other year. It also stated that all stock option expenses have been and will be borne by the parent company. However, on March 18, 2005 the Company filed a List of Errata. The Errata indicated that the previous response to BCUC IR 74.0 was in error. The Errata stated that the utility financial schedules contain $25,000 of employee stock option expense in 2004 and $40,000 in 2005 (Exhibit B-24, List of Errata: Item 4).

Commission Counsel questioned Mr. Meyers if the $40,000 in employee stock option expense was still in the application. Mr. Meyers stated that the expense was still in the application and was not aware of previous Commission decisions disallowing employee stock option expense (T5: 889-890). The Commission has disallowed employee stock option expense in the BC Gas Utility Ltd. 2003 Revenue Requirements Decision (p. 15) and in the Pacific Northern Gas Ltd. 2004 Revenue Requirements Decision (p. 47).

Commission Panel Determinations

The Commission Panel directs that the $40,000 employee stock option expense and its related tax effect be removed from the 2005 Revenue Requirements.

2.3.7 2004 Incentive Sharing Adjustments

Commission Order No. G-20-05 approved the 2004 Incentive Adjustments as based on preliminary 2004 financial results, for a total credit of $2,175,000. The Incentive Adjustments comprised a combination of operating, power purchase and DSM incentives. This credit amount is shared between customers and shareholders in accordance with the sharing formulas agreed to in the 2004 Negotiated Settlement Agreement. The customers' share is $1,469,000, which is carried forward and serves to reduce the 2005 Revenue Requirements. The remainder of $706,000 is to the shareholders' account.

FortisBC's Second Revised Application increased the approved customer share of the 2004 Incentive Adjustments from $1,469,000 to $1,791,000. The final total 2004 Incentive Adjustments are based on actual information contained in the audited 2004 financial statements.

Commission Panel Determinations

Further to the approval granted in Commission Order No. G-20-05, the Commission Panel approves the final net 2004 Incentive Adjustments of $1,791,000. This credit balance is to be carried forward and included in the determination of the 2005 Revenue Requirements.

2.4 2005 Incentive Sharing Mechanisms

2.4.1 DSM and Power Purchase Incentives and Flow-through Costs

FortisBC proposes to retain certain aspects of the existing sharing mechanisms for 2005. The Company states: “The Power Purchase Incentive and the Demand Side Management Incentive Mechanisms have been shown to be effective and desirable to customers and the Company. No changes are proposed to either mechanism for 2005.” (Exhibit B-1, Tab 8, p. 30)

FortisBC is of the view that the DSM incentive has increased the Company’s focus on meeting and exceeding the energy efficiency targets and therefore it proposes to retain the existing DSM incentive for 2005 (FortisBC Argument, p. 48). Further detail and submissions on the DSM Incentive Mechanism are summarized Section 2.5: 2005 Demand Side Management Expenditure Plan.

The Company also proposes to retain the existing power purchase incentive mechanism, under which (a) the full advantage of cost savings either currently embedded in contracts, or which are anticipated, are included in the Power Purchase Forecast, and are therefore to the full benefit of customers, and (b) variances, other than load variances, from the Revenue Requirements forecast are applied 65 percent to customer rates in the subsequent year (75 percent for variances in excess of $1,000,000) (FortisBC Argument, p. 49).

Furthermore, FortisBC proposes the continuation of flow-through treatment (i.e. customers assume 100% of the risk and benefit of variances between approved and actual amounts) for certain other costs over which it has limited or no control. Specifically, these costs are the differences between forecast and actual property taxes, provincial water fees, and the Power Purchase expense related to the Brilliant contracts for 2005. In addition to the continued flow-through treatment for the above items, FortisBC proposes to add a new flow-through item that seeks flow-through treatment for the costs of capacity block power purchases forecast for November and December 2005 (FortisBC Argument, p. 50).

Intervenors did not specifically comment on these Incentive Mechanisms and Flow-Through Costs.

Commission Panel Determinations

The Commission Panel approves the continuation of the existing Power Purchase Incentive and the DSM Incentive Mechanisms for 2005. The Commission Panel also approves for 2005 the continuation of the above proposed flow-through cost items as well as the flow-through for the costs of capacity block power purchases forecast for November and December 2005. In addition, the Commission Panel directs FortisBC to treat income taxes and the expensed portion of Cost of Debt as flow-through cost items in 2005.

2.4.2 Operating Expense Incentive

FortisBC is proposing a temporary asymmetrical sharing mechanism for 2005 with respect to O&M expenses. The Company states that: " Under this proposal, to the extent that 2005 O&M Expense, net of capitalized overheads, are lower than the forecast O&M Expense of $36,173,000 (Exhibit B-26), the variance will be shared equally with customers. Actual O&M Expense in excess of the forecast O&M Expense of $36,173,000 will be entirely to the account of the shareholder." (FortisBC Argument, p.50)

Submissions

NRI was initially concerned that FortisBC was still proposing a modified form of PBR for O&M for 2005. NRI goes on to state however, that: "On further consideration, we don't think that this is a significant issue." (NRI Argument, p. 2).

BCOAPO agrees with the general approach proposed by FortisBC with respect to the 2005 sharing mechanism (BCOAPO Argument, p. 7).

KOECA addressed the issue of PBR and the incentive mechanism extensively, during cross examination and in their Final Argument. KOECA states that it protested the inception of the previous PBR scheme because it believed it had serious flaws. KOECA goes on to point out that: "…there never has been a stated rationale for 50-50 sharing between the utility shareholders and the customers" and it submits that 50-50 sharing for cost savings is so rich for the company that it is compelled to cut services until there is a negative reaction (KOECA Argument, p. 3). KOECA states that: "The incentive system must be constructed so that there is little or no incentive for undesirable activity." (KOECA Argument, p. 3) It asks that the Commission set up a process immediately to determine what sharing ratio should appropriately be set for any incentive mechanism the company is allowed to use, from now on. It goes on to ask that in the meantime the Commission rule that a sharing ratio of 90-10 (in favour of the customers) be instituted (KOECA Argument, p. 4).

FortisBC argues that BCOAPO, IMEU, and KOECA are in effect seeking to re-write the rules of PBR long after the rules were agreed to by customers and the utility, after the results of each year have been finalized, and after the monies have long since been disbursed to the shareholder and customers. FortisBC also states that it is difficult to conceive of how the Commission could, by reducing the monies approved for O&M force FortisBC's shareholders to pay for improvements to customer service. Any forced cuts will only end up hurting customers. FortisBC encourages customers and the Commission to focus on the results of the utility's programs as reflected in objective measures of customer service levels (FortisBC Reply Argument, p. 19).

Commission Panel Determinations

The Commission Panel reviewed and considered the evidence on the proposed asymmetrical operating expense incentive mechanism. While the Commission Panel supports the concept of a sharing mechanism with respect to O &M Expenses in general, it does not agree that sharing should start with the "first dollar". The Commission Panel is of the view that it is management's normal responsibility to try to achieve a reasonable level of saving over budget amounts.

In the current circumstances, it is the Commission Panel's view that it is important to maintain a fair balance in terms of risk sharing between customers and shareholders, and that this generally implies sharing should occur for both positive and negative O&M expense variances.

The Commission Panel is of the strong opinion that only the cost savings from true productivity/efficiency improvements in business processes and procedures should be subject to sharing and that cost savings generated through deferral or cancellation of planned activities are not acceptable for sharing. The Commission Panel is confident that the Company will produce savings from productivity/efficiency improvements inasmuch as Mr. Hughes, President and CEO, testified that FortisBC is very focused on productivity and the management of operations and maintenance costs (T2:77).

Finally, the Commission Panel firmly believes that a very strong link needs to exist between the granting of O&M expense incentives to shareholders and the achievement of objective and measurable performance targets by the Company. **Consequently**, **the Commission Panel directs FortisBC to establish for 2005, an operating expense incentive mechanism with the following parameters:**

(a) The total variance for consideration will be calculated as the difference between the forecast 2005 O&M expenses, net of capitalized overheads, and the actual 2005 O&M expenses, net of capitalized overheads;

(b) Favourable variances, which result from the deferral or cancellation of planned activities/programs and/or reductions to existing service levels, will not be eligible for the sharing mechanism. FortisBC is directed to record these type of favourable variances in a deferral account, whose disposition will be dealt with by the Commission at a future date;

(c) The initial $500,000 of a positive or negative variance [as determined by the conditions set out in (a) and (b)] will be shared on a flow-through basis, i.e. 100% to the customer's account;

(d) Both positive and negative variances in excess of the $500,000 "deadband" in (c) will be subject to sharing. The sharing ratio will be 60:40 to shareholders and customers, respectively;

(e) The sharing of an eligible favourable O&M expense variance in (d) will also be subject to the satisfactory achievement of FortisBC's performance targets (see following paragraph (f) for a detailed discussion). If the Company experiences an unsatisfactory result in any one or more performance targets, the Commission will determine at the 2005 Annual Review whether to disqualify FortisBC from sharing in an eligible favourable operating expense variance in 2005. The Commission will apply a high standard of review, as necessary; and

(f) In reference to (e) above, the Commission Panel further directs that within 60 days of this Decision, FortisBC is to file with the Commission, for review and approval, objective and measurable performance metrics and specific targets to be achieved in 2005. These performance metrics should be appropriate for the measurement of actual performance in the generation, transmission, distribution, and customer service functions of the Company (Commission Panel determinations with respect to Customer Service are set out in Section 2.7). For example, SAIDI, CAIDI could be considered appropriate performance metrics for certain functions.

The following example (assuming a favourable variance) will serve to demonstrate the functioning of the above operating expense incentive mechanism.

Forecast 2005 O&M Expenses, net of capitalized overheads	$36,173,000 [1]	Exhibit B-66, p.1
Assumed actual 2005 O&M Expenses, net of capitalized overheads	35,104,000	
Gross Variance	1,069,000	Favourable
Less: Assumed favourable variance due to deferral of planned activity	200,000	to deferral account
Net Variance	869,000	Favourable
Less: $500,000 "Deadband"- 100% to customers	500,000	
Variance eligible for sharing	369,000	Favourable
Shareholder's share @ 60%	221,400	
Customer's share @ 40 %	147,600	

In the above example calculation, customers would effectively "recapture" $847,600 of the total favourable variance of $1,069,000.

2.4.3 Review of PBR

FortisBC intends to complete a comprehensive review of PBR with a view to engaging in stakeholder consultations by the fourth quarter of 2005. FortisBC says that it will propose implementation in 2006 at the earliest if a fair and workable mechanism can be determined (FortisBC Argument, p. 51).

KOECA argues that a PBR must be reviewed thoroughly, with all necessary evidence brought forward in an oral public hearing to determine whether PBR should be continued at all (KOECA Argument, p. 4). BCOAPO supports FortisBC's proposal for stakeholder consultation, but believes it should be primarily aimed at identifying issues of concern and points of disagreement between all parties involved. BCOAPO submits that this should help establish a more focused and efficient Commission process for review of FortisBC's PBR mechanism (BCOAPO Argument, p. 7).

Commission Panel Determinations

The Commission Panel agrees with FortisBC's intentions and timeline to engage in stakeholder consultations to review its existing PBR mechanism. The Commission Panel directs FortisBC to complete its review of PBR prior to submitting its 2006 Revenue Requirements Application and to propose to the Commission its preferred process for review and implementation of its recommendations. The Commission will determine at that time an appropriate review process going forward.

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[1] Subject to adjustments discussed elsewhere in this Decision.

2.5 2005 Demand Side Management Expenditure Plan

2.5.1 Application

FortisBC filed its planned 2005 DSM expenditures under Tab 10.1 of its Application. The planned expenditures are a one-year extension of FortisBC's 1999-2004 DSM Business Plan. As such, it is a one-year continuation of its existing resource acquisition strategy, programs and incentives. FortisBC proposes to file an updated DSM Potential Study by June 30, 2005 and to file a new DSM Business Plan, covering the period 2005-2014, by October 31, 2005. These latter proposals are a component of FortisBC's Resource Plan – Action Plan.

FortisBC's DSM plan is comprised of expenditures for programs in the Residential, General Service and Industrial sectors, as well as costs for Planning and Evaluation, including salaries, consulting fees for planning reviews, ongoing program monitoring, and periodic evaluation reports and training costs. Both the costs of the DSM Potential Study and the DSM Business Plan are included in the 2005 Planning and Evaluation costs. In sum, FortisBC has set out total 2005 DSM expenditures of approximately $1.8 million for forecast total 2005 savings of 19.1 GWh. At the time that FortisBC filed its Application, these amounts could be compared to 2004 forecast costs and savings of approximately $2.0 million and 21.0 GWh, respectively (for further detail, please refer to Exhibit B-1, Tab 10.1, pp. 5-11; Exhibit B-12, Response to BCUC IR 112.0-117.0; and Exhibit B-17, Report of the DSM Technical Committee).

FortisBC submits that its 2005 DSM Plan, filed in compliance with Section 45 (6.1)(c) of the UCA, is reasonable, prudent, and in the public interest, and therefore requests an Order of the Commission that the 2005 DSM plan meets the requirements of Section 45(6.2)(b) of the UCA and is in the public interest (FortisBC Argument, p. 57).

2.5.2 Demand Side Management Technical Committee

Commission Order No. G-14-05 specified that issues associated with DSM would be reviewed by a Technical Committee as an adjunct to the Hearing. The Committee comprised FortisBC and Commission staff as well as Registered Intervenors that expressed an interest to participate. The Commission directed the DSM Technical Committee to submit a report with recommendations to the Commission one-week prior to the commencement of the Hearing (Exhibit A-4).

FortisBC filed the Report of the DSM Technical Committee on March 9, 2005 (Exhibit B-17). The Committee considered a number of issues and concerns in detail over the course of two meetings. There was particular focus on the methodologies that FortisBC uses to forecast the costs and savings in its DSM Plan and to determine the cost-effectiveness of the component programs. FortisBC provided a detailed explanation, stepping through the calculation spreadsheets where appropriate, to the ultimate satisfaction of Committee members. The Committee agreed that a sensitivity analysis on input variables such as penetration rates would be a useful component of future filings and would improve the assessment of the cost-effectiveness of the various DSM programs. FortisBC intends to include sensitivity analyses in future DSM filings.

The Committee also highlighted a concern that the Terms of Reference for the DSM "2005 Energy Efficiency Potential Assessment", as included in Appendix D to Tab 10.1 of the Application, did not include any focus on capacity savings. In response, FortisBC updated the Terms of Reference for this study to eliminate the concern that capacity savings potential would not be addressed. The update to the Terms of Reference is included in Appendix One of the Report of the DSM Technical Committee (Exhibit B-17). FortisBC indicated that the cost of including a study of capacity savings would be re-allocated from other study components, leaving the total study costs of $24,000 unchanged.

The Committee recommended that the existing DSM Incentive Mechanism and DSM Incentive Committee continue for 2005. The Committee was of the view that there was no basis at present on which to rebase any DSM targets in advance of the comprehensive review of PBR that FortisBC intends to complete by the end of 2005 (refer also to FortisBC Argument, p. 51). The Committee recommended that there would be no need to call a DSM panel at the Hearing. After canvassing comment from those Registered Intervenors that did not participate in the DSM Technical Committee, the Commission accepted this recommendation (Exhibit A-16). No issues with respect to the DSM Plan were raised during the Hearing and no written submissions on the DSM plan were received in argument by any party.

2.5.3 Commission Panel Determinations

The Commission Panel has reviewed the FortisBC DSM Expenditure Plan and the Report of the DSM Technical Committee. **The Commission Panel approves the DSM Expenditure Plan as filed and acknowledges that this Plan meets the requirements of Section 45(6.1) of the UCA.**

The Commission Panel also accepts the recommendation of the DSM Technical Committee that the existing DSM Incentive Mechanism and DSM Incentive Committee continue for 2005. The Commission Panel is satisfied by the response of FortisBC to the other issues of concern raised by the Committee; namely, its intention to file appropriate sensitivity analyses in future filings and to include in its DSM potential study a focus on capacity savings potential. **The Commission Panel directs FortisBC to file its DSM potential study by June 30, 2005 and its 2005-2014 DSM Business Plan by October 31, 2005, the timelines proposed by FortisBC.**

2.6 Transition Plan

2.6.1 Introduction

Commission Order No. G-39-04 approved the acquisition by Fortis Pacific of a reviewable interest in Aquila(BC). The latter company became FortisBC after the acquisition.

Aquila(BC) and Aquila Networks Canada (Alberta) Ltd. ("Aquila Alberta") were affiliates of each other and operated on an integrated basis. The two organizations shared certain functions including, for example, executive management, customer call centre, most of the finance function, human resources, and legal services.

As part of Fortis Pacific's application to acquire a reviewable interest, the company represented that it would unwind certain of the shared functions between the B.C. and Alberta operations and establish and operate FortisBC on a stand-alone basis. Fortis Pacific submitted that establishing the utility on a stand-alone basis would allow it to effectively address customer service quality issues and operational improvements, focus the management's attention on the B.C. service area, and create a more transparent regulatory environment. The stand-alone entity would also have independent financing capacity in capital markets.

Commission Order No. G-39-04 directed Fortis Pacific and, as appropriate, FortisBC to file quarterly reports outlining planning activity, timetables and financial evaluation and impacts of their implementation. By the time the Oral Hearing commenced, the Company had filed two quarterly reports (Exhibit B-12, BCUC IR 123) and a detailed Transition Plan (Exhibit B-1, Tab 10.3). The quarterly reports and the Transition Plan illustrate FortisBC's intentions and progress to date on the changes being made in the areas of customer service and operations, and on setting up a stand-alone organization. FortisBC forecasts that the aforementioned activities will cause 2005 O&M expenses, before capitalized overheads, to increase by $1,158,000 (Exhibit B-66, p. 1). In 2005 FortisBC also expects to incur capital expenditures of $460,000 for the new call center in Trail, B.C. (Exhibit B-12, BCUC IR 124.1). The combined effect of these expenditures requires an increase of approximately $1.2 million in 2005 Revenue Requirements (Exhibit B-1, Tab 10.3, p. 13).

The following sections discuss the significant components of the FortisBC Transition Plan in greater detail.

2.6.2 Customer Service

Customer service is addressed separately in Section 2.7.

2.6.3 Establishment of a Stand-alone utility

During cross-examination, Mr. Hughes, President and CEO of FortisBC explained the advantages of operating a utility on a stand-alone rather than integrated basis. Mr. Hughes testified (T2: 82):

> "We believe that this stand-alone utility based in our B.C. service territory will not only produce improved customer service – why will it do that? Because it will have local knowledge, improved focus and greater responsiveness to trouble calls. But it will also, over time, produce lower costs. Let me give you a couple of examples: Lower employee turn-over, particularly in the call centre; lower building and rental costs; improved responsiveness to customer concerns and requests – for example, customer connection; and last and certainly not least, faster outage restorations."

Commission Counsel asked Mr. Hughes to provide hard evidence that demonstrates that lower costs come from a stand-alone utility (T2:114). Mr. Hughes replied:

> "Well, one of the first things I would point to, and between I think it was about 1992 and 2002 in Newfoundland Power with this model, essentially the O&M was flat. To run a utility over a period of that time with flat O&M obviously proves the value of the model. It's our experience from say Fortis (Ontario), Fortis – we changed that model and we saw a cost improvement. That was more integrated. We've seen it in many. If you go through those things I mentioned, what you will find if you look at the Fortis companies is that our cost performance improves, our customer satisfaction improves by adopting this model pre and post. In the last 15 years, Maritime Electric, you've seen the performance and cost performance." (T2:114-115).

To date, FortisBC has made significant progress toward creating the stand-alone entity. The Head Office has been established in Kelowna and the independent executive management team is mostly in place. FortisBC states that recruitment of staff includes a combination of internal reorganization, outside recruitment and transfers of skilled employees wishing to relocate. The Company also notes that no relocation and severance costs associated with the transfer of positions from Alberta are included in the 2005 Revenue Requirements (Exhibit B-1, Tab 10.3, p. 10).

FortisBC will have its own Board of Directors and it will include members from the service territory. The Board is expected to be in place by the end of 2005.

2.6.4 Field Services

FortisBC states that it intends to pursue two separate initiatives, both of which are aimed at improving customer responsiveness (Exhibit B-1, Tab 10.3, p. 12).

The first initiative is directed at reducing FortisBC's service restoration times. The Company is currently undertaking a comprehensive review with a view to establishing restoration targets applicable to all areas of its service territory. The review will be completed by the second quarter of 2005.

The second initiative is aimed at improving FortisBC's responsiveness to routine customer wait times for services such as new connections. FortisBC states that: "As in the case of restoration times, measurable targets will be established and regularly reviewed to ensure continued timely customer responsiveness on a consistent basis." (Exhibit B-1, Tab 10.3, p.12)

2.6.5 Submissions

BCOAPO opposes the $1.2 million increase in the 2005 Revenue Requirements that result from actions taken under FortisBC's Transition Plan. BCOAPO states that: "…it is not appropriate for it to require ratepayers to pay for the cost for restoring quality of service to levels that existed prior to the move to Calgary." (BCOAPO Argument, p.7) and "…that customers should not be required to bear the cost of improving customer service in the amount of $1.2 million…" (BCOAPO Argument, p. 25) It further argues that to the extent the $1.2 million is reflected in the O&M expenses, these expenses should be reduced accordingly (BCOAPO Argument, p. 25).

KOECA states: "…the Commission should not permit the company to subsequently be rewarded for restoring service levels which should never have been allowed to decline in the first place." (KOECA Argument, p. 2). KOECA argues that a way must be found to determine how much improvement the company must make before it can justify passing on service improvement costs to its customers. It further submits that: "The appropriate approach is to establish what service levels are now being targeted by the company and determine whether they were in fact already at that level in the past. If so, then the company should pay the entire cost of service restoration. If the company intends to provide service levels above those experienced in the past, then in fairness it should be able to recover costs for doing so, but only for the increment above past service levels." (KOECA Argument, p. 2).

IMEU submits is supportive of the efforts of FortisBC to focus on improving customer relations and customer service in the service territory, and to operate the utility in an efficient, safe and reliable manner. It is also pleased to see a locally managed stand-alone operation with a focus on customers and it states that: "…[the IMEU] particularly endorses the statement in FortisBC's argument that it believes that 'it [the stand-alone utility] will also produce the lowest possible costs for our customers over the long term'(Fortis Argument, Page 8)" (IMEU Argument, p. 2). Having made the above statements, IMEU continues to state several concerns, including its concern about the: "…increased costs being passed on to customers as a result of the transition of ownership from Aquila to FortisBC" (IMEU Argument, p.2).

2.6.6 Commission Panel Determinations

The Commission Panel has considered all the evidence and arguments related to this matter. The Commission Panel concurs that the largely one-time cost of moving many of the functions back to B.C. is appropriately an expense for the shareholder. However, it does not agree with Intervenors that the incremental ongoing or recurring costs associated with service improvement activities proposed in the Transition Plan should be borne by shareholders. In Section 2.3.3 the Commission Panel approved the forecast 2005 O&M expenses, before capitalized overheads (i.e. $39,569,000 subject to adjustments), which include the increase of $1,158,000 in O&M expenses related to the Transition Plan. **With respect to the establishment of the Trail Call Center, the Commission Panel also accepts the forecast 2005 capital expenditures of $460,000 and the associated increases in the 2005 Revenue Requirements.**

The targets applicable to service restoration times and customer wait times for services such as new connections should be filed with the Commission as per the Commission Panel's determinations set out in Section 2.4.2, paragraph (f).

FortisBC claims that a stand-alone utility will over time produce lower costs. The Commission Panel directs FortisBC to submit a report one year from this Decision that demonstrates the achievement of cost savings attributable to the stand-alone status of FortisBC. The Commission will determine the need for further reports on a prospective basis.

2.7 Customer Service

In its application to acquire a reviewable interest in Aquila(BC), Fortis Pacific provided evidence that "the conduct of FortisBC's business, including the level of service, either now or in the future, would be maintained or enhanced." (Exhibit B-1, Tab 10.3, p.3). FortisBC further states:

> "In addition to the intentions stated in the Application, multiple stakeholder and public consultations were conducted regarding the Acquisition and transition. During these consultations, the Company also stated its intention to, within a reasonable transition period: 1) improve the overall quality of service to customers; … " (Exhibit B-1, Tab10.3, p. 4)

The Commission, in considering the acquisition application, was mindful of the service level concerns as expressed by customers and the related undertakings of the Applicant. In Order No. G-39-04 approving the acquisition, the Commission made clear its expectations that:

> "… in due course and in a timely manner, steps will be taken to further consider and implement the plans and fulfill the commitments made in the presentations to stakeholders, in the Fortis Application and in the course of this public process." (Order No. G-39-04, Appendix A, p. 11)

With the amount of interest in and attention paid to customer service during the acquisition process, it is not surprising that customer service would be a topic of considerable focus for FortisBC and of much interest to Intervenors in this proceeding.

FortisBC addressed many customer service deficiencies under cross examination. The following is considered by the Commission Panel to be a representative sample of these deficiencies and FortisBC's view of them.

> "What's relevant is that the customer service level and the meter reading was just unacceptable. And we heard this very strongly from the customers." (T2: 103)

> "And another thing we found when we took over this utility and we made fairly good initial efforts to start changing it and we've still got a long way to go, is customer connections. The time from when a customer requested service in B.C. to when they were actually getting it, we felt was far too long." (T2: 116)

> "In principle, we are responding to customers -- what customers have been telling this utility for some time, and that is the level of dissatisfaction that they have with the customer service, the call centre, responsiveness, et cetera." (T2: 169)

> "Newfoundland Power in the early '90s was in a very similar situation as we see here in B.C. today. It was suffering from a very low customer service rating." (T3: 519)

In the course of the proceedings Intervenors were generally positive about to FortisBC's intentions and early progress with respect to improvements in customer service. IMEU's comments on the subject are, in the view of the Commission Panel, generally representative of Intervenor views:

> "The IMEU is supportive of the efforts of FortisBC to focus on improving customer relations and customer service in the service territory and has been generally impressed by the efforts of the new management of the Company to respond to customer concerns" (IMEU Argument, p. 2).

2.7.1 Metrics and Strategies

In Exhibit B-1 at Tab 10.2, FortisBC provides an informative overview of its views on customer service measurement and tracking. The Commission Panel is of the view that customer service may be measured as it occurs, in terms of objective measures of customer service activity, and after the fact, in terms of customer satisfaction response when surveyed. Typically, objective measures are an indication of performance in "real time", while survey responses measure reaction to performance after the fact and can lag actual performance by a considerable margin depending on the timing of the survey and the degree and nature of the interaction with the (in this case) service provider.

FortisBC indicated its intentions with respect to revising its approach to the measurement of customer service.

> "In general it seems more reasonable to directly measure things that are readily quantifiable, such as reliability, rather than measure them through qualitative questions in the survey. Going forward, it is intended that the customer survey tool be used to more accurately measure the quality and convenience of the customer's day-to-day interactions with the Company, and employ other metrics for strictly objective facets of customer service." (Exhibit B-1, Tab 10.2, p27)

FortisBC indicated that in addition to revising the survey questionnaire, it planned to establish metrics and key performance indicators for all departments for the purpose of linking departmental productivity levels in all areas to customer service. Some indicators that FortisBC believes are important to customers are (Exhibit B-1, Tab 10.2, pp 28-29):

- Billing Accuracy;
- Emergency response times;
- First call resolution;
- Commitment to follow-up;
- Tracking completion time for new service requests;
- Meter reading accuracy; and
- Field service complaints.

The following reflects the strategies that FortisBC is currently implementing, or intends to implement, believing that they will result in an improvement in customer service:

> "FortisBC plans to establish its own customer service functionality and is focused on strategies to improve service. These improvements include a more effective call centre, increased meter reading and billing accuracy, enhanced bill format and provision for in-person service. Also, improvements in field service delivery through more effective work processes and resource deployment will decrease wait times for services such as new connections and trouble call response. The Company intends to establish benchmarks to monitor its progress." (Exhibit B-1, Tab 10.3, p. 17)

FortisBC has identified that the costs of these initiatives, when netted against the forecast reduction in shared services cost from FortisAlberta, form the major part of the approximate $1.2 million increase in revenue requirements discussed in Section 2.6.1 (Exhibit B-1, Tab 10.3, p. 17).

2.7.2 Commission Panel Determinations

The increase in costs to support improvements in customer service has been approved elsewhere in this Decision. In defense of its O&M expense budget, FortisBC encouraged customers and the Commission to focus on the results of the utility's programs as reflected in objective measures of customer service levels (FortisBC Reply Argument, p. 19). The Commission Panel is concerned that although FortisBC indicates that it intends to establish benchmarks to monitor its progress in improving customer service, no specific objective measures have been identified by FortisBC as deliverables resulting from the increase in funding as requested and approved. In the view of the Commission Panel, it would be unreasonable under normal circumstances to approve an increase in funding in the absence of clear targets against which improved performance is expected and may be measured. However, in the circumstances, the Panel supports the need for substantial improvements in service and recognizes the need for urgency in undertaking the initiatives necessary to bring about these improvements.

Therefore, the Commission Panel directs FortisBC to file within 60 days of this Decision a comprehensive set of objective and measurable performance metrics showing respective performance at the beginning of 2005 (estimates where actual is not available) and targets for December 31, 2005 for service areas as follows:

1. **Billing Accuracy**
2. **Emergency response times**
3. **First call resolution**
4. **Commitment to follow-up**
5. **Tracking completion time for new service requests**
6. **Meter reading accuracy**
7. **Field service complaints**
8. **Call center**

Further, FortisBC is directed to report to the Commission by October 31, 2005, actual performance for each of the measures to September 30, 2005, and by January 31, 2006, actual performance for each measure to December 31, 2005.

2.8 Accounting Issues

2.8.1 Depreciation and Amortization Study

FortisBC's last formal depreciation study was undertaken in 1983 and a discussion paper on the service life of transmission and distribution assets was completed in 1999. The Negotiated Settlement Agreement for 2000-2002, approved by Commission Order No. G-134-99, included a reduction of depreciation rates (and therefore depreciation expense) for transmission and distribution assets from 35 years to 50 years, and a further offset to depreciation expense in the form of a Rate Stabilization provision. Neither change was based on an expert-prepared depreciation study examined by the Commission. Since 2000, depreciation rate changes have resulted in a lower annual depreciation expense of about $3.3 million. The Rate Stabilization Adjustment was utilized in 2001, which set-up a $3.1 million adjustment to offset accumulated depreciation (Exhibit B-12, BCUC IR 33.6-33.8; T5: 863-866; FortisBC Argument, pp. 36-38).

The DBRS credit rating report expressed that currently low depreciation rates are a challenge and it observed that the Company's current average depreciation rate appears low in comparison to other utilities (Exhibit B-12, BCUC IR 13.0, p. 2). Similarly, the Moody's credit rating report cites one of the Company's credit challenges to be the relatively low depreciation rate for rate-making purposes (Exhibit B-12, BCUC IR 15.0, p. 1).

Dr. Booth, expert witness for BCOAPO, stated that the depreciation rate should be based on the economic useful life of the assets and it shouldn't be fixed for other purposes (T4: 759). Mr. Meyers from FortisBC indicated that the Company expects to carry out a depreciation study later in 2005 and intends to perform depreciation studies on five-year intervals going forward (T5: 863). Mr. Wait argues that the depreciation rate for vehicles should be increased so that the difference between the vehicle sale value and depreciated value would be minimal (Wait Argument, pp. 3-4).

FortisBC proposes to conduct a depreciation and amortization study by an independent consultant during 2005, for submission with the 2006 Revenue Requirements application (Exhibit B-1, Tab 6, p. 9; Exhibit B-12, BCUC IR 33.6). The Company states that the depreciation study will address issues raised during the proceeding including disposition of the Rate Stabilization Account; different depreciation rates for the generation plants; and depreciation rates for fleet vehicles and computer software. FortisBC argues that it is inappropriate to make any changes to depreciation rates or methodology until a depreciation study is completed (FortisBC Argument, pp. 37-38).

FortisBC states that its policy is to record depreciation expense in the year after the assets are placed in service (Exhibit B-12, BCUC IR 29.1.2).

Commission Panel Determinations

The Commission Panel accepts that the currently approved depreciation rates should not be changed in 2005 until a formal depreciation and amortization study has been completed. The Commission Panel directs FortisBC to file a depreciation and amortization study as part of its next revenue requirements application. The next revenue requirements application will include a rate impact analysis for both with and without any depreciation and amortization rate changes.

2.8.2 Adjustment for Capital Expenditures

The Company calculates the Adjustment for Capital Expenditures on a quarterly weighted average instead of on a 13-month weighted average. The Company states that either method should provide similar results over the long term. The Company argues that should the Commission prefer that the Company move to a 13-month average for calculating the Adjustment for Capital Expenditures in the determination of rate base, the Company suggests that this change be introduced as part of the Company's 2006 Revenue Requirements application (FortisBC Argument, pp. 29-30; Exhibit B-12, BCUC IR 37.0; T5: 867-868).

Commission Panel Determinations

The Commission Panel agrees that the Company should continue to use the quarterly weighted average method to calculate the Adjustment for Capital Expenditures in 2005. The Commission Panel directs the Company to calculate the Adjustment for Capital Expenditures using the 13-month average method, commencing in 2006.

2.8.3 Allowance for Funds Used During Construction

AFUDC represents the cost of capital incurred by the Company while assets are under construction. The Company recognizes that customers should only contribute to assets that are "used and useful". Consequently, the Company deducts AFUDC from revenue requirements and adds it to capital costs, to be recovered through depreciation expense over the life of the asset (Exhibit B-1, Tab 8, p. 26).

The Company has calculated an AFUDC rate of 6.48 percent based on a return on equity of 9.78 percent and weighted average cost of debt of 6.66 percent (Exhibit B-1, Tab 8, p. 26; Exhibit B-12, BCUC IR 80.5 & 85.3).

The Company explained that AFUDC is calculated monthly on a project by project basis for projects with a forecast cost greater than $100,000 and expected to last more than three months duration. The Utility includes Construction Work in Progress ("CWIP") that attracts AFUDC in its rate base. Revenue requirements, including financing costs, are calculated on the mid-year rate base which includes CWIP. Revenue requirements are then reduced by AFUDC, to reflect the cost of financing the CWIP portion of rate base that is not used and useful. The Company stated that Terasen Gas and Pacific Northern Gas Ltd., both regulated by the Commission, do not include AFUDC as a reduction to revenue requirement and exclude CWIP subject to AFUDC from rate base. However the Company states that the net result of using either method should be the same (Exhibit B-12, BCUC IR 85.1-85.10).

The Company provided a reconciliation of the deduction of AFUDC in Schedule 3 to show that the Company has properly deducted AFUDC in calculating income tax expense (Exhibit B-79). Commission Counsel in cross-examination questioned the Company's use of including CWIP that attracts AFUDC in rate base and the practices of other utilities regulated by the Commission. Mr. Lee responded that the Company had no preference between the methodologies (T5: 873).

FortisBC argues that since 1990 it has included CWIP in the calculation of rate base, together with the corresponding deduction of AFUDC in the calculation of revenue requirements. FortisBC does not propose to change its current treatment, and believes that its current treatment better reflects the actual income tax and accounting treatment of AFUDC. If the Commission wishes to change the method of accounting for CWIP and AFUDC, FortisBC argues that the change should be applied prospectively beginning in 2006 as part of the Company's 2006 revenue requirement application (FortisBC Argument, p. 30).

Commission Panel Determinations

The Commission Panel accepts that the Company should continue to calculate CWIP and AFUDC using the current method in 2005. The Commission Panel directs FortisBC in its next revenue requirements application to review its current practice of including CWIP attracting AFUDC into rate base. The review should include a comparison of other electric and gas utilities regulated by the Commission, an analysis of the alternate methods, and a proposal by the Company on whether to continue or change its current AFUDC and CWIP methodology.

The Commission Panel directs the Company to recalculate its AFUDC rate based on the weighted average cost of debt from the Third Revised Application and the return on equity allowed through this Decision. The resulting approved AFUDC rate shall be applied to calculate the AFUDC amounts in 2005.

2.8.4 Capitalization of PowerSense Costs

FortisBC is proposing a change in the accounting treatment of certain PowerSense costs in the amount of $85,000, such that these costs are charged to capital rather than operations (Exhibit B-26, p. 4). The DSM Technical Committee discussed the reasons behind the request with only Mr. Wait expressing concern (Exhibit B-17, p. 3).

Mr. Wait argues that the $85,000 charge for DSM awareness should continue as an operating expense and not be capitalized. He expressed concern for capitalizing costs that do not have physical assets attached and the procedure would cost ratepayers more for ROE and equity (Wait Argument, p. 9). Currently the Company amortizes DSM (deferred energy management) costs over 8 years (Exhibit B-12, BCUC IR 34.1-34.3).

Commission Panel Determinations

The Commission Panel approves the change in accounting treatment of certain PowerSense costs as proposed by the Company. The Commission Panel directs that the upcoming depreciation and amortization study will address the appropriateness of the current amortization period for deferred DSM costs.

2.8.5 Deferred Charges

Net-of-tax Deferral Accounting

Currently, FortisBC treats DSM costs net-of-tax as directed in Commission Order No. G-55-95. All other deferred charges that have been recorded by the Company are on a gross of tax basis. At Transcript Volume 5, page 887, Commission Counsel questioned the appropriateness of recording all deferred charges on a net-of-tax basis. Mr. Meyers responded that, in his opinion, the net-of-tax treatment is appropriate to ensure proper matching of costs and benefits (FortisBC Argument, p. 59).

The Company proposes that deferred amounts related to the proposed 2005 O&M Expense and power purchase sharing mechanisms be recorded net-of-tax so that the associated income tax is correctly matched either to the customers or the shareholder (Exhibit B-12, Response to BCUC IR 34.5). The Company does not propose to extend net-of-tax treatment to other deferral accounts. The Company is of the position that any change in the treatment of deferred charges must apply on a prospective basis only, and should be made only after a full assessment of the impact has been completed (FortisBC Argument, pp. 59-60).

The Commission believes that a consistent treatment of deferral accounts is warranted to ensure proper matching of costs and benefits. **The Commission Panel directs that all deferred charges (excluding preliminary and investigative costs charges transferred to capital projects) be treated using net-of-tax deferral accounting commencing in 2005.**

Tax Rate for Net-of-tax Deferral Accounting

The Company currently books net-of-tax deferrals using the combined federal and provincial statutory tax rate including federal surtax. The 2005 combined statutory tax rate with surtax is 35.62 percent and 34.5 percent without surtax. Mr. Lorimer agreed that the federal surtax was deductible against the large corporation tax. In response to a question by Commission Counsel, Mr. Lorimer rationalized that the 35.62 percent tax rate was appropriate (Exhibit B-12, BCUC IR 34.1; T5 887-888).

In its calculation of the large corporation tax for 2005 the Company has included a federal surtax reduction to compute the net payable large corporation tax (Exhibit B-12, BCUC IR 81.5).

In 2005 the ability to apply the federal surtax to reduce large corporation tax effectively excludes the federal surtax in the combined corporate income tax rate. **The Commission Panel directs that the tax rate to use for net-of-tax deferral accounting is the net effective tax rate to the Company. For 2005 the appropriate tax rate to use for net-of-tax deferral accounting is 34.5 percent without the federal surtax.**

Cost of Regulatory and Related Activities

The Company requests approval for the deferral of the cost of regulatory and related activities. In Table 6.4B, Forecast 2005 Deferred Charges and Credits, the Company proposes to include in 2005 forecast deferral additions of $250,000 for the 2005 Revenue Requirements proceeding, $75,000 for the 2006 Revenue Requirements proceeding, and $150,000 for Other Regulatory proceedings (Exhibit B-1, Tab 6, p. 13).

The Company explained the Other Regulatory proceedings amount is a provision for expected and unexpected regulatory proceedings during the year. The Company anticipates the most significant costs would be for the 2005 Generic Return on Equity hearing plus intervention in proceedings of other utilities such as BC Hydro's Rate Design hearing. The Company states that it is not possible to estimate costs with a reasonable degree of certainty until the scope and process of a proceeding has been determined (Exhibit B-12, BCUC IR 34.7).

The Commission Panel approves gross deferral account additions of $250,000 and $75,000 in 2005 for the 2005 and 2006 Revenue Requirements proceedings, respectively. The Company will file with the Commission upon completion of each of these two proceedings a review of the actual costs, a comparison of the costs from actual to budget, and a demonstration that the costs have been prudently incurred.

The Commission Panel denies the $150,000 provision for Other Regulatory proceedings to be included in rate base. The Commission Panel directs the Company to set-up a non-rate base short-term interest bearing deferral account for each regulatory proceeding that it proposes to seek cost recovery for. The account will collect actual costs incurred for each proceeding. At the conclusion of each proceeding the Company may apply for a prudency review of actual incurred costs for inclusion in rate base as a deferral account.

Series 04-1 Senior Unsecured Debentures Issue Cost and Amortization

FortisBC requests approval for the issue cost of the Series 04-1 Senior Unsecured Debentures in the amount of $2,091,000. The Company also requests amortization of the issue cost of the Series 04-1 Senior Unsecured Debentures in the amount of $2,091,000 over ten years commencing on January 1, 2005. The amortization period matches the 10-year term of the bond (Exhibit B-26, p. 3; Exhibit B-1, Tab 8, p. 18; Exhibit B-12, BCUC IR 23.1).

The Commission Panel approves the $2,091,000 issue cost of the Series 04-1 Senior Unsecured Debentures and the amortization over ten years commencing on January 1, 2005.

Amortization of the Costs Incurred for 2004 Revenue Requirement process

The Company requests amortization of the costs incurred in FortisBC's 2004 Revenue Requirements NSP over a one-year period (Exhibit B-26, p. 3; Exhibit B-12, BCUC IR 34.3).

The Commission Panel approves the amortization of costs incurred in FortisBC's 2004 Revenue Requirements NSP for a one-year period in 2005.

Costs and Amortization of the System Development Plan and Resource Plan

The Company requests the amortization of the costs of the 2005-2024 System Development Plan and the 2005 Resource Plan, in an aggregate amount of $900,000, over five years commencing on January 1, 2005 (Exhibit B-26, p. 3). The December 31, 2004 balances are $800,000 for the System Development Plan and $100,000 for the

Resource Plan (Exhibit B-12, BCUC IR 29.0, Table 1-B (2005)). The Company states that these planning activities are carried out at intervals of approximately five years, and are considered to be an ongoing, although intermittent, operating expense. Therefore, the Company proposes to include the amortization of costs in O&M expense (FortisBC Argument, p. 60).

The Commission Panel approves a five-year amortization for each of the System Development Plan and the Resource Plan costs. The Commission Panel determines that net-of-tax deferral accounting is to be used for deferred charges. Consequently, the System Development Plan and Resource Plan costs are not to be amortized to operating expense. Instead these costs are to be amortized to deferred amortization expense.

Capital Cost Allowance Rate Change Deferral

In its Revised Application, FortisBC incorporates changes to the 2005 Revenue Requirements to reflect capital cost allowance ("CCA") rate changes relating to new transmission and distribution assets announced in the February 23, 2005 Federal Budget (Exhibit B-19, p. 6). FortisBC requests approval of a deferral account and recovery in 2006 of higher income tax expense that will arise in 2005 if the new CCA rates announced in the February 23, 2005 Federal Budget are not enacted prior to December 31, 2005 (Exhibit B-26, p. 5).

The Commission Panel approves a deferral account and recovery in 2006 of higher income tax expense that arises in 2005 if the new CCA rates announced in the February 23, 2005 Federal Budget are not enacted prior to December 31, 2005.

2.8.6 Provision for Income Tax Audits

The Company has included an amount of $100,000 in its 2005 Revenue Requirements as a provision for income tax audits. The Company has been audited by the Canada Revenue Agency ("CRA") for the years up to and including 1998. The Company expects that it will be audited for the years subsequent to 1998 in the near future. The Company believes it is both reasonable and prudent to include this provision in its 2005 income tax expense. The Company indicated that a cumulative provision for income tax audits for the years 1999 to 2004 exists, in the amount of $350,000. FortisBC proposes this provision be retained pending an audit from CRA for these years. Any unused provision upon completion of the audits would be credited to the benefit of customers in calculating the following year's revenue requirement (FortisBC Argument, p. 33; Exhibit B-77, Undertaking U-44).

FortisBC confirmed that the accumulated provisions for tax audits have not been factored into the rate base calculations (Exhibit B-78, Undertaking U-45). IMEU argues that it does not believe that the provision for tax audit should be maintained. Also, IMEU submits that the $350,000 which has been collected from customers should be returned to customers in 2005 (IMEU Argument, 17).

FortisBC in its reply to IMEU believes that the Company's position is a prudent method of providing for the eventual costs of tax audits, and that its proposal to retain the provision and to dispose of any unused amounts upon completion of the audits be approved by the Commission (FortisBC Reply Argument, pp. 29-30).

Commission Panel Determinations

The Commission Panel directs the $100,000 provision for tax audit to be removed from the 2005 Revenue Requirements. The Commission Panel also directs that the cumulative provision of $350,000 for income tax audits already collected be returned to ratepayers in the 2005 test year.

2.8.7 Capital Tax Refund

FortisBC was reassessed for B.C. Capital taxes for the taxation years 1994 through 1998. The primary issues arising from the assessments arose from the netting of CIAC against book value and the netting of certain deferred charge credits against deferred charge debits for purposes of computing the Company's paid-up capital for capital tax purposes. The Company paid the reassessed amounts and appealed the reassessments. In early 2004, the Company, together with Terasen Gas, met with representatives from the B.C. Ministry of Finance to put forth its position on the calculation of the capital taxes. On February 11, 2005 the Company received notice that its appeal has been allowed by the Minister of Finance, and it is awaiting final reassessment (Exhibit B-12, BCUC IR 82.1).

The Company proposes that the capital taxes refund amount, including interest and net of related income taxes, be shared equally between the Company and its customers. The Revised Application includes a provision for one-half of the estimated B.C. Capital Tax refund of $908,000 applied on an after-tax basis, to reduce the 2005 B.C. Capital Tax expense by $292,000 (Exhibit B-19, p. 7). FortisBC argues that since the Company aggressively pursued the appeal, and in view of the fact that PBR is intended to provide incentives to the Company to find ways to reduce cost and to share these cost savings with the customer, it considers it reasonable that the refund be shared on a 50-50 basis (FortisBC Argument, p. 35).

Mr. Meyers agreed that capital tax was a flow-through cost borne by the ratepayers and that the ratepayers paid for the costs of pursuing the appeal. Mr. Meyers stated that the Company aggressively pursued the assessment and that the sharing of the benefit would continue to provide incentives to the Company to continue to appeal similar types of assessments. Upon further questioning from Commission Counsel, Mr. Meyers agreed that as a part of the Company's normal business operation it has an obligation to pursue the tax assessment to keep costs down. Commission Counsel also questioned why the Company was treating the refund on an after-tax basis for the flow-through to customers. Mr. Lorimer replied that the B.C. Capital Taxes, as opposed to the large corporation tax, was a tax deductible item in those years (T5: 843-846).

IMEU does not support the regulatory treatment of B.C. Capital Tax as proposed by the Company. IMEU submits it is completely inappropriate for the Company to be claiming any portion of any refund or positive assessment from the appeals of these tax matters. IMEU considers that, since the customers bore the full cost of the appeals and bore the full cost of the taxes paid during the period, the customers should be entitled to a full refund of the success of the appeals. IMEU notes that if the challenge were unsuccessful, yet prudently undertaken, the cost of the pursuit of the appeal would have been borne by the customers (IMEU Argument, pp. 3, 15-16).

BCOAPO does not support a sharing of the B.C. Capital Tax refund. BCOAPO notes that Mr. Lorimer admitted that FortisBC was not the only utility to appeal the capital tax assessment (T3: 516). BCOAPO argues there is no evidence that the efforts of FortisBC, rather than the efforts of other utilities, were responsible for the capital tax refund (BCOAPO Argument, pp. 25-26).

Commission Panel Determinations

The Commission Panel denies the proposed sharing of the B.C. Capital Tax refund. The Commission Panel directs the Company to include in 2005 the full after-tax refund amount without any sharing to the Company.

3.0 2005 CAPITAL PLAN AND 2005-2024 SYSTEM DEVELOPMENT PLAN

3.1 Introduction

In conjunction with its 2005 Revenue Requirements filing, FortisBC filed its 2005-2024 System Development Plan and its 2005 Capital Plan. FortisBC states that these plans are intended to comply with the requirements of Section 45 of the UCA (Exhibit B-1, Tab 1). Section 45(6) of the UCA states that "A Public Utility must file with the Commission at least once each year a statement in a form prescribed by the Commission of the extensions to its facilities that it plans to construct." Section 45(6.1) requires that the utility file a capital expenditures plan for a period specified by the Commission in addition to plans for the acquisition of energy and plans for reducing the demands for energy.

In its November Application FortisBC stated that it was seeking an Order that its 2005 System Development Plan meets the requirements of Section 46(6) of the UCA and an Order that its 2005 Capital Expenditure Plan satisfies the requirements of Section 45(6.2)(a) and (b) of the UCA (Exhibit B-1, Tab 9, pp. 5-6). In its Second Revised Application FortisBC no longer sought an Order for the System Development Plan. In clarification, Mr. Macintosh stated that the Orders FortisBC is seeking are contained in the Second Revised Application and did not include an Order for the approval of the System Development Plan, but required an order approving the 2005 Capital Plan (T2: 67). Mr. Debienne stated that although they were not seeking approval, the System Development Plan needs to be considered when evaluating the Capital Plan (T3: 345).

3.2 2005-2024 System Development Plan

The System Development Plan is a long range planning document for capital expenditures on the transmission and distribution system. It considers a 20-year time frame for the transmission system and a 5-year time frame for the distribution system and was preceded by the 1998 Master Plan. Although the time frame for the report is 20 years, the majority of expenditures are anticipated to occur in the next five years. The total transmission and distribution capital forecast for the first five-year period is in excess of $400 million (Exhibit B-1, Tab 9, p. 19).

Inputs to the plan include the forecast growth for the Kootenay and Okanagan regions and assessments of equipment condition and maintenance plans. Each resulting project was assessed against criteria for safety, public impact, restoration time, thermal capacity, system effect of failure, and voltage. Some projects were given a mandatory designation for safety reasons (Exhibit B-2, pp. 2-4).

3.2.1 Bulk Transmission Plan

The following section discuses system deficiencies and/or changes from the 1998 System Plan. Although the most significant deficiencies were addressed by the 230 Kootenay Development project and the South Okanagan Supply reinforcement project, FortisBC has identified several other areas of concern.

One area of concern is the reliability of supply to the City of Kelowna. FortisBC identified that Kelowna will be exposed to a significant load loss from the coincident loss of circuits 72 and 74 or BC Hydro's 2L255 and 2L256 from Vernon. (Exhibit B-2, p. 10). With this occurrence Kelowna could experience a loss of two thirds of its load, with the remainder of load under rotating blackouts. FortisBC testified that the concern with these lines lies with the fact that they share common rights of way and could be subject to outage events such as forest fires or other common mode outages. It was also concerned about the exposure to Kelowna under conditions of maintenance outages. This condition is referred to as an N-1-1 condition. In the previous plan only a loss of one line was considered. However, according to Western Electricity Coordinating Council ("WECC") standards, when it is reasonable to assume a multiple element outage due to one cause a utility must consider the multiple element outage under N-1 contingency standards (T2: 265-267). The solution to this concern is to replace the 161 kV line with a 230 kV transmission line from Vaseux Lake Terminal to the Anderson Terminal in Penticton.

Other changes identified include the supply to the Boundary area and to Osoyoos as well as the need for additional Remedial Action Schemes for Vaseux Lake Terminal and Kelowna to prevent voltage instability in the Penticton/ Oliver and the Kelowna areas (Exhibit B-1, Tab 9, p. 18; Exhibit B-2, pp. 12, 13, 17, 29, 40).

3.2.2 Transmission and Distribution

FortisBC identified a significant number of sub-transmission and distribution projects required for growth and sustaining projects. These are listed in Appendix C of Exhibit B-2 on pages 2 and 3. Distribution projects are listed on page 4 and Telecommunications, Scada, and Protection projects are listed on page 5. All projects have been prioritized according to the criteria described above, and are listed on pages 6 and 7 of Appendix C.

3.2.3 Rate Impacts

FortisBC estimated that the Capital Plan would result in an average increase in rates of 4.8 percent per year for the first five years (Exhibit B-12, BCUC 92.3). As a result of further questions during the Technical Committee meetings FortisBC also estimated that the impact of all other cost components with the Capital Plan included is an average rate increase of 5.2 percent per year (Exhibit B-20, Appendix 1).

However Mr. Debienne stated that the results calculated in response to BCUC 92.3 were misleading because the table contained the Capital Expenditures for the System Development Plan in 2005 and then included the Capital expenditures for the entire company in the remaining years to 2010 (T2: 228). Mr. Debienne also stated that a more accurate representation of the impacts of the System Development Plan can be found in Appendix 1 to Exhibit B-20. While this Exhibit shows the rate impacts for all capital expenditures, the rate impact for the System Development Plan would be approximately two-thirds of that, or a cumulative impact of 20 to 25 percent over six years (T2: 231-232).

3.2.4 Submissions

Arguments from IMEU, BCOAPO, and NRI were generally supportive of the System Development plan and the possible improvements in reliability, but all expressed some concern for the rate impact. IMEU expressed some concerns about the completeness of the System Development Plan, but was encouraged by the Company's commitment to have an open dialogue on the Plan. Mr. Wait had specific comments on the Big White Project and the East Osoyoos Substation, the Boundary reconfiguration, and the lines 30, 32, and 37 (Kaslo, Crawford Bay, Lambert Terminal areas). He also suggested that the 230 kV line from Vaseux Lake to Penticton was not needed and should be delayed. In conclusion he wished to have the System Development Plan address the issues he raised.

FortisBC argued that the System Development Plan and the Capital Plan were developed to ensure that investments in the existing system are sufficient to maintain system integrity and reliability and to optimize the life of the company's assets (FortisBC Argument, p. 9). FortisBC believes the plans are efficient and that it has economized it to the extent possible. However it notes that it is continuing to do analysis to optimize the plan on a year to year basis. (FortisBC Argument, p. 12-13). Regarding the impact on rates, FortisBC acknowledges the impact and notes that for the next 6 to 7 years customers will see a rate bulge as the system is renewed, but in the long term customers will enjoy relatively low rates because of the low cost of generation. In comparison to other utilities, the cost of equipment will be the same, as the company uses the same material and practices as other utilities and that therefore the rates will be comparable to other utilities on that basis (FortisBC Argument, pp. 12-15).

With regard to the need for N-1-1 criteria for the City of Kelowna, FortisBC acknowledges that this is a change from previous criteria but believes it to be necessary because of the possible impacts on Kelowna (FortisBC Argument pp. 14-15).

3.2.5 Commission Panel Determinations

Although the Commission has not been requested to approve the System Development Plan, the Commission Panel has several comments. First, the Commission Panel commends the effort FortisBC has put forward in constructing the System Development Plan. The Commission Panel believes that FortisBC's thorough review of the needs of the system and prioritization of the identified projects will greatly assist future capital expenditures investment decisions. Second, the Commission Panel encourages FortisBC to treat this plan as a living document, to continue to consult with stakeholders, and to keep the inputs to the plan current as the plan evolves. With respect to the rate impacts of the System Development Plan, the Commission Panel is concerned that sustaining a rate increase of approximately 5 percent per year over the next six years may be difficult. Thus, the Commission Panel suggests that for the next capital plan review, and subsequently thereafter, FortisBC should develop alternate scenarios that envision a perhaps less efficient plan but which would involve delaying capital expenditures. The Commission Panel is not suggesting that these scenarios would be preferred, but that their cost impacts need to be known in order to make choices between lower rate increases and higher long term costs. The Commission Panel also notes that customers have enjoyed relatively lower rates than other utilities for a considerable period during the 1980's and 1990's when capital investment levels were much lower.

With respect to the appropriate reliability levels for the City of Kelowna, the Commission Panel notes that the criteria of N-1 is a minimum standard set by the WECC for bulk transmission systems and adopted by most utilities. The Commission Panel acknowledges that there are situations (particularly in large urban centers) where the consequence of a lower probability occurrence of an N-1-1 or N-2 event requires the N-1 standards to be exceeded. Each case is a judgment call and must be evaluated on its own merits. However it is common practice to have N-2 contingency levels for certain load centers in large urban centers (e.g. Vancouver and Victoria). **The Commission Panel accepts that an N-1-1 contingency level for Kelowna is appropriate at this time.**

3.3 2005 Capital Plan

3.3.1 2005 Capital Plan Summary

FortisBC is seeking an order that the 2005 Capital Plan, as setout in Tab 9 of Exhibit B-1, satisfies the requirements of Section 45 (6.2) (a) and (b) of the UCA. The 2005 Capital Plan contains expenditures of $49.4 million (AFUDC and loadings included) for which project approval has been previously received from the Commission. These projects are the Kootenay 230 kV System Development Project, the South Okanagan Supply Reinforcement Project, the Kelowna Area Upgrade and the Upgrade and Life Extension projects involving Unit 5 and Unit 6 at the Upper Bonnington power plant. (Exhibit B-1, Tab 9, p. 4).

As part of the Capital Plan FortisBC proposed that the following four criteria be used to determine if a project should be subject to a CPCN application:

1. the total project cost is $20 million or greater; or
2. the project is likely to generate significant public concerns; or
3. FortisBC believes for any reason that a CPCN application should proceed; or
4. after presentation of a Capital Plan to FortisBC stakeholders, a credible majority of those stakeholders express a desire for a CPCN application.

FortisBC argued that these criteria were consistent with Commission Order No. G-96-04 and directives regarding the British Columbia Transmission Corporation ("BCTC") (Exhibit B-1, Tab 9, p. 6).

FortisBC notes that the Big White Supply Project will be the subject of a Certificate of Public Convenience and Necessity ("CPCN") Application in 2005.

The 2005 Capital plan for Transmission, Stations, Distribution and Telecommunications is based primarily on the System Development Plan, while the 2005 Capital Plan for Generation is based on the Upgrade and Life Extension program as well as other capital sustaining requirements (Exhibit B-1, Tab 9, p. 5).

3.3.2 New Projects

Generation

By a December 8, 2004 letter, FortisBC advised the Commission that in keeping with its proposed CPCN criteria it did not intend to file a CPCN for the Lower Bonnington Upgrade and Life Extension Project. However on May 19, 2005 FortisBC submitted a CPCN application for this project. This project was originally delayed pending the outcome of an agreement with BC Hydro to clarify the entitlement benefits for an upgraded turbine. The subsequent agreement improved the actual benefits of the upgrade.

Transmission and Stations

Although there are numerous small sustaining capital projects, the main projects driving new capital are the Big White Supply project at a total cost of $24.5 million with $3.0 million in 2005; the Ellison Distribution source at a total cost of $8.25 million with $0.25 million in 2005; the Black Mountain distribution source at a total cost of $7.25 million and $0.25 million in 2005; and the new East Osoyoos source at $5.75 million with $0.25 million in 2005; and the Kettle Valley distribution source at a total cost of $7.65 million with $0.15 million in 2005.

Distribution Projects

The Commission Panel notes that the largest expenditure is for new connects ($4.5 million) with the remainder made up of a larger project with respect to the Creston upgrade to the Lambert Terminal project as well as a large number of smaller projects.

Telecom, SCADA, and Protection and Control Projects

The largest project in this category is the Distribution Substation Automation project with total expenditures forecast at $6.2 million dollars with $0.60 million in 2005. The remainder consists of a number of modest sustaining projects totaling $1.4 million.

CPCN Requirements

As discussed above, FortisBC has proposed that a number of criteria be used to guide FortisBC when applying for CPCN's. No intervenors commented on the CPCN criteria.

3.3.3 Commission Panel Determinations

The Commission Panel confirms that the 2005 Capital Plan satisfies the requirements of Section 45(6.2)(a) and (b) of the UCA.

With regard to the CPCN Criteria, the Commission Panel is in general agreement with FortisBC's assessment of the appropriate criteria to guide the Company and the Commission when applying for CPCN's. However FortisBC has missed an important distinction with respect to the BCTC application. BCTC has acknowledged that the Commission has the authority to designate any projects it deems necessary for a CPCN application, regardless of the criteria. **In exercising this prerogative the Commission will be guided by the suggested criteria. However, in practice the Commission intends to review each year's capital filings and will determine with reasons which projects will require CPCNs.**

The Commission approves all capital projects listed in Tab 9 of Exhibit B-1, except for the following projects, for which the Commission Panel directs FortisBC to submit CPCN applications.

1. **Big White Supply:** As FortisBC suggests, this project is required because its total cost will exceed $20 million and because of public concerns with respect to routing and capital cost recovery.

2. **East Osoyoos Source:** This is required because of uncertainty with respect to the timing of this project and alternative solution. In addition, there seems to be some uncertainty regarding the supply from Bentley substation.
3. **Kettle Valley Distribution Source:** As with (2) above, there appears to be some uncertainty with regard to the best solution for the Boundary area. The Commission Panel is of the view that allowing public comment on the proposed solution would be of value.
4. **Distribution Substation Automation:** This is required because it is not clear to the Commission Panel what the possible risks and benefits are associated with the project, what precedent it may set for future projects, and if FortisBC is selecting the appropriate technology.

The Commission Panel invites FortisBC to withdraw its May 19, 2005 CPCN application for the Lower Bonnington Upgrade and Life Extension Project.

4.0 2005 RESOURCE PLAN

4.1 Background

The Commission's mandate to direct and evaluate the resource plans of energy utilities is intended to facilitate the cost-effective delivery of secure and reliable energy services. The Commission's Resource Planning Guidelines (the "Guidelines") outline a comprehensive process to assist utilities in the development of such plans. The Commission requires that any resource plans filed under Section 45(6.1) of the UCA be prepared in accordance with its Guidelines.

The Commission requires consideration of all known resources for meeting the demand for a utility's product, including those which focus on traditional and alternative supply sources, and those which focus on conservation of energy and DSM. Resource planning is intended to facilitate the selection of cost-effective resources that yield the best overall outcome of expected impacts and risks for ratepayers over the long run. The process aids in defining and assessing market-based costs and benefits, while also entailing the assessment of tradeoffs between other expected impacts that may vary across alternative resource portfolios. Such impacts may be associated with objectives such as reliability, security of supply, rate stability and risk mitigation, or specific social or environmental impacts. In sum, a resource planning process that assesses multiple objectives and the tradeoffs between alternative resource portfolios is key to the development of a cost-effective resource plan for meeting demand for a utility's service (Guidelines, pp. 1-2).

On December 21, 2004 FortisBC filed its Resource Plan as Volume 3 of its 2005 Revenue Requirements Application. FortisBC prepared and filed its Resource Plan in response to the Commission's directive to utilities to file such plans as contemplated by Section 45(6.1) of the UCA. FortisBC states that its Resource Plan is consistent with the Guidelines.

4.2 2005 Resource Plan Summary

FortisBC's 2005 Resource Plan is a study of its load and resource Requirements over the period 2005-2024. It summarizes its Resource Plan objectives as to reliably meet customer load requirements, in agreement with stakeholder expectations, with existing and new resources if needed, with minimum rate and environmental impacts and with the guidance of the B.C. Energy Plan.

FortisBC's long-term firm requirements and its current planning in this regard establish the initial frame of reference for its Resource Plan. FortisBC's hydroelectric generation plants are expected to supply approximately 214MW of firm capacity and 1,569GWh of energy in 2005, or roughly 30 percent and 50 percent of its capacity and energy requirements, respectively. FortisBC has long-term purchase agreements for additional firm resources with the Columbia Power Corporation/CBT Power Corporation ("CPC/CBT"), for 149MW of capacity and 984GWh of energy through 2056, and with BC Hydro under the PPA, for 200MW of capacity and associated energy through 2013. The total of its long-term firm resources currently supply about 98 percent of its energy needs and about 76 percent of its capacity requirements (Exhibit B-4, pp. 5, 19). FortisBC assessed its load and resource balance through 2024 with its existing and planned resources. Its planned resource additions include its Upgrade and Life-Extension program, Upper Bonnington Re-Powering, and purchase options from local existing and planned resources such as Cominco and the CPC/CBT Brilliant Expansion. The results of its study indicate that with existing owned resources and supply contracts, FortisBC will be able to meet almost all of its energy requirements until 2013 when the 200MW BC Hydro PPA potentially expires. FortisBC notes that there will continue to be a small capacity-related energy shortfall during peak winter periods, growing only slightly to 2013 given that the energy take under the BC Hydro PPA can increase as load grows.

FortisBC's current strategy for acquiring additional resources includes the purchase of capacity-related energy from the market with a combination of short-term advance purchases of capacity and/or energy blocks as well as purchases from the spot market. FortisBC states that it favours capacity purchases because they allow peaking energy to be supplied from BC Hydro under the PPA and because they do not involve any surpluses. FortisBC has regarded this as a more cost-effective strategy than securing long-term firm resources to meet peak demands because it minimizes over-purchases of energy, with the consequent risk that the sell-back of un-needed energy will be at a lower price. Further, FortisBC is constrained from exporting when taking energy from BC Hydro under the PPA. FortisBC acknowledges that while it views its current strategy as cost-effective, it faces the risk of fluctuating power purchase expenses given the exposure to market volatility, as well as reliability risk associated with the market's ability to supply its peaking needs (Exhibit B-4, pp. 19-20). FortisBC's resource planning allowed it to review this strategy in view of expected load growth over the planning horizon. It also allowed FortisBC to investigate the impact if the BC Hydro PPA is not be renewed after 2013, given the significant annual shortfalls in capacity and energy that would occur under this scenario.

FortisBC's Resource Plan presents a comprehensive set of Case Scenarios to assess various strategies to maintain its Load and Resource balance over the 2005-2024 planning horizon. FortisBC models one set of three cases under which it pursues its existing market strategy, while considering separate scenarios wherein the BC Hydro PPA continues until 2024 with no new firm resources added (Case A-1), the BC Hydro PPA ends in 2013 and no new firm resources are added (Case A-2), and the BC Hydro PPA ends in 2013 and is replaced with a new firm resource (Case A-3). FortisBC models a second set of three cases under which it pursues a new market strategy and assumes the BC Hydro PPA continues, while considering separate scenarios wherein no new firm resources are added (Case B-1), a 75MW Peaking Plant is added in 2008 (Case B-2), and a BC Clean Resource (Biomass Plant) is added in 2010 (Case B-3). And finally, FortisBC models a third set of three cases under which it pursues a new market strategy and assumes the PPA ends in 2013, while considering separate scenarios wherein the BC Hydro PPA is replaced with a new 250MW firm resource (Case C-1), a 75MW Peaking Plant is added in 2008 and the BC Hydro PPA is replaced with a new 250MW firm resource (Case C-2), and a BC Clean Resource (Biomass Plant) is added in 2010 and the BC Hydro PPA is replaced with a new 250MW firm resource (Case C-3).

There are a number of assumptions common to the analysis of each Case, including common discount rates (nominal 8, 10, and 12 percent values), common Load and DSM forecasts and, where relevant, common forecast market prices for electricity based on a forecast of Mid-C index values for the 2005-2024 period. FortisBC's Resource Plan considers Load and DSM forecasts consistent with the forecasts provided in support of its 2005 Revenue Requirements Application. While it assumes a constant DSM forecast over the time period of its Resource Plan, FortisBC addresses uncertainty in the factors underlying its load forecast, such as economic and population growth rates, by incorporating a High and Low load forecast. The High forecast assumes a 25 percent increase in the annual load growth rate, while the Low forecast incorporates a 20 percent reduction in the annual load growth rate (Exhibit B-4, pp. 22-30, 59).

In contrast to the existing market strategy modeled in the A-Cases, under which the shortfall between firm resources and requirements is met with short-term monthly or one-year ahead purchases (aside from roughly 75MW of purchases in the spot market), the new market strategy pursued under the B Cases is characterized by meeting the shortfall with medium-term three to five year energy block purchases (again, with roughly 75 MW of spot market purchases). FortisBC modeled the new market strategy as a test of the protection it affords against market volatility risk and reliability risk under the expectation, in part, that this strategy is less susceptible to price shock risk. Medium-term block purchases are considered an effective hedge against price shock because if prices rise the sell-back price of surpluses rises accordingly, offsetting increased costs.

In sum, the modeling of each Case allows FortisBC to assess the incremental cost and rate impacts associated with moving to a new market strategy, losing the BC Hydro PPA, building a peaking plant resource, or building a BC Clean energy resource. FortisBC assessed the sensitivity of its modeling results to changes in discount rates, variations in market prices and the degree of exposure to market price volatility, as well as changes to the assumptions regarding the relative amounts of energy purchased in the spot market in the relevant Cases.

FortisBC concludes, in part, that:

- The existing market strategy under the expected load forecast is the lowest-cost portfolio under the scenario that the BC Hydro PPA continues until 2024 (Case A-1);
- The existing market strategy would continue to be the lowest-cost portfolio if it is not possible to renew the PPA (Case A-2), but the exposure to the market under this scenario would likely be unacceptable, notwithstanding the uncertainty about the viability of the market at that time, and would require the addition of a new long-term firm resource;
- If the PPA is replaced by a new long-term firm resource, the impact on power purchase costs are expected to be significant, an estimated five percent levelized rate impact;
- The new market strategy, while more costly, could be justified with an extreme rise in market prices of approximately six times, but only marginally justified with a moderate rise of about three times, considering also the possibility of price decreases and the benefits of improved reliability;
- A more detailed study of the new market strategy would be required in order to more fully assess the trade-off between increased cost and offsetting risk, and to optimize the new strategy in this regard;
- Adding a BC Clean resource would entail significant cost increases and may not be desired, while other options, such as purchasing “green tags”, could be economic and will be investigated;
- The peaking plant resource, as an alternative to short-term market purchases, is not recommended due to its increased cost; and
- These conclusions are supported under reasonable variations in load forecast, discount rates and market prices.

All told, on the basis of its Resource Plan FortisBC concludes that additional long-term firm resources are not needed until when and if the BC Hydro PPA expires, potentially in 2013. Further, FortisBC states that it should consider reducing its exposure to short-term market purchases (FortisBC Argument, p. 53).

FortisBC proposes the following Action Plan based on its conclusions (Ex. B-4, p. 74; FortisBC Argument, p. 53-54):

1. The Company will begin discussions with BC Hydro, with a view to gaining certainty regarding the status of the PPA beyond 2013.

2. The Company will conduct a more detailed study of a much shorter time frame than was assessed in this Resource Plan study, approximately five years, to optimize a new market strategy that provides more protection from market volatility and improved reliability. FortisBC comments that modeling the market is a complex undertaking and involves a variety of possible strategies and products that could be purchased. It contemplates that it may be possible that some combination of medium term purchases from Cominco and peaking purchase from others can provide a similar level of protection from market volatility and improved reliability at lower cost than the energy block purchases that were simulated in this Resource Plan.

3. The Company will update and file its DSM Potential Study and complete a new DSM plan covering the period 2005-2014, investigating whether a more aggressive program is more cost-effective.

4. The Company proposes to update its Resource Plan on a bi-annual basis. FortisBC states that it is essential that with the dependence on the market to meet some of its requirements, the Company needs to detect shifts in load growth and market trends as soon as possible in order to make the necessary adjustments to its resource plan.

5. The Company will investigate options other than addition of a new long-term firm clean resource for complying with the B.C. Energy Plan.

4.3 Submissions

FortisBC refers in argument to the following two issues raised in respect to its Resource Plan (FortisBC Argument, p. 54):

- Finalizing the PPA with BC Hydro for long term firm resources; and
- The proposed strategy to reduce exposure to market prices.

FortisBC is of the view that while there is risk associated with finalizing an agreement with BC Hydro, successful negotiations can be concluded prior to 2013 when the PPA is due to expire, FortisBC is optimistic that it won't be a protracted negotiation given its prior experiences of working with BC Hydro (FortisBC Argument, p. 55).

FortisBC refers to its extensive analysis of the new market strategy to conclude that there is a reasonable likelihood of financial benefits to the customer by moving to a strategy that lessens exposure to the spot market. Because it recognizes that such a strategy is very sensitive to market factors, FortisBC proposes to conduct a more detailed study over a shorter time frame than was necessitated in its Resource Plan in order to optimize a strategy that provides more protection from market volatility and improved reliability (FortisBC Argument, pp. 55-56).

FortisBC submits that its Resource Plan is reasonable and prudent, meets the requirements of Section 45(6.2)(b) of the UCA, and is in the public interest (FortisBC Argument, p. 56; FortisBC Reply Argument, p. 28).

4.4 Commission Panel Determinations

The Commission Panel has reviewed the FortisBC Resource Plan, and all of the associated evidence adduced over the course of the hearing. **The Commission Panel accepts the Resource Plan, and component Action Plan,**

determining that it is reasonable and prudent, and that it meets the requirements of Section 45(6.2)(b) of the UCA and is in the public interest.

The Commission Panel has some concerns about the methodological framework that underpins the Resource Plan to the degree that the approach to explicitly account for uncertainty is not especially sophisticated. In one example, the Commission Panel determined that the conclusions of the Resource Plan are not robust to the impact on the new market strategy from changes to the sell back price of surplus energy. The Commission Panel appreciates that FortisBC recognizes that its Resource Plan could be improved in general with greater attention to sensitivity analysis, and in particular with a detailed study of a new market strategy over a shorter time horizon. The Commission Panel encourages FortisBC, both in the next iteration of its resource planning study and in the forthcoming study of a new market strategy, to provide a more comprehensive treatment of the uncertainty in its planning parameters. Besides expanding upon its sensitivity analyses, FortisBC could explore the potential of a simulation analysis, with the use of distributions around key input variables where possible, as a means to improve its accounting of uncertainty in its resource planning study.

With reference to FortisBC's proposed Action Plan, the Commission Panel supports the initiative to begin discussions with BC Hydro, with a view to gaining certainty regarding the status of the PPA beyond 2013. The Commission Panel recognizes that the results of the Resource Plan indicate that a sufficient window of time exists over which FortisBC can gain certainty on the status of the PPA before needing to consider other resource options. The Commission Panel requests that FortisBC file a status update on the progress of negotiations with BC Hydro at the same time as it files its next revenue requirements application, or sooner as applicable. The Commission Panel also requests that FortisBC file at that time a status update on the progress of its detailed study of a new market strategy, including preliminary results as relevant. As noted earlier in this Decision, the Commission Panel directs FortisBC to file its DSM potential study by June 30, 2005 and its 2005-2014 DSM Business Plan by October 31, 2005, the timelines proposed by FortisBC.

FortisBC proposes to update its Resource Plan on a bi-annual basis. In light of the results of the 2005 Resource Plan, the Commission Panel accepts this timeline for the next iteration of the Resource Plan, anticipating then that FortisBC will file an updated plan at the same time it files a 2007 Revenue Requirements application. However, the Commission Panel does not approve FortisBC's proposed timeline as a matter of policy in this instance. The Commission Panel will determine the timeline for any resource planning updates on a prospective basis with its review of future Resource Plans.

DATED at the City of Vancouver, in the Province of British Columbia, this 31st day of May 2005.

Original signed by:

L.F. Kelsey
Panel Chair and Commissioner

Original signed by:

P.G. Bradley
Commissioner

APPEARANCES

P. MILLER	Commission Counsel
G.K. MACINTOSH, Q.C. K. CAIRNS D. O'LEARY	FortisBC Inc.
C. WEAFER	Interior Municipal Electrical Utilities
R. GATHERCOLE P. MACDONALD	The BC Old Age Pensioners Organization Council of Senior Citizens Organizations of BC Federated Anti-Poverty Groups of BC Senior Citizen's Association of Canada End Legislated Poverty
D. SCARLETT	Kootenay-Okanagan Electric Consumers' Association
R. TARNOFF	Natural Resources Industries
A. WAIT	Himself

R. GORTER W. KRAMPL R.W. RERIE D. CHONG	Commission Staff
R. STUBBINGS	Commission Consultant
ALLWEST REPORTING LTD.	Court Reporters

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

and

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

EXHIBIT LIST

Exhibit No.	Description
COMMISSION DOCUMENTS	
A-1	Letter dated December 14, 2004 and Order No. G-111-04 approving an interim rate increase effective January 1, 2005 and establishing the Regulatory Timetable for the review process
A-2	Letter dated December 18, 2005 providing information for the FortisBC Workshops and Pre-hearing Conference proceedings
A-3	Letter dated December 20, 2005 advising Participants that issues to be included on the Issues List will be discussed at the Pre-hearing Conference
A-4	Letter dated January 24, 2005 releasing Order No. G-14-05, the Issues List and the Amended Regulatory Timetable
A-5	Letter dated January 19, 2005 responding to Mr. Karow's January 9, 2005 submission (Exhibit C2-4)
A-6	Letter No. L-9-05 dated January 28, 2005 denying FortisBC's request for a Negotiated Settlement Process
A-7	Letter and Commission Information Request No. 1 dated January 28, 2005
A-8	Letter dated February 2, 2005 regarding Helmut Wartenberg's Information Request (Exhibit No. C8-3) to the Commission
A-9	Letter dated February 2, 2005 declining Mr. Karow's January 24, 2005 request to postpone the regulatory timetable and to post the Curriculum Vitae of Commission Board members and staff on the web (Exhibit No. C2-5)
A-10	Letter dated February 17, 2005 responding to Mr. Scarlett's letter of January 26, 2005 commenting on FortisBC's eligibility for the 2004 Incentive Payment
A-11	Letter and Order No. G-20-05 dated February 22, 2005 regarding the 2004 Incentive Adjustments

Exhibit No.	Description
A-12	Letter dated February 24, 2005 regarding the Oral Public Hearing location and start time
A-13	Letter and Commission Information Request No. 1 to the BC Old Age Pensioners Organization *et* al dated March 3, 2005
A-14	Letter to Registered Intervenors dated March 11, 2005 regarding whether they are supportive of the FortisBC Demand Side Management Technical Committee and the Load Forecast Technical Committee recommendations (Exhibit B-17 and B-18) with request to respond by March 16, 2005
A-15	Public Hearing Procedural Letter dated March 16, 2005
A-16	Letter dated March 17, 2005 accepting the recommendations of the Demand Side Management and Load Forecast Committees that there is no need to call hearing panels in the respective subject areas
A-17	Letter dated March 17, 2005 responding to Mr. Karow's e-mail of March 17, 2005 regarding Information Request's
A-18	Chart from FortisBC 2005 Revenue Requirements – Operations and Maintenance Costs (before Overheads capitalized)

APPLICANT DOCUMENTS

B-1	**FORTISBC INC.** 2005 Revenue Requirements Application dated November 26, 2004
B-2	FortisBC 2005-2024 System Development Plan submitted November 26, 2004
B-3	Notice of Counsel retainment dated December 16, 2004 from Dean O'Leary Farris, Vaughn, Wills & Murphy
B-4	Letter dated December 21, 2004 filing the 2005 Resource Plan (including Appendix D)
B-5	January 20, 2005 Workshop Presentation - 2005 Resource Plan
B-6	January 18 and 20, 2005 Workshop Presentation – System Development Plan (SDP) 2005-2024
B-7	January 21, 2005 Workshop Presentation – 2005 Revenue Requirements

Exhibit No.	Description
B-8	Letter dated January 27, 2005 requesting a revision to the Timetable and process for disposing of the Application
B-9	Letter dated January 31, 2005 replying to comments regarding the 2004 Incentive Program
B-10	Letter dated February 8, 2005 regarding Technical Committees
B-11	2004 Annual Review Powerpoint presentation dated January 20, 2005
B-12	Response dated February 18, 2005 to Commission Information Request No. 1 - (Note: Question 104 response includes attachment with original confidential report from PowerNex *Associates* Inc. for which FortisBC Inc. has provided authorization to now release as non-confidential)
B-12A	Excel spreadsheet files from Exhibit B-12 (CD)
B-13	Response dated February 18, 2005 to The BC Old Age Pensioners Organization *et al.* Information Request No. 1
B-14	Responses dated February 18, 2005 to Information Request No. 1 from the following: IMEU Han Karow Kootenay-Okanagan Electric Consumers Association Natural Resource Industries Alan Wait Helmut Wartenberg
B-15	Letter dated February 24, 2005 requesting that FortisBC Inc. be exempted from the requirement of filing the March 1, 2005 report on transition activities
B-16	Letter and Information Request No. 1 dated March 4, 2005 to the BC Old Age Pensioners Organization
B-17	Letter dated March 9, 2005 and Report of the Demand Side Management Technical Committee
B-18	Letter dated March 9, 2005 and Report of the Load Forecast Technical Committee
B-19	Letter dated March 10, 2005 and revisions to 2005 Revenue Requirements Application
B-20	Letter dated March 11, 2005 and Report of the Capital Additions Technical Committee

Exhibit No.	Description
B-21	Letter dated March 11, 2005 and Report of the Power Purchase Technical Committee
B-22	Letter and Witness Panels dated March 16, 2005
B-23	Letter dated March 15, 2005 and the FortisBC Semi-Annual Demand Side Management Report in response to Commission Information Request 111
B-24	Letter dated March 18, 2005 filing Errata to FortisBC's Information Responses filed February 18, 2005 (Exhibit B-14)
B-24A	Final Errata Page – Response to Karow Information Request No. 1
B-25	Letter dated March 18, 2005 filing a Revised 2005 Revenue Requirements Application ("Second Revised Application")
B-26	Letter dated March 22, 2005 filing a Revised 2005 Revenue Requirements Application ("Third Revised Application")
B-27	Undertaking: Panel 2 – Transcript Page 134, lines 22-26
B-28	Undertaking: Panel 2 – Transcript Page 152, lines 20-26
B-29	Undertaking: Panel 2 – Transcript Page 168, lines 6-8
B-30	Undertaking: Panel 2 – Transcript Page 182, lines 12-15
B-31	Undertaking: Panel 2 – Transcript Page 183, lines 4-5
B-32	Undertaking: Panel 2 – Transcript Page 187, lines 9-21
B-33	Undertaking: Panel 3 – Transcript Page 205, line 5 to Page 206, line 24
B-34	Undertaking: Panel 3 – Transcript Page 208, lines 1-22
B-35	Undertaking: Panel 3 –Transcript Page 218, lines 8-26 and Page 219, lines 1-25

Exhibit No.	Description
B-36	Undertaking: Panel 3 – Transcript Page 219, lines 16 and 17
B-37	Corrected version of Exhibit C5-9
B-38	Undertaking: Panel 3 – Transcript Page 306, lines 25-26, and Page 307, lines 1-3
B-39	Undertaking: Panel 3 – Transcript Page 309, lines 13-15
B-40	Undertaking: Panel 3 – Transcript Page 312, lines 13-16
B-41	Undertaking: Panel 3 – Transcript Page 313, lines 12-14 and lines 17-18
B-42	Undertaking: Panel 3 – Transcript Page 318, lines 1-3
B-43	Undertaking: Panel 3 – Transcript Page 322, lines 22-25
B-44	Undertaking: Panel 3 – Transcript Page 325, lines 25-26
B-45	Undertaking: Panel 3 – Transcript Page 327, lines 3-4
B-46	Undertaking: Panel 3 – Transcript Page 374, lines 15-22
B-47	Undertaking: Panel 3 – Transcript Page 376, lines 13-26, and Page 377, lines 1-5
B-48	Undertaking: Panel – Transcript Page 385, lines 24-26, and Page 386, lines 1-2
B-49	Undertaking: Panel 3 – Transcript Page 393, lines 10-14
B-50	Undertaking: Panel 4 – Transcript Page 437, lines 24-26
B-51	Undertaking: Panel 4 – Transcript Page 445, lines 1-7

Exhibit No.	Description
B-52	Undertaking: Panel 4 – Transcript Page 493, line 26, and Page 494, lines 1-3
B-53	Undertaking: Panel 6 – Transcript Page 512, lines 23-26, and Page 513, lines 1-8
B-54	FortisBC Management Discussion and Analysis dated February 3, 2005 regarding Three Months and Twelve Months Ended December 31, 2004 compared to Three Months and Twelve Months Ended December 31, 2003
B-55	Booth Evidence – Recalculation of Interest Coverage Ratios (Summary)
B-56	Evidence, dated June 1996, of Laurence D. Booth and Michael K. Berkowitz on Capital Structure and Fair Return before the Alberta Energy and Utilities Board in the Alberta Electric Utilities 1996 Tariff Applications
B-57	Excerpt, dated April 13, 1994, from Volume 7, Page 1183 of the BC Gas Utility Ltd., West Kootenay Power Ltd., and Pacific Northern Gas hearing process on the Rates of Return on Common Equity
B-58	Excerpt from FortisAlberta & FortisBC – British Columbia – Your Bill (Bill Insert)
B-59	Undertaking: Panel 4 – Transcript Page 493, line 26, and Page 494, lines 1-3, and Page 495, lines 8-10
B-60	Undertaking: Panel 5 – Transcript Page 668, lines 20-23
B-61	Undertaking: Panel 5 – Transcript Page 673, lines 14-15
B-62	Undertaking 29: Panel 6 - Transcript Page 819, lines 16-20
B-63	Undertaking 30: Panel 6 - Transcript Page 820, lines 14-18
B-64	Undertaking 31: Panel 6 - Transcript Page 821, lines 25-26, and Page 822, line 1
B-65	Undertaking 32: Panel 6 - Transcript Page 826, lines 17-26, and Page 827, lines 1-21
B-66	Undertaking 33: Panel 6 - Transcript Page 828, lines 20-26, and Page 829, lines 1-8

Exhibit No.	Description
B-67	Undertaking 34: Panel 6 - Transcript Page 829, lines 14-26, and Page 830 lines 1-19
B-68	Undertaking 35: Panel 6 - Transcript Page 831, lines 1-26, and Page 832 lines 1-4
B-69	Undertaking 36: Panel 6 - Transcript Page 833, lines 12-14
B-70	Undertaking 37: Panel 6 - Transcript Page 833, lines 23-26, and Page 834, lines 1-3
B-71	Undertaking 38: Panel 6 - Transcript Page 834, lines 10-12
B-72	Undertaking 39: Panel 6 - Transcript Page 835, lines 10-13
B-73	Undertaking 40: Panel 6 - Transcript Page 847, lines 12-14
B-74	Undertaking 41: Panel 6 - Transcript Page 850, lines 6-10
B-75	Undertaking 42: Panel 6 - Transcript Page 851, lines 26, and Page 852, line 3
B-75A	Letter dated April 13, 2005 regarding correction to Undertaking (Exhibit B-75)
B-76	Undertaking 43: Panel 6 - Transcript Page 854, lines 25-26, Page 855, 1-15
B-77	Undertaking 44: Panel 6 - Transcript Page 860, lines 8-21
B-78	Undertaking 45: Panel 6 - Transcript Page 861, lines 12-13
B-79	Undertaking 46: Panel 6 - Transcript Page 874, lines 3-7
B-80	Undertaking 47: Panel 6 - Transcript Page 878, lines 20-26 and Page 879, lines 3-4
B-81	Undertaking 48: Panel 6 - Transcript Page 883, lines 14-26 from March 24, 2005

Exhibit No.	Description
INTERVENOR DOCUMENTS	
C1-1	**KOOTENAY-OKANAGAN ELECTRIC CONSUMERS ASSOCIATION** – Notice of Intervention dated November 30, 2004 from Donald Scarlett
C1-2	Letter dated January 26, 2005 commenting on FortisBC's eligibility for the 2004 Incentive Payment
C1-3	Information Request No. 1 dated February 2, 2005 to FortisBC Inc.
C1-4	Table – Actual and Allowed ROE
C2-1	**KAROW, HANS** – Notice of Intervention dated December 2, 2004
C2-2	Letter dated December 27, 2004 regarding Mr. Karow's interim submission
C2-3	Letter dated January 3, 2005 filing Mr. Karow's follow-up submission
C2-4	E-mail dated January 9, 2005 – Follow-up submission with respect to his January 3, 2005 and December 27, 2004 filings
C2-5	Email dated January 24, 2005 enclosing a further follow-up to the January 3, 2005 and December 27, 2004 submission and information request
C2-6	Information Request dated February 2, 2005 to FortisBC Inc.
C2-7	E-mail dated March 17, 2005 regarding general information request
C3-1	**WAIT, ALAN** – Notice of Intervention dated December 7, 2004
C3-2	Letter dated January 27, 2005 commenting on FortisBC's eligibility for the 2004 Incentive Payment
C3-3	Information Request No. 1 dated February 2, 2005 to FortisBC Inc.
C3-4	Excerpt from Waneta HydroElectric Expansion Project Report
C3-5	2004 Revenue Requirements - Appendix A to Order No. G-38-04 – Page 11 of 27 dated March 3, 2004

Exhibit No.	**Description**
C4-1	**NATURAL RESOURCE INDUSTRIES** – Notice of Intervention dated December 7, 2004 from Richard Tarnoff
C4-2	E-mailed dated January 28, 2005 regarding whether FortisBC Inc. should receive an incentive for 2004
C4-3	Information Request No. 1 dated February 2, 2005 to FortisBC Inc.
C4-4	Letter dated February 3, 2005 advising that Richard Tarnoff will also be representing Hedley Improvement District
C5-1	**THE BC OLD AGE PENSIONERS ORGANIZATION *ET AL*.** – Notice of Intervention dated December 16, 2004 from Richard Gathercole
C5-2	Letter dated January 24, 2005 confirming availability of BCOAPO's witness, Mr. Lawrence Booth
C5-3	Letter dated January 27, 2005 commenting on FortisBC's eligibility for the 2004 Incentive Payment
C5-4	Information Request No. 1 dated February 2, 2005 to FortisBC Inc.
C5-5	Evidence of Laurence Booth filed February 25, 2005
C5-6	Letters and responses dated March 11, 2005 to Commission Information Request No. 1 and FortisBC Inc. Information Request No. 1
C5-6A	Detailed information regarding Information Request responses to Exhibit C5-6 (CD)
C5-7	Letter dated March 14, 2005 responding to Commission letter of March 11, 2005 regarding support of FortisBC Inc.'s Technical Committees recommendations (Exhibit A-14)
C5-8	Witness aid, headed "Background", with chart
C5-9	Table – Percentage deviation of actuals from forecast loads for each group and the average over the period 1995-2003
C6-1	**COLUMBIA POWER CORPORATION** – Notice of Intervention dated December 23, 2004

Exhibit No.	Description
C7-1	**SLACK, BURYL** – Notice of Intervention dated December 30, 2004
C8-1	**WARTENBERG, HELMUT** – Notice of Intervention dated January 4, 2005
C8-2	Letter dated January 18, 2005 citing concerns and summary requests
C8-3	Information Request No. 1 dated January 27, 2005 to the British Columbia Utilities Commission
C8-4	Information Request No. 1 dated February 1, 2005 to FortisBC
C9-1	**TERASEN GAS INC.** – Notice of Intervention dated January 5, 2005 from Scott Thomson
C10-1	**INTERIOR MUNICIPAL ELECTRICAL UTILITIES (IMEU)** – Notice of Intervention dated January 5, 2005 from R.E. Carle
C10-2	Letter dated January 12, 2005 from Christopher P Weafer, Owen·Bird advising that he has been retained as counsel for the IMEU
C10-3	Letter dated January 27, 2005 commenting on FortisBC's eligibility for the 2004 Incentive Payment
C10-4	Information Request No. 1 dated February 2, 2005 to FortisBC Inc.
C10-5	E-mail dated March 17, 2005 in response to H. Karow e-mail of March 17, 2005 (Exhibit C2-7)
C11-1	**POWERHOUSE DEVELOPMENTS INC.** – Notice of Intervention dated January 5, 2005 from W.P. Harland
C12-1	**GLACIER POWER BC LTD.** - Notice of Intervention dated February 7, 2005 from Neil Murphy

Exhibit No.	**Description**
INTERESTED PARTY DOCUMENTS	
D-1	Renninger, Bud – Web registration received January 6, 2005
D-2	Web registration dated February 7, 2005 from Neil Murphy, Glacier Power BC Ltd. requesting Interested Party status – **WITHDRAWN** – Changed to Intervenor Status
LETTERS OF COMMENT	
E-1	Letter of Comment dated December 14, 2004 from Robb Mayes
E-2	Letter of Comment dated December 14, 2004 from David Egli
E-3	Letter of Comment received December 15, 2004 from Elkink Ranch Ltd.
E-4	Letter of Comment dated December 15, 2004 from Ron Planiden
E-5	Letter of Comment dated December 31, 2004 from Ken Hoffman and Lori Robertson
E-6	Letter of Comment dated December 31, 2004 from Derrick M. May, P.Eng.
E-7	Letter of Comment dated January 3, 2004 from R.C. Cassan
E-8	Letter of Comment dated December 25, 2004 from James Johnston
E-9	Letter to the Editor, Castlegar News dated January 6, 2005 from Marilyn Idle
E-10	Letter of Comment received January 7, 2005 from Tom Stanley
E-11	Letter to the Editor dated January 4, 2005 from Ed Chenail
E-12	Letter of Comment dated January 13, 2005 from Van Quaia
E-13	Letter of Comment dated January 19, 2005 from John Slater, Mayor, Town of Osoyoos
E-14	E-mail from Robert Hobbs, Chair, BCUC providing clarification on two points contained in Ms. Idle's Letter to the Editor of the Castlegar News (Exhibit E-9)
E-15	Letter of Comment dated February 3, 2005 from David Pehota

Exhibit No.	Description
E-16	Letter of Comment dated February 9, 2005 from Elizabeth Strong
E-17	Letter of Comment dated February 21, 2005 from Helen Kennedy
E-18	Letter of Comment dated February 24, 2005 from Donna Krane